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July 1, 2019

VIA U. S. AND ELECTRONIC MAIL

Mr. Steven M. Kahl, Executive Secretary
North Dakota Public Service Commission
State Capitol Building, Dept. 0408
600 East Boulevard
Bismarck, ND 58505-0480

RE: XCEL ENERGY 2020-2034 UPPER MIDWEST RESOURCE PLAN
CASE NO. PU-19-___

Dear Mr. Kahl:

Pursuant to the provisions of the Settlement approved by the Commission in Case No. PU-07-776, Northern States Power Company, doing business as Xcel Energy, submits eight (8) copies of its 2020-2034 Upper Midwest Resource Plan (Plan) filed with the Minnesota Public Utilities Commission.

We look forward to continued conversations with Commission Staff regarding this Resource Plan and the opportunity to build upon previous discussions to implement a separate, formalized Resource Plan process in North Dakota for the next planning cycle. We also offer to present this 2020-2034 Resource Plan to the Commission at a future Periodic Information Exchange meeting, Informal Hearing, or another venue of the Commission's choice.

Overview

The development of the Company's 2020-2034 Resource Plan is the product of a stakeholder process in Minnesota involving public workshops, an independent expert analysis, and information sharing. The Plan was also designed to support the Company's goal of reducing carbon emissions (in 2005) 80 percent by 2030, and continue progress toward its ultimate vision of 100 percent carbon-free energy by 2050.

At the same time, this Plan ensures the same level of reliability our customers have enjoyed for decades. This is accomplished primarily through the proposed extension of the Company's Monticello nuclear plant by an additional 10 years and the continued operation of the Prairie Island nuclear units through their current license. In addition, Xcel Energy proposes to purchase the 765 MW Mankato Energy Center combined cycle facility, and construct a new natural gas combined cycle plant at our Sherco site in 2026. These large, dispatchable resources will be critical as we retire 2,400 MW of coal-fired baseload in the next decade and transition to a system that is more than 50 percent intermittent renewables. Finally, we also propose several peaking resources but defer these additions until the latter part of the Plan period with the view that resources such as batteries will continue to improve and decline in cost.

The key components of the 2019 IRP include:

- Extend the Monticello nuclear plant license from 2030 to 2040, and operate both Prairie Island units through the end of their current licenses (PI Unit 1 to 2033 and PI Unit 2 to 2034),
- Retire our last two coal units early: the King plant in 2028 (nine years early) and Sherco 3 in 2030 (ten years early);
- Continue our plan to retire Sherco 1 and 2 in 2026 and 2023, respectively, and commit to offering Sherco 2 into MISO on a seasonal basis until its retirement,
- Acquire and operate the 765 MW Mankato Energy Center (MEC) and build, own and operate a 750 MW Sherco Combined Cycle (Sherco CC) to satisfy capacity and operational need created by coal closures,
- Acquire 4,000 MW of utility-scale solar generation between 2025 and 2034,
- Add 1,202 MW of cumulative wind by 2034 as part of a "no going back" strategy, replacing wind scheduled to retire during that period.
- Starting in 2031, add 1,728 MW of cumulative firm dispatchable resources by 2034,
- Include energy efficiency programs representing an average of approximately 780 GWh of savings in Minnesota annually for each year through 2034, in addition to 400 MW of Demand Response by 2023.

With this proposed Plan, Xcel Energy believes it can keep annual cost growth at or below the rate of inflation. This is accomplished by deferring resource additions until later in the plan, making use of existing assets on our system, and through aggressive Demand Side Management activities, mainly in Minnesota. Additionally, the Company foresees that technological improvements will continue to drive the costs of renewables down - a key consideration in the Plan's inclusion of significant solar additions in the latter half of the next decade.

"North Dakota Plan" Assumptions Scenario (Exclusion of Externalities)

As discussed in the Planning Landscape chapter of this 2020-2034 Resource Plan, Xcel Energy plans and operates a single Upper Midwest system (the NSP System) that serves customers in five states. Consistent with the terms of the Settlement in Case No. PU-07-776, since 2008 we have filed our Upper Midwest Resource Plans with the North Dakota Commission, and included in each of them an analysis of a Resource Plan scenario compliant with Federal and North Dakota laws only.

As with the previous 2016-2030 Resource Plan, the current Plan refers to this scenario as simply the "North Dakota Plan". It differs from the Preferred Plan in three ways:

1. All assigned CO_2 costs have been removed;
2. Exclusion of MN Community Solar Garden program costs; and
3. Exclusion of incremental Demand Response program cost.

While there are no renewable energy objectives or policy mandates currently impacting the expansion resources, the Company's long-term objective relative to power generation is to achieve an 80 percent reduction in its 2005 carbon emissions by 2030, and to achieve carbon-free generation by 2050. For the North Dakota Plan scenario, we maintain this goal and propose the same resource additions to our system as reflected in our Preferred Plan.

You will note that in the modeling for the North Dakota Plan, solar additions for 2027-2029 in the Preferred Plan are delayed to 2029 - 2030. The exclusion of the Community Solar Gardens (CSG) do not impact the resources additions for the North Dakota Plan. Instead, the costs of CSG are allocated so that North Dakota customers pay a market rate for the energy from the CSG resources. The allocation of the costs to North Dakota will also reflect previous cost-recovery decisions that exclude costs related to the disputed resources identified in the rate case Settlement of Case No. PU-12-813 and subsequent cases. As discussed previously, our preferred plan also includes a large incremental addition of demand response in recognition of the Minnesota Commission's Order requiring 400 MW of additional DR by 2023. The Present Value of Revenue Requirements (PVRR) over the 2020 – 2034 period for the North Dakota Plan is $37,598,000 while that of the Preferred Plan is $37,851,000.

While modeling a "North Dakota Plan" scenario may provide some additional insight for this Commission, the Company is committed to exploring how we can improve the resource planning process in North Dakota. We proposed in December 2018 a framework outlining some of the essential pieces of a more formal, focused North Dakota resource plan process, including a presumption that the default approach to NSP System planning would continue to be initiated from an integrated system view. Xcel Energy presented the proposal further at an Informal Hearing with the Commission in March of this year. At that time, the Commission indicated interest in exploring a formalized North Dakota process, so the Company looks forward to engaging further to develop such a framework for the next resource planning cycle.

North Dakota Combustion Turbine

Pursuant to the Settlement in Case No. PU-12-813, the Company agreed to take steps to locate a system natural gas combustion turbine (CT) in the state of North Dakota, to be operational by December 31, 2025. Specifically, Xcel Energy agreed to:

"…develop, own, and operate (or alternatively, cause to be developed and operated on its behalf through a power purchase agreement or other contractual arrangement) a combustion turbine with a capacity of at least 200 MW in eastern North Dakota, no later than December 31, 2025. The costs of the generating facility will be allocated to all state jurisdictions served by the Company in a manner consistent with other NSP System resources. Attainment of this commitment is contingent on the Company's receipt of all necessary and appropriate permits and regulatory approvals. Further, except as modified by this Section II, all provisions of the 2036 Commitment remain in place, including without limitation, the requirements that the combustion turbine agreed to in this paragraph reasonably 1) addresses a system capacity need and 2) represents a least-cost resource when also considering the local reliability and system benefits of developing thermal generation in North Dakota."

The 5 year Action Plan within this 2020-2034 Resource Plan runs from 2020 through 2024. Thus, the Commission will not find specific mention of a North Dakota natural gas CT addition in the current short term Action Plan; rather, proposed resource additions in 2025 will be within the Action Plan developed in the next Resource Planning cycle and addressed directly in that filing.

While the longer term plan for resource additions does not reflect a firm peaking plant need until 2031, Xcel Energy acknowledges the Negotiated Agreement commitment and will continue to assess 1) NSP System capacity needs over the next couple of years, 2) the likelihood of gaining the necessary approvals in all NSP System states, and 3) the operational feasibility and cost-effectiveness of a peaking plant located in eastern North Dakota. Given the long planning horizons in these Resource Plans, many

things can change in the next 5 to 10 years in terms of energy policy, technology, and economic conditions. The Company remains committed to locating more generation in the state, and a more timely and beneficial option may become evident over time.

Summary

This plan demonstrates that we can achieve our 2030 environmental goal with existing technologies and resources while maintaining both reliability and affordability. And it advances a framework that achieves our objectives in manageable steps as opposed to transitioning the entire system and grid all at once. By doing so, we can continue to ensure the reliability of our system and maintain flexibility to respond to future market trends, technology advancements, and changing regulatory policies.

Please contact me at (701) 241-8632 or via email at dave.sederquist@xcelenergy.com. Alternatively, you may wish to contact PJ Martin at (612) 321-3065 or Philip.J.Martin@xcelenergy.com if you have any questions regarding this filing.

Sincerely,

David H. Sederquist
Sr. Regulatory/Financial Consultant
Xcel Energy

cc: Pat Fahn
Jack Schuh

414 Nicollet Mall
Minneapolis, MN 55401

PUBLIC DOCUMENT
NOT PUBLIC DATA EXCISED

July 1, 2019

—Via Electronic Filing—

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: 2020-2034 UPPER MIDWEST INTEGRATED RESOURCE PLAN
DOCKET NO. E002/RP-19-368

Dear Mr. Wolf:

Northern States Power Company, doing business as Xcel Energy, is pleased to submit our 2020-2034 Upper Midwest Integrated Resource Plan to the Minnesota Public Utilities Commission. This plan identifies the resources we will need to serve our customers over the next 15 years.

This Resource Plan charts the path toward achieving some of the most ambitious decarbonization goals of any utility in the U.S. Specifically, we aim to reduce carbon emissions from 2005 levels by 80 percent by 2030, and provide 100 percent carbon-free energy by 2050. This Resource Plan sets out our plan to reach the 2030 goal through retirement of our coal fleet, extension of nuclear, aggressive renewable additions and demand-side management including both energy efficiency and demand response, and a mix of load-supporting, firm dispatchable resources. Not only does this Resource Plan achieve these goals, it does so reliably and affordably.

We look forward to discussing this Resource Plan with the Commission, stakeholders, and the community.

Request for Protection of Trade Secret Information

The Company recognizes and supports the need for transparency in review of our Resource Plan. We also take seriously our responsibility to maintain the security of

the information and systems involved in the delivery of safe, reliable energy to our customers.

Appendix J3: Y2 Study: King & Sherco Unit 3 Coal
Attachment J3 is marked as "Non-Public" in its entirety and is provided with Critical Energy Infrastructure Information (CEII) redacted. Attachment J3 contains information regarding the MISO area grid, including specific information about the Xcel Energy and other transmission owner systems as it relates to the potential retirement of Xcel Energy's Allen S. King and Sherburne County Generating Plant (Sherco) Unit 3. While MISO has redacted all CEII from the report, Xcel Energy maintains that the balance of the information is "security information" as defined by Minn. Stat. § 13.37, subd. 1(a).

Pursuant to Minn. R. 7829.0500, subp. 3, the Company provides the following description of the excised material:

1. **Nature of the Material**: Prepared study.
2. **Authors:** The study was prepared by MISO.
3. **Importance:** The study contains security information.
4. **Date the Information was Prepared**: The study was finalized November 14, 2018

Appendix J4: Y2 Study: Monticello, Prairie Island, & All Coal & Nuclear
Attachment J4 is marked as "Non-Public" in its entirety and contains redactions to CEII for the same reasons noted for Attachment J3. Xcel Energy maintains that the balance of the information is "security information" as defined by Minn. Stat. § 13.37, subd. 1(a).

Pursuant to Minn. R. 7829.0500, subp. 3, the Company provides the following description of the excised material:

1. **Nature of the Material**: Prepared study.
2. **Authors:** The study was prepared by MISO.
3. **Importance:** The study contains security information.
4. **Date the Information was Prepared**: The study was finalized November 27, 2018

Appendix N1: NSP 2013 Annual Electric Utility Forecast Report
Certain portions of Appendix N1 are marked as "Non-Public" as it contains private data on individual customers, including names, addresses, and energy usage data for our largest electric customers. This information is maintained by the Company as "nonpublic data" and "private data on individuals" pursuant to Minn. Stat. §§ 13.02 and 13.03. This report also contains forecast data of annual system consumption and generation. This information is trade secret information as defined by Minn. Stat. §13.37(1)(b). This information derives independent economic value from not being generally known or readily ascertainable by others who could obtain a financial advantage from its use.

Appendix N3: 10-Year Plan: South Dakota
Certain portions of Appendix N3 have been designated as Trade Secret information pursuant to Minnesota Statute § 13.37, subd. 1(b). In particular, the information includes confidential pricing and other contract terms, as well as confidential forecast data. The information designated as Trade Secret derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use.

Appendix N5: Biennial Report: Renewable Energy Obligation-Renewable Energy Standard Compliance Report
Certain portions of Appendix N5 have been designated as Trade Secret information pursuant to Minnesota Statute § 13.37, subd. 1(b). In particular, this report contains forecast data of annual system consumption and generation. The information designated as Trade Secret derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use.

Appendix N7: Annual Report: Solar Energy Standard
Certain portions of Appendix N7 contain information we have marked as "Non-Public" including information identifying customer names, locations, energy usage or bill credits. This information is maintained by the Company as "nonpublic data" and "private data on individuals" pursuant to Minn. Stat. §§ 13.02 and 13.03.
We have also marked as "Non-Public" capacity factor information relating to specific Purchase Power Agreements (PPAs). The terms of the Commission approved PPAs require that this information be non-public. Further, this is considered to be "nonpublic data" pursuant to Minn. Stat. §13.02, Subd.9, and is

also "Trade Secret" information pursuant to Minn. Stat. §13.37, subd. 1(b) as it derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use.

Appendix R: Study: Interconnection Cost Estimates-CC (Excel Engineering)
Appendix R is marked as "Not Public" in its entirety as it includes information the Company considers to be trade secret data as defined by Minn. Stat. § 13.37(1)(b). As set forth below, the information designated as Trade Secret derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use.

Pursuant to Minn. R. 7829.0500, subp. 3, the Company provides the following description of the excised material:

1. **Nature of the Material**: Prepared study.
2. **Authors:** The study was prepared by Excel Engineering.
3. **Importance:** The study contains competitively sensitive data related to project costs.
4. **Date the Information was Prepared**: The study was prepared during the fourth quarter of 2018.

Copies of the filing have been served on Commission staff, the Department of Commerce, and the Office of the Attorney General – Residential Utilities Division. We have also provided a copy to the Minnesota Environmental Quality Board. Interested parties will be able to obtain copies from our web site at xcelenergy.com/UpperMidwestEnergyPlan

Please contact Bria Shea at (612) 330-6064 or bria.e.shea@xcelenergy.com if you have any questions regarding this filing.

/s/

CHRISTOPHER B. CLARK
PRESIDENT
NORTHERN STATES POWER COMPANY MINNESOTA

Enclosures
c: Service Lists

Xcel Energy®

UPPER MIDWEST INTEGRATED RESOURCE PLAN

2020-2034

Northern States Power Company
Docket No. E002/RP-19-368

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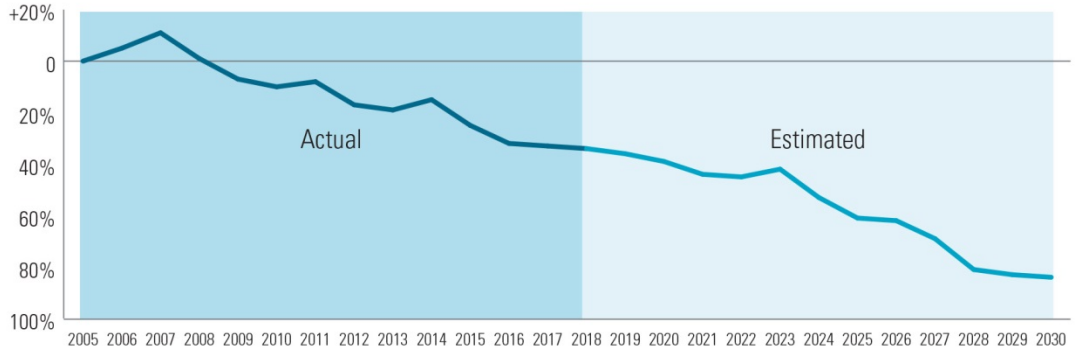
2020-2034 UPPER MIDWEST INTEGRATED RESOURCE PLAN

CHAPTER 1
EXECUTIVE SUMMARY

I. INTRODUCTION

This 2020-2034 Upper Midwest Integrated Resource Plan charts the path toward achieving some of the most ambitious carbon reduction goals of any utility in the U.S. Specifically – we aim to reduce carbon emissions 80 percent by 2030, and provide 100 percent carbon-free energy by 2050. This Resource Plan not only reaches the 2030 goal through retirement of our coal fleet, extension of nuclear, aggressive renewable additions, and demand-side management including both energy efficiency (EE) and demand response (DR), and a mix of load supporting, firm dispatchable resources – it embraces technology and innovation and is well-grounded in reliability and affordability. And while the last stretch of total carbon reduction – from 80 to 100 percent – will require technologies that have not yet been developed or deployed economically, we are confident that we can work with regulators, policymakers, and stakeholders to position ourselves so we are prepared to take advantage of the cost-effective solutions that emerge over the course of the next 30 years.

Figure 1-1: Projected Carbon Emissions Through 2030



Our Preferred Plan is the product of an unprecedented stakeholder process that included 13 public workshops, independent expert analysis, and months of information sharing as we developed a Preferred Plan. As a result of those efforts, our Preferred Plan is the product of an unusual amount of consensus this early in the Resource Plan process. That consensus is represented by an agreement signed by the Company, the Clean Energy Organizations,[1] Center for Energy and Environment,

[1] The Clean Energy Organizations include Clean Grid Alliance, Minnesota Center for Environmental Advocacy, Fresh Energy, and Union of Concerned Scientists.

Sierra Club, and LIUNA Minnesota and North Dakota that resolves (among those parties) many of fundamental building blocks of our plan.

Those building blocks include the elimination of coal-fired generation from our system by 2030, as well as the reduced, seasonal dispatch of Sherco 2 until its retirement in 2023. The agreement also includes the acquisition of at least 3,000 megawatts (MW) of utility-scale solar by 2030, and a substantial increase in EE programs, representing an average annual savings of over 780 gigawatt hours (GWh). Finally, the agreement includes support for the Company's proposal to take ownership of the Mankato Energy Center (MEC) combined cycle (CC), which will be central to our reliability strategy as we retire 2,400 MW of coal and integrate several gigawatts (GW) of new renewable resources. The Company's Preferred Plan builds upon this agreement and adds proposals to operate our carbon-free Monticello nuclear plant for an additional 10 years beyond its current license, add a significant amount of DR resources, and construct a new CC at our Sherco site. In total, we have an ambitious plan that supports the Company's goal of reducing carbon emissions 80 percent by 2030, and it moves us toward our ultimate vision of 100 percent carbon-free energy by 2050.

Figure 1-2: Preferred Plan Highlights

Close coal plants
Retire the last of our coal plants in the Upper Midwest by 2030, a decade earlier than planned

Add renewables
Add at least 3,000 megawatts of solar by 2030, enough to power more than 650,000 homes each year, and complete our largest-ever wind expansion by 2022

Continue carbon-free nuclear
Start the process to gain regulatory approval to run our carbon-free Monticello nuclear plant until at least 2040

Bridge to carbon-free
Use natural gas-fired plants in the coming years as a reliable, cleaner source of electricity as we bridge toward future carbon-free technologies

Throughout this process, we have taken steps to ensure that we can meet these progressive carbon reduction goals while preserving the reliability our customers have enjoyed for decades. To that end, the Company's engineering and operations teams have conducted extensive analyses to ensure that we can continue to serve customers

every hour of every day, even as we progress toward relying on intermittent resources for a majority of our generation. In this work, we have aimed to embrace change while addressing the physical realities of our system and the responsibility that comes with providing a genuinely essential service.

The addition of several gigawatts of renewable resources requires that we consider not only our traditional summer peak, but also whether we have sufficient dispatchable resources to meet other peaks, including in winter when solar energy is typically unavailable and wind resources may not be available for long periods of time. Our Preferred Plan addresses these reliability issues in three ways. First, the extension of Monticello by an additional 10 years and the continued operation of Prairie Island will anchor our grid in around-the-clock, carbon-free energy. Second, we are proposing to take ownership of the Mankato Energy Center and build a new CC plant at our Sherco site in 2026. These dispatchable resources will be critical as we retire 2,400 MW of coal-fired baseload and transition to a system that is nearly 60 percent renewable and intermittent generation. Finally, we propose several firm dispatchable, load-supporting resources – but defer these additions until the latter part of the decade, in anticipation of technological advancements that will improve the functionality and drive down the cost of resources, like storage, that can take the place of traditional gas peaking units.

We also recognize that the achievement of our carbon reduction goals will depend on our ability to keep rates affordable. We believe that our Preferred Plan accomplishes this by keeping annual cost growth below the rate of inflation. The modest cost of our plan is facilitated by our strategy of deferring resource additions until later in the plan and making use of existing assets on our system. Additionally, we believe technological improvements will continue to drive the costs of renewables down, which is a key element in our strategy of proposing significant solar additions in the latter half of the next decade.

We also know that our proposed plan includes impacts both on the communities we serve and our employees. We appreciate not only the challenge – but the stakes for those impacted – and we plan to build on our successful track record of working with our communities, policymakers, stakeholders and employees to successfully manage this clean energy transition.

We further recognize that the agreement underlying our Preferred Plan is simply the beginning of a process. And although elements of our Preferred Plan are captured by the Settlement, the parties to the agreement have not endorsed the entire plan and the Commission has not yet approved the plan. As a result, we look forward to a healthy discussion on the best way forward. That said, we view the agreement – which

promises the elimination of coal and the new prominence of solar on our system – as a great foundation from which to work. We believe both the process and outcome of this collaborative effort are a testament to the regulatory landscape in the states we serve, and we look forward to continuing the discussion around this transformational plan and our collective energy future.

II. EXECUTIVE SUMMARY

In our last Resource Plan (Docket No. E002/RP-15-21), we discussed the rapid evolution of our industry due to changing technology, enhanced customer expectations, and the increasing consensus around the importance of carbon reduction. We also noted that partnership among our stakeholders, communities, and the Company would become even more important to navigating these changes. In approving our prior plan, the Commission likewise noted that resource planning is a collaborative and iterative process and that a full understanding of the relevant facts requires exposure to the views of engaged and knowledgeable stakeholders.

We are filing this 2020-2034 Upper Midwest Integrated Resource Plan following an unprecedented stakeholder process that included 13 public workshops with topics from the evolving resource planning process, to more technical considerations, such as transmission and system reliability. We also engaged a third-party consultant—Energy and Environmental Economics, Inc. (E3) to conduct independent, parallel analysis to inform the Company's future resource strategy. E3 presented its findings to a diverse group of stakeholders at a workshop in April 2019. We then presented our own preliminary Preferred Plan at our final stakeholder workshop in May 2019.

We believe this combination of a significant internal effort, extensive collaboration, independent expert analysis, and transparency has improved not only the process that led to the development of our Preferred Plan but also the plan itself. In fact, it was through this stakeholder engagement that the Company, the Clean Energy Organizations,[2] Center for Energy and Environment, Sierra Club, and LIUNA Minnesota and North Dakota were able to reach an agreement that addressed many of the cornerstones of our Preferred Plan, including: (1) retirement of our last two coal units by 2030; (2) seasonal dispatch of Sherco 2 until its retirement in 2023; (2) acquisition of the MEC CC; (3) acquisition of at least 3,000 MW of utility-scale solar by 2030; and (4) a substantial EE goal.

We acknowledge that this agreement is just the start of the process – a process that

[2] The Clean Energy Organizations include Clean Grid Alliance, Minnesota Center for Environmental Advocacy, Fresh Energy, and Union of Concerned Scientists.

began with the Commission and its request to conduct a holistic review of our baseload resources. As we return to the Commission and begin to engage with the Commission directly in this Integrated Resource Plan docket, we look forward to the opportunity to demonstrate the substantial benefits of our Preferred Plan. It is also true that the terms of the agreement outlined above do not cover all components of our Preferred Plan, and we recognize that stakeholders continue to have wide-ranging perspectives on our collective energy future. We welcome those perspectives as part of this process, and we look forward to more collaboration and iteration as this docket moves forward. That said, we view the agreement as a very good start and a positive outcome from our stakeholder process; we appreciate the Commission setting us on the path; and, we believe the agreement demonstrates that stakeholders and the Company can find common ground and build consensus around key building blocks of a plan that satisfies the needs of our five-state Upper Midwest region – and meets individual state goals as well. Indeed, meeting the varied interests of our integrated system was an important foundation of our planning process.

Both the agreement and our overall Preferred Plan are consistent with the Company's environmental goals. For more than a decade, Xcel Energy has been a leading wind energy provider in the nation and has pursued a successful strategy to transition to clean energy. We have surpassed both national and international goals, including the U.S. commitment under the Paris Climate Accord of 26-28 percent reduction in carbon emissions by 2025. To-date, we have reduced carbon emissions 38 percent companywide from 2005 levels. We are proud of these achievements and grateful to our many stakeholders who have played a role in our journey.

In December 2018, the Company expanded on its commitment to clean energy by announcing industry-leading goals to reduce carbon emissions 80 percent Company-wide by 2030,[3] and to provide 100 percent carbon-free electricity across our service territory by 2050. This 2020-2034 Upper Midwest Integrated Resource Plan charts a path to accomplishing these goals through the elimination of all coal generation on our system by 2030, the addition of over 5,000 MW of renewables, and the expansion of our industry leading EE and DR programs. It accomplishes these environmental milestones while not sacrificing operational reliability or affordability. Specifically, we propose to do the following:

- ***Coal Resources -*** Retire our last two units early: King in 2028 (nine years early) and Sherco 3 in 2030 (ten years early). Additionally, continue our plan to retire Sherco 1 and 2 in 2026 and 2023, respectively, and commit to offering Sherco Unit 2 into Midcontinent Independent System Operator (MISO) on a seasonal basis until its retirement.

[3] From 2005 levels.

- ***Nuclear Resources-*** Operate our Monticello unit through 2040 (10 years longer than its current license) and operate both Prairie Island units through the end of their current licenses (PI Unit 1 to 2033 and PI Unit 2 to 2034).[4]
- ***Renewable Resources –*** While the exact wind and solar mix could vary based on a variety of reasons, at this time we propose to add 4,000 MW of cumulative utility scale resources by 2034 (the first being in 2025) and approximately 1,200 MW of cumulative wind by 2034 to replace wind that is set to retire from our system during that period.
- ***Combined Cycle Resources –*** Acquire and operate MEC and build, own and operate the Sherco CC to satisfy significant capacity and operational need created by coal closures.
- ***Firm Load Supporting Resources –*** Starting in 2031, add approximately 1,700 MW of cumulative firm dispatchable, load-supporting resources by 2034.
- ***Demand Side Management (DSM) -*** Include EE programs representing approximately 780 GWh of savings annually through 2034 (compared to average annual energy savings of 444 GWh in our last Resource Plan) and the addition of 400 MW of incremental DR by 2023 with a total of over 1,500 MW DR by 2034.

This plan demonstrates that we can achieve our 2030 goal with existing technologies and resources while maintaining both reliability and affordability.[5] However, it also creates opportunities to introduce emerging technologies as part of the solution. We see opportunities for innovation in our ongoing EE and DR programs. Likewise, we believe the industry will deliver new and improved technologies that will support our long-term need for firm, load supporting resources. The plan also advances a framework that achieves these goals in manageable steps as opposed to transitioning the entire system and grid all at once. By doing so, we can continue to ensure the reliability of our system and maintain flexibility to respond to future market trends, technology advancements, and changing regulatory policies
Below, we discuss our proposed resource mix further, as well as the priorities and considerations that drove the development of our plan.

[4] Given that our operating licenses for Prairie Island run until 2033 and 2034, we believe there is sufficient time to address the future of that plant in upcoming resource plans.
[5] As we explained our December 2018 announcement, we recognize that serving customers with 100 percent carbon-free electricity will likely require technologies not yet commercial available, and we look forward to discussing these technological developments in future resource plans.

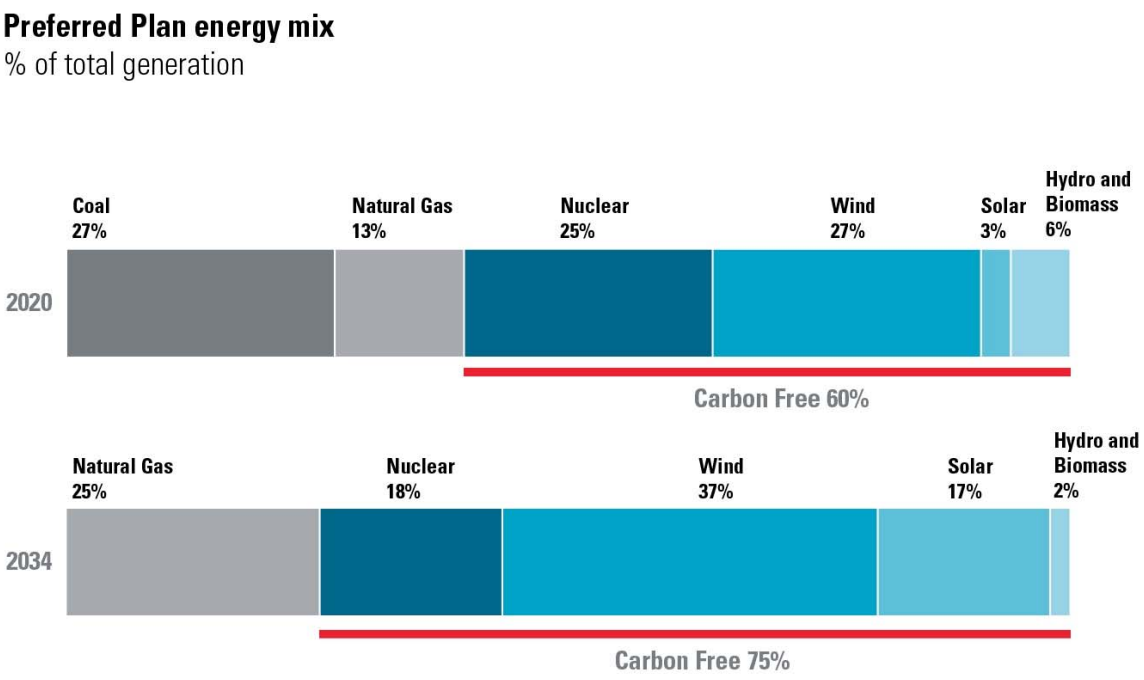
A. Proposed Resource Mix

Our Preferred Plan reflects a significant transformation of our resources. We have more than 1,300 MW of energy resources subject to power purchase contracts that are expiring. Our plan is also informed by an extensive study of all of our baseload resources, completed in response to the Commission's last Resource Plan Order. That study included seven Attachment Y2 studies by MISO and a more traditional NERC-based analysis of our fleet by an external consultant. All of these potential retirements were then studied in conjunction with the addition of significant renewable resources needed to meet our 80-by-30 goal, which identified reliability and stability issues that will need to be resolved as we move through the planning period.

As a result of this work, our Preferred Plan takes a measured approach to adding and retiring resources, and it prioritizes reliability and long-term system planning – as it must. In the first five years, we have no incremental capacity needs and propose only minimal additions.[6] In fact, there are no significant resource additions until 2025 when our first utility-scale solar is proposed. By relying on our existing resources in the near term, we preserve flexibility to respond to changing customer needs and regulatory policies, and we can monitor technological change to ensure we make future resource investments at the speed of value when they are in the best interest of our customers. We will continue our aggressive support of EE and DR and are looking to emerging resources to be part of that solution.

[6] Our actions in the next five years will address previously approved or pending resource additions and retirements, wind repowering and procurement to meet specific customer or program needs, community solar garden growth, and DSM programs.

Figure 1-3: Preferred Plan Energy Mix through 2034



That said, in light of the potential baseload retirements and expiring power contracts, we must address nearly 75 percent of the energy-producing resources on the NSP System during the 15-year planning horizon. We developed the Preferred Plan with an eye toward maximizing cost-effective renewable resources, backed by natural gas to support renewable integration and system reliability, in an effort to minimize market and commodity exposure. By doing so, our system will not be overly reliant on any one fuel source, and we will retain our trademark reliability – along with the flexibility to consider the economics of new resources as our baseload plants retire.

We discuss the components of our proposed resource mix in greater detail below.

1. Coal

With respect to coal-fired generation, our 2020-2034 Resource Plan represents a monumental step forward in transitioning our fleet. Today, as a result of our agreement with the Clean Energy Organizations, Center for Energy and Environment, Sierra Club, and LIUNA, we are proposing to retire our King plant in 2028 and Sherco 3 in 2030 – meaning that Xcel Energy will complete its transition away from coal-fired generation in 2030 – a full decade earlier than previously anticipated. In total, we plan retire approximately 2,400 MW of coal-fired generation in the next decade.

The early retirement of these plants allows us to reduce and ultimately eliminate our reliance on coal, enable additional cost-effective renewable resources, and save customers money. In addition to these retirements and the early retirements of Sherco Units 1 and 2 approved in our 2015 Resource Plan, we are also proposing to offer Sherco Unit 2 into MISO on a seasonal basis until its retirement in 2023, which we expect will reduce its carbon emissions in the near term.

This accelerated transition away from coal requires the Company to plan for the retirement of 2,400 MW of coal-fired generation in the next decade, which represents almost one-fourth of the total capacity in our current generation fleet. This will be an unprecedented period of transition for our system that necessitates a prudent replacement strategy. Our strategy for replacing these MWs includes a combination of natural gas CC resources, continued reliance on nuclear generation, large renewable additions during the planning period, and a continued commitment to both EE and DR, all of which will be critical to maintaining reliability throughout this baseload transition. We discuss each in turn below.

2. Nuclear

Carbon-free nuclear generation has been a cornerstone of our generation fleet for nearly half a century. Today, our nuclear plants generate about half the carbon-free energy for our Upper Midwest customers – amounting to the avoidance of about 7 million metric tons of carbon dioxide annually. This is equivalent to removing 1.5 million cars from the road. Our nuclear fleet is therefore critical to meeting our "80-by-30" goal and maintaining that level into the future.

Our nuclear units enable the Company to achieve and maintain our carbon reduction goals while incorporating incremental renewables at a reasonable pace and maintaining reliability. Nuclear is also an important system resource during the winter months, as it does not experience fuel supply issues and has a great track record during cold weather events – making it a critical piece of our reliability strategy, which we discuss below.

In light of these considerations and others discussed later in this filing, our Preferred Plan includes operating our Monticello nuclear plant until 2040, along with the continued operation of Prairie Island through its current operating licenses (which expire outside the planning period of this Resource Plan, in 2033 and 2034). By continuing the operation of these plants and extending our Monticello license, we can continue to enjoy the substantial carbon-free benefits these baseload units provide while saving our customers money by leveraging existing assets on our system.

Absent a Monticello operating extension, based on the reliability needs of the system, any suitable replacement resource would add carbon to our portfolio. We simply could not maintain our system reliably, or affordably, given the massive renewable additions and corresponding transmission infrastructure that would be required to replace our Monticello nuclear plant, if it were even possible by 2030, given MISO's current transmission expansion issues.

The recommendation to extend the Monticello unit is supported by its operational performance, which has achieved an average capacity factor of 96.5 percent over the past three years (including a record-setting 99.3 percent in 2018). Moreover, we achieved this performance all while reducing production costs by more than 20 percent since 2015. We believe this performance demonstrates that we can achieve deep carbon reduction along with industry-leading safety and reliability at an affordable cost. For all of these reasons, our nuclear strategy is sound and is in our customers' best interest and consistent with the public interest.

Procedurally, we intend to bring a petition for a Certificate of Need (CON) to address the Monticello license extension request to the Commission in the coming years. In that filing, we will provide detailed capital budgets and O&M forecasts, as well as economic modeling to justify our request. Given that the Prairie Island Units' licenses do not expire until 2033 and 2034, we believe we have time to address the future of these units in our next Resource Plan. We look forward to engaging with the Prairie Island Indian Community, Monticello, and Red Wing as we begin a discussion about the role of nuclear in our energy future.

3. Renewable Resources

Substantial renewable additions are a central component of our energy future and thus a cornerstone of this Preferred Plan – which proposes to add 4,000 MW of cost-effective, utility-scale solar generation and approximately 1,200 MW of cumulative wind resource additions. While the exact mix of wind and solar added to our system may vary (in concert with a variety of factors including technology advancements and price changes), our commitment to renewable energy will not.

In total, our Preferred Plan envisions a system that is approximately 60 percent renewable energy – a level that puts us among those leading the nation. And, while we are confident in our ability to deliver on our reliability commitment at this high level of renewable penetration, we are somewhat cautious at the same time about going much beyond those levels in light of our own experience, as well as recent industry studies regarding the complexity and complications of an exceedingly high

renewable grid.[7] That said, some of our customers and municipalities have environmental goals that include the achievement of 100 percent renewable energy to meet their needs, and we are confident we can meet those needs given the substantial renewable additions proposed in this Resource Plan.

The capacity value of renewables combines with our cost-effective gas and nuclear generation to deliver safe and reliable service that will withstand the summer and winter peaks of the Upper Midwest. Significantly, with these additions, there would be enough solar generation to power more than 650,000 homes each year.

Wind generation also continues to play a prominent role in this Resource Plan. Xcel Energy has long been one of the nation's leading providers of wind energy, and we are currently engaged in the largest build-out of new wind resources in our Company's history – thanks in large part to the Commission's approval of our last Resource Plan and our 1,850 MW wind portfolio. By 2024, wind will provide approximately 35 percent of the electricity for our customers in this region, making it the largest component of our overall generation portfolio.

4. Combined Cycle Resources

In addition to our carbon-free nuclear baseload resources, the continuation of dispatchable generation on our system will be vital to our ability to manage the retirement of approximately 2,400 MW of coal-fired generation over the next decade while maintaining reliability. It will also facilitate our ability to successfully integrate large amounts of renewables; we can ramp the output of these resources up or down in response to our system's changing needs throughout the day, as renewable resources generate more or less energy due to their variable nature. Finally, dispatchable generation will also help us plan for the expected marginal decline in load carrying capability from renewables as their penetration increases, which we believe could result in additional capacity needs.

To that end, our Preferred Plan includes our acquisition of MEC (a 760 MW two-unit CC), as proposed in Docket No. IP6949,E002/PA-18-702,[8] as well as our plan to build the approximately 800 MW Sherco CC located in Becker, Minnesota in the mid-2020s. As discussed in the pending MEC docket, that plant is already an integral part of our system, as its output is committed to the Company through two Commission-approved PPAs. By securing ownership of the plant, we can mitigate the risk

[7] *See* https://twin-cities.umn.edu/news-events/research-brief-planning-future-energy-demand-renewable-energy and MISO's *Renewable Integration Impact Assessment* (RIIA), which we discuss in Appendix J2: Reliability Requirement.
[8] We will incorporate any Commission decision from that docket into our modeling and supplement the record as necessary.

associated with expiration of the first PPA in 2026, thereby achieving additional certainty with respect to capacity and dispatchable energy.

As discussed in our last Resource Plan, we propose to locate a CC at the existing Sherco site because it will allow us to cost-effectively address significant transmission issues identified by the MISO Attachment Y2 study, ensure the stability and reliability of the transmission system, mitigate impacts to the local community and our employees, and potentially provide improved access to natural gas supplies for communities in Central Minnesota.

Together, our MEC acquisition and constructing the Sherco CC will not materially impact the amount of gas generation on our system. As already discussed, MEC is already an existing resource on our system, and the Sherco CC will primarily offset the retirement of other gas generation on our system, including the Cottage Grove facility (approximately 250 MW in 2027) and Black Dog 5 (approximately 300 MW in 2032). This additional gas generation is not only reasonable, but an operational necessity in light of the much larger coal retirements planned – and the large amounts of variable renewable additions we anticipate in the same period.

5. Load Supporting Resources

Reliability is the bedrock of any resource plan. We are particularly focused on the reliability of our system in this plan, however, as we plan for such a large turnover of our baseload fleet and transition to a portfolio that is approximately 60 percent renewable and intermittent generation. We recognize that our transition to cleaner energy will only be successful if we can execute our vision without disrupting our customers' lives and businesses, so we are steadfastly committed to maintaining our performance when it comes to this core tenant of our business.

Based on the results of extensive reliability studies that we discuss further below, we are proposing approximately 1,700 MW of cumulative additions of firm dispatchable, load supporting resources from 2031-2034. The need for these dispatchable resources emerges in this later timeframe due to the major plant retirements already discussed, as well as the expiration of several PPAs. Our reliability analysis demonstrates that these additions are necessary to continue to support grid reliability and resiliency in light of the increased renewables being added to the system and the baseload units being retired. That said, because these units are not needed until the out years of our current plan, we have not identified a specific resource type to meet this need. However, with the expected price declines and technology development, between now and the 2030s, we fully expect utility-scale storage will be an integral resource used to meet this need. Likewise, we believe the deployment of advanced

grid investments could position DR to better compete with traditional generation to fill some of this firm dispatchable need. We are committed to pursuing all of these options not only in the longer term, but in the near term as well in order to position ourselves to leverage this technology as it matures.

In addition, as discussed in our last Resource Plan, system retirements will impact our current blackstart plans and we are currently analyzing our blackstart path to determine the best fit for our system needs. While we do not propose any action related to the system blackstart at this time, we anticipate addressing this in our next Resource Plan or earlier, if system needs dictate the need to do so.

By keeping options open and remaining technology agnostic, we can acknowledge the need for a firm resource at the tail end of our plan but allow the market to advance as we file future resource plans and continue to collaborate with our stakeholders and the Commission as the need for these resources begins to materialize.

In the meantime, we are analyzing potential locations and sizing of storage solutions as well as the potential values storage assets might provide to the system.

6. Energy Efficiency

Our Preferred Plan also proposes to add significant amounts of EE based on the December 2018 *Minnesota Energy Efficiency Potential Study: 2020-2029*. In fact, our proposal includes an annual average of over 780 GWh of savings for 2020-2034. Our last Resource Plan included 1.5 percent annual EE savings assumption, but our current proposal achieves much higher levels of savings – ranging from approximately 2 to 2.5 percent annually. Relative to a 1.5 percent assumed savings level, our proposal achieves more than 200 MW of additional demand savings by 2023, and more than 800 MW by 2034.

7. Demand Response

Finally, consistent with the Commission's Order in our last Resource Plan, our Preferred Plan proposes to add 400 MW of incremental DR by 2023 (with a total of over 1,500 MW of DR by 2034). When it comes to DR, the Company leads the way in MISO, with 830 MW registered in the current planning year. In the last Resource Plan, the Commission ordered the addition of 400 MW of incremental DR by 2023. As we understood the Commission's reasoning, it sought to add incremental, cost effective DR to avoid near-term reliance on additional combustion turbines. As can be seen in our analysis, however, no combustion turbines or other firm, dispatchable resource additions are required until the 2031 timeframe as the model instead prefers

solar additions as the most attractive resource in the 2025-2030 timeframe.

That said, we decided to include the DR in our Preferred Plan for several reasons: (1) to be consistent with the Commission's Order in our last Resource Plan, (2) to fill gaps if/when the solar capacity credit declines, (3) to help meet firm dispatchable resource needs in the 2030s, (4) to help support customer programs, and (5) to integrate new and emerging technology and tools. We note that for purposes of our modeling, we have included all of the DR identified in the Brattle study as cost-effective, including expansions to conventional DR programs (i.e., Savers Switch, smart thermostats, and interruptible rates) and a non-conventional smart electric water heater program. Additionally, we included the addition of Auto DR, another non-conventional DR program that automates control of various end-uses like HVAC and lighting. We believe the advancement of our grid and technology generally may take the form of less traditional DR, so we are requesting the flexibility to evaluate and pursue the required incremental DR through a variety of means and technologies over the coming years.

In this filing, our objective is to bring forward information on all of the viable options so the Commission, stakeholders, and the Company can engage in an informed exchange.

B. Plan Priorities

1. Reliability

The foundation of our business is providing safe and reliable electric service, and the purpose of a Resource Plan is to identify the appropriate resources to continue providing that service to our customers. Building on the reliability and stability issues identified as part of our Baseload Study and renewable integration work, and recognizing that many other utilities within the MISO planning area are also planning to retire their baseload units, we made reliability and resilience a primary consideration of this Resource Plan.

To that end, we have conducted a detailed analysis of what resources will be necessary over the full planning period – once many of our baseload units are retired and the renewable resources have taken their place as our primary source of generation. As part of that work, we have paid increased attention to analyses around our winter peak, when solar is diminished and wind facilities can also drop off as a result of extreme temperatures. That analysis points to a baseline operational level of firm resources needed to continue to support a reliable and resilient grid at all hours of the day, on all days of the year. This operational guidance was then used in our modeling

tool, Strategist, to inform the resource decisions and ensure that all resource mixes we considered would be operationally feasible and reliable to meet our ongoing need to serve our customers. Below, we summarize how we determined the appropriate operational requirement.

Within a large pool of generation resources and an established wholesale energy market like MISO, there is a tendency for market members to project reliance on market resources based on the size of that pool, rather than the specific performance of those resources and the capabilities of the overall system to deliver additional resources. As we move further into a future that relies less on centralized and dispatchable generation resources, these operational considerations around system and resource capabilities become exponentially more important. In other words, as renewable penetration increases throughout the MISO footprint, it becomes increasingly important to consider the variable nature of these resources and their effect on the overall pool when considering reliability and market reliance. Thus, while we can, and do, still rely on the market, that reliance should be tempered during extreme events, because the nature of these events is such that they tend to impact a geographical footprint that is broader than a single plant or transmission line outage. While MISO is working to address these transmission needs, there is a clear need for more collaboration to enable transmission capability to help support the market's ability to facilitate carbon-free objectives going forward.

Due to the variability of renewable generation, the current generation fleet encounters times in which Net Load (defined as the difference between gross demand and renewable generation supply at a given point in time) is near, or even equal to, the gross demand on the system. This is evident in extreme cases, such as the 2019 polar vortex (when MISO used an average of 6,500 MW resource "reserves[9]" to remain operational), but also during normal winter operations like February 5, 2019, which was representative of conditions we typically experience throughout the winter season. For instance, on February 5th, the system encountered 16 hours of demand greater than 5,500 MW (60 percent of annual peak demand). During this same time, the Net Load was above 5,400 MW, with wind and solar together producing only 6 percent of their installed nameplate capacity (dipping at certain hours to 3 percent). Another example, on July 29, 2018, the entire MISO wind portfolio (over 17,000 MW at that time) had a combined output of minus 11 MW – meaning the wind turbines that were online, were taking more power than they were producing. This hour was part of an approximately 110 hour sustained stretch in which the combined output of all wind resources in the MISO footprint fell well below the accredited values used in

[9] These reserves consisted of non-firm resources offered by neighboring regional transmission organizations into the MISO market

present planning processes.

This real-world experience reveals several operational truths:

- First, variable resources cannot meet demand in all hours of the year; firm dispatchable resources are necessary.
- Second, simply increasing the level of renewables on the system cannot address resource shortfalls. With an increased level of renewables, we see some improved ability to meet demand but still encounter several hours in which the net load is very close to the gross load. In fact, the amount of additional renewable generation that would be required to meet customer demand in the above scenarios and without other resources could be in excess of 180,000 MW.
- Third, our ability to rely on the MISO market during winter peaking events is limited by periods of extremely low renewable generation across the MISO footprint and a shortfall of these resources compared to their accredited capacity.
- Finally, the current state of battery storage technology does not have the ability to match the duration of such events without significant (and very expensive) over-build of those resources, and DSM programs also lack the scale to significantly impact the analysis.

In light of these issues, we have determined that sufficient firm, dispatchable resources are required to meet the approximate 6,400 MW winter peak load obligation, and we have imposed this requirement in our Strategist modeling as part of this Resource Plan. Figure 4 below demonstrates the calculation of the firm resources used meet this need.

Figure 1-4: NSP System Reliability Requirement Calculation

Peak Demand Proxy	6,400 MW
Firm Demand Response Proxy	-200 MW
Firm Market Supply Proxy	-500 MW
Reliability Requirement (Firm Dispatchable Resources)	5,700 MW

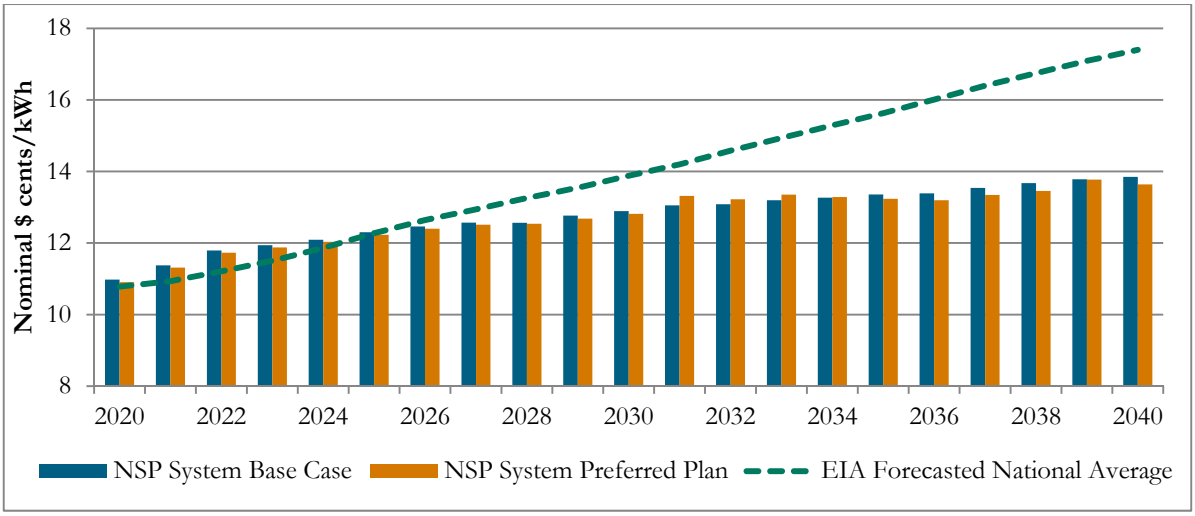
Our analysis shows that these resources will help us match the net load gaps discussed above by ensuring that we maintain a stable and reliable energy system for customers,

while moving through our baseload transition and achieving our nation-leading carbon goals. We discuss our reliability and operational analysis in greater detail later in this filing.

2. *Affordability*

Another priority for Xcel Energy, and our Resource Plan, is energy affordability. Currently, the average monthly Minnesota Xcel Energy residential customer's electricity bill is below the national average. Our goal is to keep bill increases at or below the rate of inflation – and this Resource Plan positions us well for success. In fact, our Preferred Plan achieves over 80 percent carbon reductions (from 2005 levels) for a nominal customer cost of just over one percent Compound Annual Growth Rate (CAGR) over the plan period. The opportunity to achieve such significant reductions in our carbon emissions for a nominal increase in cost is one of the principal benefits of our Preferred Plan. The following graph shows the relative cost growth of our Preferred Plan in comparison to the national average:

Figure 1-5: Preferred Plan Average Rate Impact for the NSP System



To be clear, the resources the Company needs to add over the next 15 years to continue providing safe and reliable service, to comply with state energy requirements, and to address plant retirements and PPA expirations come at some cost. But we believe that cost – which keeps rates at or below the level of inflation – is both modest and appropriate compared to the substantial benefits we have described here.

III. CONCLUSION

Our Preferred Plan – which accounts for more variables and changes than any other previous Xcel Energy resource plan – proposes to eliminate coal, add even more renewables, and continue our industry-leading EE and DR programs, all while preserving reliability and affordability for our customers. It also meets the varied interests of our five-state Upper Midwest region. And by planning ahead and charting an orderly, gradual transition of our generation fleet, we believe we can achieve all of these goals while managing the impacts to our host communities and employees, preserving the reliability and stability of our system, and maintaining affordability for our customers. For these reasons, and those discussed throughout this filing, we believe our Preferred Plan is in the public interest and merits Commission approval.

CHAPTER 2
PLANNING LANDSCAPE

I. INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission this 2020–2034 Upper Midwest Integrated Resource Plan, which eliminates coal-based generation from our system by 2030, proposes to add thousands of megawatts of renewable resources – and charts the path toward achieving some of the most ambitious carbon reduction goals of any utility in the United States.

Northern States Power Company-Minnesota is a wholly-owned operating subsidiary of Xcel Energy, Inc. that owns and operates, in conjunction with its affiliate Northern States Power Company-Wisconsin, the integrated NSP System of generation and transmission assets that serves more than 1.8 million customers in Michigan, Minnesota, North Dakota, South Dakota, and Wisconsin. This Resource Plan builds on our strong foundation of cost-effective environmental performance and the generating fleet transition we began in our last Resource Plan.

Our plan is founded on unprecedented levels of stakeholder engagement and technical analyses that examined an orderly retirement of our baseload generating units. We analyzed numerous assumptions and sensitivities to identify the plan that best meets customer needs, achieves our obligations and goals, and ensures we maintain a resilient and reliable grid. The Preferred Plan we propose emerged as the best suite of resources that balances our planning objectives, as follows:

Figure 2-1: Xcel Energy Integrated Resource Plan Objectives

To understand our Preferred Plan, we first present a Reference Case. The Reference

Case is the baseline scenario identifying the resources necessary to continue meeting our customers' needs, comply with renewable energy requirements, achieve our 80 percent CO_2 reduction from 2005 levels objective, add 400 MW of incremental Demand Response (DR) consistent with the Commission's Order in our last plan, and achieve the significant EE targets identified in the *Minnesota Energy Efficiency Potential Study*.[1]

The Commission's Rules provide the factors to consider in issuing its findings of fact and conclusions.[2] In addition to considering the characteristics of the available resource options and of the Preferred Plan as a whole, resource options and plans must be evaluated on their ability to:

A. Maintain or improve the adequacy and reliability of utility service,
B. Keep the customers' bills and the utility's rates as low as practicable, given regulatory and other constraints,
C. Minimize adverse socioeconomic effects and adverse effects upon the environment,
D. Enhance the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations, and
E. Limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control.

Our Preferred Plan meets these criteria, and provides the flexibility to address the evolving planning landscape, including the changes we expect to the NSP System to achieve our ambitious vision of a 100 percent carbon-free energy mix by 2050. That said, we respectfully request the Commission to approve our Preferred Plan, as follows:

- ***Coal Resources.*** Retire our last two units early: King in 2028 and Sherco Unit 3 in 2030. Additionally, continue our plan to retire Sherco 1 and 2 in 2026 and 2023, respectively.
    - Our plan also commits to offer Sherco Unit 2 into MISO on a seasonal basis until its retirement, and working with our employees at, and the communities around, the Sherco and King plants to support them through the transition of our remaining coal fleet.
- ***Nuclear Resources.*** Operate our Monticello unit through 2040 (10 years longer than its current license) and operate both Prairie Island units through

[1] Available at: http://mn.gov/commerce-stat/pdfs/mn-energy-efficiency-potential-study.pdf
[2] Minn. R. 7843.0500, subp. 3

the end of their current licenses (PI Unit 1 to 2033 and PI Unit 2 to 2034).[3]

- We expect to initiate a Certificate of Need proceeding with the Commission within the next five years and begin working toward license extension with the Nuclear Regulatory Commission during this timeframe.

- ***Renewable Resources.*** While the exact wind and solar mix could vary based on a variety of reasons, at this time we propose to add 4,000 MW of cumulative utility scale resources by 2034 (the first being in 2025) and approximately 1,200 MW of cumulative wind by 2034 to replace wind that is set to retire from our system during that period. We specifically request flexibility in the timing and amounts of renewable additions to take advantage of market and other conditions that we believe will provide value to our customers.
  - ***Wind.*** We are committed to pursuing repowering and/or contract extension opportunities for this resource and we intend to pursue incremental wind resources as needed to meet customer needs in growing customer programs like Renewable*Connect.
  - ***Solar.*** Our Preferred Plan proposes an initial planned addition of 500 MW in 2025. Our plan includes forecasted growth of distributed solar. If actual distributed solar capacity exceeds our expectations, we anticipate this will displace a portion of our proposed grid-scale solar resources.

- ***Combined Cycle Resources.*** Acquire and operate the Mankato Energy Center and build, own and operate (Sherco CC) to satisfy significant capacity and operational need created by coal closures.[4]

- ***Firm Load Supporting Resources.*** Extend the life of Blue Lake Units 1-4 through 2020-2023.[5] Add approximately 1,700 MW of cumulative firm dispatchable, load-supporting resources between 2031-2034. Because these units are not needed until the out-years of our current plan, we have not identified a specific resource type to meet this need. With the expected price declines and technology development between now and the 2030s, we believe utility-scale storage will be an integral resource used to meet this need.

- ***Demand Side Management.*** EE programs representing 2-2.5 percent of savings annually (over 780 GWh for each of 2020-2034), compared to average

[3] Given that our operating licenses for Prairie Island run until 2033 and 2034, we believe there is sufficient time to address the future of that plant in upcoming resource plans.
[4] MEC is currently pending Commission consideration in Docket No. IP6949, E002/PA-18-702. For the Sherco CC, we expect to submit our plans in a separate proceeding.
[5] Pending decision in Docket E,G002/D-19-161.

annual energy savings of 444 GWh in our last Resource Plan, and the addition of 400 MW of DR by 2023. We are requesting the flexibility to evaluate and pursue the required incremental DR through a variety of means and technologies over the coming years.

- ***Storage and Other Emerging Technologies.*** Pursue storage and other emerging technologies, on both a large and small scale.

Finally, as we have previously discussed, system retirements will impact our current blackstart plans, or our ability to restart the system in the event of a catastrophic failure. While we do not propose any action related to the system blackstart at this time, we anticipate addressing this in our next Resource Plan or earlier, if system needs dictate the need to do so.

The balance of our Resource Plan discusses the evolving planning landscape, presents our Preferred Plan and the economic modeling framework from which it emerged, and estimated customer cost and rate impacts. We additionally provide Appendices that include the results of our Baseload Study, Load and Distributed Energy Resource (DER) forecasts, and discussion about our Supporting Transmission and Distribution Infrastructure, Environmental Regulations and Compliance, and numerous others.

II. PLANNING LANDSCAPE

Every business that conducts long term planning needs to account for both its internal goals and the external environment within which it operates. In this Chapter, we discuss some of the key internal and external market contexts that affect how we have developed, and plan to execute on, our Preferred Plan – which supports our ambitious carbon reduction vision, to reduce our carbon emissions to 80 percent below 2005 levels by 2030.

Specifically in this section we examine:

- Xcel Energy's Carbon Reduction Goals
- Regional Reliability and Market Constructs
- Distributed Energy Resources (DER)
- Community and Employee Considerations
- Customer Preferences
- Supply and Technology Trends
- Jurisdictional Updates

While all of these factors affect how we develop our plan, a few stand out above others as being particularly influential in this Integrated Resource Plan cycle – chief among them, regional market constructs and renewable integration. While the regional system operator that designs many of our market and planning requirements continues to examine the effects of high renewable adoption on the grid, it has not yet developed robust and forward-looking capacity accreditation constructs to account for how renewables' contributions to peak demand will change over time. This introduces complexity to designing a plan far into the future, and how we carry out those plans.

Likewise, while we are committed to substantially increasing renewables on our system to achieve our carbon reduction goals, we also anticipate facing challenges to integrating this new clean generation, given the delayed interconnection studies and current limited state of open transmission availability. Our ability to connect these new renewables in a cost-effective manner depends materially on constructs that enable careful management of our interconnection rights in the near-to-medium term as well as new transmission in the long term.

These and other factors, such as DER adoption rates, community and employee impacts, and satisfying the needs of five different states, all affect how we developed the Preferred Plan presented in this filing – and the issues we anticipate encountering as we pursue our goals to lead the energy transition while keeping our grid services

reliable and affordable.

A. Carbon Reduction Goals

In December 2018, the Company announced its goals to reduce carbon dioxide (CO_2) emissions 80 percent by 2030 below 2005 levels companywide, and to serve customers with 100 percent carbon-free electricity by 2050. We believe our 2030 goal is achievable with the clean generation and energy storage technologies available today. We believe our 2050 vision, however, will be achievable only with advancements in new technologies such as: carbon-free dispatchable generation technologies and longer-duration storage that are not currently available at the necessary scale and cost, or carbon capture and sequestration. Until these or other technologies are further developed and commercialized, we will require a certain amount of conventional flexible and dispatchable generation to integrate increasing levels of renewables on the grid.

To achieve our 80 percent reduction by 2030 goal, we anticipate the following elements will be essential parts of future plans, across one or more of our service areas:

- Adding thousands of megawatts of additional renewable resources to our system and incrementally retiring emitting baseload generation, while also incorporating flexible, dispatchable generation to enable grid reliability throughout this transition;
- Operating our carbon-free nuclear units at least through the remainder of their licenses, with the potential for license extensions;
- Supporting the strategic electrification of certain end uses and enabling flexible demand, which will help to reduce carbon emissions in other sectors while also providing flexible loads to help integrate more renewables;
- Investing in critical infrastructure, such as transmission and advanced grid technology on our distribution system, to integrate the DER our customers choose, as well as improve reliability and the customer experience.

These goals, the science behind them, and the path we will take to achieving them, are all detailed further in Appendix E: Xcel Energy Carbon Report:Building a Carbon-Free Future.

With these aggressive carbon goals in mind as one of the main tenets of our Preferred Plan, below we discuss the key forces that affect how we have developed, and plan to execute on, our Preferred Plan.

B. Regional Reliability and Market Constructs

The Company's Upper Midwest system is part of the Midcontinent Independent System Operator (MISO) market. MISO is charged with several responsibilities, chief of which are overseeing wholesale energy markets in the member region and planning for bulk system reliability (i.e. transmission planning, generator interconnection, and ensuring sufficient reserve margins). Many aspects of MISO's operations affect how we conduct resource planning, but here we focus primarily on system reliability constructs that will be increasingly tested as we and others transition to a fuel mix relying on more variable renewable resources.

1. Reserve Margin

One of MISO's core responsibilities includes administering resource adequacy requirements to enable utilities like us, and other Load Serving Entities (LSEs), across the region to fulfill their obligation to serve customers reliably. Trends are emerging, however, that raise questions regarding how planning constructs will adapt to ensure the system remains reliable as emitting, but stable, baseload generation continues to retire and be replaced by clean, but variable, renewable energy.

MISO and its system reliability oversight organization, the North American Electric Reliability Corporation (NERC) undertake studies to determine the appropriate level of reserve capacity that should be maintained, what affect a resource retirement has on the broader system, and how increasing renewable adoption will change how they analyze and ensure grid reliability. All of these studies point toward an increasingly complex grid that will have to be carefully managed through the transition to a lower-carbon future.

MISO's Planning Reserve Margin (PRM) analysis is one important piece of the current reliability planning paradigm. The PRM is an estimation of how much generating capacity, over and above expected customer load, needs to be present on the system to ensure reliability in all but the most extreme circumstances (called a 1-in-10 year Loss of Load Expectation or LOLE). In the 2018 report, MISO established a reference planning reserve margin of 17.1 percent for the 2018-2019 planning year; in other words, they determined that the total installed capacity available on the system should be 17.1 percent higher than the system's peak load.[6] This reference threshold is provided to the NERC, which sets standards and studies

[6] MISO's PRM for the 2018-2019 Planning Year indicates a PRM for both installed capacity (ICAP) and a rating that derates capacity to account for potential outages (called UCAP). The UCAP PRM for the 2018 planning year is 8.4 percent These two measures of PRM are discussed further in the next section on Minimum System Needs.

reliability across the continent, and of which regional system and transmission operators like MISO are a part.

As part of its oversight and governance activities, NERC conducts a reserve margin analysis across all system operators in North America, in a report called the Long Term Reliability Assessment (LTRA). The 2018 LTRA indicated that MISO is one of three regions that are projected to drop below their reference reserve margin levels by the year 2023, unless certain measures are taken.[7] This report indicates that inclusion of Tier 2 resources (those that are in more advanced stages of planning but not yet under construction) would likely allow for the MISO footprint to preserve system reliability. However, the unprecedented rate of announced, but not yet evaluated, baseload generation retirements and uncertainty in future firm capacity additions creates a tension between maintaining reliability and transitioning away from baseload generation.

It is important to note that retiring some baseload generation and transitioning to a cleaner grid with more wind and solar does not present an insurmountable challenge; indeed we are proposing to retire all of our coal by 2030. Rather, the transition will need to be actively and carefully managed, likely with incremental retirements and supporting transmission upgrades that are carefully studied.

2. Renewable Integration Challenges

In addition to challenges around baseload retirement issues, we also see planning issues developing around how renewable additions are evaluated for their reliability impacts. In the aggregate, when MISO has studied high levels of renewable penetration on the grid, grid instability increases and capacity values of variable resources decline, sometimes significantly. Retaining firm dispatchable generating units helps ensure the system will continue to operate reliably.

MISO has also recognized that its capacity accreditation framework – the manner by which it assesses variable renewables' ability to contribute to peak demand needs – will likely change as these resources become more prevalent on the grid. However, MISO has not yet developed sufficiently robust forward guidance for resource planning processes to account for how those values might change in the future, which creates uncertainty in the resource planning process. We discuss these renewable integration studies and specific capacity accreditation issues in more detail below.

[7] *See* "NERC Long Term Reliability Assessment 2018" at 14. Available at: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2018_12202018.pdf

a. Renewable Integration Impact Assessment

In preparation for an expected future grid with high levels of non-dispatchable renewable penetration and declining baseload generation, MISO is undertaking additional studies with respect to its system's reliability and resource adequacy of its system. The *Renewable Integration Impact Assessment* (RIIA) seeks to inform future long-term planning by understanding what the power system will need to operate reliably with these high levels of variable resources, specifically by examining operational adequacy, transmission adequacy, system stability and resource adequacy limitations.

In Phase I, the study examined a scenario in which variable generation achieves a 40 percent share of the total capacity on the MISO system. It found that the complexity of operating such a system reliably is significantly higher than that of even a system with 30 percent variable resources. Under the circumstances studied, the system experienced more dynamic stability issues and other operational stressors, and resource adequacy requirements increased. For example, the modeled system exhibited high levels of energy curtailment and very high ramping rates in the hours when variable resources were not always available to meet demand. In this scenario, loss of load projections were narrowed to fewer likely hours during the year, but the probability of occurrence increased significantly over the current state. This points to the value that flexible, dispatchable resources supporting grid stability continue to provide in these scenarios; while they run for fewer hours than the current market constructs would warrant, they need to be able to respond quickly, moving from minimum generation levels to higher levels of output to meet these fluctuations in net load quickly.

Further, at high levels of wind and/or solar adoption, the RIIA study found that appropriate resource adequacy values to assign these resources degraded, sometimes significantly from current levels. As a key piece of planning our future system, these resource adequacy capacity accreditation values are discussed in more depth below.

b. Capacity Accreditation Values

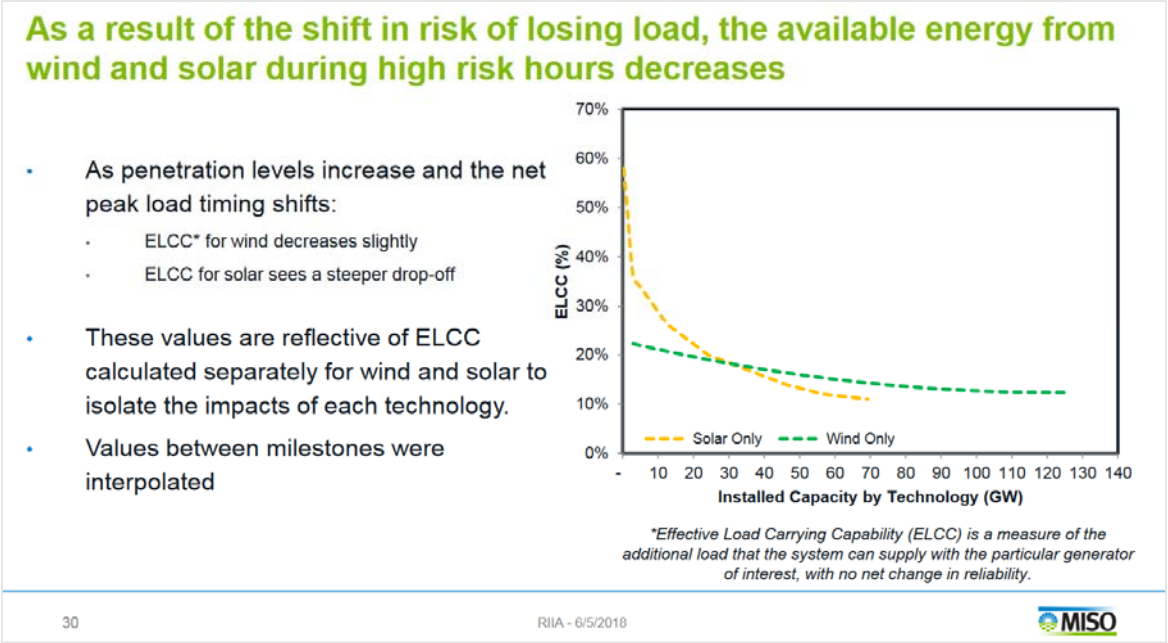
Variable renewable resources such as wind and solar are becoming more cost competitive and utilities across the region, including the Company, are increasingly adopting these technologies as important components of their resource mixes. This generation is largely displacing more traditional, thermal dispatchable units. As variable resources are dependent on natural resource availability in a given moment (i.e. wind blowing or sun shining), their capacity does not replace retiring dispatchable units one-for-one in terms of the amount of energy it produces, or assurance that this capacity will produce energy when needed. To account for this, MISO applies a

certain accreditation discount to these resources to get a more appropriate probabilistic view of how much capacity can be counted on to contribute to peak demand across the year. This is captured in a measure called the Effective Load Carrying Capability (ELCC).

These administratively set values have a significant impact on how we achieve our carbon reduction goals while maintaining affordable and reliable service. Currently, MISO assigns wind generation an average ELCC value of 15.7 percent; meaning that for every 100 MW of wind installed, only 15.7 MW can be counted as capacity toward the planning reserve margin. For new solar resources, in the absence of an observed historical value, MISO assigns the current initial year default ELCC of 50 percent. The appropriateness of these values in reflecting actual grid conditions is dependent on the pace at which wind and solar penetration increases on the grid, and subsequently how MISO conducts review and adjusts the values. The ELCC is currently evaluated as an annual average, and forward values are not projected.

In reality, however, the capacity value these intermittent resources can provide are subject to diminishing marginal returns. When a single variable resource type increases its penetration level on the grid, each incremental unit of capacity inherently provides a little less capacity benefit to the system than the last unit. For example, MISO's RIIA study estimates that solar in particular would experience steep ELCC reductions within the first 10 gigawatts installed, and this value continues to drop off at higher levels of adoption. Further, in particular for these variable assets, the realized capacity value may change throughout the year, as the capacity value a wind or solar plant can provide reasonably changes in accordance with seasonally variable environmental conditions.

Figure 2-2: Modeled Wind and Solar ELCC as Penetration Increases[8]



The operational realities surrounding future variable resource additions and their seasonal aspects aside, we continue to use the administratively-set annual average ELCC levels in our planning that MISO has established for today's market.

While we recognize that it is difficult for MISO to accurately project future wind and solar penetration levels and load shapes (two key variables in determining future ELCC values), this presents a key challenge as we plan our future system. As the ELCC construct does not currently provide forward-looking values, we have to apply current values to our resource modeling process, even though we are modeling 15 years into the future. However, we know in reality that these values will degrade as we and others add variable renewables to the MISO system, and so what appears to be a net capacity surplus today may look rather different in future assessments.

It is worth noting here that we may encounter changing assumed resource adequacy contributions for use-limited resources in the future as well. In general, resources such as DR and energy storage would be subject to declining ELCC values as they become more prevalent on the system, in the same way wind or solar ELCCs realistically decline.[9] Notably, MISO is also considering changes to how it accounts

[8] MISO. *"Renewable Integration Impact Assessment"* Workshop presentation June 5, 2018. Available at: https://cdn.misoenergy.org/20180605%20RIIA%20Workshop%20Presentation213125.pdf

[9] *See* the E3 Study in Appendix P2 for further discussion on how marginal ELCC for DR and energy storage resources may decline as adoption increases.

for DR's capacity accreditation overall, such as enforcing more stringent testing requirements. MISO is also following up on actual performance during DR events, which may result in accredited value reductions going forward. Both these factors mean that the DR we currently depend on as a baseline resource in our portfolio, in addition to that which we may select in this or future resource plans, may not yield the same benefits in future years as we have historically expected.

c. Interconnection Queue

The current state of grid interconnection processes and transmission capabilities in MISO introduce complexity not only to our planning processes, but also how we execute on the plan.

The MISO generator interconnection process is designed to allow generators reliable, non-discriminatory access to the electric transmission system, in a timely manner, while maintaining transmission system reliability. Recently, as the number of proposed projects in MISO has expanded significantly, this process has been mired in delays. Delay impacts are particularly evident in the Definitive Planning Process (DPP) phases, where MISO undertakes generation interconnection studies. Current studies are a number of months behind, due to the large volume (including speculative requests) and a generator interconnection process that allows late withdrawals from the queue with limited consequences. Despite some recent process reforms, MISO has not been able to keep pace with the expanding queue. And where projects do make it through the DPP, they are sometimes assigned high transmission system upgrade costs that challenge the project's economic viability. MISO's interconnection challenge is multi-faceted.

First, there is a substantial volume of capacity currently in the queue requesting study and interconnection approval. As of early June 2019 there were over 100 GW of new capacity in the active MISO queue (although this number has fluctuated substantially), the vast majority of which is comprised of wind and solar projects.[10] Each cycle of the DPP is handling expanding levels of requested capacity; for example, the recently completed cycle for the MISO West region (started in August 2016) started out with 31 projects totaling just over 5,600 MW.[11] The April 2019 DPP study cycle,

[10] MISO "Generator Interconnection: Overview." Updated as of June 1, 2019, at: https://cdn.misoenergy.org/GIQ%20Web%20Overview272899.pdf
[11] *See* "MISO DPP 2016 August West Area Phase 1 Study." Siemens (August 20, 2018). Available at: https://cdn.misoenergy.org/GI_DPP_2016_Aug_West_Phase1_SIS_Report277263.pdf

scheduled to begin in March 2020, includes 58 projects totaling 8,800 GW in the same area.[12] While the level of proposed new renewable project is a positive indication of aspirational renewable development in the region, MISO has also indicated that a substantial amount of this capacity is speculative, in early stages of project development or representing duplicative requests.

Further, the existing transmission system's capability to interconnect new projects without substantial infrastructure upgrades is limited, and thus, the generation interconnection planning studies indicate there will likely be costly upgrades assigned to the prospective generators. In the past, initiatives such as CapX2020 and Multi-Value Projects (MVPs) were able to integrate large quantities of new renewable power and socialize transmission infrastructure costs across a larger swath of benefitting MISO customers. However, wind power in particular expanded on the MISO grid faster than expected, and the interconnection capacity afforded by these projects has been largely used. Since then, few new transmission lines have been proposed or approved for the purposes of renewable integration.

Generally speaking, this means that, if new generation projects in the queue want to interconnect, the generation interconnection study process identifies substantial additional transmission system upgrade costs and assigns them to the generation owner(s). In the aforementioned MISO West DPP cycle that recently completed, for example, the approximately 5,600 MW of proposed projects were expected to incur approximately $3.2 billion in transmission upgrades, if all were to interconnect to the system.[13] These assigned high-cost transmission system upgrade requirements can sometimes render projects uneconomic, forcing a queue withdrawal and additional MISO study on the remaining projects.

d. Regional Seam Issues

Limitations on transmission infrastructure and coordination, both within MISO and between MISO and the Southwest Power Pool (SPP), illustrate further challenges.

Within MISO, the transmission system is showing constraints and the resulting curtailment slows our progress toward a cleaner energy future across the Upper Midwest system. Currently, wind generation from the western part of MISO flows toward the load centers in the east such as the Minneapolis–St. Paul area and load centers across the transmission interconnection between Minnesota and Wisconsin. However, existing west-to-east transmission capacity is, at times, operating at its limit.

[12] *See* MISO "Definitive Planning Phase Estimated Schedule." Updated as of June 1 2019. Available at: https://cdn.misoenergy.org/Definitive%20Planning%20Phase%20Estimated%20Schedule106547.pdf
[13] "MISO DPP 2016 August West Area Phase 1 Study." Siemens, September 2018, at xvii.

The transmission interface across the Minnesota-Wisconsin border in particular is currently stability-limited, and trying to force additional renewable energy through these lines could result in voltage collapses in Northern Wisconsin that would destabilize the grid. Curtailing this energy at its source in the west is operationally and economically inefficient, keeping us from fully utilizing the inexpensive and clean energy to which we have access; but, without additional transmission capacity, we will more frequently encounter this problem as we add more renewable generation to our system.

Further, coordination (or historical lack thereof) between MISO and SPP introduces challenges to bringing onto the system, and utilizing, more clean energy. First, for projects that can be considered interregional in nature, a project must currently meet economic benefit hurdles in a joint review, as well as separate MISO and SPP regional evaluations. This slows the process significantly, and may overestimate the amount of interconnection upgrades required, adding to project uncertainty and cost.

Second, although our load and generation sit within MISO, the nature of power flows inevitably results in some of our energy entering the SPP system. In turn, both MISO and SPP may charge to transmit that energy from the point of generation to the load, challenging a project's economic viability or raising customer costs for projects already online.

Finally, MISO and SPP disagree on what should happen when one region or the other has to "lean" more on the system than its contracted delivery amounts for a certain time. Where SPP would levy penalties in this scenario, MISO views this situation as a normal and acceptable result of an integrated grid. All of these issues increase transaction costs and uncertainty for a given generation project coming online, and represents a potential barrier to efficiently bringing additional renewable generation to the grid.

3. Mitigation Efforts

In response to direction from FERC and in recognition of the challenges described above, MISO is undertaking several actions that could serve to mitigate challenges to bringing new, clean resources online. In essence, they allow generation owners to leverage existing interconnection agreements to maximize utilization and fit renewable additions into the relatively few remaining open spaces on the grid. While we expect these processes to mitigate some of the near term challenges to additional renewable capacity, they do not address all challenges (in particular our ability to depend on neighboring regions for renewables and maintaining reliability) and we expect that longer term solutions will eventually need to be developed.

a. Generator Replacement Process

Interconnection study delays and speculative queueing are challenges not only to projects that are actually commercially viable, but also to generation owners that are looking to retire aging assets. Companies that are required to meet a certain level of reserve capacity, like Xcel Energy, face potential compliance and commercial risk if we retire existing assets without the ability to re-utilize that interconnection capacity. Recognizing these issues, MISO filed and received approval for a proposed Replacement Generator Process that would allow current generation owners to retain and re-utilize these interconnection rights where a resource plans to retire, within certain technical limitations on the new generator's attributes. The new generating units could be developed on the same site, or on a site in close proximity that uses the same grid interconnection point. Per the new MISO tariff provisions, the new generation resource would need to have an in-service date not later than three years after the existing generator ceased operation. Importantly, these projects would be studied outside the traditional DPP timeline, with the intention of avoiding the significant delays associated with that process, as described above.

b. FERC 845

In 2018, FERC issued Order 845, *Reform of Generator Interconnection Procedures and Agreements*[14] that also opens additional opportunities for generation owners to add resources to the system outside the normal interconnection queue process. The Order directs all transmission providers to develop a procedure to allow interconnection customers to use surplus availability at an existing point of interconnection without that new project entering the full MISO queue and planning process, within certain technical limitations. MISO has referred to surplus interconnection availability as "Net Zero" interconnection, as the addition of this new project would not result in an overall increase to the interconnection capacity requirements of the site; rather, it would be expected to increase the overall *utilization* of the interconnection site.

While MISO allowed Net Zero resources prior to FERC 845, the new Order also allows existing interconnection rights owners the first right to utilize the surplus availability on that interconnection. It also revises the definition of a generating facility to explicitly include energy storage resources. These actions work to support generation owners increasing renewable utilization on existing interconnections, and could support future project hybridization (e.g. solar and storage or wind and storage). We expect that generator replacement, Net Zero, and other FERC Order

[14] See Reform of Generator Interconnection Procedures and Agreements, 163 FERC ¶ 61,043 (2018) (Order No. 845).

implementation efforts will alleviate some of the barriers to planning and executing on a future with substantial renewable additions. However, these do not address the underlying challenges around queue length and timeline, intra-MISO and interregional seams congestion challenges, and integrating high levels of renewables reliably and affordably. MISO has recently attempted to mitigate the queue volume challenge by proposing process reforms that increase the stringency of entering this phase of interconnection process; however, while recognizing the challenges MISO faces, FERC recently rejected the proposal.[15] While the Company and others have begun contemplating new MVP-like projects, the lack of alignment across MISO and long lead-times required for such projects mean that these challenges are unlikely to be resolved in the near term.

C. Distributed Energy Resources

At the same time as we work to clean our power supply, we also recognize that customers are now exercising more choice around how and from where they consume energy. This is a key consideration as we plan our resource mix for the next 15 years.

Some customers are choosing DER that can reduce customer consumption and even provide energy back to our system from decentralized locations on the grid. Examples of DER include, but are not limited to: rooftop solar panels, energy storage, community solar gardens, or the EE enabled by a smart thermostat or time of use electric rate. To-date, community solar gardens makes up the clear majority of the DER on our system in the Upper Midwest.

Our customers' adoption of DER and new types of load mean that consumption patterns from our centralized power system are changing. This can represent an opportunity: if we can harness the benefits of these resources to make demand more flexible, we can use this to better match demand to energy production from our large, variable renewable resources. For example, we could utilize managed or "smart" charging of electric vehicles (EVs), to delay charging to off-peak hours or to times when renewable output is the highest. We could also use advanced metering technology alongside customer programs and tariffs to enable load shifting away from peak hours.

There are also DER coming onto our grid, in the form of electric transportation options – enabling not only flexible load opportunities but also broader economy-wide emissions reduction – and we have developed several programs and rate options

[15] *See* FERC "Order Rejecting Tariff Revisions re: Midcontinent Independent System Operator, Inc. under ER19-637." Available at: https://elibrary.ferc.gov/idmws/file_list.asp?accession_num=20190319-3076

to encourage that adoption.

The transportation electrification initiatives we have implemented and continue to develop are not only enabling customer choice, but also to the broader economy in helping to meet greenhouse gas (GHG) emissions reductions goals. The transportation sector is now the leading contributor to Minnesota's overall emissions,[16] and as our system (and the state's electric sector more broadly) continues to transition to a cleaner energy mix, transportation's share of GHG emissions will continue to expand. This shift highlights an opportunity for the electric sector to facilitate GHG reductions in the transportation sector, as electricity is increasingly used for transportation fuel.

While the opportunities are exciting, it is also important to recognize that customer adoption of DER and new types of load behind the meter introduce uncertainties in our planning processes, particularly if we do not have adequate visibility into how and when that new DER or demand is coming onto our system.

One tool we have to mitigate this DER and electrification uncertainty is our Integrated Distribution Plan (IDP) and grid modernization efforts. Our IDP process and proposed investments will help us leverage DER and new load to enable more flexible demand management, improve reliability and, we anticipate, enable better decision-making about large-scale investments as well. In our last IDP we discussed these enabling technologies, which include: Advanced Distribution Management Systems (ADMS), which will allow us to better integrate DER onto our grid and maintain reliability; the Field Area Network (FAN), which enables two-way communication from field devices and Company back office operations; Advanced Metering Infrastructure (AMI), which enables time of use rates by metering consumption at smaller time intervals; and automated, remote reliability-sensing and enhancing technologies such as and Fault Location, Isolation, and Service Restoration (FLISR). Many of these investments will help us develop capabilities to use load more flexibly. We also hope to enhance the customer experience by creating new programs and offerings that fit their needs and preferences based on the capabilities these investments provide.

Our Preferred Plan is substantially dependent on anticipated customer load, which incorporates the best estimates we have about customer adoption of DER, as well as robust statistical forecasting methods. We have also modeled sensitivities to address some of this uncertainty. But we still often do not have visibility into which

[16] See the Minnesota Pollution Control Agency's statewide GHG inventory data, available at https://www.pca.state.mn.us/air/greenhouse-gas-emissions-data.

technologies, and at what pace, customers will adopt and thus, how that changing load will affect our grid needs in the future.

D. Community and Employee Considerations

As we move forward with our carbon reduction goals, we are cognizant that phasing out some of our legacy generation assets has a significant impact not only on our energy mix, but on the economies of communities where those plants are located and the employees who work in those plants. This is particularly true of our coal facilities, where the plants are prominent places of employment and contributors to the property tax base in the community. This is why we make efforts to spur economic development in locations where our current units will eventually be phased out.

For example, since our most recent Resource Plan, where we proposed to retire the Sherco 1 and 2 coal units in Becker, we have worked extensively with local units of government, community stakeholders, and the State to draw new development to support the local economy. This includes a planned CC generating unit at the Sherco site, the relocated Northern Metal Recycling facility, and, prospectively a new Google data center with energy matched by a wind facility. Some of that activity (e.g. the Google data center) is also anticipated to spur new renewable energy development on our system.

Related, we are participating in a study overseen by Center for Energy and Environment (CEE) that will examine the impacts of the large baseload generation plants in Minnesota on the host communities. The other participants in the study include the Coalition of Utility Cities, Minnesota Power, and the Prairie Island Indian Community. The study will consist of a quantitative and qualitative component. The quantitative component of the study is similar to the study we conducted for Sherco 1 and 2 in our last Resource Plan. For the qualitative component, CEE will engage with host community residents and business to gauge awareness, opinions and concerns around potential power plant closures. Efforts on both components are underway and we will supplement this Resource Plan filing when each component is completed. As this docket progresses, we expect to be able to incorporate further findings and hold additional discussions incorporating the finalized report outcomes. Further discussion of the scope and status of this study is included as Appendix O2.

In addition to community impacts, we are also aware that these plant closures impact our employees and their families. With this in mind, and consistent with our past practices, we will work with these impacted employees to transition them to other Xcel Energy plants or areas of the company. In the past, when plants have been closed or converted (and impacted headcount) we have provided résumé writing

services, support for interview practice, job training, and job shadowing opportunities. Through natural attrition and job relocations, we have been able to successfully "re-home" nearly all impacted employees from plant closures and conversions to-date.

Moving forward we will work with local unions and set a course to negotiate multiskilling for our impacted sites. This skill set will position our employees for other job opportunities within Xcel Energy. As we get closer to closure dates, temporary workforce will be utilized to back fill benefit employees who have relocated to other positions within the company. This strategy lessens the burden and stress for benefit employees to find positions, as plants near closure dates. In addition, plant management, Work Force Relations and Human Resources will work together with other business organizations within the company to help coordinate interviews for affected employees.

And, as we continue toward achievement of our aggressive carbon goals, we will continue to make significant investments in clean energy in the states we serve. As we do so, we will look for opportunities to create fair access to clean energy programs, jobs and economic development opportunities. Going forward, we continue to be dedicated to working with employees, communities, and stakeholders to manage community impacts throughout our clean energy transition.

E. Customer Preferences

Our Upper Midwest system continues to serve a diverse mix of customers with varied interests and preferences. While most customers continue to prioritize affordability, we have seen increasing interest in sustainability, carbon reduction, and clean energy objectives. Again, these are important considerations to keep in mind while planning our resource mix for the future.

1. Municipal

Cities and municipalities are increasingly setting and developing strategies around sustainability and climate goals. In fact, there are 11 cities in our Upper Midwest jurisdiction that have set carbon reduction or renewable energy goals. Minneapolis is the most prominent example, as evidenced by the Clean Energy Partnership that had just started when we filed our last Resource Plan. Since then, the partnership has flourished and advanced, helping to achieve progress toward the city's sustainability goals. Other municipalities and communities are also developing goals and action plans around renewable energy and climate goals. We work with many of these communities through our Partners in Energy program to support achievement of these goals.

2. Commercial and Industrial Customers

Our commercial and industrial customers place a high priority on keeping costs low to remain competitive in their own markets. This is particularly true of large industrial customers, where energy costs can make up a substantial portion of their operating expenses. However, corporate efforts to achieve sustainability goals are also increasing, both in the US broadly and within our system. And as the cost of renewable energy declines, affordability and sustainability goals increasingly go hand in hand. Within our system, several of our corporate customers are co-members of the Minnesota Sustainable Growth Coalition, which is a business-led public-private partnership working to advance clean energy and other sustainability and circular economy objectives. We hear from these and other corporate customers across our Upper Midwest system that sustainability and clean energy are important to them, and they want us to offer products that meet these needs, and Renewable*Connect is one such product.

In 2015 we worked with customers to develop Renewable*Connect. The program achieved full subscription in its first year, and in January 2019 we filed for an expansion of this program, and included an option for high load factor customers (i.e. those that operate continuously during the day) to be served primarily with competitively priced wind and a smaller portion of solar. Significantly, this program advances the sustainability goals of the participating companies without creating additional costs that must be carried by other, non-participating customers. In 2019, we also developed a new program called Certified Renewable Percentage (CRP). The CRP is a new Renewable Energy Certificate (REC)-based accounting methodology that clarifies the percentage of our system energy delivered to customers that is renewable. The CRP is not a subscription service or program customers need to enroll in. Instead, the Company will retire sufficient RECs on behalf of all our retail customers such that the total RECs retired annually reflects the portion of delivered energy that is renewable. This will allow all retail customers to claim the percentage of renewable energy on the system as the starting point towards their sustainability goals.

Our willingness to work with customers to balance clean energy objectives and affordability needs, while facilitating economic development opportunities, has also attracted new customers to the service area. The new Google Data Center slated for development in Becker is a clear example. Google has an objective to match 100 percent of its energy consumption needs with renewable energy purchased from incremental projects, and has future plans to go even further by sourcing carbon-free energy for its operations on a 24/7 basis. We were able to work together with Google to develop a proposal to help it achieve its renewable energy goals.

3. Residential Customers

Residential customers likewise tell us that they value choices and clean, affordable, reliable energy. In response, we have developed programs that offer more convenient payment options, rebates for EE upgrades, and the chance to reduce the environmental impact of their consumption by choosing renewable energy. Customers are taking advantage of these programs in large numbers – and they have expressed strong satisfaction with their ability to select programs that best meet their individual energy needs.

F. Supply and Technology Trends

Trends around the supply of generation and energy storage equipment we need to fulfill our resource plan have a significant impact on the mix and timing of our resource proposals.

In the years since our last Resource Plan, wind and solar technology costs have continued to improve overall; solar in particular has experienced significant cost declines, with installed costs falling over 35 percent on average since 2015.[17] Consistent with past years, we generally expect wind and solar capital costs will continue to decline, although at perhaps a slower pace as these technologies advance on their respective maturity curves. We also expect technology advancements improve capacity factors. These two factors continue to improve the cost competitiveness of wind and solar resources in real terms, changes to incentive policies notwithstanding, relative to the other resource options we may consider. For example, the National Renewable Energy Laboratory projects that large-scale solar prices could decline 17 percent in real terms over the next 10 years.[18] For modeling purposes, however, our generic representations of these resources are static in terms of capacity factor and accredited capacity, and we have represented the combined future cost and performance trends through the levelized energy cost forecast for these technologies.

We also continue to examine the role energy storage can play in meeting our system needs. The Company has been developing our experience around the type of services energy storage can provide to our system, through the operation of an existing

[17] Bolinger, Mark and Seel, Joachim. *Utility Scale Solar 2018 Edition*. Lawrence Berkeley National Laboratory September 2018. Available at: https://emp.lbl.gov/utility-scale-solar

[18] This projection reflects data provided by the NREL's *Annual Technology Baseline* report, which we use in our modeling. This trend reflects changes in projected solar levelized costs in real terms (2016$) and are not adjusted for the potential impact of tax credits.

pumped hydro facility in Colorado and several pilot battery energy storage installations across Xcel Energy's service areas. Technologically, we expect grid-scale energy storage will support our clean energy goals in the future, by helping us maintain grid stability and supporting peak management while integrating the higher quantities of intermittent renewable generation we envision on our system. We are committed to pursuing this technology although challenges remain, in particular for battery energy storage, to managing seasonal renewable energy variability and longer duration demand-shifting needs.

From a cost perspective, battery energy storage has experienced significant improvements over the last few years and we would expect battery energy storage costs to further decline going forward. There are also other battery chemistries and different types of storage that may emerge as technology research and development continues. While we are confident utility-scale battery storage will be a part of our long-term resource mix, we are also evaluating the potential for near-term battery storage around our service territories to fulfill distribution system or other needs.

Finally, as we have noted, achieving our 100 percent carbon-free electricity by 2050 goal will require further development of technologies that have not yet been identified and commercialized. While not included in our resource planning optimization, we continue to monitor industry activity around other emerging technologies that may contribute to achievement of our goals. In addition to potential new battery chemistries mentioned above, potential emerging clean energy technologies include advanced nuclear reactors, carbon capture and storage applications, hybridized gas-hydrogen generators, other types of energy storage technologies beyond batteries, and others. As new technologies achieve commercialization, we will remain technology agnostic as we consider including them in our future resource planning analyses.

G. Jurisdictional Updates

Our integrated Upper Midwest system provides service on a multi-jurisdictional basis to 1.8 million customers across five states. Through this integration, we have historically leveraged economies of scale to support needed investments. Each resource on the Upper Midwest system – whether generation or transmission – was developed in consideration of the whole system, to take advantage of the economies of scale available through integrated system planning. Below we provide a brief overview of key prevailing and emerging energy policy in Minnesota, North Dakota, South Dakota, Wisconsin, and Michigan, where these objectives may affect our future planning for the Upper Midwest system as a whole.

1. *Minnesota*

In 2007, Minnesota passed the Next Generation Energy Act, which set successive, economy-wide greenhouse gas reduction goals relative to 2005 levels; 15 percent below reduction by 2015, 30 percent below by 2025, and 80 percent below by 2050. Since that time, the electric sector has outpaced emissions reductions in all other sectors, achieving a 29 percent reduction below 2005 levels by 2016 (the most recent year reported). However, the state has missed its economy-wide goal, achieving approximately 12 percent reduction over the same time period.[19] This data drives our view that the electric sector can, and likely must, facilitate reductions in other sectors, such as transportation and building energy use, if Minnesota is to meet its economy-wide carbon reduction goals.

Specific to the electric sector, the Minnesota Renewable Portfolio Standard, passed in 2007, remains our prevailing clean energy requirement. The 2019 session included passage, however, of energy storage provisions that (1) enable utility-owned energy storage pilot projects, and clarifying cost recovery for such pilots, (2) requiring resource plans to include an Energy Storage Systems Assessment, including how storage may contribute to generation and capacity needs and ancillary services, and (3) requiring a cost-benefit study of energy storage systems by the Department of Commerce.[20] We provide our Energy Storage Systems Assessment in Appendix F7.

2. *North Dakota*

Since our last Resource Plan, we submitted a Resource Treatment Framework (RTF) simultaneously to the Minnesota Public Utilities Commission (MPUC) and the North Dakota Public Service Commission (NDPSC). The RTF filing was submitted to the NDPSC in compliance with a Commission Order adopting the Negotiated Agreement in the Company's last rate case,[21] with the purpose of establishing a framework to address the costs and benefits of the Company's Upper Midwest system resources in a way that was both fair to all customers and aligned with North Dakota's policy objectives.

In the RTF, we developed a proposal that evaluated four potential implementation structures: (1) legal separation of the North Dakota portion of the system; (2) pseudo

[19] *See* Minnesota Pollution Control Agency "Greenhouse Gas Emissions Data." Available at: https://www.pca.state.mn.us/air/greenhouse-gas-emissions-data
[20] "19-5227 – Omnibus Jobs, Economic Development, Comerce and Energy." Available at: https://www.senate.mn/committees/2019-2020/3098_Committee_on_Jobs_and_Economic_Growth_Finance_and_Policy/19-5227.pdf
[21] See North Dakota Case No. PU-12-813. In Minnesota, the Company submitted the RTF consistent with our commitments made in MPUC Docket No. E002/M-16-223

separation, applying generator-specific cost/benefit allocations; (3) proxy-pricing, which would replace the cost of a disputed generation resource with a proxy price deemed acceptable; or (4) gaining regulatory alignment in the selection of resources, so that all states could fully participate in the integrated NSP system. Our intent was to seek a framework solution that can not only address current resource disputes, but also those that may arise in the future.

Our initial proposal would have legally separated the North Dakota portion of our service area into a separate operating company, with pseudo-separation identified as a second best option. Under the legal separation framework, we felt confident we could retain the benefits of economies of scale in our resource planning, yet be able to customize resource portfolios for certain states, to the extent necessary. Pseudo-separation could also prove feasible, if each state agreed to the method by which we would propose to conduct these cost allocations.

In response to this proposal, the North Dakota Staff recommended against legal separation, instead preferring a solution that used a form of proxy pricing to determine appropriate resource cost allocations for resources in the Upper Midwest system. Further, Staff was interested in pursuing the Company's proposal to institute a formal resource planning process in the state, in order to provide the North Dakota Commission with more information about planned resource additions earlier in the process, and to provide the Company more certainty regarding the state's policy objectives and deemed customer needs.

While we do not see proxy pricing as a viable forward-looking solution for reconciling resource treatment, we continue to believe that instituting a formal resource planning process is beneficial and will provide more clarity to the Commission and the Company on what resources may work as system resources. In response to the Commission's request for a more detailed proposal, we submitted a framework outlining essential pieces of a North Dakota Resource Plan, including a default presumption that the system would continue to be planned in an integrated fashion, and a proposed timeline for filing that is consistent with the Minnesota process. We discussed the proposal at an informal hearing with North Dakota Commissioners in March of this year, where the Commission confirmed that it is interested in a more formalized resource planning process.

Currently, we do not recover the full PPA costs of the Aurora, Marshall, and North Star solar PPAs, the Community Based Energy Development (C-BED) PPAs, or the Renewable Development Fund (RDF) PPAs from our North Dakota customers.

3. South Dakota

We have also faced challenges in recovering the costs of certain resources in South Dakota. In December 2016, the South Dakota Public Utilities Commission (SDPUC) suspended the fuel clause adjustment in order to investigate the costs of certain disputed resources recovered through the fuel clause.[22] The Company worked with South Dakota Commission Staff to development a Settlement to address these concerns. In September 2017, the Commission approved a Settlement Stipulation that addressed the costs recovery for the Aurora solar resource and several biomass resources. The Settlement also required the development of proxy prices for several remaining disputed resources, which include the Marshall and North Star solar PPAs, C-BED PPAs, and Renewable Development Fund PPAs. The Company submitted a proxy price proposal to the South Dakota Commission which provided eight potential proxy pricing options for the Commission's consideration and recommends a combination of market-based and index-based pricing, depending on the particular resource.[23] We are engaging in ongoing discussions with South Dakota Staff as we work toward a resolution of these outstanding issues. While we are working to develop proxy prices as a resolution for past resources, when disputes arise in the future we would work to develop a cost allocation mechanism to allocate the costs and benefits of new resources to the participating jurisdictions.

Currently, we do not recover the full PPA costs of the Aurora solar project from our South Dakota customers and we are recovering the costs of the PPAs for the disputed resource subject to refund based on the resolution of the proxy price proceeding.

4. Wisconsin

In Wisconsin, the Company is subject to a Renewable Portfolio Standard (RPS) equal to 12.89 percent of its three-year average in-state retail energy sales. In 2018, excluding renewable energy used for voluntary renewable programs, NSPW provided 24.3 percent of its retail energy sales from RPS-eligible renewable-based energy sources, and the Company is in compliance with its 2018 RPS requirements.[24] This requirement has not changed recently. However, the state's newly elected governor has identified climate objectives as one focus of his administration. In line with these goals, the administration has proposed carbon reduction goals for the state's electric sector that are broadly consistent with our objectives to reduce emissions by 80 percent from 2005 levels by 2030, and 100 percent by 2050. It is not yet clear

[22] *See* South Dakota Docket No. EL16-037.
[23] *See* South Dakota Docket No. EL18-004.
[24] *See* Docket 5-RF-2018 *Renewable Portfolio Compliance Plan for CY 2018. Northern States Power Company, a Wisconsin Corporation.*

whether these proposed goals will result in additional mandates for the electric sector.

5. Michigan

In Michigan, the Company is subject to a Renewable Energy Standard (RES) equal to 15 percent of retail sales by 2021, with a goal of 35 percent renewables and 25 percent energy waste reduction by 2025. We are ahead of schedule on both these goals, already exceeding the 2021 RES requirements and expecting to meet the 2025 goals by 2020.

This year will also be the first time we are required to submit a Resource Plan to the Michigan Public Service Commission, in accordance with Public Act 341 of 2016. Michigan's new Resource Plan process allows us to file the same resource plan in Michigan as we are filing with the Minnesota Commission, and on a similar timeframe, with the understanding that the Michigan Commission may ask for additional supplemental information to help them evaluate the plan as it relates to Michigan.[25] We plan to file this multi-state Resource Plan in Michigan on July 31.

H. Conclusion

We believe our progressive carbon reduction goals are the right path forward for the our customers, our employees, our Company and the State. We are confident in our ability to achieve these goals while maintaining the reliability and affordability our customers count on. This transition, while exciting, is not without challenges. We will continue to navigate significant market and regulatory uncertainty, jurisdictional differences, technology changes and more. That said, we are optimistic that these challenges also present opportunities to engage with customers, regulators, market operators, communities, and employees on our goals in a way that meets multiple stakeholders' objectives.

[25] *See* U-15896/U-18461 at 11.

CHAPTER 3
MINIMUM SYSTEM NEEDS

Our resource planning process focuses on deep carbon reductions while serving our Upper Midwest customers reliably and affordably. In this Chapter, we describe in more detail how we arrived at the minimum amount of resources our system will need through the planning period. The system needs and existing resources evaluated here formulate the baseline upon which we have developed the Reference Case, our modeling scenarios, and ultimately our Preferred Plan.

We have made the following changes to aspects of our Minimum System Needs approach with this Resource Plan:

- *Supply-side Resource Treatment for DSM.* In this Resource Plan we are treating both EE and DR as supply-side resources, rather our previous treatment of EE as an adjustments to future load. Supply-side resources available to the model now include incremental EE and DR in "bundles," or amounts of achievement that we formed from the *Minnesota Energy Efficiency Potential Study* and *Brattle Demand Response Potential Study*, respectively.
- *Reliability Requirement.* We have developed and applied a threshold requirement for firm dispatchable resources. This Requirement is needed to ensure system reliability and resilience until MISO evolves its capacity accreditation construct to better recognize the variability and declining incremental electric load carrying capability of wind and solar resources.

I. MEETING CUSTOMER NEEDS

Forecasting customers' needs for electricity is a key component of any resource plan, and provides the foundation for determining the type and amount of resources that will be needed over the 15 year planning period. The first step is forecasting the amount of electricity our customers will need over the planning period. To this, we add a reserve margin that is prescribed by MISO. We then subtract the resources we already have or expect to have (with some adjustments), to determine our net surplus or need.

We illustrate this concept and discuss each of the components below.

Figure 3-1: Net Resource Need/Surplus Calculation

Customer Needs Forecast
Plus MISO Reserve Margin
Equals **Total Capacity Obligation**
Minus Demand Response Capability
Minus Generation Capacity (measured by UCAP)
Minus Generation Adjustments
Equals **Net Resource Need/Surplus**

A. Customer Needs Forecast

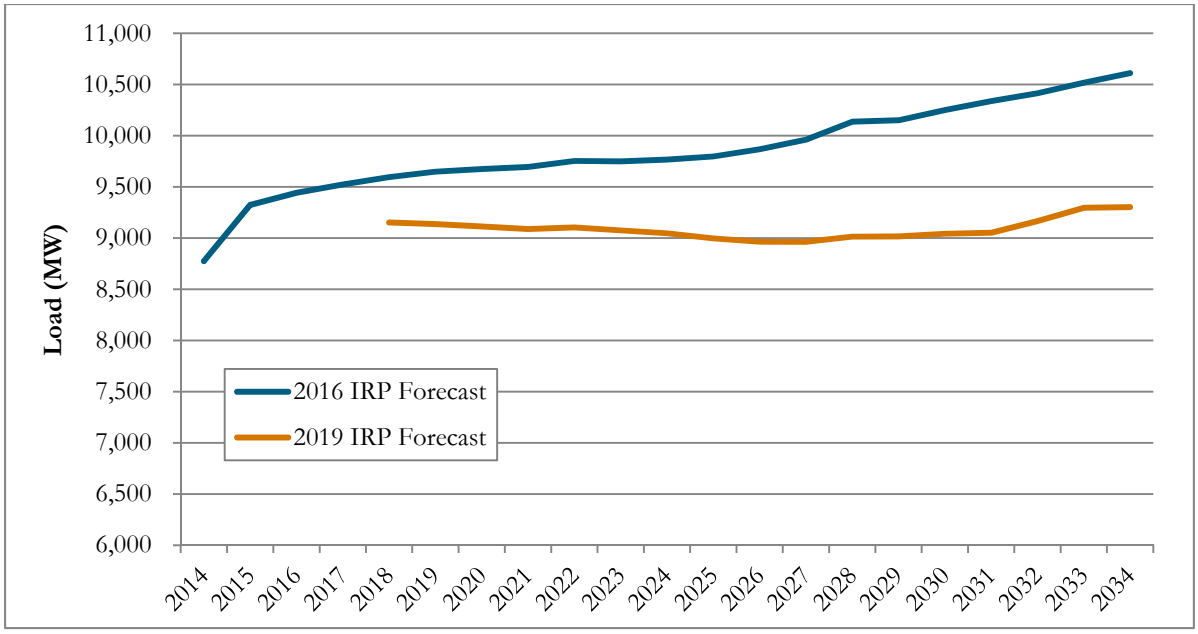
Forecasting our customers' energy needs starts with a capacity, or peak demand, assessment, which informs the total amount of generating capacity (in megawatts, or MW) needed to meet our customers' needs in the highest demand hour (i.e. peak-hour) in each year of the planning period. We also assess the amount of total energy (measured in megawatt hours or MWh) we expect customers to consume in each year of the planning period. Together, the peak demand and total energy needs inform the type of generating resources that will best meet customer needs.

1. Peak Demand Requirements

We use econometric analysis and historical actual coincident net peak demand data to determine system capacity requirements for each year. We provide a detailed discussion about our peak demand forecasting methodology in Appendix F1.

Our current forecast shows essentially flat load relative to current levels, with an average annual growth rate of less than 0.2 percent, after accounting for EE. Figure 3-2 below shows the current forecast in relation to the forecast from our last Resource Plan.

Figure 3-2: Forecasted Peak Load, After Energy Efficiency Adjustments (MW)[1]



We have changed our approach to how we present our peak forecast from our last Resource Plan based on our treatment of EE as a supply-side resource in this Plan. The peak forecast in our previous Resource Plan included both a demand reduction associated with historic EE, as well as from the impact of future incremental EE as approved in the previous Resource Plan.

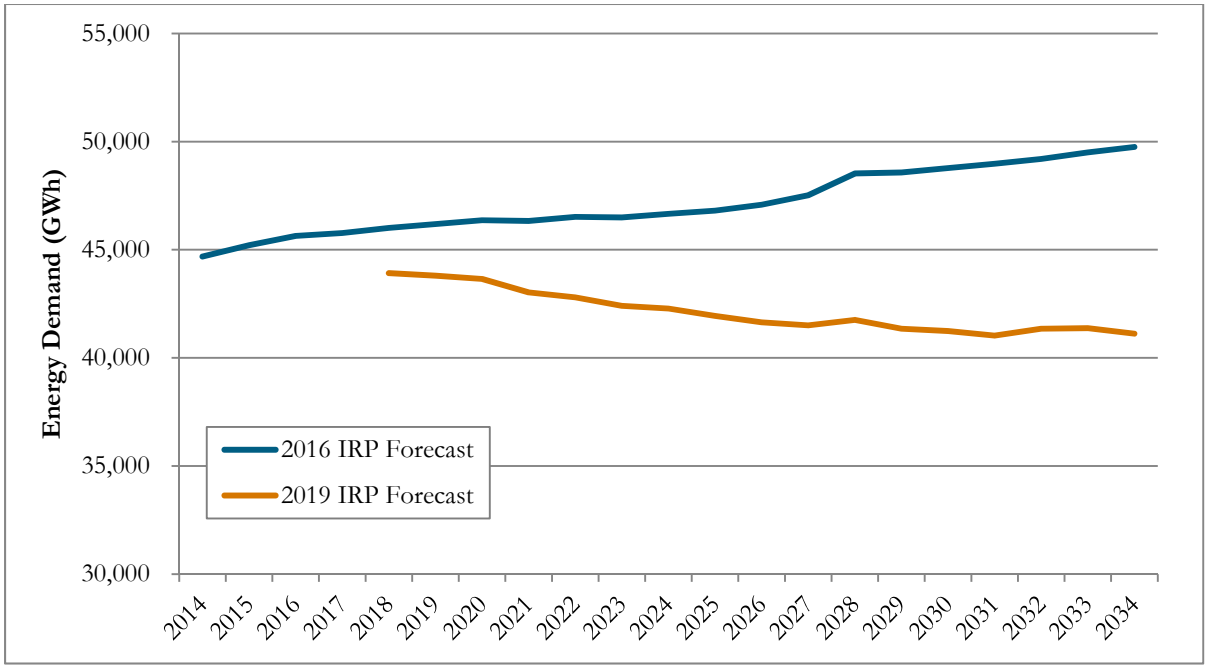
For this Resource Plan, we have changed our approach to addressing EE in two ways. First, the load forecast used in our Strategist modeling no longer has embedded incremental EE, although it is shown in that manner in the charts above for comparison purposes with previous Resource Plans. Instead, we treat EE as a supply-side option that the Strategist model can select in its resource optimization. To do so, we developed EE "Bundles," which we describe in Part III below and in more detail in the Strategist Assumptions Appendix F2. As a result, rather than adjust our peak forecast based on an assumed level of future EE adoption (this would have been 1.5 percent per the level approved in our last Resource Plan), we are reflecting our commitment to *higher* levels of EE achievement (approximately 2.5 percent reduction) in our Reference Case. This level of EE reflected in the Reference Case is representative of two of the EE Bundles available for Strategist to select.

[1] Although we modeled EE bundles as supply-side resources in this Resource Plan, we show the estimated resulting EE as a load reduction from gross load for purposes of the chart above.

2. Energy Requirements

We forecast declining energy needs of approximately 0.4 percent over the 2020-2034 planning period, after accounting for EE included in the Reference Case. As discussed above, the inclusion of two incremental EE Bundles reflects achievement of approximately 2.5 percent EE, which leaves our Net Demand substantially lower than forecast in our last Resource Plan. Figure 3-3 below compares our estimated net energy demand adjusted by the two EE Bundles, to the energy forecast in our last Resource Plan.

Figure 3-3: Forecasted Net Energy Requirements, After Energy Efficiency Adjustments[2] (GWh)



3. Forecast Adjustments

After determining the base peak capacity and energy demand forecasts, we make certain forecast adjustments to account for the impact of events or trends we reasonably expect to occur in the planning period. We summarize our key adjustments below:

DSM. In past Resource Plans, the load forecasts used by Strategist were adjusted for

[2] Although we modeled EE bundles as supply-side resources in this Resource Plan, we show the estimated resulting EE as a demand reduction from gross demand for purposes of the chart above.

the expected effects of existing DSM programs. In this Resource Plan, based on feedback from stakeholders, incremental EE is no longer embedded in the load forecast, rather EE is treated as potential supply-side resource in our modeling, like DR. Both EE and DR are shown as separate line items in our Loads and Resources table below, though in an effort to maintain consistency with Load and Resource reporting between this and previous Resource Plans, we show EE "above the line" as a subtraction from gross load. We further discuss the EE and DR (collectively, DSM) in the context of our resource planning process in Appendix G1.

Distributed and Small Scale Customer Solar Generation. We have historically considered customer adoption of distributed solar (i.e. DG solar as well as CSG) installations as a modification to load in the resource planning process. In this Resource Plan, we have accounted for DG solar including CSG resources as a supply-side resource with assumed adoption levels, as shown in the Loads and Resources calculation below. Reference Case assumptions currently take into account interconnection requests and expectations based on policy-driven programs. However, we also conduct sensitivity testing around potential increased levels of adoption and are working to develop new tools that improve our understanding of how key market drivers will affect customer distributed solar adoption going forward. We note that our methods for projecting distributed solar installations are currently evolving. As our tools and methods mature, we will increasingly incorporate them into both our Resource Plan and IDP processes.

Expected Customer Changes. We also make adjustments to account for known changes in load on our system. These typically reflect expected changes in specific large customers' electricity usage, either as a result of increased behind the meter energy generation (decreasing demand) or increased production activities (increasing demand).

Light Duty Electric Vehicle Adoption. We adjust our residential energy and peak demand forecasts to account for increasing use of plug-in electric vehicle charging. These forecasts are based on expectations around current stock and future adoption (including the effect of financial incentives to facilitate adoption), and the expected electricity consumption per vehicle.

We use standard statistical modeling techniques to reflect these and other potential sources of variation around our expected forecasts. We discuss our forecasting process, inputs, assumptions, adjustments and results in more detail in Appendix F1: Load and Distributed Energy Resource Forecasting.

II. MISO RESOURCE ADEQUACY REQUIREMENTS

MISO prescribes Resource Adequacy (RA) requirements that are intended to help ensure adequate reliability of the bulk electric supply system. MISO's RA process requires load serving entities (LSE) like the Company to maintain resources that exceed their level of demand by a specific margin (planning reserve margin or PRM) to cover potential uncertainty in the availability of resources or level of demand.[3] The RA requirements are fundamental to the resource planning process, and inform the level of capacity we need in our portfolio to adequately serve customers over a long-term planning process. We describe the various aspects of the calculation below, and note that our effective reserve margin is 2.98 percent.

MISO's RA requirements are set based on an annual planning period; the 2018/2019 planning period covers June 1, 2018 through May 31, 2019. Prior to each planning year, MISO determines two different capacity obligations for each LSE; one for the entire MISO footprint as a whole, and one for the Local Resource Zone (LRZ or Zone) where the LSE resides.[4] For any particular planning year, an LSE's PRM is the greater of the LSE's capacity obligation for the MISO footprint or its capacity obligation for its LRZ.

A. MISO Footprint Capacity Obligation

By November 1 prior to a planning period, MISO issues the finalized PRM applicable to all LSEs within its footprint. MISO determines the PRM by performing a technical probabilistic analysis to determine the minimum PRM needed to achieve a Loss of Load Expectation (LOLE) of 0.1 day per year, expressed as a percentage. For example, for the planning year covering June 1, 2018 through May 31, 2019 the overall MISO PRM was 17.1 percent on an installed capacity (ICAP)[5] basis and 8.4 percent on an unforced capacity rating (UCAP) basis.[6] The study also provides

[3] The factors affecting availability and demand include: Planned maintenance, Unplanned or forced outages of generating facilities, Deratings in resource capabilities, Variations in weather, and Load forecasting uncertainty.

[4] Almost all of the NSP system load is located within LRZ 1, which includes almost all of Minnesota, western Wisconsin, and the Dakotas. Approximately 7 MW of load along the Minnesota-Iowa border is located in LRZ 3.

[5] ICAP refers to units' Installed Capacity Rating, which is a capacity accreditation measure based on annual or historical tested generating. The ICAP is the lesser of the generator verification testing capacity or the interconnection service capacity.

[6] UCAP refers to units' Unforced Capacity Rating, which is a function of the unit's installed capacity and its anticipated forced outage rate. A generator's anticipated forced outage rate is typically based on the individual unit's historical performance. UCAP = ICAP x (1 – Forced Outage Rate). *See* "Planning Year 2018-2019 Loss of Load Expectation Study Report" at 5. Available at: https://www.misoenergy.org/api/documents/getbymediaid/80578

forward-looking PRM values, through 2028. Over the planning period MISO examined in the 2018-2019 LOLE study, the UCAP PRM remained relatively constant between 8.3-8.4 percent.

Each LSE is required to have resources sufficient to meet the forecasted demand at the time of MISO's peak demand, plus its PRM margin. MISO's tariff acknowledges a state regulatory body's authority to establish a PRM for LSEs within its jurisdiction, which would override the PRM otherwise determined by MISO. None of the NSP System states have established a PRM separate from MISO.

B. Zonal Capacity Obligation

Additionally, MISO makes an annual determination regarding the amount of capacity required within each of MISO's Zones, called the Local Clearing Requirement (LCR). The LCR is determined as a function of each Zone's Local Reliability Requirement (LRR) and its Capacity Import Limit (CIL). The LRR represents the necessary resource requirement in order for a Zone to achieve an LOLE of 0.1 day per year, without relying on resources outside of the Zone. Each Zone, having a smaller footprint than the overall MISO footprint does not benefit from the same level of peak load diversity as does the larger, more diverse MISO footprint. Thus, it can be expected that a Zone's LLR is greater than the sum of its LSEs' MISO footprint obligations. If a Zone within which an LSE operates has import capacity, however, the resulting LCR is reduced. As a result, LSEs usually plan their minimum system needs based on the MISO-wide PRM rather than the zonal requirement.

For the 2018-2019 planning year, Zone 1 was assigned an LRR of 114.8 percent, which, in capacity terms equates to an LRR of 20.2 GW. However, when accounting for Zone 1's CIL of 4.4 GW, Zone 1's LCR is 15.8 GW. This is less than the MISO footprint PRM of 18.4 GW. Thus, Zone 1's import capabilities allow LSEs within Zone 1, including the Company, to plan to the MISO-wide UCAP PRM of 8.4 percent rather than the higher LRR value.

C. Capacity Obligations Derived From Forecasted Demands

After determining the relevant PRM, each LSE can derive its MISO-wide and zonal capacity obligation from its forecast of peak demand (peak load). While LSEs typically forecast the peak demand for their individual system, the resource adequacy process requires the LSE to also forecast:

- The LSE's demand at the time of the MISO footprint's peak demand (MISO Coincident Peak Demand, or MISO CPD), and

- The LSE's demand at the time of the LRZ's peak demand (Zonal Coincident Peak Demand, or Zonal CPD).

Again, because each LRZ footprint is smaller than the MISO footprint, the LRZ's load diversity is lower than the load diversity of the MISO system, and an LSE's Zonal CPD is equal to or greater than its MISO CPD.

The NSP System CPD factor measures how closely our system peak matches the MISO system peak. A coincidence factor of 95 percent indicates that we expect to experience load levels that are approximately 95 percent of our peak load during times when the total MISO system load is peaking. In other words, the timing of our peak and the MISO peak does not match exactly, so we are able to reduce the amount of reserves we carry as a result. After accounting for the coincidence factor, our effective reserve margin drops from 8.4 percent to 2.98 percent. We illustrate this calculation in Figure 3-4 below.

Figure 3-4: MISO Planning Reserve Margin Calculation – NSP System Planning Year June 1, 2018 to May 31, 2019

$$(95\ percent\ coincidence\ factor)x\ (1 + 8.4\ percent) - 1 = 2.98\ percent\ effective\ reserve\ margin\ for\ NSP$$

Putting these pieces together, we used our effective reserve margin, in combination with our annual load forecasts over the planning period, to determine our overall capacity obligation for the same period. For 2020, this calculation results in the following approximate obligation:

Table 3-1: Capacity Obligation Calculation – 2020 Example

Total Capacity Obligation Component	Value
Forecasted load	9.1 GW
NSP Effective Reserve Margin	x (1+ 2.98%)
NSP Obligation	**= 9.4 GW**

Our estimated obligation for all planning period years can be found in the Load and Resources table in Section VI. below.

D. Capacity Accreditation of Resources

After these obligation levels have been determined, we consider the type of resources

suitable to meet that requirement. MISO's tariff and business practices set forth procedures to enable various types of resources to be used to achieve our RA requirements. While there are different requirements among the various types of resources, common characteristics require resources participate in the annual registration process, requiring annual testing and reporting of capability or reporting of historical output. Each resource must have firm delivery to load, and resources must be available throughout the entire planning period.

Resources used to achieve MISO's RA requirements are referred to as "Planning Resources." Planning Resources include the following sub-types:

- *Capacity Resources*: Physical Generation Resources (i.e. physical assets and purchase agreements), External Resources if located outside of MISO's footprint, and DR Resources participating in MISO's energy and operating reserves market, available during emergencies.
- *Load Modifying Resources*: Behind-the-Meter Generation and DR available during emergencies, which reduces the demand for energy supplies coming from the LSE.
- *Energy Efficiency Resources*: Installed measures on retail customer facilities designed and tested to achieve a permanent reduction in electric energy usage while maintaining a comparable quality of service.

MISO's resource accreditation represents a measure of a resource's reliable contribution to the system's resource adequacy needs. A generator's operation, maintenance, and utilization directly impact the portion of nameplate capacity rating recognized as an accredited resource. Therefore, instead of using installed or nameplate capacity (i.e. ICAP), MISO calculates the unforced capacity value (i.e. UCAP) for each resource to determine its expected contribution to RA. These are calculated differently depending on the resource's dispatchability or variability:

- *Dispatchable generation resources, DR and EE* – MISO assigns a UCAP value for dispatchable generation resources by discounting their installed capacity by an anticipated forced outage rate. Resources where availability depends on other factors are measured differently; for example, MISO has a process to determine the UCAP for DR resources using a documented process of assessing the resource's observed responsiveness and load reduction effectiveness.
- *Variable resources* – MISO assigns variable resources, such as grid-scale solar and wind, a UCAP value that is a function of the individual unit's historical performance during the peak hours of the planning period. Currently, these units are measured on historical performance during the operating hours of

1500 to 1700 in the months of June-August over the three most recent summers. Each site must have one complete historic period of data prior to unit accreditation. If sufficient operating history is not available, MISO assigns a proxy value.

Our modeling selects resources based on their UCAP values, to ensure we maintain adequate capacity on our system over the planning period. Additionally, as discussed below in Section IV, we included a further Reliability Requirement in our planning process to address MISO's evolving processes.

III. DEMAND SIDE MANAGEMENT

DSM programs offer our customers opportunities to lower their energy use and manage their peak demand, in particular through our Conservation Improvement Programs. As noted previously, these programs include both EE and DR. We base our forecasts and potential incremental additions on historic achievements through our programs, as well as external studies about expected and potentially achievable adoption rates.

As previously discussed, we adjusted the customer capacity and energy forecasts in this Resource Plan to distinguish incremental EE from the load forecast. We modeled incremental DR and EE achievements as "Bundles" to be evaluated alongside other resource options. Each Bundle represents a combination of program achievements expected to lead to a certain amount of avoided load or energy per year, at an estimated blended cost.

For EE, these Bundles include measures that work to reduce a customer's overall energy usage throughout the year. The DR Bundles, on the other hand, reflect a customer's commitment to discrete reductions in demand (e.g. on a day when peak load is expected to be high otherwise). These actions are expected to reduce the anticipated annual system peak demand, as well as smooth demand on specific days when weather or other conditions lead to high demand at a certain point in time. In the Order approving our last Resource Plan,[7] the Commission directed that the Company "shall acquire no less than 400 MW of additional DR by 2023." In this Resource Plan, we included one DR Bundle in our modeling for both the Reference Case and Preferred Plan.

We discuss the studies that informed our expected EE and DR levels, our analysis,

[7] *See* E002/RP-15-21 Order Approving Plan with Modifications and Establishing Requirements for Future Resource Plan Filings (January 11, 2017), Order Point 10.

and the changing DSM landscape in more detail in Appendix G1.

IV. RELIABILITY REQUIREMENT

A new planning element we included in this Resource Plan is a Reliability Requirement which, in short, will ensure that we can serve customers with reliable energy every hour of every day.

The need for the Reliability Requirement stems from the inherently variable nature of renewable resources and availability of any time limited resource. Further, as the penetration of these resources increases, their value to meet peak customer needs decreases. Although MISO is beginning to recognize these challenges, its current planning constructs do not yet incorporate any measures to address them. Until MISO determines how best to address these gaps, we believe it is incumbent on us as the utility to take steps to ensure that our system is resilient and that our customers will be reliably served. Fundamentally, we have a responsibility to ensure we have access to a sufficient level of firm dispatchable resources in all grid conditions that can flexibly adapt to variable renewable resource performance to meet our customers' needs.

To develop the Requirement, we analyzed industry insights and data from case studies, including the 2019 polar vortex and normal winter and summer days. From this information, we developed a method determine a threshold level of firm dispatchable resources needed to serve customer loads, that reflects a reasonable level of reliance on MISO resources and DR to meet a portion of the need.

Figure 3-5 below demonstrates the calculation of the Reliability Requirement we applied in our modeling for this Plan.

Figure 3-5: NSP System Reliability Requirement Calculation – 2020 Example

Peak Demand Proxy – 6.4 GW
Minus Firm DR (Winter) Proxy – (0.2) GW
Minus Firm Market Supply Proxy – (0.5) GW

Reliability Requirement - 5.7 GW
(Firm dispatchable resources)

To implement this Requirement, we applied it as a threshold in our Strategist modeling to ensure that our firm dispatchable resources do not fall below this level – even while our Preferred Plan achieves an 80 percent carbon reduction by 2030. In

the 2020-2034 planning period, the Requirement ranges from approximately 5.6 GW early in the planning period, to about 6.0 GW by the end of the planning period. We clarify here, however, that while this concept is essential to include until MISO evolves its capacity accreditation constructs, the Requirement as applied in our modeling has little effect for this Resource Plan. The model does not select any firm dispatchable additions as a direct result of the Reliability Requirement until near the end of the planning period, in 2031. This long runway leaves ample time for MISO and its stakeholders to address this aspect of its planning and provide additional direction.

V. EXISTING RESOURCES

Our current generating resources[8] comprise a diverse portfolio including nuclear, coal, wind, biomass, solar, hydro, natural gas and oil-fueled facilities. Physical generating assets owned by the Company have a net maximum capacity of over 9,500 MW, including 850 MW of wind.[9] In addition to these assets, we maintain PPAs representing a net maximum capacity of over 3,700 MW.[10] Together, these provide over 13,200 MW of generation resources, of which over 4,300 MW[11] is supplied by renewables. A total of over 6,000 MW[12] is supplied by carbon-free resources.

A. Renewable Resources

In total, we currently have over 4,300 MW of renewable capacity serving the NSP System, including:[13]

- Over 2,600 MW of wind
- 840 MW of solar, including community solar programs and grid-scale solar[14]
- 680 MW of hydroelectric power[15]
- 160 MW of biomass and landfill gas

[8] As of July 2019; excludes some resources included in modeling that are expected to be online by the end of 2019.
[9] Maximum capacity represented here reflects capacities included in Strategist modeling. It approximates Net Maximum Capacity, which is defined as the units Gross Maximum Capacity, less any capacity that is used for that unit's station service or auxiliary load.
[10] This total excludes 425 MW of renewable diversity capacity credit from contracts with Manitoba Hydro.
[11] *Id.*
[12] *Id.*
[13] Note: these values are approximate.
[14] Per Docket No. E002/RP-15-21 Order Point 4a (January 11, 2017), our solar acquisitions will exceed the 650 MW through CSG resources or other cost-effective acquisitions. The CSG program is on track to exceed the ordered 650 MW by year ending 2019, per the most recent forecast CSG Monthly Report (filed June 14, 2019) and included in this filing as Appendix N8.
[15] Excluding capacity associated with diversity agreement contracts with Manitoba Hydro.

B. Nuclear

Our Monticello and Prairie Island nuclear plants provide nearly 1,740 MW of clean energy and capacity to our customers and play an important role in achieving our goal of an 80 percent reduction in system carbon emissions by 2030, while maintaining reliability and affordability. The monthly capacity factors of our nuclear facilities are historically 90 percent or higher. Together, our nuclear plants currently provide nearly 30 percent of our energy mix. In terms of production costs (fuel plus O&M), both plants have achieved reductions of more than 20 percent since 2015, with average costs now below $30/MWh.

C. Coal

Our coal fleet includes our Sherco Units 1, 2, and 3 in Becker, Minnesota and the Allen S. King plant in Oak Park Heights, Minnesota. This coal fleet provides almost 2,400 MW of baseload and cycling generating capacity, and supports system reliability. In our last Resource Plan, the Commission approved our proposal to retire Sherco Units 1 and 2 in 2026 and 2023, respectively. These retirements are reflected in our Reference Case discussed below. Our Preferred Plan further proposes to retire the King plant in 2028 and Sherco 3 in 2030, after which coal would no longer be part of our energy mix.

D. Natural Gas (and Oil-Fired) Fleet

Our natural gas fleet consists of both intermediate and peaking generation. We have five owned or contracted intermediate-type generating assets that provide just over 2,400 MW of capacity. We have peaking-type resources located at seven sites, providing another 2,350 MW of capacity. Combined, these facilities provide valuable load following capabilities for our system, cycling as necessary to provide important flexibility to our generation operations and support to our growing renewable resources. Our Reference Case also includes pending and proposed capacity resource additions including MEC as proposed in Docket No. IP6949,E002/PA-18-702, and the Sherco CC that the Commission acknowledged in its Order in our last Resource Plan.[16] These pending resources appear in separate line items in our net resource calculation below.

[16] The Commission approved our proposed schedule to retire Sherco Units 1 and 2, and found that more likely than not there will be a need for approximately 750 MW of intermediate capacity coinciding with the retirement of Sherco Unit 1 in 2026. *See* In the Matter of Xcel Energy's 2016-2030 Integrated Resource Plan, ORDER APPROVING PLAN WITH MODIFICATIONS AND ESTABLISHING REQUIREMENTS FOR FUTURE RESOURCE PLAN FILINGS, Ordering Point Nos. 7 and 8, Docket No. E002/RP-15-21 (January 11, 2017).

VI. NET RESOURCE SURPLUS/DEFICIT

As described above, our forecast of customers' peak demand and MISO Resource Adequacy requirements are used to determine our overall total generating capacity obligation. From this, we deduct our expected load management achievements and UCAP generating capacity of the various resources we have included in our Reference Case to determine our net generation capacity surplus or deficit. We anticipate a net surplus through 2026 and a deficit thereafter.

Table 3-2: Reference Case Load and Resources,[17] 2020-2034 Planning Period

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
System needs															
Forecasted gross load	10,499	10,559	10,621	10,684	10,755	10,820	10,886	10,954	11,140	11,232	11,320	11,418	11,518	11,619	11,717
Forecasted EE[18] (reduction to load)*	(1,386)	(1,472)	(1,517)	(1,609)	(1,707)	(1,822)	(1,921)	(1,992)	(2,125)	(2,215)	(2,278)	(2,366)	(2,352)	(2,324)	(2,415)
Forecasted net load	**9,112**	**9,087**	**9,103**	**9,075**	**9,048**	**8,998**	**8,965**	**8,963**	**9,014**	**9,016**	**9,042**	**9,052**	**9,166**	**9,295**	**9,301**
MISO System Coincident	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
Coincident Load	8,657	8,633	8,648	8,621	8,595	8,548	8,517	8,514	8,564	8,565	8,590	8,599	8,708	8,831	8,836
MISO PRM	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%
NSP Obligation	**9,384**	**9,358**	**9,374**	**9,345**	**9,317**	**9,266**	**9,232**	**9,230**	**9,283**	**9,285**	**9,312**	**9,321**	**9,439**	**9,572**	**9,579**
Reference Case resources (UCAP)															
Load Management *(existing)*	940	955	970	989	1,007	1,023	1,038	1,053	1,066	1,054	1,043	1,032	1,021	1,010	1,000
Load Management* *(potential study)*	270	290	312	322	339	380	392	406	421	438	456	476	497	527	550
Coal	2,390	2,390	2,390	2,390	1,699	1,699	1,699	1,017	1,017	1,017	1,017	1,017	1,017	1,017	1,017
Nuclear	1,603	1,603	1,603	1,603	1,603	1,603	1,603	1,603	1,603	1,603	1,603	992	992	992	484
Natural Gas/Oil	3,295	3,295	3,295	3,295	3,141	2,829	2,624	2,136	2,018	2,018	2,018	2,018	1,765	1,765	1,765
MEC*	627	627	627	627	627	627	627	627	627	627	627	627	627	627	627
Sherco CC*	0	0	0	0	0	0	0	727	727	727	727	727	727	727	727
Biomass/RDF	110	110	110	86	86	63	63	63	22	22	22	22	22	22	22
Hydro	877	997	989	989	989	162	162	162	162	162	162	162	156	152	152
Wind	596	650	696	670	659	642	637	622	616	594	593	578	575	511	492
Grid-scale solar	182	182	181	180	179	178	177	176	175	174	174	173	172	171	170
Solar*Rewards Community Solar	335	339	344	348	352	356	360	365	369	373	377	381	385	389	393
Distributed Solar	42	48	55	60	66	72	78	83	89	95	100	105	111	116	121
Existing Resources	**11,267**	**11,486**	**11,571**	**11,559**	**10,746**	**9,634**	**9,460**	**9,040**	**8,913**	**8,905**	**8,920**	**8,311**	**8,066**	**8,026**	**7,521**
Net Resource (Need)/Surplus	**1,884**	**2,128**	**2,196**	**2,213**	**1,429**	**368**	**228**	**(190)**	**(370)**	**(380)**	**(392)**	**(1,010)**	**(1,373)**	**(1,546)**	**(2,058)**

While the Order also addressed next steps for the replacement generation at Sherco, legislation was passed as part of the 2017 Legislative Session that in summary, allows the Company to proceed with the construction of the replacement unit at Sherco in accordance with the parameters specified in the legislation, and without a Certificate of Need. *See* Laws of Minnesota 2017, chapter 5 – H.F. No. 113, section 1.

[17] In addition to existing and approved resources, those indicated with a * include pending or proposed resources that we have included across all Scenarios, including the Reference Case.

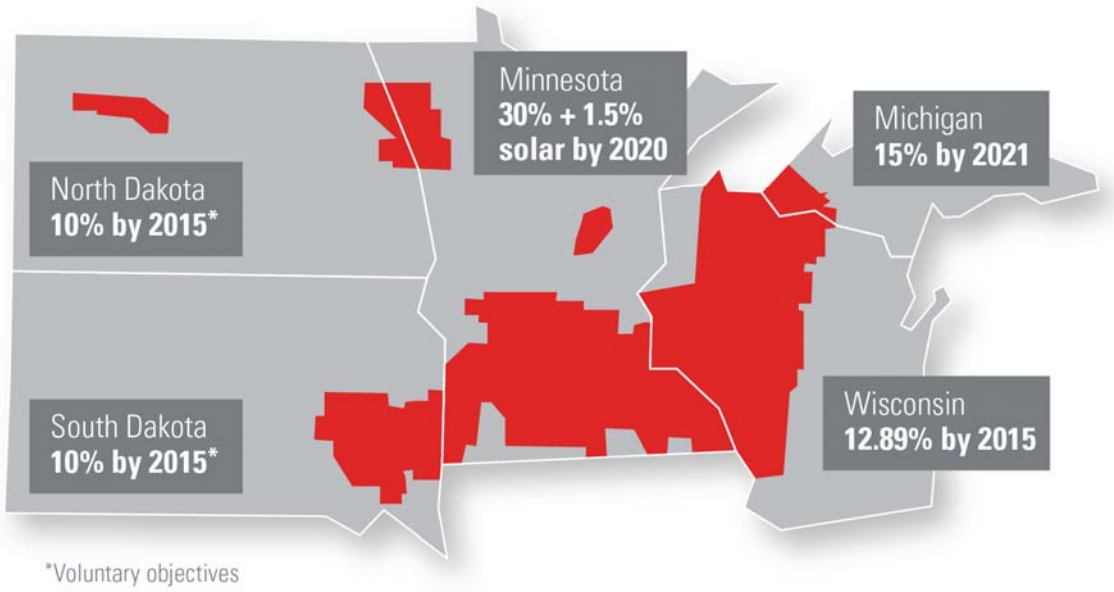
[18] Includes EE savings from historically installed measures, as well as future EE from bundles modeled in this Resource Plan, achieving 2-3% savings levels. Also includes minimal EV and coincidence adjustments.

VII. MEETING RENEWABLE ENERGY REQUIREMENTS AND GOALS

A. Minimum Compliance Requirements

Each of the states in the NSP System has a different public policy with respect to renewable energy requirements or objectives. Figure 3-6 below illustrates each state's renewable energy standard (RES).

Figure 3-6: Renewable Energy Requirements and Objectives – NSP System



Three of our states have renewable standards expressed as a percentage of electric retail sales from qualifying resources by a certain date. Minnesota's RES is the highest, requiring that 30 percent of the Company's energy come from renewables, with at least 24 percent of the electricity we provide to retail customers coming from wind energy by 2020[19] Legislation passed in the 2013 session also established a Solar Energy Standard (SES) for Minnesota that requires that investor-owned utilities in the state generate 1.5 percent of 2020 retail sales, net of customer exclusions, from solar energy resources. Of that 1.5 percent, 10 percent must come from systems with

[19] This requirement is included in the total 30 percent RES, and we are authorized to count a limited amount of solar energy towards an overall 25 percent wind and solar requirement (amounting to 1% of total sales). The SES is assessed separately. Large hydro does not count as a renewable energy source for purpose of the Minnesota RES. Minn. Stat. § 216B.1691.

capacity less than 40 kW.[20] The legislation also established a goal of 10 percent of energy sales from solar by 2030.

North Dakota and South Dakota each have a voluntary objective that includes renewable or recycled energy.[21] Further, our North Dakota regulators have indicated that compliance with the North Dakota Renewable Energy Objective should be accomplished with competitively-priced energy.

To-date we have implemented a strategy to have the entire NSP System comply with, at the very least, the highest of renewable energy requirements across our jurisdictions; in this case, the Minnesota RES. This strategy also places us in compliance with the specific requirements in each of our other jurisdictions. As a result, we have been planning for renewable energy additions, and allocating their benefits, to all of our jurisdictions (with certain exceptions as discussed in the Planning Landscape). As state energy policies continue to evolve, however, we will continue to examine whether this requires a strategy change going forward, and engage our Commissions as needed on that topic.

B. RES Compliance

Given existing and previously approved resources, we project continued compliance with the renewable energy goals and standards in each of our NSP states. The Company currently maintains a set of banked Renewable Energy Credits (RECs) for future compliance.[22] In the past, we have leveraged our REC bank to manage the size, type, and timing of renewable energy additions on our system, to ensure that we identify and acquire the renewable generation resources that provide our customers with the greatest value at the lowest cost. Given our recent focus on adding renewable capacity, however, we now generate RECs in excess of our baseline obligations each year. We currently generate sufficient RECs annually from eligible renewable resources to account for over 40 percent of the energy we provide our NSP System customers, which outpaces our annual requirement

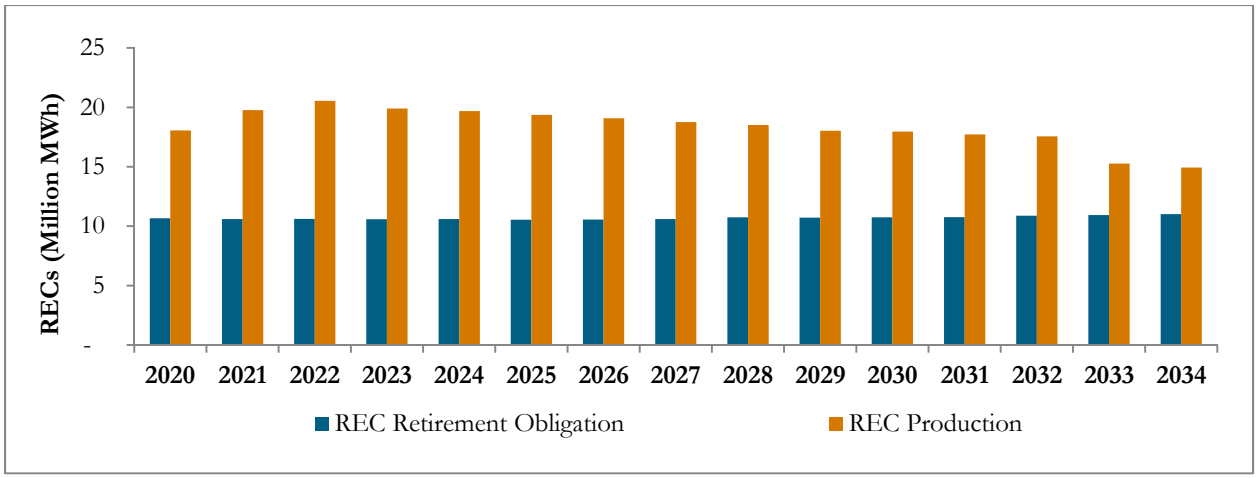
[20] The original legislation set a threshold of 20 kW, but was increased to 40 kW in 2018, per HF3232. *See* "Minnesota Renewable energy Standard: Utility Compliance." Minnesota Department of Commerce (January 2019) at 7. Available at: https://www.leg.state.mn.us/docs/2019/mandated/190330.pdf

[21] As defined in North Dakota Century Code, 49-02-25, recycled energy means "systems producing electricity from currently unused waste heat resulting from combustion or other processes into electricity and which do not use an additional combustion process. The term does not include any system whose primary purpose is the generation of electricity unless the generation system consumes wellhead gas that would otherwise be flared, vented, or wasted." South Dakota Codified Law 49-34A-94 contains a similar definition.

[22] A REC is an accounting device designed to reflect the renewable energy attributes of a particular MWh of renewable energy generation. RECs are the currency for compliance with state renewable targets.

Figure 3-7 below illustrates annually generated RECs across the NSP System in the Reference Case scenario. In this scenario, we will have sufficient RECs to comply with the current renewable energy goals and standards of all of our NSP jurisdictions through 2034, even without securing additional renewable resources.

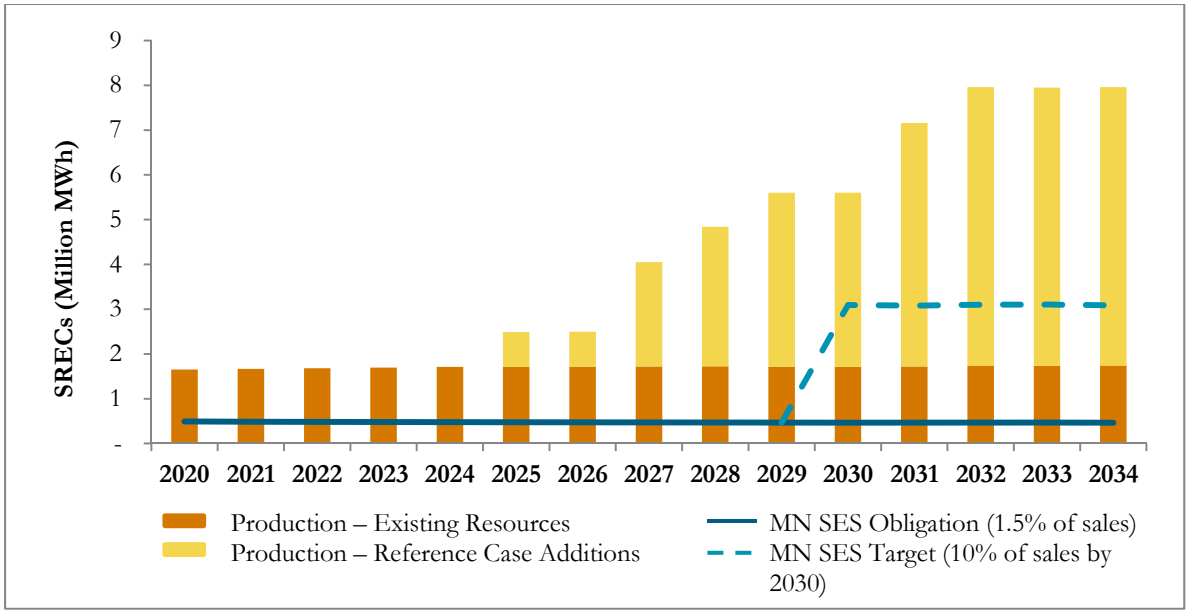
Figure 3-7: REC Production and Retirement Obligations for NSP System – Existing Resources Only



C. SES Compliance

As previously mentioned, Minnesota law requires us to provide our customers with solar-generated energy equal to at least 1.5 percent of our annual customer demand by 2020, and a goal of 10 percent by 2030. We have developed a portfolio of programs to provide solar options to residential and commercial customers, and have also grown our utility-scale solar profile. As a result, we expect to meet the SES requirements through the planning period, per our Reference Case. We also expect the solar capacity additions included in our Reference Case to provide sufficient energy to meet the 10 percent goal by 2030. Figure 3-8 below demonstrates our annual estimated SREC production relative to Minnesota requirements and goals, for the Reference Case scenario.

Figure 3-8: NSP System SREC Production and Minnesota Annual Requirements



We discuss our renewable energy standard compliance further in Appendix N4: Renewable Energy Compliance Positions.

VIII. ENERGY POLICY AND COMPANY GOALS

As demonstrated, we believe that we are well positioned to meet minimum system needs. At least through 2024, we expect that we will be able to meet those needs with existing and already-approved resources. However, in 2018, we committed to an ambitious carbon reduction vision, to achieve 80 percent below 2005 carbon emissions levels by 2030 and 100 percent carbon-free energy by 2050. We are committed to achieving this goal, and as such, have modeled our Reference Case, Preferred Plan, and all other scenarios using our 80 percent carbon reduction target as a guidepost.

IX. REFERENCE CASE

We incorporate all of the aforementioned elements into the Strategist modeling tool, which allows us to explore how we best meet our customer and policy requirements under a variety of conditions and at a reasonable cost. We work with internal and external subject matter experts to develop starting assumptions that reflect their expert opinion of likely future conditions. We then test the robustness of the plans through sensitivity analysis by individually changing key assumptions and re-running

the plans under these changed assumptions. Our analysis resulted in the following Reference Case Expansion Plan, depicted in Tables 3-3 and 3-4 below:

Table 3-3: Reference Case Annual Expansion Plan (UCAP)[23]

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Grid-Scale Solar	0	0	0	0	0	250	0	500	250	250	0	500	250	0	0
Battery	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CC	0	0	0	0	0	0	0	727	0	0	0	0	0	0	0
Firm Dispatch-able	0	0	0	0	0	0	0	0	0	0	0	0	206	330	330
DR	270	20	21	10	17	41	12	14	15	17	19	20	21	22	23
EE	115	130	116	133	143	145	154	157	155	140	138	136	129	126	126
Wind	0	0	0	20	7	11	10	11	2	17	2	9	5	82	247
Distributed Solar	154	22	22	21	21	21	21	20	20	20	20	20	20	20	19
Total	**540**	**172**	**159**	**184**	**188**	**468**	**196**	**1,453**	**442**	**443**	**179**	**685**	**630**	**579**	**745**

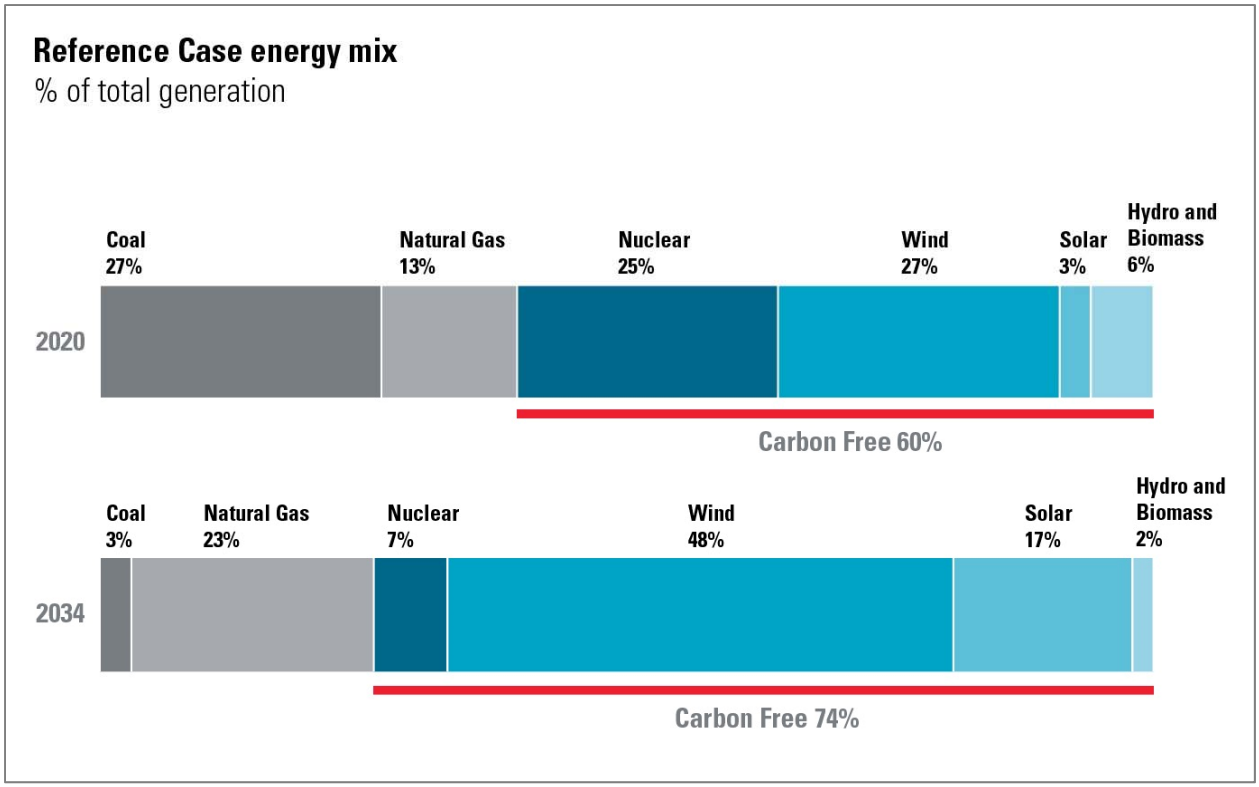
Table 3-4: Reference Case Annual Expansion Plan (ICAP)[24]

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Grid-Scale Solar	0	0	0	0	0	500	0	1000	500	500	0	1000	500	0	0
Battery	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CC	0	0	0	0	0	0	0	835	0	0	0	0	0	0	0
Firm Dispatch-able	0	0	0	0	0	0	0	0	0	0	0	0	232	374	374
DR	270	20	21	10	17	41	12	14	15	17	19	20	21	22	23
EE	115	130	116	133	143	145	154	157	155	140	138	136	129	126	126
Wind	0	0	0	126	45	70	66	72	10	107	16	56	31	523	1581
Distributed Solar	154	22	22	21	21	21	21	20	20	20	20	20	20	20	19
Total	540	172	159	290	226	777	252	2,098	700	784	193	1,232	932	1,065	2,123

The Reference Case presented here would result in the following energy mix:

[23] Note: This table includes CC, EE, DR, and Distributed Solar resources that are also reflected in the Load and Resources Table.
[24] Note: This table shows ICAP values of the resources indicated in Table 3-4 above.

Figure 3-9: Reference Case Energy Mix in 2020 and 2034



We outline and discuss the starting assumptions, scenarios, and sensitivities that formed our Strategist analysis, and resulted in our Preferred Plan, below and in Appendices F2 and F3.

CHAPTER 4
THE PREFERRED PLAN

The Preferred Plan we propose in this 2020-2034 Upper Midwest Resource Plan reflects extensive collaboration with stakeholders as well as independent expert analysis. It supports our states' clean energy goals and the Company's goal of reducing carbon emissions 80 percent by 2030 – and our ultimate vision of 100 percent carbon-free energy by 2050.

Key components of our Preferred Plan include:

- Retiring nearly 2,400 MW of remaining coal-fired capacity by 2030, including previously approved Sherco 1 and 2 retirements and newly proposed accelerated retirement timelines for Sherco 3 and King. We also plan to implement seasonal dispatch at Sherco 2 prior to its retirement.
- Adding thousands of megawatts of new renewable resources, including substantial solar additions and replacement of expiring wind PPAs.
- Continuing to operate our nuclear plants at least until the end of their licenses, and extending operation of Monticello to 2040, as these resources anchor the grid in around the clock carbon-free energy.
- Significantly increasing our EE and DR resources, which will reduce our overall system demand.

Maintaining grid reliability and resilience through this transformation – as we must – will require firm and dispatchable load supporting resources and potentially significant transmission development. Accordingly, in order to meet reliability needs and support renewable integration as we retire legacy coal units, our Plan includes continued operation of our nuclear units (including a proposed 10-year extension of Monticello), acquisition of the MEC CC, and construction of a CC at Sherco, which we proposed in our last Resource Plan.

At the same time, we believe there may are exciting opportunities to pilot batteries, DER, and other clean, innovative technologies in the Upper Midwest. With respect to DR, in particular, we are seeking the flexibility to evaluate and pursue the required incremental DR through a variety of means and technologies that may go beyond conventional DR.

We have also sought to retain strategic flexibility by deferring decisions on certain generating units such as Prairie Island, which can be addressed in the next planning cycle. Doing so leaves room for innovation and allows for reassessment of

technologies, costs, and capabilities before making substantial investments. It is also consistent with our longstanding belief that a deliberate and well-thought-out fleet transition is critical to facilitating successful community and employee transitions.

Finally, our Preferred Plan comes at a reasonable cost to our customers – with estimated rate impacts that are at, or below, the rate of inflation. In other words, we can achieve industry-leading reduction to CO_2 emissions at a cost that is consistent with the expected national average increase in electricity prices.

In summary, the course we have charted in this Preferred Plan drives toward our goal of achieving significant carbon reductions by 2030 and positions us to deliver on our longer term vision of a carbon-free electricity mix by 2050 – all without sacrificing our ability to deliver the reliable and affordable power that our customers count on every day. In this section we discuss: (1) our primary planning objectives and how they are reflected in our Preferred Plan, (2) the key components of the Plan and the actions we intend to take to achieve it, (3) the estimated customer cost impacts of our Preferred Plan, and (4) how this Plan meets the Commission's public interest objectives. We take each in turn.

I. PLANNING OBJECTIVES

When we began this Resource Plan process more than a year ago, we framed key planning objectives that would set the framework for development of our plan. The objectives are complex. They sometimes overlap and conflict, but each played a critical role in guiding our thinking and analysis which ultimately culminated in a plan that achieves substantial environmental benefits, maintains reliability, keeps costs low, and minimizes risks to our customers.

Figure 4-1: Xcel Energy Integrated Resource Plan Objectives

A. Environmental and Innovation

Environmental benefits and the technological innovations that will help us achieve them are front and center in this Resource Plan process. We have made a bold commitment to achieve 80 percent carbon reduction from 2005 levels by 2030, and have considered this target a modeling pillar for all of our potential scenarios. Our Preferred Plan achieves this goal in several ways. First, our Preferred Plan eliminates coal from our system by 2030, extends our carbon-free Monticello nuclear plant to 2040, adds at least 4,000 MW of new renewable resources, including substantial new solar capacity additions, maintains the wind levels committed to in our previous resource plan, and replaces renewables with renewables when they reach the end of their life.

It is important to note that, because many of these resource additions are not needed for a number of years, maintaining flexibility in how we achieve our carbon goals is essential. We have watched the planning landscape evolve at a remarkable rate over the last decade and we expect the rapid pace of innovation to continue. In fact, we expect technological advancements and innovations will create opportunities that we can seize upon in future procurement processes and integrated resource planning cycles if we retain the flexibility to do so. For example, future technology costs and transmission considerations may influence our mix of wind, solar and other non-emitting resources. Likewise, the need for firm and dispatchable load supporting capacity additions beyond 2030 may be better filled by battery storage and other advanced technology solutions. Where appropriate, we aim to be technology agnostic

and open to what is coming next.

B. Reliability

Our responsibility to ensure a reliable electricity supply for our customers is a fundamental underpinning of our Preferred Plan. We therefore developed a Reliability Requirement that establishes a minimum level of firm dispatchable resources that is required to serve our customers' needs in every hour of every day. The Reliability Requirement was developed through analysis of industry trends and careful study of our system's performance (and the broader MISO system's performance) during both winter and summer days when renewables were unavailable, sometimes for lengthy durations. We discuss the development of the Reliability Requirement in greater detail in Appendix J2.

This Requirement does not drive any resource additions in our Preferred Plan until after 2030. Prior to 2030, our Preferred Plan relies on two primary sources to ensure reliability: (1) the MEC and Sherco CCs and (2) our nuclear units. With respect to the CC units, intermediate gas resources efficiently address reliability challenges because they can vary output to adapt as demand for electricity changes over the course of the day and year. The CC units are large rotating machines, so also provide important grid stability benefits and can also play an important role in our blackstart plans.[1] With respect to nuclear generation, our proposed Monticello extension not only represents a carbon-free workhorse of a resource, it also enhances fuel diversity and provides a generation resource that is not subject to seasonal fuel supply limitations.

C. Cost

Along with leading the clean energy transition and enhancing the customer experience, keeping customer costs low is one of Xcel Energy's central, guiding objectives. Since our last Resource Plan, renewable technology costs – and in particular, solar costs – have continued to decline; we expect this trend to continue going forward. Taking advantage of technological advancements is one reason that we can deliver a Preferred Plan that delivers deep carbon reductions for a nominal customer cost of just over one percent Compound Annual Growth Rate (CAGR) over the planning period. And over the long run, our Preferred Plan is expected to yield net present value savings. In comparison to the Reference Case, which does not

[1] As previously discussed, upcoming generation retirements will impact our current blackstart plans (*i.e.,* our ability to restart the system in the event of a catastrophic failure). While we do not propose any specific action related to the system blackstart at this time, we anticipate addressing this in our next Resource Plan or earlier, if system needs dictate the need to do so.

include accelerated coal retirements or an extension of the Monticello nuclear unit, the Preferred Plan yields $203 million of benefits on present value revenue requirements (PVRR) basis and $461 million of benefits on a present value societal costs (PVSC) basis.

D. Risk and Flexibility

Finally, while holding environmental, reliability, and cost objectives in balance, we also seek to mitigate customer risk by ensuring fuel diversity, maintaining appropriate capacity length in our portfolio, and maintaining flexibility in our plans. Portfolio fuel diversity is essential to risk mitigation – especially so, as we transition away from coal. Incorporating a mix of nuclear, load management, intermediate and peaking natural gas capacity, and renewables into our long-term plans ensures that our portfolio is adequately diverse and mitigates the risk associated with overdependence on any one fuel source. Further, the proposed resource additions identified in our Preferred Plan result in a capacity position that is between 500 to 1,000 MW long in any given year. We believe this modest length is prudent, particularly as we propose to substantially increase renewable resources – adding more than 4,000 MW of incremental new renewable capacity, much of which we anticipate will be grid-scale solar – in addition to our already large wind fleet.

Both MISO and independent analyses suggest that capacity accreditation for solar in particular will decline substantially as more capacity is added. We expect MISO will ultimately recognize this conclusion from its ongoing study of issues associated with integration of high levels of renewables in its planning construct.[2] Therefore, what we believe today to be a long capacity position may actually erode over time.

Maintaining a significant amount of flexibility in our future plans is essential to reliably and affordably navigating the transition of our fleet. To that end, we are deferring a decision on pursuing a license extension at the Prairie Island nuclear plant to subsequent resource plans, thereby preserving flexibility to respond to market conditions at that time. We are also optimistic that the firm dispatchable, load supporting resources needed in the post-2030 timeframe could be provided by new non-emitting technologies rather than traditional gas CTs. In addition, as we look to add solar resources to meet capacity needs in the mid to late 2020s, we are also open to allowing other resource types to compete, to ensure that we secure the most cost-effective resource solutions for our customers. As the industry and technology

[2] We discuss MISO's *Renewable Integration Impact Assessment* (RIIA) in more detail in our Baseload Study, provided as Appendix J1.

continue to rapidly evolve we will evaluate opportunities to bring these potential alternative solutions onto our grid.

E. Our Employees and Communities

Underscoring all four of our objectives is our commitment to our employees and the communities within which we operate. We do not make plant closure decisions lightly, and we are committed to supporting our employees at the Sherco and King plants as we prepare to retire these facilities. In the past we have provided career support services to our employees facing plant closures, and we expect to continue providing this support in the future. We also know that the Company is a major presence in terms of employment and local tax revenues in Becker and Oak Park Heights and the surrounding areas. We also have partners at our Sherco site with Liberty Paper and SMMPA (Southern Minnesota Municipal Power Agency). We are currently participating, alongside Minnesota Power, in a Host Community Impact study, to better understand the potential impact of power plant retirements on host communities. A similar study helped inform our work with the communities surrounding our Sherco 1 and 2 Units, and their planned closure as approved in our last Resource Plan. Since that time, we have worked with Becker and Sherburne County, as well as existing and prospective customers to spur economic development in the area, which also includes our plans to build, own, and operate the Sherco CC. As discussed in Appendix O1: Summary of IRP Stakeholder Engagement, we are committed to continue to work with our employees and communities to navigate this transition together.

II. THE PREFERRED PLAN

Our Preferred Plan is the product of an unprecedented stakeholder process that included 13 public workshops, independent expert analysis, and months of analysis and information sharing. As a result of those efforts – as well as the significant engagement of our stakeholder community over the past year, our Preferred Plan is the product of an unusual amount of consensus this early in the Resource Plan process.

Significant consensus has emerged around the following components of our Preferred Plan:

- Elimination of coal-fired generation from our system by 2030,
- Reduced, seasonal dispatch of Sherco Unit 2 until its retirement in 2023,
- Acquisition of at least 3,000 MW of utility-scale solar by 2030,

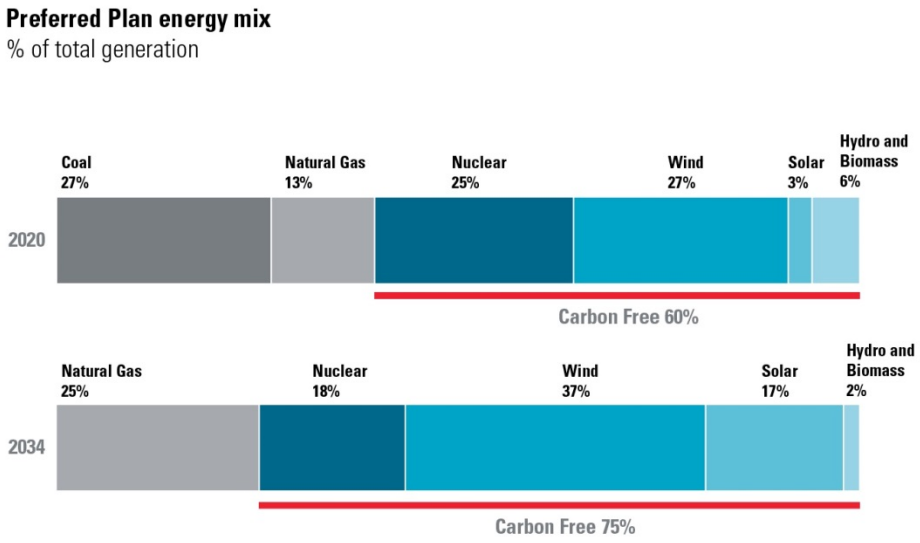
- A substantial increase in EE savings, and
- Support for the Company's proposal to take ownership of the MEC.

Our Preferred Plan builds upon this foundation and includes even more renewable resources, additional DR resources, continued operation of our carbon-free Monticello nuclear plant for an additional 10 years, and a new CC at our Sherco site. In the balance of this section, we present the change in our Energy Mix that will result from our Preferred Plan, and discuss key aspects of the transition below.

A. Transforming Our Energy Mix

From an energy mix perspective, the Preferred Plan eliminates the coal energy contribution and increases the renewable energy contribution by over 20 percent by 2034, rising to approximately 56 percent.

Figure 4-2: Preferred Plan Energy Mix



The fleet transformation underlying our Preferred Plan achieves a nearly 84 percent reduction in CO_2 emissions from 2005 levels by 2030, and maintains at least an 80 percent CO2 reduction through 2034.

Table 4-1 below presents the amount and timing of the resource additions that comprise our Preferred Plan.

Table 4-1: Preferred Plan Resource Additions (MW)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Grid-Scale Solar	0	0	0	0	0	500	500	1000	500	500	500	0	500	0	0
Battery	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CC	0	0	0	0	0	0	0	835	0	0	0	0	0	0	0
Firm Dispatch-able	0	0	0	0	0	0	0	0	0	0	0	606	0	374	748
DR	270	20	21	10	17	41	12	14	15	17	19	20	21	22	23
EE	115	130	116	133	143	145	154	157	155	140	138	136	129	126	126
Wind	0	0	0	126	45	70	66	72	10	107	16	56	31	523	81
Distributed Solar	154	22	22	21	21	21	21	20	20	20	20	20	20	20	19
Total	**540**	**172**	**159**	**290**	**226**	**777**	**752**	**2,098**	**700**	**784**	**693**	**838**	**700**	**1,065**	**997**

In the next section, we discuss key aspects of our Preferred Plan and our fleet transition in more detail.

B. Fleet Transition

Our 2020-2034 Resource Plan represents a progressive step forward in transitioning our fleet – meaning that the Company will complete its transition away from coal-fired generation in 2030 – a full decade earlier than previously anticipated. In total, we plan to retire approximately 2,400 MW of coal-fired generation in the next decade. This will be an unprecedented period of transition for our system that necessitates a prudent replacement strategy. Our strategy for replacing this capacity includes a significant amount of additional renewable generation supported by natural gas CC resources, continued reliance on nuclear generation, and large EE and DR additions during the planning period.

1. Renewable Resources

Substantial renewable additions are a central component of our energy future and a cornerstone of this Preferred Plan. Although the quantities of future wind and solar additions may shift somewhat in concert with technology and market fluctuations, our commitment to renewable energy will not. In total, our Preferred Plan envisions a system that is approaching 60 percent renewable in 2034. High levels of renewables combined with cost-effective gas and nuclear generation will combine to create a safe and reliable system that will withstand the summer and winter extremes of the Upper Midwest. Our Preferred Plan proposes to add at least 4,000 MW of cumulative utility-scale resources by 2034 (the first being in 2025) and approximately 1,200 MW of wind by 2034, to replace wind that would otherwise retire from our system during that period.

With these additions, there would be enough solar generation to power more than 650,000 homes each year. Wind generation also continues to play a prominent role in this Preferred Plan. Xcel Energy has long been one of the nation's leading providers of wind energy, and we are currently engaged in the largest build-out of new wind resources in our Company's history – thanks in large part to the Commission's approval of our last resource plan and our 1,850 MW wind portfolio. By 2034, wind will provide 37 percent of the electricity for our customers in this region, making it the largest component of our overall generation portfolio.

2. Coal Resources

Large coal-based generating units have been an important baseload resource to stable grid operations for many decades. As we and other utilities move away from coal for economic, environmental and public policy reasons, we must do so with the maintenance of a resilient and reliable grid at the forefront of our minds.

In our most recent Resource Plan, the Commission approved our proposal to retire our Sherco Units 1 and 2 in 2026 and 2023, respectively. Our proposal to retire these units early was informed by technical analyses that also determined the Sherco CC included in this Preferred Plan is essential to mitigate grid issues. Similarly, our proposal in this Resource Plan to retire our remaining two coals units early – King in 2028 (nine years early), and Sherco 3 in 2030 (ten years early) – is informed by technical and other analyses discussed in our Baseload Study, provided as Appendix J1. As also described in the Economic Modeling Framework Chapter of this Resource Plan, we have included estimated grid reliability mitigation costs into our Strategist modeling underlying the Preferred Plan.

Finally, our Preferred Plan also includes a commitment to offer Sherco Unit 2 into MISO on a seasonal basis until its retirement in 2023 and Commission consideration.

3. Nuclear Resources

Our Preferred Plan proposes to operate our Monticello nuclear unit through 2040 (10 years longer than its current license), and continued operation of both of our Prairie Island units through the end of their current licenses (PI Unit 1 to 2033 and PI Unit 2 to 2034).[3] Nuclear is central to achieving our carbon reduction goals while incorporating incremental renewables at a reasonable pace and maintaining reliability.

[3] Given that our operating licenses for Prairie Island run until 2033 and 2034, we believe there is sufficient time to address the future of that plant in upcoming resource plans.

Nuclear is also an important system resource during the winter months, as it does not experience fuel supply issues and has a great track record during cold weather events – making it a critical component of our reliability strategy. Finally, the continued operation of Monticello contributes to the affordability of our plan by leveraging an existing, high-performing asset on our system. We discuss the benefits of nuclear, as well as the performance of our nuclear fleet, in greater detail in Appendix K.

4. Combined Cycle Resources

In addition to our carbon-free nuclear baseload, the continuation of dispatchable generation on our system will be vital to our ability to manage the retirement of approximately 2,400 MW of coal-fired generation over the next decade while maintaining reliability. It will also facilitate our ability to successfully integrate large amounts of renewables, because we can ramp the output of these resources up or down in response to our system's changing needs throughout the day as renewable resources generate more or less due to their variable nature. To that end, our Preferred Plan includes our proposed acquisition of MEC,[4] which is a 760 MW two-unit CC, as well as our plan to build the approximately 800 MW Sherco CC located in Becker, Minnesota in the mid-2020s.

As discussed in the pending MEC docket, that plant is already an integral part of our system, as its output is committed to the Company through two Commission-approved PPAs. By securing ownership of the plant, we can mitigate the risk associated with expiration of the first PPA in 2026, thereby achieving additional certainty with respect to capacity and dispatchable energy. As discussed in our last Resource Plan, siting a CC at the existing Sherco site will cost-effectively address grid issues identified by the MISO Attachment Y2 study of the Sherco Unit 1 and 2 retirements. Additionally, the Sherco CC will primarily offset the retirement of other gas units on our system, including the Cottage Grove facility (approximately 250 MW in 2027) and Black Dog 5 (approximately 300 MW in 2032). Replacing this capacity is not only reasonable but operationally necessary in light of the much larger coal retirements planned and the large amounts of variable renewable additions we anticipate in the same period. The Sherco CC will also mitigate impacts to the local community and our employees, and potentially provide improved access to natural gas supplies for communities in Central Minnesota. We discuss the Sherco CC further in Appendix L.

[4] As proposed in Docket No. IP6949,E002/PA-18-702. We will incorporate any Commission decision from that docket into our modeling and supplement the record as necessary.

5. Firm and Dispatchable Load Supporting Resources

Reliability is central to resource planning. We are particularly focused on the reliability of our system in this Resource Plan, however, as we embark on a complete transformation of our baseload fleet, and transition to a portfolio of variable renewables that approaches 60 percent of our overall generation. Our transition to cleaner energy will only be successful if we can execute our vision without disrupting our customers' lives and businesses by ensuring a resilient grid that enables us to meet our obligation to provide reliable service.

To this end, our Preferred Plan proposes to begin adding approximately 1,700 MW of cumulative firm dispatchable, load-supporting resources in the 2031 to 2034 timeframe. The need for these dispatchable resources emerges in this later timeframe due to the major plant retirements already discussed, as well as the expiration of several PPAs. Our reliability analysis underlying this Resource Plan demonstrates that these additions are necessary to continue to support grid reliability and resiliency in light of the increased renewables being added to the system and the baseload units being retired.

That said, because these units are not needed until the out-years of our current plan, we have not identified a specific resource type to meet this need. With the expected price declines and technology development between now and the 2030s, we believe storage will be an integral resource used to meet this need. Likewise, we believe the deployment of advanced grid investments could position DR to better compete with traditional generation for this purpose. We are committed to pursuing all of these options not only in the longer term, but also in the near-term in order to leverage this technology as it matures. Generally, by keeping options open and remaining technology agnostic, we can acknowledge the need for a firm resource at the tail end of our plan, but allow the market to advance as we submit future Resource Plans, continue to collaborate with our stakeholders, and engage with the Commission as the need for these resources begins to materialize.

In the meantime, we are analyzing potential locations and sizing of storage solutions as well as the potential values storage assets might provide to the system.

6. Energy Efficiency and Demand Response

Demand Side Management (DSM, which collectively is EE and DR) resources empower our customers to control their energy usage and their monthly electric bills. Load control DR programs are an important part of our resource mix as they can be used during periods of peak demand, helping maintain system reliability. EE reduces

the consumption of energy all together, which has both system and environmental benefits. Taken together, DSM resources are an important part of maintaining system reliability as well reaching our environmental goals.

The DSM aspects of our Preferred Plan includes average annual energy savings of over 780 GWh in each of 2020-2034, compared to average annual energy savings of 444 GWh in our last Resource Plan. In addition, our Preferred Plan also incorporates an incremental 400 MW of DR by 2023 and grows to over 1,500 MW total by the end of the planning period. Importantly, this Resource Plan also signals a change in how we approach EE. In previous plans, we have treated EE as a reduction to customer load. In this Resource Plan, EE is considered a supply-side resource that the economic modeling considers alongside other resource types.

In our last Resource Plan, the Commission approved 1.5 percent annual EE savings on a go-forward basis. The level of EE we propose in this Plan is based on the 2018 *Minnesota Energy Efficiency Potential Study,* and proposes to achieve savings levels ranging from approximately two percent to 2.5 percent annually. This level of EE achieves more than 800 MW of additional demand savings by 2034 compared to the 1.5 percent level approved in our last Resource Plan.

Finally, consistent with the Commission's Order in our last Resource Plan, our Preferred Plan proposes to add 400 MW of incremental DR by 2023, and grows our total portfolio to over 1,500 MW total by the end of the planning period. When it comes to DR, the Company leads the way in MISO, with 830 MW registered in the current planning year. In our last Resource Plan, the Commission ordered the addition of 400 MW of incremental DR by 2023. As we understood the Commission's reasoning, it sought to add incremental, cost effective DR to avoid near-term reliance on additional combustion turbines (CTs). As can be seen in our analysis, however, no CTs or other firm, dispatchable resource additions are required until the 2031 timeframe as the model instead prefers solar additions in the 2025-2030 timeframe.

That said, we decided to include the DR in our Preferred Plan for several reasons: (1) to be consistent with the Commission's Order in our last Resource Plan, (2) to fill gaps if/when the solar capacity credit declines, (3) to help meet firm dispatchable resource needs in the 2030s, (4) to help support customer programs, and (5) to integrate new and emerging technology and tools. We note that for purposes of our modeling, we have included all of the DR identified in the Brattle study as cost-effective, including expansions to conventional DR programs (i.e., Savers Switch, smart thermostats, and interruptible rates) and a non-conventional smart electric water heater program. Additionally, we included the addition of Auto DR, another

non-conventional DR program that automates control of various end-uses like HVAC and lighting.

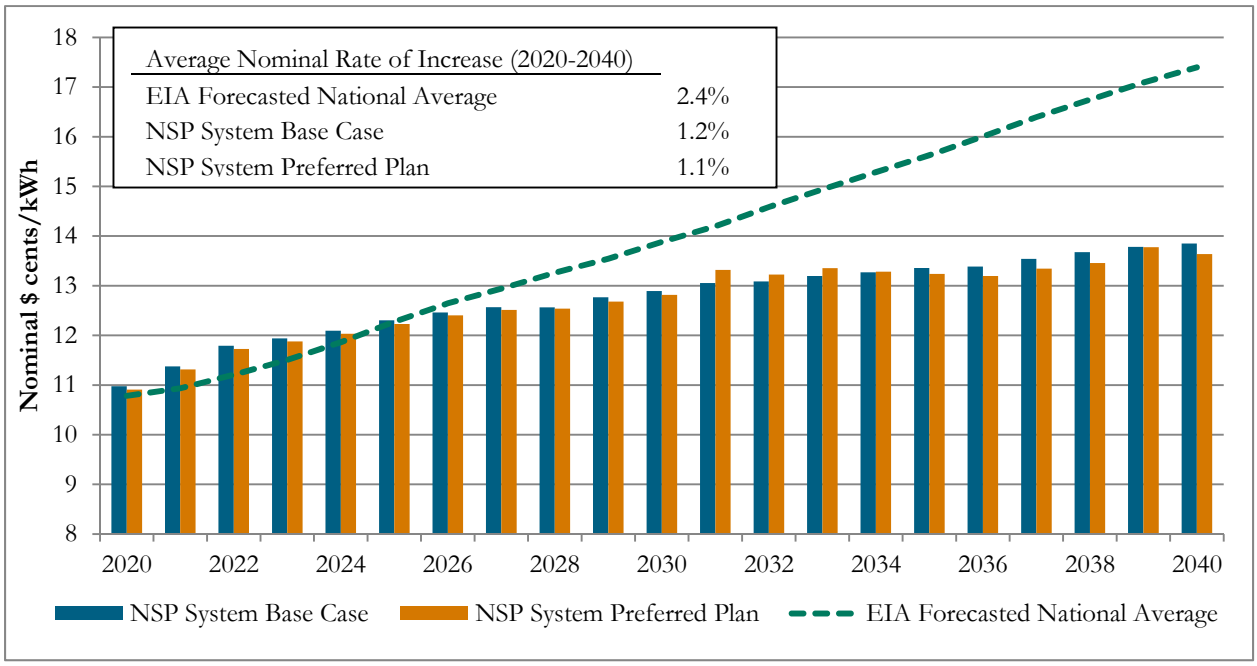
We believe the advancement of our grid, and technology generally, may take the form of less traditional DR, so with this Resource Plan we are requesting the flexibility to evaluate and pursue the required incremental DR through a variety of means and technologies over the coming years. Our objective with this resource type is to bring forward information on several viable options so the Commission, stakeholders, and the Company can engage in an informed exchange. We provide an analysis and detailed discussion of EE and DR in Appendix G1. We also discuss how we applied EE and DR as supply-side resources in our Strategist modeling in Chapter 5. Economic Modeling Framework.

C. Keeping Rates Affordable for Customers

Our Preferred Plan keeps annual cost growth at or below the rate of inflation. In other words, we can achieve significant CO_2 emissions reductions, with cost impacts that are roughly consistent with the expected national average increase in electricity prices.

To show the cost impact of our Preferred Plan over the long-term, we provide as Figure 4-3 below, a CAGR comparison to the national average nominal cost CAGR.

Figure 4-3: Preferred Plan Average Nominal Cost Comparison (NSP System)



* *Notes: National energy cost forecast from Energy Information Administration (EIA) Annual Energy Outlook 2019, Table Energy Supply, Disposition, Prices and Emissions – Reference Case. End use prices, all sector average.*[5] The Preferred Plan and Reference Plan lines include the costs of Solar Rewards*Community.

We derived this long-term projection using a combination of a shorter-range financial forecast and the Strategist model. The modest cost increase associated with our plan is attributable, in large part, to our strategy of deferring resource additions until later in the plan and making use of existing assets on our system. We believe technological improvements will continue to drive the costs of renewables down, which is a key driver in our strategy of proposing significant solar additions in the latter half of the next decade.

We provide our full analysis and discussion regarding customer cost and rate impacts in Chapter 6: Customer Cost and Rate Impacts.

[5] *See* https://www.eia.gov/outlooks/aeo/data/browser/#/?id=8-AEO2019&region=0-0&cases=ref2019&start=2017&end=2050&f=A&linechart=~ref2019-d111618a.70-8-AEO2019&ctype=linechart&sid=ref2015-d021915a.70-8-AEO2015~ref2019-d111618a.70-8-AEO2019&sourcekey=0 The EIA's Annual Energy Outlook was published in January 2019. The report is available at https://www.eia.gov/outlooks/aeo/pdf/aeo2019.pdf.

In the next section, we discuss the actions we plan to take over the next five years, and in the longer term, to achieve our Preferred Plan and deliver on our goals to achieve deep carbon reductions in our electricity mix.

III. ACTION PLANS

A. Five-Year Plan

Our Preferred Plan does not identify any incremental capacity needs through 2024. Thus, our actions in the next five years primarily address previously approved or pending resource additions and retirements, wind repowering and procurement to meet specific customer needs, and continuing to achieve reductions in energy demand and load through ambitious DSM programs. We also plan to make targeted investments in supporting infrastructure to accommodate increased renewable energy and DER on the grid, and to gain operational experience with technologies that may play a larger role on our grid in the future.

Wind. We expect that the 1,850 MW of wind generation resulting from our recent acquisitions and RFPs will achieve commercial operation by 2022. These additions were assumed across all of our scenario analyses. Further, we expect to replace the approximately 170 MW of wind capacity that will expire in the next five years. We are committed to pursuing repowering and/or contract extension opportunities for this capacity, as part of our "no going back" renewables strategy. Further, we intend to pursue incremental renewable resources as needed to meet customer needs in growing customer programs like Renewable*Connect.

Solar. Our Preferred Plan includes significant amounts of large scale solar resources. However, the initial planned addition of 500 MW does not occur until 2025, which is just outside of our five-year Action Plan window. In order to procure this initial tranche of solar, we expect to implement a competitive acquisition process in the 2023 to 2024 timeframe. We expect this timeline will allow us sufficient lead time to acquire these solar resources and bring them online by the end of 2025.

On the distributed solar side, we have included forecasted growth in our plan. If actual distributed solar capacity additions exceed our expectations, we anticipate this will simply displace a portion of our proposed utility-scale solar resources.

Hydro. We anticipate adding 125 MW of energy and capacity through a PPA with Manitoba Hydro in 2021. This incremental contract with Manitoba Hydro is in addition to our existing PPA and diversity exchange and was executed in 2010.

Nuclear. Our Preferred Plan includes a request to operate our Monticello nuclear unit for an additional 10 years beyond its current license. While the license does not end until 2030, we expect to begin a Certificate of Need proceeding with the Commission within the next five years. We also expect to begin working toward license extension with the NRC during this timeframe.

Natural Gas/Oil Peaking. We anticipate extending the life of Blue Lake Units 1-4 through 2020-2023,[6] which provides 153 MW of peaking capacity to the NSP System. Our Preferred Plan further includes our acquisition of MEC, which is currently pending Commission consideration. Finally, we plan to continue development activities associated with the Sherco CC during the next five years.

In addition, as discussed in our last Resource Plan, system retirements will impact our current blackstart plans and we are currently analyzing our blackstart path to determine the best fit for our system needs. While we do not propose any action related to the system blackstart at this time, we anticipate addressing this in our next Resource Plan or earlier, if system needs dictate the need to do so.

Coal. As approved in our last Resource Plan, we will take action with MISO and retire Sherco Unit 2 in 2023, and intend to offer it into MISO on a seasonal basis until that time. Though outside the five-year action window, we are proposing to retire the remainder of our coal units (Sherco 1, Sherco 3 and King) before 2030. As with our previous plant retirements, we plan to begin working with our employees and host communities to prepare for this transition.

Demand Response. Our Preferred Plan proposes to acquire 400 MW of DR resources by 2023, which we intend to evaluate and pursue through a variety of means and technologies over the coming years.

Supporting infrastructure. Aside from the grid-scale and DER additions included in our Plan, sufficient supporting infrastructure is essential to facilitate our fleet transformation, ensure grid resilience and reliability, and to enable greater DER and DR resources on our system. For example, we anticipate completing transmission investments, such as the Huntly-Wilmarth project, in late 2021. We expect further and substantial transmission infrastructure development will be necessary over the long-term, which will involve planning in the near-term. We also are continuing to refine our advanced grid strategy and intend to propose implementation of foundational grid modernization investments – and continue our work to integrate

[6] Pending decision in Docket E,G002/D-19-161

planning processes at all levels of the grid.

Gaining technology experience. As discussed above, we know that energy storage will be essential for our future grid, in order to integrate variable renewable energy without the use of traditional firm dispatchable generation. In the near term, we plan to take steps to gain additional experience with energy storage in the NSP system. For instance, we are co-investing in a microgrid project with Fort McCoy in the NSPW system that will pair solar with storage as a resiliency solution, supplementing traditional diesel backup generators. This project, slated to come online in 2021, will not only support resiliency at Fort McCoy, but will also help us gain valuable experience in maintaining and operating an energy storage facility, especially in the context of new market guidelines in MISO. We anticipate that it will produce income streams to the benefit of all customers through energy price arbitrage, ancillary services, and using the battery as a capacity resource.

Resource treatment across states. We continue to explore options with the North Dakota Public Service Commission to create a resource planning process that can more formally accommodate generation portfolio preferences. We believe additional discussions with all of our state Commissions will be necessary during the five-year action planning period to address differing energy policies and changes in cost allocations that may result.

B. Long-Term Plan

By 2025 we expect we will have achieved approximately 60 percent CO_2 reduction from 2005 levels, per the measures highlighted in our Preferred Plan. In the 2025 and beyond timeframe, there are several key aspects of our system that we will need to address to ensure we can achieve both our 2030 carbon reduction goals, and ultimately, our longer term goals to achieve 100 percent carbon-free electricity. For instance, we anticipate that increasing levels of variable renewable energy and additional baseload unit retirements will necessarily affect the way MISO plans for the broader grid in the future. Notwithstanding the rapid pace of change occurring in our industry, there are several action items on our long-term planning horizon.

New Transmission Infrastructure. Increasing renewable energy on the broader MISO grid is nearly a certainty; wind and solar projects make up over 85 percent of proposed capacity currently in the MISO generator interconnection queue.[7] However, as noted

[7] MISO "Generator Interconnection: Overview." Updated as of June 1, 2019, at: https://cdn.misoenergy.org/GIQ%20Web%20Overview272899.pdf

previously, the queue process is mired with delays and high interconnection cost estimates, in large part due to a lack of available transmission capacity. While generator replacement processes will help us place renewables on our system using existing interconnection rights to an extent, we will need more transmission capacity to come online to effectively achieve the level of renewables we envision on our system – and more broadly within MISO – by 2030 and beyond.

Increasing energy storage on our system. As previously noted we expect that battery energy storage system costs have room to decline over the next several years. We also know that, as variable renewable adoption on the grid increases and more baseload capacity comes offline, we will need a mix of low and non-emitting technologies that can address renewable variability and ensure reliability cost effectively for customers. Battery energy storage holds substantial promise for meeting these needs, and given expected cost declines, we anticipate that we will be able to install cost effective energy storage on the NSP System in the future.

Prairie Island. Our Preferred Plan continues the operation of both Units to the end of their current operating licenses – 2033 for Unit 1 and 2034 for Unit 2. Our baseload scenario modeling results presented in the next Chapter show that there may be value in extending the life of this plant. However, given our operating licenses extend nearly to the end of the planning period, we do not yet need to begin pursuing relicensing. Therefore, we plan to continue working with our stakeholders and evaluate Prairie Island in the context of our future system in subsequent resource planning cycles, rather than locking into a decision at this time. In the meantime, however, Prairie Island continues to serve an important function on the grid and in providing cost-effective and carbon-free baseload power through the planning period.

North Dakota CT. As discussed further in Part IV below, the Company agreed to take steps to locate a natural gas CT in the state of North Dakota, to be operational by December 31, 2025. We remain committed to locating more generation in North Dakota in the future, and we expect to address this resource in our next Resource Plan.

Meeting Statewide Statutory Environmental Goals. Minnesota's Next Generation Energy Act contains a goal for statewide carbon reductions of 80 percent (from 2005 levels) by 2050. While the statewide goal is for all sectors, the Preferred Plan we propose in this Resource Plan achieves over 80 percent reduction by 2030. We know that the electric sector has a unique role to play in achieving the statewide goals. E3's Minnesota PATHWAYS Report, included as Appendix P3, indicates that reducing carbon emissions in the electricity sector enables beneficial electrification to further mitigate emissions in other sectors – in particular the transportation and building

sectors. As we discuss in this Resource Plan, our path to achieving 80 percent carbon reduction from 2005 levels in our system relies on retiring baseload coal units, increasing renewable energy, extending nuclear operating licenses, and implementing incremental DSM, and including energy storage. To be sure, all electric utility systems are different and will encounter different challenges on their path to carbon reduction – and there remain challenges to maintaining that level of carbon reduction if current barriers (e.g. transmission constraints or lack of cost effective long-duration storage options) are not mitigated. However, the analysis findings that led us to our current Preferred Plan give us confidence that the electric sector as a whole can help achieve Minnesota's 80 percent carbon reduction by 2050 goal. We further discuss our outlook regarding this statewide goal and potential barriers in Appendix H.

Meeting Company Goals to Achieve 100 Percent Carbon Free Electricity by 2050. As noted throughout this Resource Plan, our Preferred Plan charts a path toward achieving our 2030 carbon reduction goals, and positions us to address our longer term vision of achieving 100 percent carbon-free electricity by 2050. This goal, however, is not one we can achieve cost-effectively or reliably without substantial technological breakthroughs. This includes, in particular, carbon-free dispatchable energy resources that will help us balance variable renewables' output relative to customer demand. Significant research and development is required to bring potential new technologies to commercialization stage; these could include solutions such as longer-duration battery energy storage, other types of energy storage, hydrogen-fired generation, advanced nuclear technologies, carbon capture and storage, and others.[8] We continue to monitor potential emerging technologies and are excited to see what applications will emerge to help make our vision a reality in the long term.

IV. NORTH DAKOTA PLAN

As discussed in the Planning Landscape, we plan and operate a single Upper Midwest system that serves customers in five states. Consistent with the terms of the Settlement in Case No. PU-07-776, since 2008 we have filed our Upper Midwest Resource Plans with the North Dakota Commission, and included in each of them an analysis of a Resource Plan scenario compliant with Federal and North Dakota laws only. As with the previous 2016-2030 Upper Midwest Resource Plan, the current Plan refers to this scenario as simply the "North Dakota Plan."

[8] Selected emerging technologies are discussed further in Appendix F6.

A. Plan Components

Our Preferred Plan for our Upper Midwest system is designed to support the Company's goal of an 80 percent reduction in carbon emissions by 2030. Our 2030 goal is not driven by a particular policy directive from one of our jurisdictions. We believe planning to meet this goal is in the best interest of all our customers. Therefore, this objective is reflected in our North Dakota Plan. The North Dakota Plan differs from the Preferred Plan in the following ways:

1. All CO_2 costs have been removed;
2. Incremental Demand Response (DR) was removed; and
3. Community Solar Garden (CSG) program costs are excluded.

When we developed our Preferred Plan we included the externality and regulatory costs of CO_2 approved by the Minnesota Public Utilities Commission. Removing the CO_2 in the North Dakota Plan had only minor impacts as shown below:

Table 4-2: Expansion Plan Comparisons
Preferred Plan – North Dakota Plan – Summary of Differences

Preferred Plan

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total
Large Scale Solar	0	0	0	0	0	500	500	1000	500	500	500	0	500	0	0	4,000
Battery	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CC	0	0	0	0	0	0	0	835	0	0	0	0	0	0	0	835
Firm Dispatchable	0	0	0	0	0	0	0	0	0	0	0	606	0	374	748	1,728
DR	270	20	21	10	17	41	12	14	15	17	19	20	21	22	23	542
EE	115	130	116	133	143	145	154	157	155	140	138	136	129	126	126	2,041
Wind	0	0	0	126	45	70	66	72	10	107	16	56	31	523	81	1,202
Distributed Solar	154	22	22	21	21	21	21	20	20	20	20	20	20	20	19	442

North Dakota Plan

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total
Large Scale Solar	0	0	0	0	0	500	500	500	0	1000	1000	0	500	0	0	4,000
Battery	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CC	0	0	0	0	0	0	0	835	0	0	0	0	0	0	0	835
Firm Dispatchable	0	0	0	0	0	0	0	0	0	0	0	606	0	374	748	1,728
DR	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EE	115	130	116	133	143	145	154	157	155	140	138	136	129	126	126	2,041
Wind	0	0	0	126	45	70	66	72	10	107	16	56	31	523	81	1,202
Distributed Solar	154	22	22	21	21	21	21	20	20	20	20	20	20	20	19	442

Difference - North Dakota Plan Compared to Preferred Plan

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total
Large Scale Solar	0	0	0	0	0	0	0	-500	-500	500	500	0	0	0	0	0
Battery	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Firm Dispatchable	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DR	-270	-20	-21	-10	-17	-41	-12	-14	-15	-17	-19	-20	-21	-22	-23	-542
EE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Distributed Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

In the modeling for the North Dakota Plan, solar additions for 2027-2029 in the Preferred Plan are delayed to 2029-2030. As discussed previously, our Preferred Plan also includes a large incremental addition of DR in recognition of the Minnesota Commission's Order in our last Resource Plan requiring 400 MW of additional DR by 2023. While we expect most of these DR programs to be implemented in Minnesota, as we continue to develop additional DR programs for our system we would consider proposing to add cost-effective DR programs for our North Dakota customers as well.

The exclusion of the costs of CSG does not impact the resources additions for the North Dakota Plan. Instead, the costs of CSG are allocated so that North Dakota customers pay a market rate for the energy from the CSG resources. The allocation of the costs to North Dakota will also reflect previous cost-recovery decisions that exclude costs related to the disputed resources identified in the rate case Settlement of Case No. PU-12-813 and subsequent cases.

B. Resource Planning Framework Status

On December 21, 2018 we proposed a framework that outlined essential pieces of a North Dakota Resource Plan, including a default presumption that the system would continue to be planned in an integrated fashion.[9] We discussed the proposal at an informal hearing with North Dakota Commissioners in March of this year. The North Dakota Commission confirmed that they are interested in a more formalized resource planning process. We look forward to working with the North Dakota Commission and Staff to further develop a North Dakota planning process.

C. North Dakota Combustion Turbine

Pursuant to the Settlement in Case No. PU-12-813, the Company agreed to take steps to locate a system natural gas CT in the state of North Dakota, to be operational by December 31, 2025. Specifically, Xcel Energy agreed to:

> *…develop, own, and operate (or alternatively, cause to be developed and operated on its behalf through a power purchase agreement or other contractual arrangement) a combustion turbine with a capacity of at least 200 MW in eastern North Dakota, no later than December 31, 2025. The costs of the generating facility will be allocated to all state jurisdictions served by the Company in a manner consistent with other NSP System resources. Attainment of this commitment is contingent on the Company's receipt of all necessary and appropriate permits and regulatory approvals. Further, except as modified by this Section II, all provisions of the 2036 Commitment remain in place, including without limitation, the requirements that the combustion turbine agreed to in this paragraph reasonably 1) addresses a system capacity need and 2) represents a least-cost resource when also considering the local reliability and system benefits of developing thermal generation in North Dakota.*

The five-year Action Plan associated with this 2020-2034 Resource Plan runs through

[9] *See* North Dakota Case No. PU-12-813.

2024. Thus, the Commission will not find specific mention of a North Dakota natural gas CT addition in the current short-term Action Plan; rather, proposed resource additions in 2025 will be within the Action Plan developed in the next Resource Planning cycle and addressed directly in that filing.

While the longer-term plan for resource additions do not reflect a firm peaking addition until 2031, we acknowledge the above-stated Settlement commitment and will continue to assess NSP System capacity needs over the next couple of years, the likelihood of gaining the necessary approvals in all NSP System states, and the operational feasibility and cost-effectiveness of a peaking plant located in eastern North Dakota. Given the long planning horizons, many things can change in the next 5 to 10 years in terms of energy policy, technology, and economic conditions. We remain committed to locating more generation in the state and a more timely and beneficial option may become evident over time.

V. PUBLIC INTEREST ANALYSIS

Based on our detailed analysis, we conclude that the Preferred Plan is in the public interest. We believe it best balances our goals to ensure reliability, achieve significant carbon reduction, and maintain reasonable costs to customers.

The Commission's Rules identify the factors that the Commission is to consider when determining if the Resource Plan selected is in the public interest.[10] Specifically, these Rules require that resource options and resource plans are to be evaluated on their ability to:

- Maintain or improve the adequacy and reliability of utility service,
- Keep the customers' bills and the utility rates as low as practicable, given regulatory and other constraints,
- Minimize adverse socioeconomic effects and adverse effects upon the environment,
- Enhance the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations, and
- Limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control.

[10] Minn. R. 7843.0500, subp. 3.

Our Preferred Plan is best able to meet these criteria, especially when analyzed on a comprehensive basis in light of the planning landscape the Company and the broader industry operate within.

A. Reliability

Our Preferred Plan is designed to allow us to continue to provide safe and reliable service to our customers as we take steps to achieve deep carbon reductions in our electricity mix. We know that as we, and other utilities in Minnesota, the Upper Midwest, and the broader MISO market retire baseload units and continue to add substantial variable renewable generation capacity to the grid, planning processes will need to adapt to ensure a reliable and stable grid. We have done the work to understand potential grid impacts from the orderly fleet transition we propose. We have also developed a Reliability Requirement that will ensure we continue to serve our customers' energy needs every hour of every day in the interim until MISO updates its planning construct to recognize the changes underway. We discuss the work we have done to we meet our obligation to provide reliable service in our Baseload Study, provided as Appendix J1.

Related, in connection with our pursuit of vast new quantities of renewables, we have included the proposed MEC acquisition and planned Sherco CC as resources in our Preferred Plan in order to ensure new renewable resources can be adequately integrated. We also leave open the possibility that future firm, dispatchable needs identified in the Plan could be met with non-emitting alternatives such as DR or energy storage. Finally, we discuss other supporting infrastructure that will support our goals to integrate additional variable renewable energy in Appendix I. By including these various elements, our Preferred Plan positions us to ensure the continued adequacy and reliability of the NSP system throughout the planning period and beyond.

B. Impact to Customer Bills

Affordability is one of the key objectives that framed our analysis. Our Preferred Plan achieves significant carbon reductions while ensuring reliability at a cost in line with expected inflation rates, or an annual cost increase of just over one percent, on average, over the planning period. The fact that we do not need to take any actions in the near-term supports the flexibility that we seek with this plan, which we believe is more beneficial now than ever – given the pace of technological innovation and cost reductions we have observed and expect to continue into the future. Therefore, we believe that our Preferred Plan will keep our rates as low as practicable, given future market and other uncertainties as we have described in this Plan.

C. Environmental Effects

Xcel Energy is leading the nation with an ambitious goal of serving our customers with a completely carbon-free resource mix by 2050 – and on our way to reaching this goal, reducing our carbon emissions by 80 percent from 2005 levels by 2030. Our Preferred Plan is a critical step in planning to meet these ambitious carbon reduction goals, while also keeping in mind the socioeconomic impacts of retiring large baseload generation units. We have proposed to close all of our remaining coal units by the end of 2030, which will significantly reduce the amount of carbon attributable to our system. At the same time, we are also planning to vastly expand the amount of renewable energy capacity on our system, and continue to operate Monticello through 2040 – both of which will provide substantial amounts of clean energy to serve our customers. All of these actions work to ensure we achieve our environmental goals and carbon-free vision.[11]

D. Socioeconomic Impacts

We recognize that plant closures can have a significant impact on our plant employees and the communities that have hosted our plants for many years – and we bore this in mind when developing our Preferred Plan. By announcing our plans to retire Sherco 3 and King far in advance of proposed retirement dates, employees will have time to build additional skills and transition to other parts of the Company, if desired. Like we have in the past, we will work with these employees to support their transitions. We will also continue working with the host communities and other stakeholders around those communities. We are currently working, in conjunction with CEE and Minnesota Power, to understand the socioeconomic effects of the plants and their closure on host communities. This commitment is evidenced in the work we have been doing in the Sherco area, after closure of our Sherco Units 1 and 2 was approved in our last Resource Plan. Among others things, we plan to develop our own gas CC plant on the Sherco site. We have been working to draw new development to the area, and with existing and prospective large industrial customers to locate facilities in the area, which will help to offset tax and other impacts from the closure of the coal units. These efforts will generate socioeconomic benefits through facility construction and ongoing operations. Our clean energy efforts also generate socioeconomic benefits, both in preserving key nuclear jobs through the Monticello

[11] Note that resources we include our Preferred Plan meets and exceeds Minnesota greenhouse gas reduction goals under 216H.02, the renewable energy standard under 216B.1691 and the solar energy standard under 216B.1691, 2f.

life extension, and spurring a large amount of new renewable construction over the planning period.

E. Flexibility to Respond to Change

Our Preferred Plan positions the Company well in the current planning landscape – meeting near-term needs and creating flexibility for the future. As we have described, planning constructs, policies, and technology costs are all creating uncertainty, which lead us to prioritize strategic flexibility in our plans to preserve the most value for our customers. For example, even though our modeling results show that extending the operating life of Prairie Island would be cost-effective under today's market conditions, we also know those conditions can change rapidly. Thus, we have deferred a decision regarding Prairie Island extension until the next Resource Plan. We also have said that we are open to meeting our firm and dispatchable capacity needs in the out-years of our Plan with options other than natural gas units, to the extent technologies sufficiently develop and are economically-favorable at that time. This flexibility enhances our ability to respond to changes in our planning landscape that would affect our operations during the planning period and preserves some agility for us to respond and adapt to these factors

F. Limiting Risks

Much like the flexibility to respond to change, the strategic flexibility inherent in our Preferred Plan limits the risk of adverse effects on the Company and our customers from factors beyond our control. For example, the Reliability Requirement we developed and incorporated into our modeling ensures that we have planned for adequate firm and dispatchable energy to meet our customers' needs until current planning constructs adapt.

Our Preferred Plan represents the best option to meet customers' needs in light of the planning landscape for the planning period, presents the best path forward for the Company, our customers, and the energy future of our Upper Midwest system, and is thus in the public interest.

VI. CONCLUSION

The Preferred Plan we propose in this 2020-2034 Upper Midwest Resource Plan reflects extensive collaboration with stakeholders as well as independent expert analysis. Our Preferred Plan proposes to eliminate coal, add even more renewables, and continue our industry-leading EE and DR programs, all while preserving reliability and affordability for our customers. It also meets the varied interests of our five-state Upper Midwest region. And by planning ahead and charting an orderly, gradual transition of our generation fleet, we believe we can achieve all of these goals while managing the impacts to our host communities and employees, preserving the reliability and stability of our system, and maintaining affordability for our customers. For these reasons, and those discussed throughout this filing, we believe our Preferred Plan is in the public interest and merits Commission approval.

CHAPTER 5
ECONOMIC MODELING FRAMEWORK

We have used the Strategist Resource Planning model to perform our economic analyses since 2000. We use Strategist as our primary resource planning software to estimate the costs of various resource expansion plan options, evaluate specific capacity alternatives, and measure the potential risks of new environmental legislation and other policy scenarios. Strategist results are a decision support tool to guide development and selection of a Preferred Plan and test the robustness of the Plan under a variety of assumptions and sensitivities.

To ultimately identify and refine our Preferred Plan, we created 15 scenarios that examined different combinations and timing of baseload unit retirements, and the resulting size, type, and timing of new resources we would need to add in order to continue meeting customers' needs and achieve our 2030 carbon reduction goals. We refer to these scenarios as "baseload study scenarios."

As we developed the various baseload study scenarios, we also conducted DR and EE Bundle analyses. This is the first Resource Plan in which DR and EE Bundles are considered supply-side resources, and as such, we had to undertake iterative analysis alongside our scenario analysis to analyze these options appropriately. Finally, after this analysis was completed, we used the outcomes and sensitivity tests to select and refine a Preferred Plan.

We discuss our assumptions, scenarios, sensitivities and how these inputs guided selection of our Preferred Plan in more detail below.

I. ASSUMPTIONS

There are several assumptions included in our baseline data inputs that are common across all scenarios studied. These factors may, in some cases, be varied within sensitivities, but are largely kept constant across the default study of each scenario.

Important starting assumptions in our analysis include:

Load Forecast. The Company employs standard probabilistic analyses to determine our load and energy demand forecasts. Our resource planning process takes the 50 percent probability level forecasts for both peak demand and energy requirements as an input, we provide a detailed description of our load forecasting methodology as Appendix F1.

In the past, these forecasts have included adjustments to account for the effects of EE as a load modifier. In order to accommodate modeling EE as a supply-side resource in this Resource Planning process, we have not included any going forward EE impacts in the load forecast for the 2020-2034 period. These energy and demand savings are now included in the three EE Bundles that we evaluate as supply-side resources.

We also incorporated an effective planning reserve margin of 2.98 percent, per MISO requirements. As discussed in Chapter 3, MISO instituted an 8.4 percent planning reserve margin requirement in the 2018-2019 planning year, and our system has a 95 percent MISO system coincident factor. Thus, our effective reserve margin is calculated in the following manner:

Figure 5-1: Effective Reserve Margin Used in Strategist Modeling

$$(95\ percent\ coincidence\ factor)\ x\ (1 + 8.4\ percent)\ -\ 1 = 2.98\ percent\ effective\ reserve\ margin$$

Existing Fleet. We develop forecasts to model our existing fleet's cost and performance assumptions (such as variable O&M, heat rate, forced outage rate, maintenance requirements, etc.) based on historical data, with adjustments for known future changes where applicable. Additional operational and performance assumptions include:

- Retirement of Sherco Units 1 and 2 in 2026 and 2023, respectively, as approved in our last Resource Plan;
- Remaining coal units are dispatched economically beginning in 2028, reflecting our expectations that MISO transitions to a multi-day commitment approach that more efficiently commits resources in accordance with load serving needs over a longer time horizon;
- Retirement of all other facilities at their current expected end of life if within the resource planning period, unless we have specifically included costs of life extension (e.g. for nuclear units in scenarios that include life extension);
- Continuation of our existing PPAs until their contractual termination dates, and
- Continued operation of the Company's owned hydroelectric resources based on historical performance.

Additional cost –related assumptions include:

- Costs are escalated based on corporate estimates of expected inflation rates,
- Costs associated with early retirement of the existing baseload coal units (King and Sherco 3), as well as costs for early retirement or re-licensing the nuclear plants were developed for use in the Baseload Study modeling.

Renewable Energy. In addition to the 1,850 MW of wind we are in the process of adding to the NSP System since our last Resource Plan, we have assumed:

- Currently approved and/or operating renewable facilities (including both those facilities we plan to own and those we plan to contract) are assumed to be replaced at their end of life or contract expiration with the equivalent amount of similar energy from generic wind and solar resources (i.e. wind would replace wind, solar would replace solar). We refer to this as "no going back;"
- Accreditation of wind resources based on the 2018-2019 Planning Year 15.6 percent MISO ELCC, accreditation of solar resources at the default 50 percent ELCC. For modeling purposes we assume these values remain the same throughout the modeling period;
- No extension of the federal production tax credit (PTC) or investment tax credit (ITC)[1] past the expiration dates as per current law.

Markets. We run scenarios in Strategist both with "markets on" (i.e. where we can buy and sell energy in the MISO wholesale market) and "markets off" (i.e. where we cannot sell to the market, but purchases are still modeled). We use the "markets on" view as a default assumption because this is more reflective of our realistic operations. Sensitivities with markets off help us test the effects of this assumption on the various scenarios.

Wholesale electricity price forecasts. Our electric power market prices are developed from fundamentally-based forecasts from external analysts Wood Mackenzie, CERA and PIRA. The forecasts we receive from these third party analysts provide monthly average on- and off-peak market pricing at the Minn Hub. We then use that market data to create an hourly shape for each month, based on the amount of thermal generation dispatched on our system. The methodology results in lower hourly locational marginal prices (LMPs) during times when a significant amount of renewable energy is on the system and higher hourly LMPs when amounts of available renewable energy are lower. Shaping the hourly prices in this manner provides a more conservative view of potential benefits we may realize from selling excess generation to the market.

[1] The ITC reverts to 10% in 2022 and beyond, per current law.

Purchase and sales limits. In our Strategist model, we include a limit as to the amount of energy that we are able to either purchase from or sell into the MISO market. This limit was developed using results from the 2018 MISO Transmission Expansion Plan (MTEP) model results and evaluating maximum levels of market interaction achieved in that modeling. For 2020-2023 we assume a market interaction limit of 1,800 MW which grows to 2,300 MW after 2023, based on the anticipated in service of the Cardinal to Hickory Creek transmission line which is expected to increase transmission outlet in our region.

Emissions rates and costs. Emission rates for existing and planned resources are consistent with historical and expected performance. We assume the following costs[2] and apply them to emitting resources as relevant:

- Achievement of an 80 percent reduction in CO_2 serving retail customers, as measured from 2005 levels, by 2030. The overall carbon emissions are allowed to increase slightly from these levels at the retirement dates of the nuclear fleet, which vary by scenario;
- $ 25.00 per ton CO_2 as a regulatory cost, starting in 2025 and escalating at inflation, with the high CO_2 externality value used prior to 2025. The societal value of CO_2 as an externality and other combinations of externality and regulatory costs were included as sensitivity cases;
- The Minnesota Commission's high externality values for other specified emissions.

Generic Resources. Strategist uses generically-defined resources to meet future demand when our already existing and approved resources are not sufficient in a given year. Generic resources are modeled as incremental units of a certain installed capacity size, but these sizes are chosen based on the amount of UCAP, or the MISO accredited capacity value the units would yield. For example, although the generic unit size for solar is rather large (500 MW installed capacity), the resource adequacy or MISO capacity credit value we would expect to receive for a plant of that size is half that (250 MW), which is more comparable to a generic thermal or storage plant we may assess. Similarly, wind UCAP values are discounted to 15.6 percent of ICAP.

[2] Note: As further discussed below, these costs are not used in evaluating the cost of our Preferred Plan for North Dakota. See our discussion regarding the North Dakota Plan in Chapter 4: Preferred Plan.

Generic units ICAP values included in modeling are as follows:[3]

- 331 MW gas-fired combustion turbine peaking unit (CT),
- 206 MW gas-fired combustion turbine peaking unit (CT),
- 856 MW gas-fired combined cycle intermediate unit (CC),
- 331 MW energy storage project, with costs and performance comparable to lithium-ion battery technology,
- 750 MW wind project
- 500 MW grid-scale single-axis tracking solar project
- 100 MW distributed solar project

Appendix F2: Strategist Modeling Assumptions & Inputs, provides more detail on Strategist assumptions. Please see Appendix F6: Resource Options, for additional discussion on supply-side resource options included in the analysis.

Customer Programs. Incremental customer programs for DR and EE were included as potential resources in the Strategist model. The derivation of these three DR and three EE "Bundles" are described in Appendix F6.

It is important to note that these Bundles represent generic DSM additions and therefore may not perfectly align with the size and timing of actual DR or EE additions to the system in the future. These Bundles were developed immediately after receiving third party studies for incorporation into modeling, without the benefit of time to develop detailed implementation plans to achieve the levels of DSM in each Bundle. Therefore, for incremental DR resource additions in particular, while the size and timing of the first Bundle generally achieves the ordered 400 MW by 2023, the actual implementation plans which detail the specific size, type, and timing of incremental additions will likely differ. Procurement plans are illustrated in Appendix G1: Demand Side Management.

DER is modeled with base and high adoptions assumptions, using similar levels as provided in our 2018 IDP filing. We discuss our DER forecasts in Appendix F1: Load and Distributed Energy Resource Forecasting.

[3] The cost and performance data for these units are based on consultant's estimates, publicly available third-party data, and internal company data. Availability dates are selected based on our estimates of the lead time needed for regulatory approvals, financing, permitting and construction.

II. SCENARIOS

As noted above, we created 15 scenarios to examine combinations and timing of baseload unit retirements, and the resulting size, type, and timing of new resources we would need to add in order to continue meeting customers' needs and achieve our 2030 carbon reduction goals. We describe key parameters of these scenarios below.

A. Reference Case Scenario

We describe the development of our Reference Case in Chapter 3: Minimum System Needs. The Reference Case (Scenario 1) is an extension of our 2015 Resource Plan, in that all of the baseload units retire at their currently scheduled retirement dates, and serves as our starting point. The approved 1,850 MW wind portfolio that is in progress is included, along with generic wind and solar units added to the plan to ensure that we do not fall below the current level of renewables we have on our system (i.e. a "no going back" portfolio). Additional renewable units are evaluated and optimized in the modeling and added where economic. In the original phases of the modeling, the DR and EE Bundles were evaluated as optimized economic alternatives, as were distributed solar, storage, and thermal CT and CC resources. The Sherco CC unit and owned MEC CC unit were included in the Expansion Plan. Firm peaking resources were included in the plan as needed to maintain the Reliability Requirement criteria.

To determine the optimal strategy regarding the future of the baseload fleet, we developed additional scenarios with varying combinations of baseload resource retirement dates. The resulting system needs were then met with a Strategist model-optimized portfolio of new resources. Internal finance, energy supply, and nuclear subject matte experts worked to develop a robust set of assumptions and potential retirement dates for the baseload units. These input assumptions include: ongoing capital expenditures, O&M expenses and decommissioning and/or life extension costs. We also incorporated the planning level estimates from the MISO Y2 studies performed as part of our Baseload Study that informed our Preferred Plan. See Appendix J1 for more details regarding this study. The scenarios we evaluated can be generally grouped into families, as described below.

B. Early Coal Family

This family of scenarios is designed to evaluate the economics (i.e. revenue requirement impacts) of retiring King and/or Sherco 3 early. We did not study life extension for coal facilities. For the early coal retirement scenarios, the early retirement date for King was assumed to be the end of 2028, and for Sherco 3 the

early date was the end of 2030. We chose these retirement dates because they generally allow an orderly and staged transition, with a major coal retirement every two to three years. In the all early coal scenarios, for example, the retirement schedule is Sherco 2 in 2023, Sherco 1 in 2026, King in 2028 and Sherco 3 in 2030.

- Scenario 2 **(Early King)** – King is retired at the end of 2028. Sherco 3 and the nuclear units are unchanged.
- Scenario 3 **(Early Sherco 3**) – Sherco 3 is retired at the end of 2030. King and the nuclear units are unchanged.
- Scenario 4 **(Early All Coal)** – King is retired at the end of 2028, Sherco 3 is retired at the end of 2030, and the nuclear units are unchanged.

C. Early Nuclear Family

This family of scenarios is designed to test the economics of retiring Monticello and/or Prairie Island early, either alone or together, and with the combination of early coal retirements. For the early nuclear retirement scenarios, the early retirement date for Monticello was assumed to be the end of 2026 and for Prairie Island 1 and 2 it was the end of 2024 and 2025, respectively. We chose these retirement dates as we felt they best balanced the need for adequate lead time to enable an early major nuclear retirement with the desire to evaluate retirement scenarios that occur well ahead of the existing retirement dates in the 2030s.

- Scenario 5 **(Early Monticello)** – Monticello is retired at the end of 2026. Coal and Prairie Island is unchanged.
- Scenario 6 **(Early Prairie Island)** – Prairie Island is fully retired by the end of 2025. Coal and Monticello is unchanged.
- Scenario 7 **(Early All Nuclear)** – Prairie Island and Monticello are both retired early per the years above, the coal units are unchanged.
- Scenario 8 **(Early All Baseload)** – All baseload units, including coal and nuclear, are retired early per the years indicated above.

D. Extend Nuclear Family

This family of scenarios is designed to test the economics of re-licensing Monticello and/or Prairie Island and extending operational life by 10 years over the current retirement dates. For the extend nuclear scenarios, the revised date for Monticello was assumed to be the end of 2040 and for Prairie Island 1 and 2 was the end of 2043 and 2044, respectively.

- Scenario 9 (**Early Coal, Extend Monticello)** – All coal was retired at the early dates and Monticello is extended for 10 years. Prairie Island is unchanged.
- Scenario 10 (**Early King, Extend Monticello)** – King was retired at the early date and Monticello is extended for 10 years. Sherco 3 and Prairie Island are unchanged.
- Scenario 11**(Early Coal, Extend Prairie Island)** – All coal was retired at the early dates and Prairie Island is extended for 10 years. Monticello is unchanged.
- Scenario 12 **(Early Coal, Extend All Nuclear)** – All coal was retired at the early dates and both Monticello and Prairie Island are extended for 10 years.
- Scenario 13 (**Extend Monticello)** –Monticello is extended for 10 years. King, Sherco 3 and Prairie Island are unchanged.
- Scenario 14 **(Extend Prairie Island)** – Prairie Island is extended for 10 years. King, Sherco 3 and Monticello are unchanged.
- Scenario 15 **(Extend All Nuclear)** –Both Monticello and Prairie Island are extended for 10 years. King and Sherco 3 are unchanged.

III. FUTURES SCENARIOS AND SENSITIVITIES

To determine how changes in our assumptions impact the costs or characteristics of different plans, we have historically evaluated how the plan responds to changes in individual input assumptions. This testing helps us assess the "robustness" of each scenario in the face of future uncertainty, meaning that we want to test how resilient the scenario is to changes in one or more key assumptions. Generally, if a given plan is extremely sensitive to changes in assumptions, it would not represent a prudent course of action for the Company to pursue, because it would subject our customers to excessive risk. While we believe there is value in evaluating the individual sensitivities, and have provided a comprehensive analysis of those sensitivities in Appendix F3, we took a slightly different approach to stress test our results in this particular Resource Plan.

A. Futures Scenarios

Consistent with the MISO MTEP Process, we adopted a scenario-based planning approach to our sensitivity analysis that we have incorporated for the first time in this Resource Plan. Since many of the input assumption variables in our modeling are correlated, we believe there is more value in looking at a combination of variable

sensitivities as opposed to "one-off" sensitivity runs. Evaluating one sensitivity at a time may isolate the impacts of the variable in question, but may not necessarily reflect a realistic future scenario.

We developed four Futures Scenarios, using the 2018 MTEP Futures as guideposts. The first two Futures Scenarios (Base PVSC and Base PVRR) represent our base assumptions, with and without carbon costs, as we have consistently provided this view as part of previous Resource Plans and are required to provide the PVRR view for our North Dakota stakeholders. The High Electrification and High Distributed Solar cases represent our new approach, in which we adjusted multiple sensitivities in each Futures Scenario to assess the combined effect of these changes. While there are certainly many assumptions we could have adjusted, we focused on the four most important variables which include fuel price forecasts, load forecasts (or variables impacting the load forecast like distributed solar), carbon and externality costs, and new resource capital costs. The assumptions made for each Futures Scenario can be seen in Table 5-1 below:

Table 5-1: 2019 Resource Plan Futures Scenarios

Futures Scenario	Description	Gas, Power, Coal Prices	Load Forecast	Carbon & Externality Costs	New Resource Capital Costs
Base Scenario (PVSC)	Base Case with Carbon Costs, Similar to MISO MTEP Continued Fleet Change (CFC) Scenario	Base	Base 50/50	High/High	Base
No Carbon (PVRR)	No Carbon Costs	Base	Base 50/50	**None**	Base
High Electrification & Low Tech Costs (PVSC)	Similar to MISO MTEP Accelerated Fleet Change (AFC) Scenario	**High**	**High Electrification Forecast**	High/High	**Low**
High Distributed Solar Deployment, Low Tech Costs (PVSC)	Similar to MISO MTEP Limited Fleet Change (LFC) Scenario	**Low**	**High DG Solar Forecast & Higher EE Levels**	High/High	**Low**

Note: bolded and underlined parameters indicate assumptions that have been modified from the Base Scenario

For the High Electrification Scenario, we examine a case in which higher load levels are expected to stimulate higher fuel demand and consequently higher overall fuel prices. To construct this Scenario, we used a high electrification forecast provided by E3, informed by their Minnesota PATHWAYS study provided as Appendix P3 to this Resource Plan, to assess the impacts of high load, high fuel price, and a low technology cost environment.

Conversely, for the High Distributed Solar Deployment Scenario, lower load levels driven by higher levels of offsetting distributed solar could reasonably be expected to drive down fuel demand and result in lower overall fuel prices. To construct this Scenario, we used an internally developed high customer adoption based distributed solar forecast to assess the impacts of low load, low fuel price and low technology cost environment. We also forced in all three EE Bundles to further reduce the load forecast and evaluate a future that truly stresses our baseload decision options.

In both the High Electrification and the High Distributed Solar Scenarios, we assumed low new resource capital costs. We believe this is an appropriate assumption to test, because trends have indicated that the market has previously underestimated realized cost reductions in renewables and other new technologies, and we feel this could continue to occur going forward. Likewise, in both these Futures Scenarios, we included carbon and externality costs, consistent with resource planning principles in Minnesota.

Figure 5-2: Peak Demand, Net of EE Impacts, by Futures Scenario (MW)

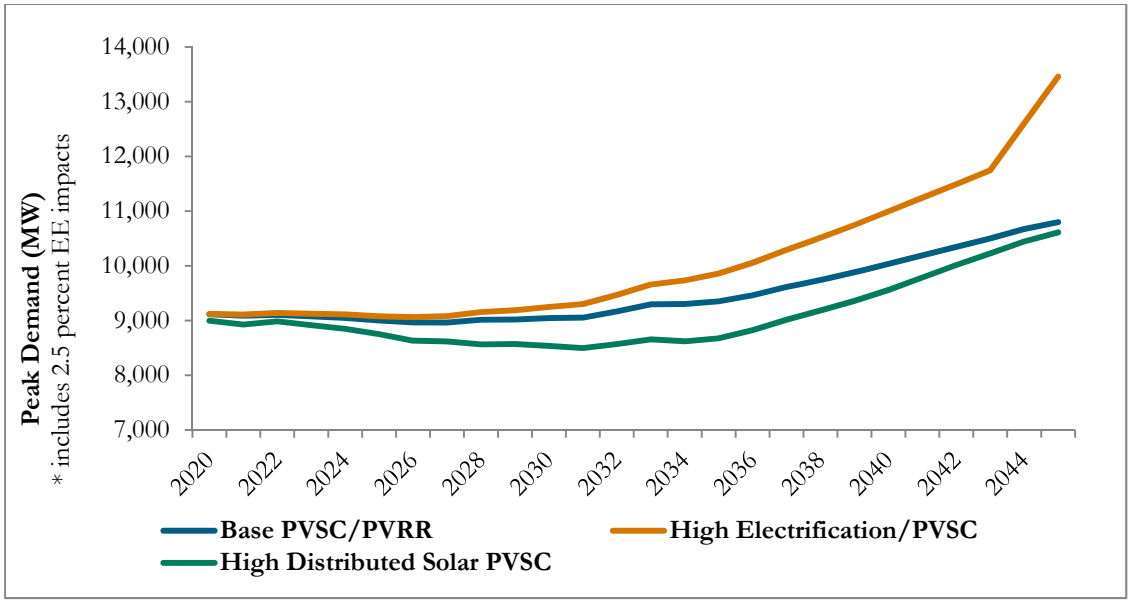


Figure 5-3: Fuel Price Assumptions, by Futures Scenario

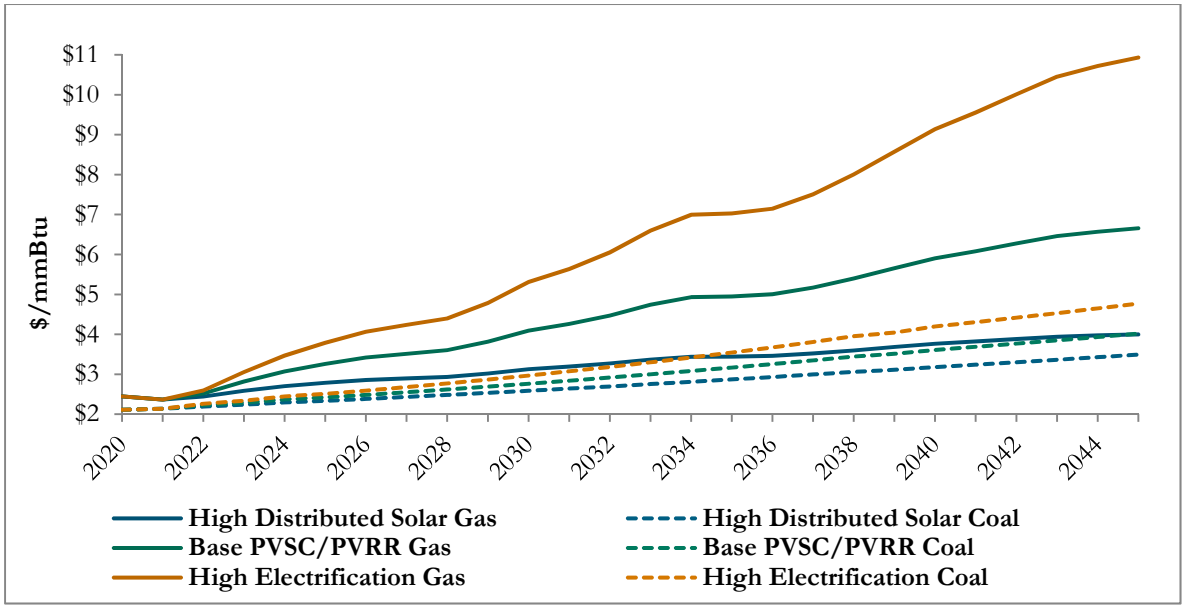


Figure 5-4: New Resource Cost Assumptions, by Futures Scenario ($/MWh; $/kW-mo)

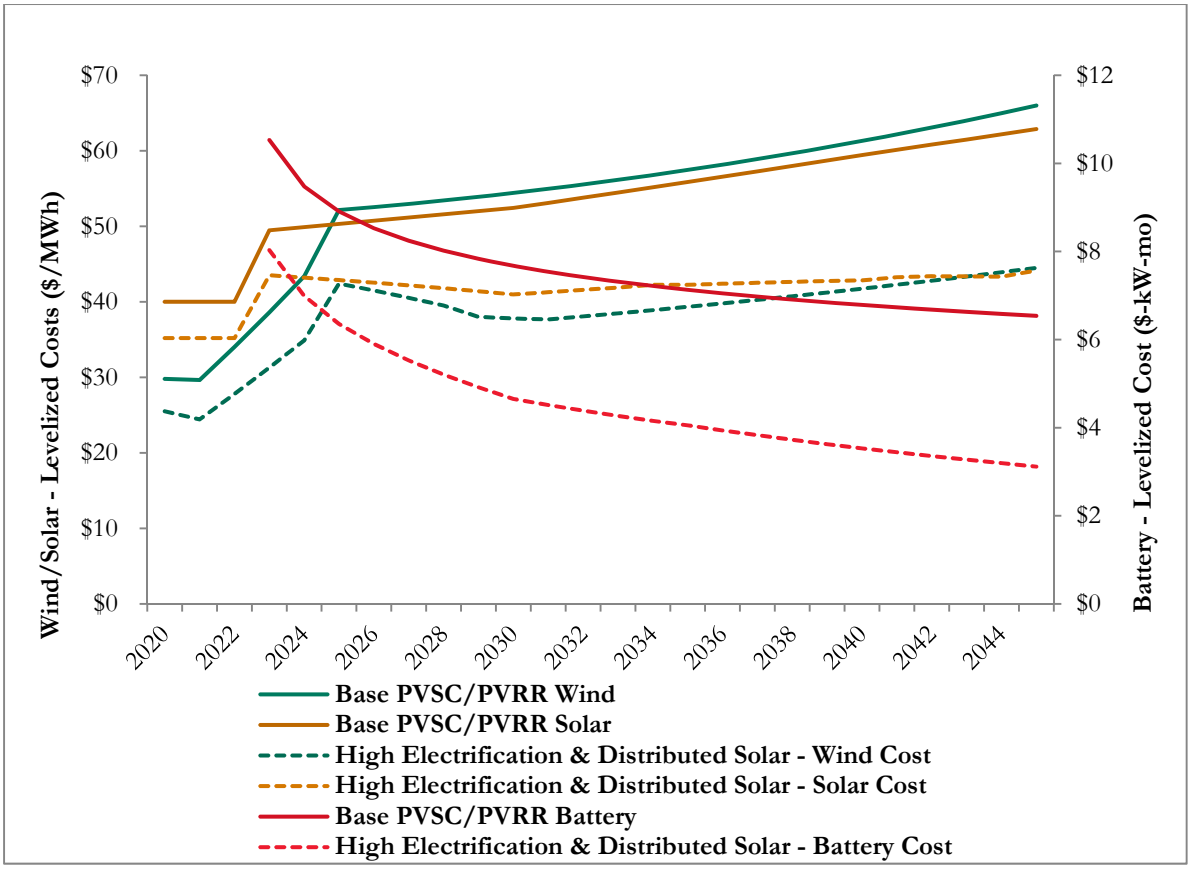
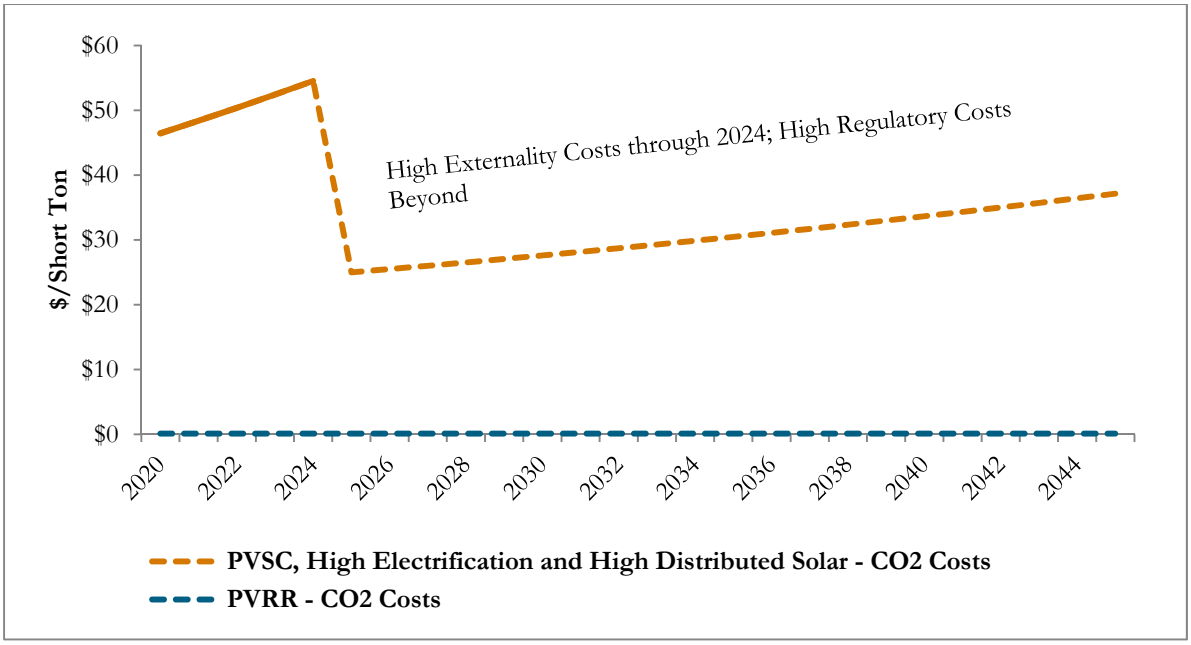


Figure 5-5: Carbon Emissions Cost Assumptions ($/Short Ton)



It is important to note that these Futures Scenarios were designed to test the performance of our baseload retirement decisions under plausible future states. These Futures Scenarios are not, however, intended to test which future is overall least cost for our system. We do not have full control over the level of distributed solar or electrification growth on our system, and have no control over variables such as fuel prices and new resource capital costs. As demonstrated in the next section, the Futures Scenario analysis shows that our Preferred Plan baseload decisions to retire all coal by 2030 and extend Monticello are likely to yield customer benefits relative to the Reference Case, even in a future where multiple key assumptions change simultaneously.

B. Traditional Sensitivities

While our primary focus has shifted to Futures Scenarios as opposed to the traditional single sensitivities, we still believe the individual sensitivities provide insights on potential plan performance. Therefore, consistent with previous Resource Plans, we tested the following individual sensitivities. Detailed results for these sensitivities can be found in Appendix F3.

- *Load.* The low load sensitivity includes high customer adoption-based DER growth and higher EE savings (i.e. it includes all three EE Bundles), which reduces load. The high load sensitivity includes high electrification load.

- *Fuel Price/Market Costs.* High and low price sensitivities were performed by adjusting the growth rate up and down, respectively, by 50 percent from the base forecast starting in year 2022.
- *CO_2 Values.* To examine the effect of CO_2 pricing, we tested high and low cost sensitivities. We also performed a sensitivity evaluating no CO_2 cost. The PVSC Base Case CO_2 values are based on the high externality cost values for CO_2 as determined by the Minnesota Commission through 2024.[4] The PVSC Base Case values starting in 2025 are based on the "high" end of the range of regulated costs.[5] Below is the list of carbon sensitivities.
    - Low Externality
    - Low Externality, Low Regulatory
    - Mid Externality, Mid Regulatory
    - High Externality
    - PVRR, or No Externality or Regulatory
- *Externalities.* Criteria pollutants values are derived from the high and low values for each of the three geographic locations in the Minnesota Commission Order,[6] with existing plants assigned the appropriate area and generic units assigned to "rural." The midpoint externality costs are the average of the low and high values. The high, low and midpoint externality costs are used in conjunction with the CO_2 sensitivities described above.
- *Resource Costs.* For wind, solar and battery energy storage we use NREL's *Annual Technology Baseline* (ATB) 2018 report to provide high and low technology cost sensitivity inputs. For wind and solar, we use the costs projected by the ATB directly. For batteries, we take a slightly different approach. Low and high battery costs are based the percent difference in the NREL ATB base, low and high battery cost forecasts, with this percent difference applied to the Company's base battery cost forecast. We did not adjust capital costs for thermal resources such as the generic CC or CTs, so all scenarios include our base cost assumptions for those resources.
- *Markets Sales Off.* As previously discussed, we assume that markets are "on" for each scenario. The "markets off" sensitivity represents a view in which we

[4] Minnesota Commission Order Updating Environmental Cost Values in Docket No. E999/CI-14-643 issued January 3, 2018.) at 31.
[5] Minnesota Commission Order Establishing 2018 and 2019 Estimate of Future Carbon Dioxide Regulation Costs in Docket Nos. E999/CI-07-1199 and E999/DI-17-53 issued June 11, 2018) at 12.
[6] Minnesota Commission Order Updating Environmental Cost Values in Docket No. E999/CI-14-643 issued January 3, 2018.

cannot access the market to sell energy outside our system.

IV. STRATEGIST ANALYSIS AND RESULTS

After identifying the scenarios and sensitivities for analysis, we used Strategist to identify the expansion plans for each of the 15 primary scenarios, and their resulting cost and emissions impacts. We faced a number of challenges as we tested the full capabilities of the model and attempted to be responsive to stakeholder requests to include a robust set of supply-side and demand-side resource options for consideration. As described below, we undertook an extensive process which attempted to balance the inclusion of a comprehensive set of resource options with the model's limitations, to arrive at a plan that demonstrates a high level of diligence and investigation. This analysis was performed iteratively in several rounds, as we refined the process and results, with each round informing modeling parameters for subsequent rounds. Achieving an appropriate balance between resource options and modeling runtime efficiency required the following adjustments, which are described in more detail in the sections below:

- Removal of our generic distributed solar resource options, with the understanding that if future DG solar growth exceeds our embedded assumptions, it can simply displace utility scale solar additions identified in the Preferred Plan.
- Shortening the modeling period to end in 2025, from the original 2057 end date.
- Testing EE and DR selection via optimizations, evaluating different combinations of the three EE and three DR Bundles for cost effectiveness, and then locking the optimal mix of Bundles in final optimizations.
- Manually inserting CT additions as a proxy placeholder for the firm, dispatchable resource needs driven by the Reliability Requirement. In reality, because these additions happen in the post-2030 timeframe, we expect the need will be met by a combination of firm dispatchable resource options. These may include battery storage, pumped hydro, DR, natural gas, and/or others.

A. Initial Full Optimization

In the first initial round of modeling, all technology alternatives (wind, solar, distributed solar, storage, DR, EE, CC, CT) were made available to the model and we developed a fully optimized expansion plan for each scenario through the end of the available years in Strategist (2057). We found that this stretched the capabilities of the Strategist tool. Due to the large number of alternatives, these runs took a significant

amount of time to complete; on average, five days of processing time per scenario. Further, the results were significantly truncated.[7] In these initial plans, no DR, EE, or distributed solar alternatives were selected for any of the scenarios. Although this set of initial runs was not reliable enough for drawing final conclusions, due to the truncation issues, we identified several refinements for the next round of modeling.

First, when comparing utility-scale solar and distributed solar, the model did not select any distributed solar. We reviewed the modeling data for these two alternatives and it was clear that, because both utility-scale and distributed solar have identical capacity accreditation[8] values and similar capacity factors, the model would only ever select the lower cost utility-scale solar. For modeling purposes, therefore, we removed distributed solar from the optimization in order to improve model runtime and reduce the number of truncated results. We note that this does not imply distributed solar is not a resource we anticipate will be added to our system – only that from a modeling perspective, distributed solar will not appear as cost-effective relative to utility-scale solar in the modeling process, and retaining both types of resources in the model for future runs would reduce the quality and runtime of the modeling process. As we have explained, any growth in distributed solar we experience on our system beyond what is in our embedded forecasts will simply serve to displace some of the utility-scale additions identified in our Preferred Plan.

Truncation challenges also informed the duration through which we modeled our plans. While our initial runs experienced truncation issues fairly early (beginning in the late 2020's), the further out we attempted to optimize portfolios, the more truncation occurred and the slower the simulation became. Based on this observation, we determined it was prudent to shorten the modeling period, using 2045 as the end year rather than 2057. We believed that this, in combination with adding 10 years of "end effects" in the modeling, would inform plans through the planning period (2020-2034) that were more robust and valid than the longer simulation would provide. Additionally, the availability, cost and performance assumptions for technologies become increasingly subjective far into the future, and we would not adequately account for new technologies that may develop within that timeframe.[9] Thus the results of modeling in that extended period would not be particularly robust and would likely misstate the resource mix and cost required to

[7] Truncation occurs when the Strategist model has more viable plans for a given year than the internal memory is able to store. The total collection of plans is sorted by accumulated cost up to that year, and the highest cost plans are discarded and not analyzed further. The Company's model is set to a maximum of 2,500 saved plans per year.
[8] I.e. Effective Load Carrying Capability, or ELCC.
[9] We note that an independent analysis from consultant E3 highlighted similar concerns and also conducts expansion plan modeling to 2045.

meet the Company's longer term vision of 100 percent carbon-free energy by 2050.

Further, including the DR and EE Bundles in full model optimizations proved to be a significant challenge for the Strategist model runtime efficiency. Given that the initial full optimizations resulted in no DSM being selected, we decided to pursue an alternative modeling path. For the next round of modeling, the first DR and the first EE Bundle were forced into the plans to test if "seeding" the model with these Bundles would lead to the second or third Bundles being chosen within the economic optimization.

B. Revised Targeted Optimization

The model revisions discussed above resulted in a somewhat improved modeling process, shortening runtimes and reducing truncation. However, the second round of modeling still took over two days per simulation, and displayed significant truncation, such that we determined additional refinements were needed. This process did, however, help us derive more information from our model runs that informed the final stages of the modeling process.

First, in almost all 15 scenarios, once the first DR and EE Bundles were forced in, the second EE Bundle was selected economically. No additional DR was selected. This result indicated that there was indeed a modeling bias (most likely due to truncation) that prevented selection of DR and EE, as defined by the Bundles, in the fully optimized results. We concluded that some other method of "manual" testing would be necessary to determine these resources' true cost-effectiveness.

Additionally, some of the scenario outcomes in this revised modeling process relied almost entirely on non-dispatchable or use-limited resources (wind, solar, storage) for the full capacity expansion plan. At this point, resource planning consulted with operations and engineering, and worked together to develop and implement a modeling element that would ensure the portfolio resulting from each scenario retained sufficient firm dispatchable generation to reliably serve customer capacity and energy requirements. We describe the Reliability Requirement in Appendix J2.

To incorporate the Reliability Requirement into the modeling, we added firm dispatchable load supporting resources, represented currently with CT resources as a proxy, to the expansion plan in specific years[10] to ensure the portfolio maintained the minimum level of firm dispatchable, load supporting resources as defined by the Reliability Requirement. Given the manual addition of firm dispatchable resources,

[10] Applicable years vary by scenario.

we also reduced the number of new resource alternatives available in certain years to further improve model run times. We believe this did not sacrifice or reduce the model's ability to find optimal solutions for the expansion plan. As an example, the large CC unit option was removed as an alternative in years where the incremental capacity need relative to the previous year was small. This targeted "pruning" of alternatives yielded faster run times and less truncation.

Accounting for all the aforementioned factors, we repeated scenario modeling while including: (1) the Reliability Requirement, (2) the targeted resource "pruning" and (3) one DR and one EE Bundle forced in, while still allowing the incremental DSM Bundles to be selected in the optimization. The second EE Bundle was almost always selected, while no additional DR was selected. Additionally, early coal retirement and nuclear extension scenarios emerged as potential preferred options, as they showed favorable PVSC and PVRR, when compared to other scenarios.

C. Energy Efficiency and Demand Response Analysis

In the next phase of modeling, we worked to refine the DR and EE analysis to identify the most cost effective Bundle combinations. After reviewing initial modeling results, we were confident that two Bundles of EE would likely be selected across all scenarios but wanted to conduct an additional round of tests to confirm. Given we observed strong PVSC and PVRR performance of early coal retirement and extended nuclear scenarios in previous rounds of modeling, we initially conducted DR and EE testing using Scenario 9 (Early King and Sherco 3 retirement with Monticello Extension) and Scenario 10 (Early King retirement with Monticello Extension) as a test. To adequately analyze the Bundles, we developed PVSC and PVRR matrices by selecting a scenario and performing optimizations that included each permutation of the three DR and three EE Bundles. This manual process eliminated the potential for DR and EE truncation, thus allowing us to conduct a robust analysis of each option.

We show results for Scenario 9 as an example below, and note that in both cases the 0 DR/2 EE combination returns the lowest PVSC and PVRR results.

Table 5-2: Scenario 9 (Preferred Plan) DR and EE Cost Effectiveness Analyses ($2019 millions)

PVSC				
	0 DR	**1 DR**	**2 DR**	**3 DR**
0 EE	$48,486	$48,203	$48,502	$48,745
1 EE	$45,390	$45,670	$45,947	$46,152
2 EE	$45,173	$45,512	$45,726	$45,910
3 EE	$45,847	$46,166	$46,389	$46,596

PVSC Deltas (as compared to 0 DR/2 EE)				
	0 DR	**1 DR**	**2 DR**	**3 DR**
0 EE	$3,313	$3,030	$3,329	$3,572
1 EE	$217	$497	$774	$979
2 EE	-	$339	$553	$737
3 EE	$674	$993	$1,217	$1,423

PVRR				
	0 DR	**1 DR**	**2 DR**	**3 DR**
0 EE	$40,029	$40,216	$40,478	$40,653
1 EE	$37,657	$37,910	$38,182	$38,344
2 EE	$37,476	$37,784	$37,925	$38,143
3 EE	$38,374	$38,589	$38,802	$39,009

PVRR Deltas (as compared to 0 DR/2 EE)				
	0 DR	**1 DR**	**2 DR**	**3 DR**
0 EE	$2,554	$2,741	$3,003	$3,177
1 EE	$181	$435	$706	$869
2 EE	-	$308	$450	$668
3 EE	$899	$1,113	$1,327	$1,533

Based on this result, subsequent model runs for the baseload analysis locked in 0 DR Bundles and two EE Bundles, and removed consideration of the remaining DR and EE Bundles from the optimization process. As discussed further in Section V and elsewhere in this Resource Plan however, we ultimately included the first Bundle of DR as part of the Expansion Plan.

D. Final Scenario Analysis

The last round of baseload scenario modeling incorporated the results of the previous rounds into defining and executing a final analysis, which we used to draw conclusions on the relative economics and operational performance of the 15 baseload scenarios. For the final model runs, two EE Bundles were manually added to the plans, and the remaining Bundles were removed from the optimization, per our previous findings that they would not be selected. The Reliability Requirement was included as a constraint, and the number and timing of alternatives were reduced as previously described, in order to improve model run performance without sacrificing the ability to effectively optimize remaining resource options. We then created expansion plans for all 15 scenarios, using PVSC assumptions, and completed the full set of sensitivities.[11]

[11] Minn. Stat. § 216B.2423

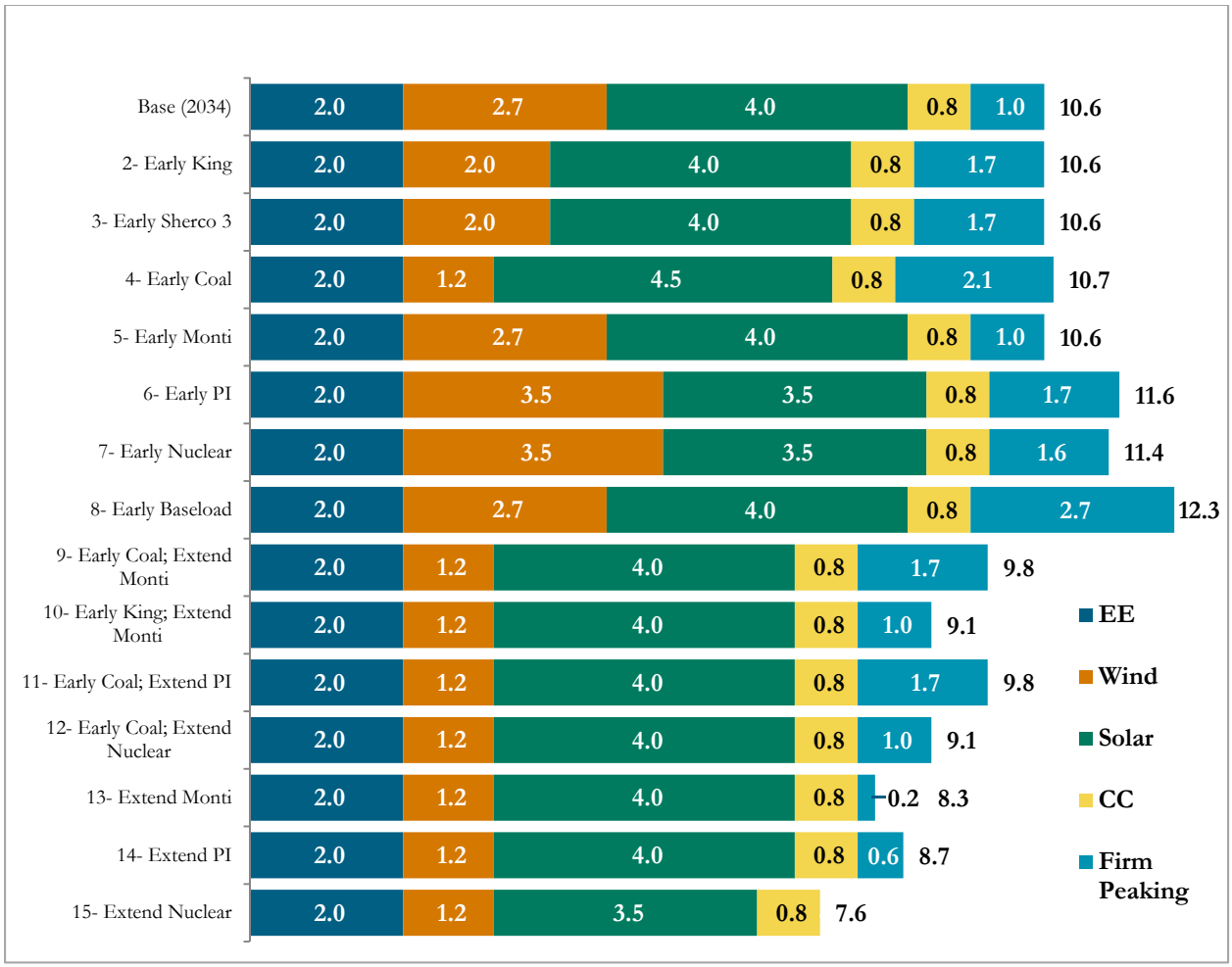
E. Modeling Results and Conclusions

Completing baseload scenario runs, as described above, allows us to examine Scenario outcomes side-by-side, to evaluate their benefits and drawbacks. Among other factors, we examine each Scenario's resource expansion profile and carbon emissions outcomes, present value costs, and several indicators of risk.

1. Capacity Additions and Emissions Reductions

The cumulative expansion plan additions through the planning period for the 15 scenarios are shown below in Figure 5-6.

Figure 5-6: Expansion Plans by Scenario
(GW, Cumulative Nameplate Capacity Resource Additions by Fuel Type)



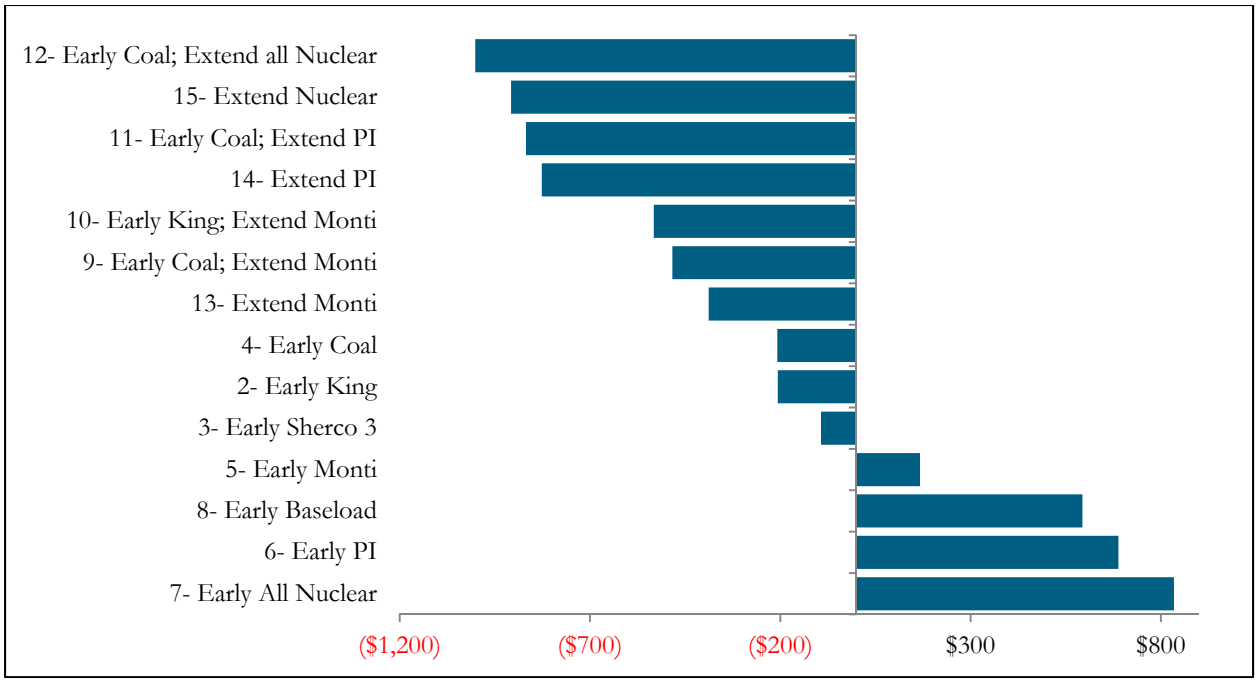
As the 80 percent carbon emissions reduction target was included as a modeling

parameter, all the scenarios achieve this goal and remain under the emissions threshold from 2030 throughout the planning period. There is minimal variability between Scenarios on this measure, other than the timeframe in which they first reach 80 percent reduction levels.

2. *Present Value Costs*

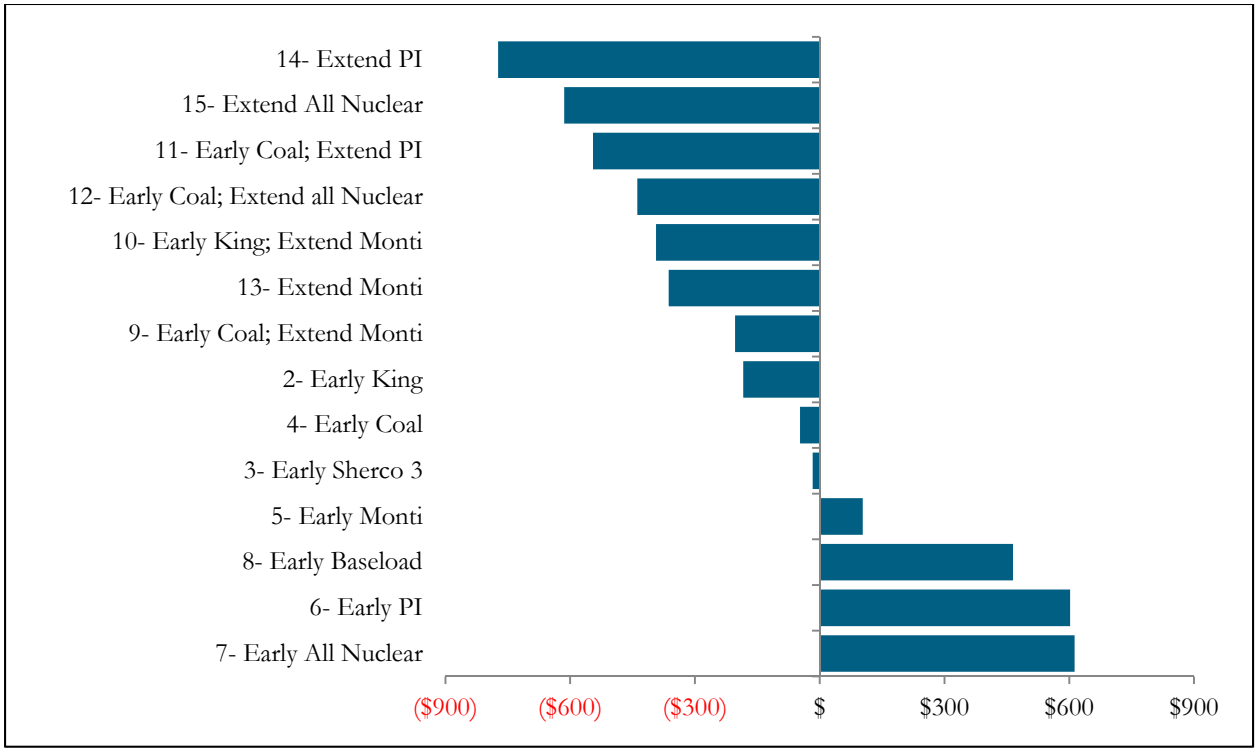
In general, plans that favored early coal retirements and nuclear extensions were the lowest cost plans, both in terms of PVSC and PVRR. The results for the 15 scenarios from the final modeling runs are shown below in Figures 5-7 and 5-8. The figures show the net present value (NPV) delta of modeled costs compared to Scenario 1 (the Reference Scenario), with negative values representing customer savings relative to the Reference Scenario and positive values representing increased costs.[12]

Figure 5-7: Scenario PVSC Deltas from Reference Case ($2019 millions)



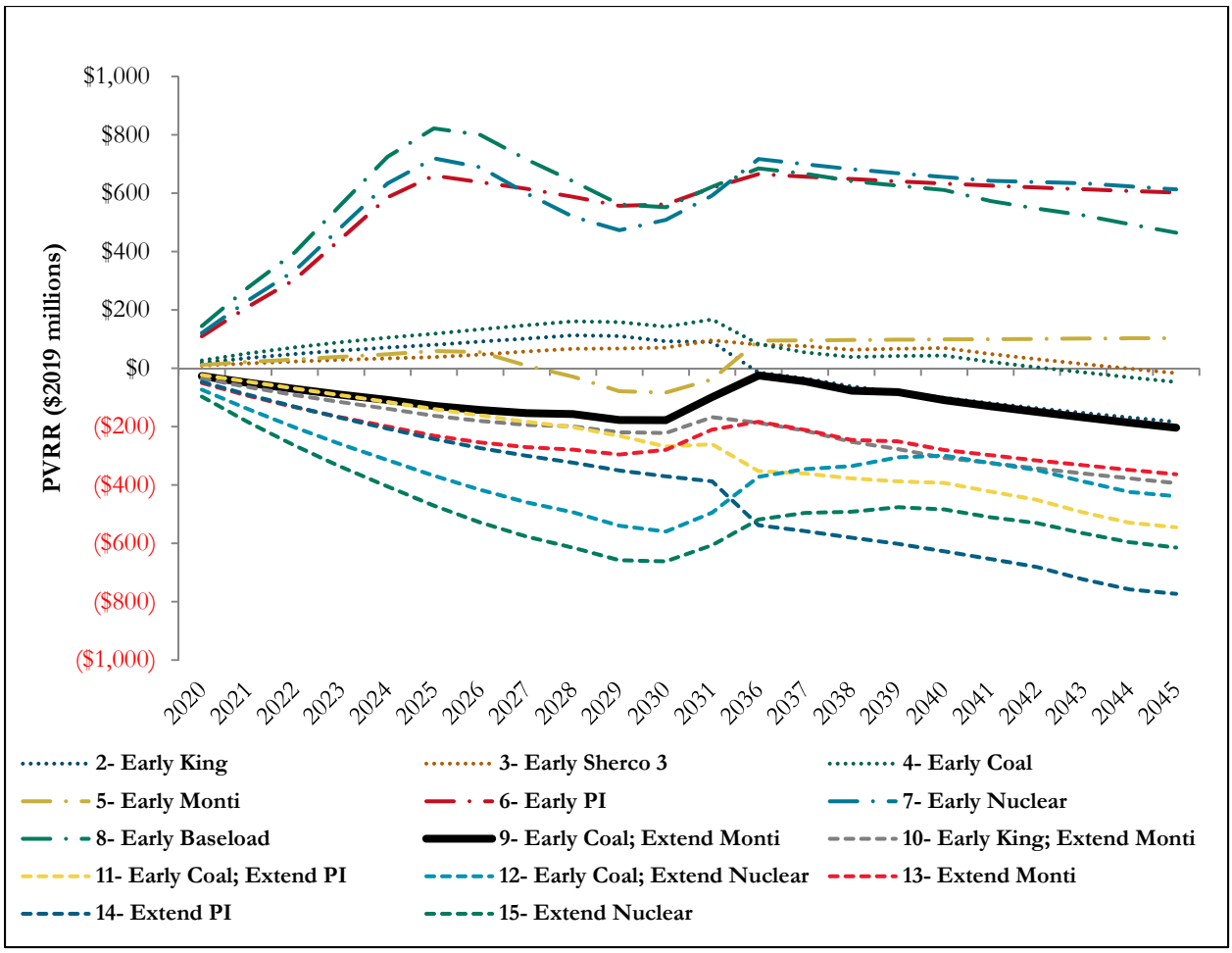
[12] Note that these PVRR and PVSC deltas shown depict NPV for 2020-2045.

Figure 5-8: Scenario PVRR Deltas from Reference Case ($2019 millions)



In addition to evaluating the total NPV of each scenario, we also examine the timing of the relative costs and benefits. Examining NPV over a time series helps us make relative comparisons of changes in costs or benefits at key "transition points" of the plans (such as retirement or extension dates, significant renewable additions, etc.). The cumulative total PVRR costs or savings for each of the scenarios are shown below in Figure 5-9. Each line on the chart illustrates the running total of the annual PVRR costs or benefits by year for a specific scenario, compared to the Reference Case. The end point of the lines in 2045 corresponds to the final PVRR deltas shown in Figure 5-8 above.

Figure 5-9: Cumulative PVRR Cost or Savings Deltas by Scenario, Compared to the Reference Plan ($2019 million)



In addition to PVSC and PVRR, the Company completed sensitivity analyses for all 15 scenarios. The results of these analyses are shown in Appendix F3.

3. Additional Risk Metrics for Baseload Scenario Evaluation

While present value costs are one factor we use to inform our Preferred Plan, we also consider other factors and elements of risk exposure for each potential Scenario. Consistent with the Resource Plan objectives presented in Chapter 4, we evaluated each scenario with regard to achieving our cost, environmental, risk and reliability goals. It is essential that our Preferred Plan meets our carbon reduction goals while also ensuring that the system remains reliable and the plan remains affordable for customers. Likewise, it is important we evaluate various risks, because forecasting into the future is inherently uncertain and we want to ensure our selected Plan

remains robust, even if some key factors change. We describe the objective risk measures we used to evaluate the scenarios in Table 5-3 below.

Table 5-3: Scenario Modeling Portfolio Risk Metrics

Objective	Metric	Definition
Cost	Base PVRR and Base PVSC	Traditional NPV measure of total 2020-2045 PVRR or PVSC costs to determine least cost plan. Plans showing cost savings are preferred.
	Worst Case Futures Scenario Cost	Measure of worst case potential cost outcomes across the four Futures Scenarios so provides insight into plan cost risk. Plans still showing cost savings in worst case Futures Scenario are preferred.
Risk	Energy Risk	Measures the absolute value of average annual total market interaction (purchases plus sales plus dump energy) associated with each plan, to assess market energy risk exposure. Plans with lower market energy exposure are preferred.
	Capacity Risk	Measures average annual net capacity position associated with each plan, to assess market capacity risk exposure. Typically, plans with lower net capacity positions are considered favorable, and our rankings reflect that. However, we also take into account certain factors that are specific to this Resource Plan, which affect the weight we place on this metric. These are discussed further below in Section V.
Environmental	Carbon Emissions Reduction	All plans achieve acceptable levels of carbon reduction, as a result of including an 80 percent carbon reduction (relative to 2005 levels) constraint in modeling.
Reliability	Firm, Dispatchable Resource to Peak Load Ratio	All plans achieve acceptable levels of reliability, measured by the amount of firm, dispatchable resources available, as a result of including the Reliability Requirement in modeling.

As noted, all scenarios meet the environmental and reliability objectives, given these targets are included as constraints in our modeling. Thus, our Scenario evaluation focuses on the cost and risk objective metrics noted above.

V. PREFERRED PLAN SELECTION AND ASSESSMENT

As described previously in this Chapter and in Chapter 4, we evaluated the PVRR and PVSC results of our 15 baseload scenarios, and how effectively each potential plan would meet our planning objectives, to determine which Scenario should form the basis of the Preferred Plan. Based on these outcomes, we selected baseload Scenario 9. Our plan charts the path toward achieving ambitious carbon reduction goals, reflects substantial stakeholder input and consensus, and ensures reliability and

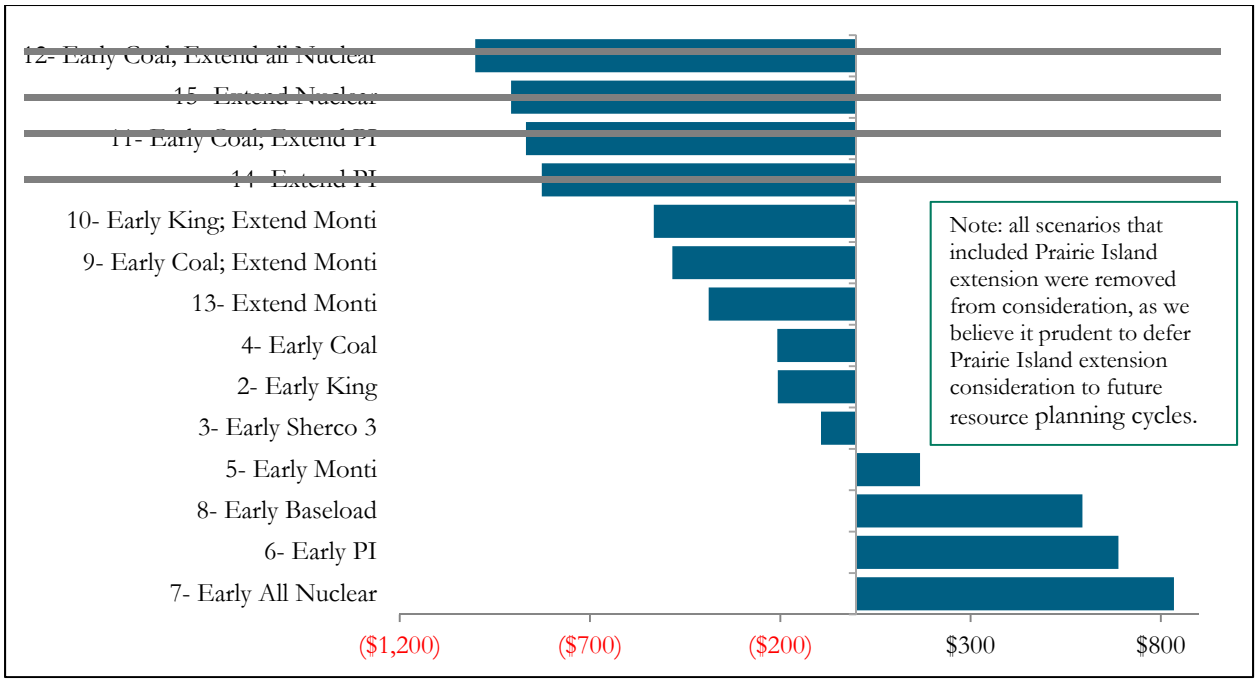
affordability for our customers. The baseload aspects of this plan include an early King retirement in 2028, Sherco 3 early retirement in 2030 and extension of our Monticello nuclear facility to 2040. We also took into account additional considerations regarding DR when finalizing the Preferred Plan. We discuss more detail regarding how we selected and evaluated our Preferred Plan below.

A. Baseload Study Analysis Results

From a modeling perspective, the PVSC and PVRR results are primary indicators of the various scenarios' economic favorability. Figures 5-8 and 5-9 shown above indicate that the nuclear extension scenarios paired with early coal retirements yielded the most attractive customer value relative to the Reference Case.

We note that while Baseload Scenario 9 was not the least cost of our 15 scenarios, several lesser cost scenarios included an extension of Prairie Island's operating license. However, as discussed previously, Prairie Island's license does not expire until the 2033-3034 timeframe just outside the planning period, and we believe there is risk avoidance value in deferring a decision on Prairie Island extension until a future Resource Planning process. As a result, we eliminated from consideration cases that include a Prairie Island extension, as shown below.

Figure 5-10: Scenario PVSC Deltas from Reference Case, PI Extension Cases Eliminated ($2019 millions)



After screening out the baseload scenarios that include Prairie Island extension, we evaluated the remaining scenarios using the cost and risk metrics discussed previously, including savings or costs achieved in a "worst-case" Futures Scenario, and average energy and capacity exposure. Of the remaining baseload scenarios available for selection, Scenarios 9 (Early Coal; Extend Monti), and 10 (Early King; Extend Monti) achieve the most favorable risk profile overall.

Further, Minn. Stat. § 216B.2422, subd. 2(c) requires that we "include the least cost plan for meeting 50 and 75 percent of all energy needs from both new and refurbished generating facilities through a combination of conservation and renewable energy resources." The Preferred Plan (Scenario 9 - Early Coal; Extend Monti) satisfies the statute's first requirement (50 percent of energy needs from conservation or renewables) because it is economically optimized and meets approximately 64 percent of energy needs with renewables and conservation. Our baseload scenario analysis satisfies this statute's second requirement (75 percent of energy needs from conservation or renewables), as Scenario 4 (Early Coal) yields the least cost plan for meeting at least 75 percent of all energy needs from both new and refurbished generating facilities through a combination of conservation and renewable energy resources. Because this scenario does not include a nuclear extension, it enables greater levels of renewable additions than the Preferred Plan that meet or exceed the 75 percent threshold.

B. Early Retirement of Sherco 3 by 2030

Excluding the Prairie Island extension scenarios, Scenarios 9 and 10 become the optimal least cost options. Both Scenarios 9 and 10 assume an early King retirement and Monticello extension; however, Scenario 9 includes an early Sherco 3 retirement while Scenario 10 does not. Both Scenarios are beneficial on a PVSC and PVRR basis, and are the most resilient of the remaining scenarios to the potential worst case evaluated, continuing to maintain customer benefits relative to the Reference case.

Given the proximity of overall customer savings and risk considerations between Scenario 9 and 10, we ultimately considered which case would fit best with our strategic objectives and our understanding of stakeholder interests. We selected Scenario 9 as our Preferred Plan, which includes the retirement of all remaining coal units. Scenario 9 provides the best fit for our carbon goals and helps mitigate the potential for regulatory or legislative action around carbon costs or carbon reduction levels. Further, general market trends toward increasing levels and decreasing costs of renewables, low natural gas prices, the need for more flexible resources, and other factors are expected to make it more and more difficult for coal resources to operate

in an efficient and economic manner beyond 2030. Finally, our interactions with customers, stakeholders, and shareholders alike have shown increasing interest in achievement of carbon reductions and other environmental solutions. From a financial risk perspective, we believe it is beneficial for the Company to reduce carbon risk exposure, and we view transitioning our generation fleet away from coal assets is one of the best ways to achieve that goal.

C. Demand Response Adjustment to Scenario 9

As noted previously, the model optimization exercise did not select any of the DR Bundles provided as options. However, the Order approving our last Resource Plan included direction to add 400 MW of incremental DR resources. Therefore, the final step in developing our Preferred Plan was to include DR Bundle 1 as part of Scenario 9. This addition increases our net long capacity position, where after 2025, our position remains long by a range of 500-1,000 MW through the remainder of the planning period. As mentioned previously, we typically view a long capacity position as less favorable; however, we believe this is an acceptable path forward given alignment with our risk mitigation planning objective, discussed further below.

D. Futures Scenarios Results

As previously discussed, a final step in our analysis process evaluated the performance of the Preferred Plan under the Futures Scenarios. Table 5-4 below provides a summary of the Futures Scenario results. Under all of these Futures Scenarios, the Preferred Plan provides savings relative to the Reference Case,[13] which suggests that the Plan is robust under a range of potential future conditions.

Table 5-4: Preferred Plan NPV Savings under Different Futures Scenarios ($2019 millions)

	Base PVSC	Base PVRR	High Electrification Scenario PVSC	High Distributed Solar Scenario PVSC
Delta	***(461)***	***(203)***	***(81)***	***(51)***

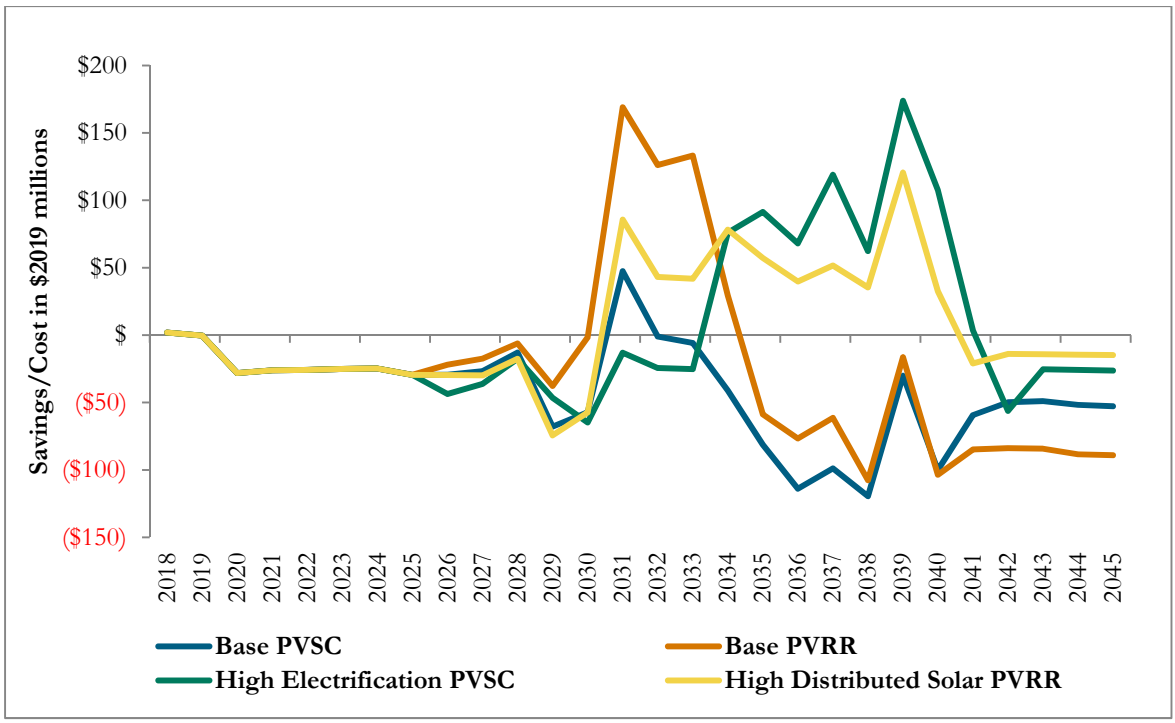
As demonstrated in the baseload scenario analysis and in Table 5-4, the Preferred Plan yields customer value of $203 million in the base PVRR and $461 million in the base PVSC scenarios. Early coal retirements paired with the Monticello extension yield

[13] Note: Each NPV result compares the Preferred Plan with Future Scenarios assumptions applied to the Reference Case with those same assumptions applied.

benefits to customers particularly when carbon costs are included. In both the High Electrification and the High Distributed Solar Futures Scenarios, customer value is marginally reduced from the Base PVRR and PVSC scenarios with $81 million of savings in the High Electrification Scenario and $51 million of savings in the High Distributed Solar Scenario.

As shown in Figure 5-11 below, the Preferred Plan consistently results in customer savings relative to the Reference Case in all Future Scenarios through 2030. At that time, however, the Base PVSC and PVRR scenarios diverge from the High Electrification and High Distributed Solar Scenarios mainly in the 2030 timeframe. A number of factors impact the annual deltas in these Scenarios and drive the divergence. Assumed low new resource capital costs in the Electrification and High Distributed Solar Scenarios likely functions as the biggest driver in upward cost pressure on the Preferred Plan in the 2030s, as in those Scenarios Monticello can be replaced with cheaper renewables. Even under these conditions,, however, the results demonstrate that over the entire planning period and across multiple Futures Scenarios, the Preferred Plan provides overall customer savings relative to the Reference Case. This demonstrates that the Plan is robust and beneficial to customers, yielding savings under a host of potential future conditions.

Figure 5-11: Preferred Plan Annual Costs or Savings Compared to the Reference Case, by Scenario ($2019 millions)



The expansion plans for the Preferred Plan under all of the Futures Scenarios analyses are provided below. In the High Electrification Scenario, higher load growth drives incremental solar and firm dispatchable resource additions above what is included in the Base PVSC/PVRR expansion plans. Specifically, the High Electrification Scenario yields an additional 1,000 MW of solar and 748 MW of firm dispatchable additions. In the High Distributed Solar Scenario, utility-scale solar is displaced by incremental distributed solar, as well as additional EE resources, per the inclusion of the third EE Bundle. Total large solar additions are decreased from 4,000 MW in the base scenarios to 2,500 MW total in the High Distributed Solar Scenario.

Table 5-5: Preferred Plan Base Expansion Plan (MW)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total
Grid-scale Solar	0	0	0	0	0	500	500	1000	500	500	500	0	500	0	0	**4,000**
Battery	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
CC	0	0	0	0	0	0	0	835	0	0	0	0	0	0	0	**835**
Firm Dispatchable	0	0	0	0	0	0	0	0	0	0	0	606	0	374	748	**1,728**
DR	270	20	21	10	17	41	12	14	15	17	19	20	21	22	23	**542**
EE	115	130	116	133	143	145	154	157	155	140	138	136	129	126	126	**2,041**
Wind	0	0	0	126	45	70	66	72	10	107	16	56	31	523	81	**1,202**
Distributed Solar	154	22	22	21	21	21	21	20	20	20	20	20	20	20	19	**442**

Table 5-6: High Electrification Scenario Expansion Plan (MW)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total
Grid-scale Solar	0	0	0	0	0	500	500	1000	500	500	500	500	500	0	500	**5,000**
Battery	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
CC	0	0	0	0	0	0	0	835	0	0	0	0	0	0	0	**835**
Firm Dispatchable	0	0	0	0	0	0	0	0	0	374	0	606	374	374	748	**2,476**
DR	270	20	21	10	17	41	12	14	15	17	19	20	21	22	23	**542**
EE	115	130	116	133	143	145	154	157	155	140	138	136	129	126	126	**2,041**
Wind	0	0	0	126	45	70	66	72	10	107	16	56	31	523	81	**1,202**
Distributed Solar	154	22	22	21	21	21	21	20	20	20	20	20	20	20	19	**442**

Table 5-7: High Distributed Solar Scenario Expansion Plan (MW)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total
Grid-scale Solar	0	0	0	0	0	500	0	500	500	0	0	500	500	0	0	**2,500**
Battery	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
CC	0	0	0	0	0	0	0	835	0	0	0	0	0	0	0	**835**
Firm Dispatchable	0	0	0	0	0	0	0	0	0	0	0	606	0	374	748	**1,728**
DR	270	20	21	10	17	41	12	14	15	17	19	20	21	22	23	**542**
EE	151	171	152	174	186	189	202	207	203	185	183	181	171	167	166	**2,687**
Wind	0	0	0	126	45	70	66	72	10	107	16	56	31	523	81	**1,202**
Distributed Solar	154	166	9	11	9	14	93	19	127	27	62	64	67	70	72	**964**

For simplicity, the table below shows cumulative expansion plan additions by resource type. It is important to note that while DR, EE and battery storage are reflected as separate categories, and no incremental additions for these resources are shown, they would be considered to fill any firm dispatchable needs identified in the expansion plans. Similarly, evolving economics and value could also shift the mix of wind and solar additions.

Table 5-8: Cumulative 2020-2034 Additions by Resource Type and Scenario (MW)

	Base Preferred Case	High Electrification	High Distributed Solar
Large Scale Solar	4,000	5,000	2,500
Battery	0	0	0
CC	835	835	835
Firm Dispatchable	1,728	2,476	1,728
DR	542	542	542
EE	2,041	2,041	2,687
Wind	1,202	1,202	1,202
Distributed Solar	442	442	964

E. Preferred Plan Benefits

We believe our analysis supports selection of Scenario 9, including the early retirement of all of our coal resources by 2030 and extension of Monticello nuclear facility to 2040, as our Preferred Plan. While all of our scenarios meet the carbon goal and Reliability Requirement we established, we believe cost and risk considerations elevate Scenario 9 above the rest as an appropriate path forward.

1. Cost

As demonstrated in our modeling analysis, the Preferred Plan achieves customer value, not only under the our Base PVSC ($461 million) and PVRR ($204 million) analysis but also under more challenging future conditions as evidenced in our High Electrification ($81 million) and High Distributed Solar ($51 million) Futures Scenario analysis. In addition, the Preferred Plan yields customer value under all of the individual sensitivities run, even in the Futures Scenario that results in the worst case customer savings outcome (High Distributed Solar Scenario). Lastly, from a customer rate impact perspective, the Preferred Plan results in annual rate increases of just over one (1) percent, which is below the rate of inflation.[14] Altogether, we believe the Preferred Plan delivers tangible customer savings while taking industry-leading steps towards a carbon free future.

2. Risk

In addition to beneficial cost outcomes, the Preferred Plan addresses major risks by maintaining portfolio diversity, retaining optionality and effectively managing market exposure. The Plan incorporates significant capacity additions to replace retiring resources, consisting of a diverse portfolio of DSM, nuclear extension, solar, wind, and firm dispatchable resource additions. Ensuring we do not become too dependent on a single fuel source mitigates risk. In addition, deferring a decision on a potential Prairie Island license extension affords us additional flexibility to reevaluate in future resource planning cycles, as technology costs and other key assumptions can change quickly.

We also evaluate factors such as energy market exposure and portfolio length. All of our baseload scenarios show high levels of market interaction, driven in part by significant renewable additions; but our selected Plan minimizes them relative to other scenarios and attempts to carefully balance and pace renewable additions with other resources. Further, we typically try to achieve a closer supply-demand balance than

[14] As noted in Chapter 4: Preferred Plan and discussed further in Chapter 6: Customer Rate and Cost Impacts

any of our baseload scenarios offer, although the 500-1000 MW of length in any scenario is relatively minimal compared to our overall system. We believe our Preferred Plan's portfolio length is warranted at this time, however, and creates an effective hedge for our customers against two key risk factors:

- *Capital Investment Wind Down At Retiring Plants.* The retirement of all 2,400 MW of our coal assets, in addition to a few other units by 2030 exposes our customers to some risk as we wind down operations and reduce capital spend at these plants. In the event of an early outage, excess capacity will give us the option to flex the retirement dates as needed if we find that a capital investment is not in our customers' best interests at that time.
- *Renewable and Use-Limited Resource Capacity Accreditation.* Solar capacity accreditation is assumed at 50 percent credit in all years of our modeling. We expect this to change as MISO changes its approach to forward capacity accreditation – recognizing that as solar penetration increases in the footprint, the accredited value of solar will decline. The same also applies for use-limited resources like DR. We discuss this emerging MISO recognition in the Baseload Study provided as Appendix J1, in conjunction with the Reliability Requirement in Appendix J2, and in discussion of our Supporting Infrastructure – Transmission & Distribution, provided as Appendix I.

VI. CONCLUSION

Considering the above we believe our modeling and analysis fully supports selection of the Preferred Plan, and strikes a strong balance in meeting our planning objectives, in service of our customers' needs. The plan sets us on a path to deliver tangible savings to our customers, while transitioning our system to meet both our 2030 carbon reduction objectives and longer term carbon-free goals.

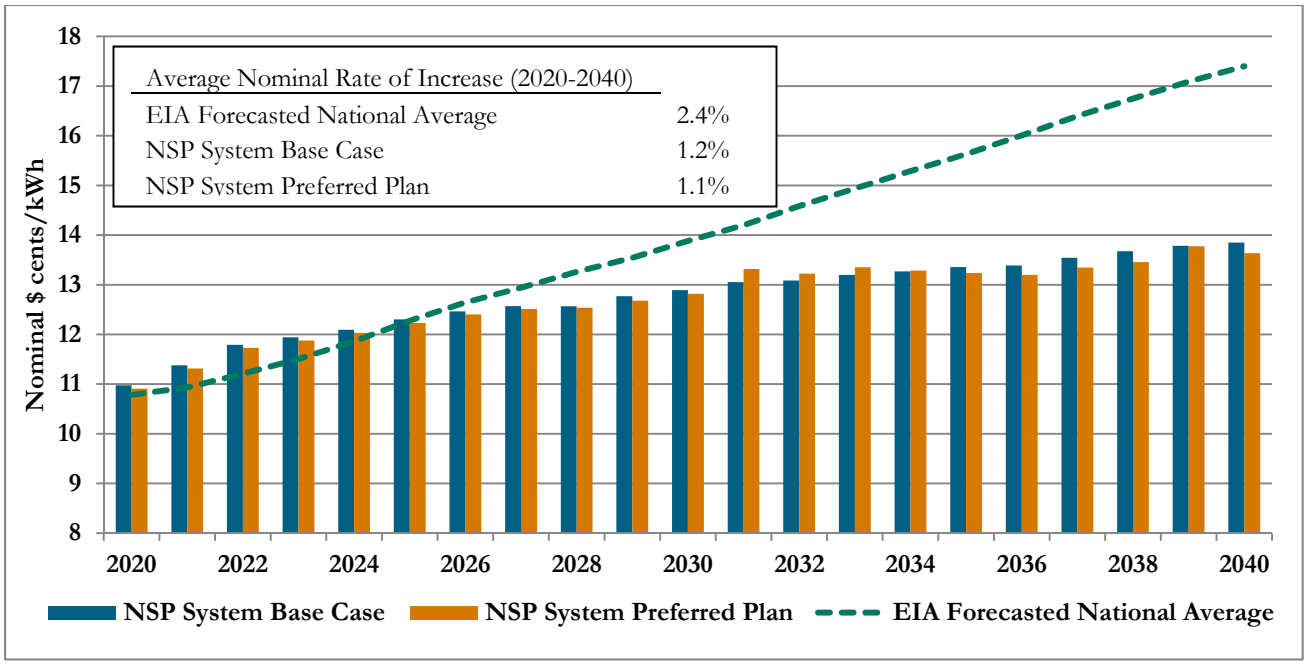
CHAPTER 6
CUSTOMER RATE AND COST IMPACTS

Overall, our Preferred Plan results in an estimated average annual increase in revenue requirements less than the Reference Case and just over one (1) percent overall. In other words, we can achieve significant CO_2 emissions reductions, with cost impacts that are roughly half of the expected national average increase in electricity prices.

Both the Reference Case and the Preferred Plan are designed to meet the Company's goal of reducing carbon emissions 80 percent by 2030, compared to 2005 levels. We did not do the full rate impact calculations discussed in this Chapter on a resource portfolio that does not meet our 80 percent carbon reduction by 2030 goal, we did run a "no 80 by 30" portfolio in our Strategist model and and confirmed that the impacts are in line with our Preferred Plan. In other words, our carbon goals do not materially increase costs for our customers.

To show the cost impact of our proposal over the long-term, we provide a Compound Average Growth Rate (CAGR) comparison of our Preferred Plan compared to the national average nominal cost CAGR for the NSP System in Figure 6-1 and Minnesota in Figure 6-2.

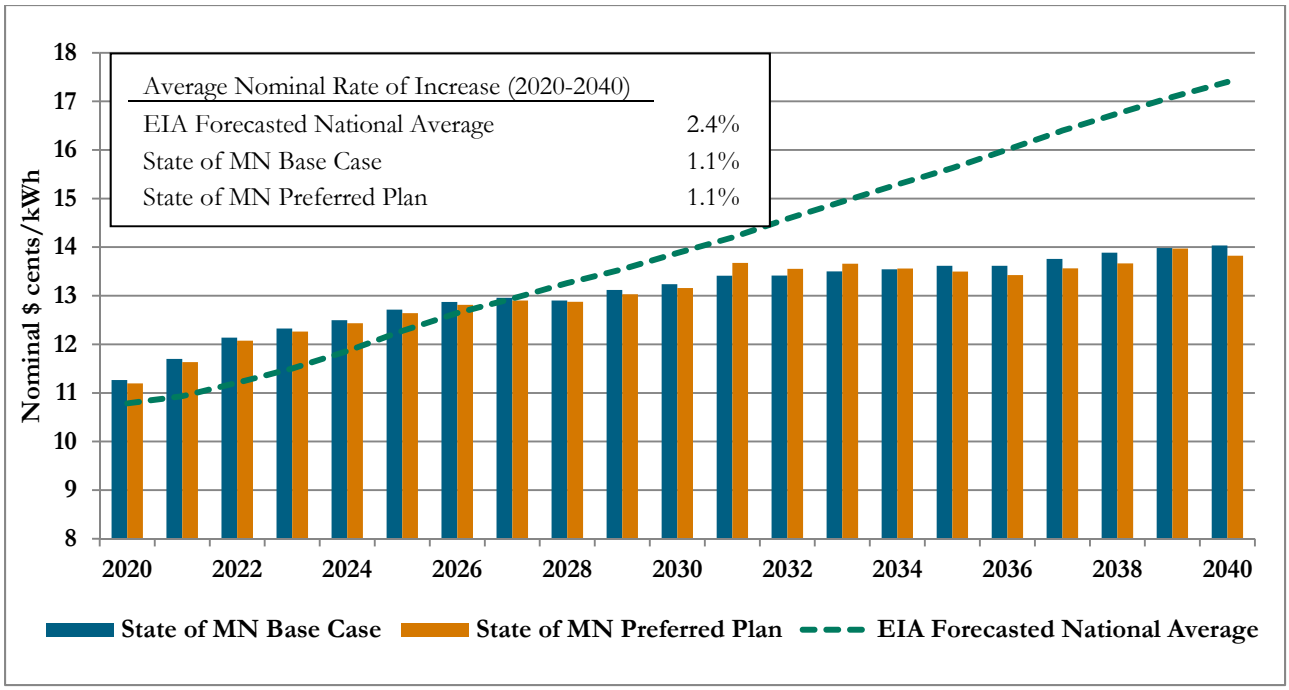
Figure 6-1: Preferred Plan Average Nominal Cost Comparison (NSP System)



* *Notes: National energy cost forecast from Energy Information Administration (EIA) Annual Energy Outlook 2019, Table Energy Supply, Disposition, Prices and Emissions – Reference Case. End use prices, all sector average.*[1] The Preferred Plan and Reference Plan lines include the costs of Solar Rewards*Community.

[1] *See* https://www.eia.gov/outlooks/aeo/data/browser/#/?id=8-AEO2019&region=0-0&cases=ref2019&start=2017&end=2050&f=A&linechart=~ref2019-d111618a.70-8-AEO2019&ctype=linechart&sid=ref2015-d021915a.70-8-AEO2015~ref2019-d111618a.70-8-AEO2019&sourcekey=0 The EIA's Annual Energy Outlook was published in January 2019. The report is available at https://www.eia.gov/outlooks/aeo/pdf/aeo2019.pdf.

Figure 6-2: Preferred Plan Average Nominal Cost Comparison (State of Minnesota)



We derived this long-term projection using a combination of a shorter-range financial forecast and the Strategist model.

We note that a detailed analysis of rate impacts in a resource planning process with long-time horizons is difficult to produce due to changes in our rates and resource needs that will occur over time. Because of the simplifying assumptions made in both the calculation methodology and the input variables, these estimated impacts may not correspond with actual rates that the Commission sets for various rate classes in the future. That said, aside from updated inputs to the class cost allocation factors used in this analysis, the methods are the same as those we used in our last Resource Plan.

In this Section, we explain how we approximated a baseline level of revenue requirements associated with our Reference Case and measured the incremental cost impacts of our Preferred Plan at the NSP system, State of Minnesota, and individual State of Minnesota customer class levels. This is generally consistent with the methodology we used in our last Resource Plan.

I. REFERENCE CASE REVENUE REQUIREMENTS FORECAST METHODOLOGY

To calculate the long-term rate impacts of the Preferred Plan as compared to the

Reference Case, we first developed a forecast of total rates under Reference Case assumptions. This forecast leveraged our detailed five-year financial forecast and a specific approach to identify costs through the end of the planning period (2034) using the CAGR of generation and fuel costs from the Strategist model.[2] Next, we analyzed the annual cost differences by category (i.e. fuel, purchased power, capital expenditures, operating and maintenance costs, taxes, depreciation, etc.) from the Strategist model results for the Reference Case and the Preferred Plan to determine the aggregate system cost impacts and jurisdictional and rate class breakouts.

To determine the overall impact to Minnesota customers and individual customer classes in Minnesota, we converted the differential in annual expenses and capital spend of the Preferred Plan compared to the Reference Case into a differential revenue requirement forecast. We then jurisdictionalized the differential revenue requirements and applied class allocation principles to calculate impacts on individual Minnesota customer classes. We provide various rate impact analyses and discuss the methodologies below.

II. ESTIMATED RATE IMPACTS AND METHODOLOGY

The primary Strategist model captures only the generation-related portion of the business, or around 50 percent of the total revenue requirements. Developing a total rate forecast beyond 2023 when detailed Company financial models are not available is dependant on making assumptions for capital expenditures and O&M costs for all areas of the business, including generation (both new and existing), transmission, distribution and corporate support services. Many of these assumptions are speculative, and the resulting total rate forecast would be similarly speculative.

A. Methodology

To calculate the rate impacts of the Preferred Plan, we started with the 2018 budget forecast of total revenue requirements for the 2019-2023 period.[3] To estimate customer impacts for the immediate five-year period, we estimated revenue requirements similar to a Jurisdictional Cost of Service (JCOSS) for each year, and then performed an estimated Class Cost of Service (CCOSS) analysis – both of which required us to make a number of assumptions.

[2] The Strategist model for the Reference Case is the same model used for the Strategist aspect of our Baseload Study, Scenario 1 Reference Case, with the exception that the first Demand Response (DR) bundle was added to the plan, as was also added to the Preferred Plan.
[3] Developed in July 2018 and updated in November 2018.

To determine the JCOSS, we had to make a number of assumptions, including the following:

- Full recovery of the Company's internal five-year forecasts of capital, O&M, and sales,[4]
- Return on Equity (ROE) of 9.20 percent,[5]
- A forecast of debt and equity ratios and debt rates appropriate for the five-year modeling term,
- Estimated historical regulatory adjustments made in rate cases.

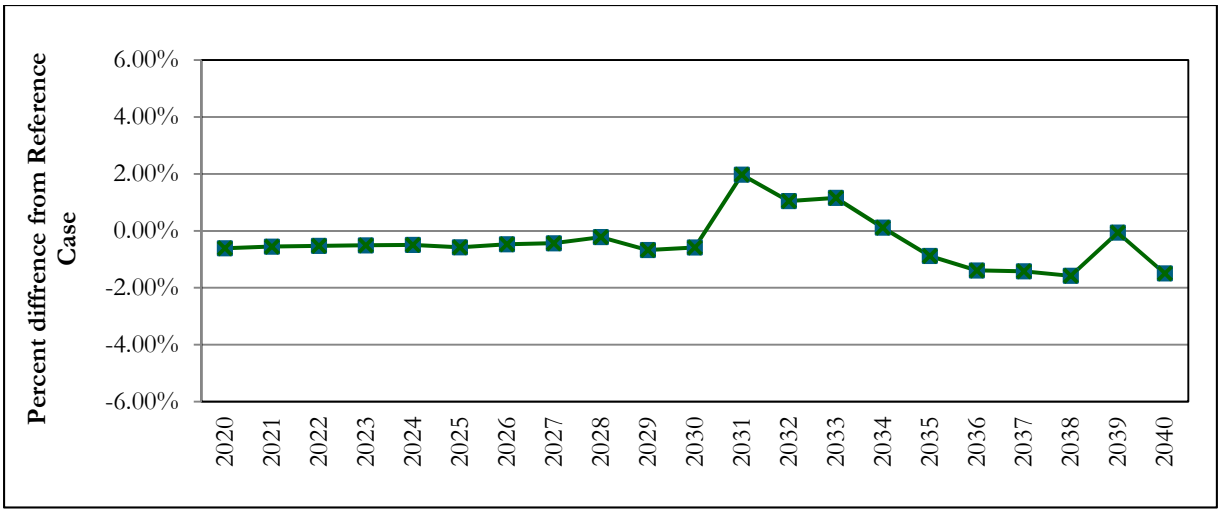
To calculate longer-term rate impacts of the Preferred Plan, we used a combination of the Company's 5-year financial forecast and the Strategist model to project total system revenue requirements for extended periods. For the period beyond 2023, we escalated the capital and O&M costs in the last year of the 5-yr model by the CAGR of the Reference Case as modeled by Strategist.[6] This approach avoids speculation on areas of the business not related to resource planning and modeling, while still using the detailed generation-related information from the Strategist model to create a "business as usual" long term rate projection. Finally, we calculated the annual difference between the Preferred Plan and the Reference Case to estimate the total rate impact of our Preferred Plan.

B. Estimated Overall Rate Impacts

Figure 6-3 below illustrates the State of Minnesota estimated rate impacts of the Preferred Plan compared to the Reference Case over the long-term.

[4] Data as of November 2018.
[5] The Company acknowledges the recent decision in the TCR docket requiring a 9.06% calculation to be used in future filings and will implement that practice once the order is received.
[6] The Reference Case is Resource Plan Scenario 1; see Appendix F2 for additional details.

Figure 6-3: Annual Percent Change in Revenue Requirements (2020-2040)
Preferred Plan above Reference Case – State of Minnesota



The modeling includes accelerated depreciation costs associated with the early retirements of Sherco 3 and King. However, consistent with the Commission's actions in the approval of the early shutdown of the Benson biomass plant (Docket No. E002/M-17-530), a regulatory asset is another tool that could be used to accompany these early retirements. The use of a regulatory asset for the remaining costs of these plants, including a cost of capital return on those assets, would be an appropriate alternative to accelerating the depreciation because it would keep the Company whole over the remainder of the plants' remaining lives. This would also serve to smooth the projected rate impacts over the planning period.

C. Key Drivers

The major inflection points in the delta of revenue requirements (and rates) is driven entirely by the differences in the set of resources that comprise each the Preferred Plan and Reference Case; these points coincide with key differences in baseload plant retirement dates between the two cases and the timing of replacement resources. The reduction in revenue requirements associated with the early coal unit retirements helps to offset a portion of the ongoing nuclear revenue requirements in the Preferred Plan in the early 2030s, as discussed in more detail below:

- *Extension of Monticello.* In 2028, costs associated with the 10-year license extension begin to ramp up in the Preferred Plan, and capital revenue requirements and O&M costs continue through 2040. In contrast, the Reference Case does not have ongoing capital and O&M costs for Monticello beyond 2030 as it is retired in that case; this results in an approximate $295 million difference between the two cases in fixed costs for Monticello,

beginning in 2031.

- *Retirement of Coal Units.* The Reference Case contains ongoing capital and O&M costs for King and Sherco Unit 3, whereas in the Preferred Plan the costs for King terminate in 2029 and Sherco Unit 3 in 2031 due to early retirement. This results in savings of approximately $45 million in fixed costs in 2029, increasing to $110 million in 2031.
- *Load Supporting Resources.* The Preferred Plan has some load-supporting, dispatchable resources added in the early 2030's associated with the Reliability Requirements Proxy discussed in the Baseload Study in this Resource Plan. With the early retirement of King and Sherco Unit 3, the Preferred Plan has a load supporting, dispatchable resource deficiency of approximately 400 MW in that time frame. The Preferred Plan extension of Monticello helps to offset some of this capacity deficiency. The net cost of the load supporting, dispatchable resources in those years ranges from approximately $35 million to $70 million.

The rate increase seen in 2031-2033 reverses in 2034 and the Preferred Plan remains an annual savings producer thereafter. The cost savings from the Preferred Plan are due to the extension of Monticello, which maintains the NSP system 80 percent carbon reduction after Prairie Island retires, without the need to add significant renewables. In the Reference Case, the model adds 2,250 MW of wind in 2034-35 to maintain the 80 percent carbon reduction level, which adds significant costs.

D. These Estimates are not Directly Comparable to Rate Impact Analysis in a Rate Case

We caution that this information should not be interpreted as directly comparable to the customer rate impact information we would provide as part of a rate case filing for reasons including the following:

- The internal forecast for 2019-2023 is not prepared at the level of detail necessary to support a rate case,
- While the forecast includes typical regulatory adjustments, we have not attempted to remove one-time effects or other one-time adjustments that are not specifically known at this time,
- We have made no assumptions of a rate case filing schedule over this period; the forecast provided assumes full recovery of annual deficiencies, suggesting a full rate case annually, and
- All factors of the Cost of Capital, including debt rates, return on equity, and

debt-equity ratios, are subject to change over the period.

III. ESTIMATED RATE IMPACTS BY CLASS PER YEAR

After determining the incremental revenue requirement impacts from the Preferred Plan and Reference Case for the Minnesota jurisdiction, we determined *class* revenue requirement impacts. We provide the estimated impacts below, then discuss the methodology and calculations that we used. The incremental revenue requirement impact of the Preferred Plan versus the Reference Case is shown in column 3 of Table 6-1 below. Column 4 of the below Table also shows the incremental impact of the Preferred Plan as a percent of the total State of Minnesota revenue requirement.

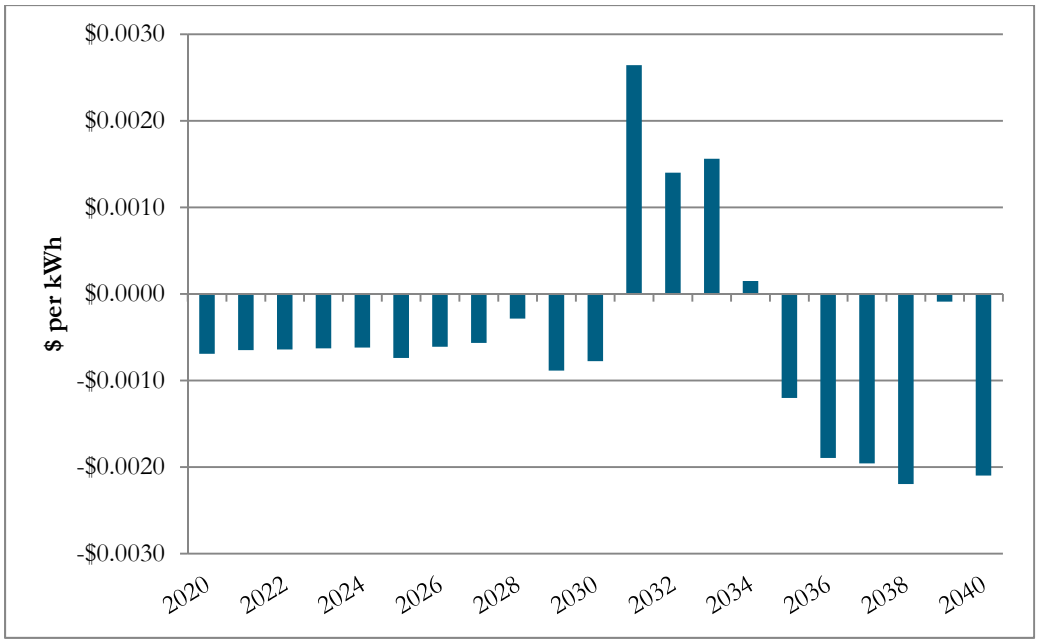
We calculated rate impacts in $ per kWh by dividing each class's revenue requirement in each year by the forecasted sales in each year.

Table 6-1: Estimated Incremental Impact of Preferred Plan
State of Minnesota – All Customers

1	2	3	4
Year	**State of MN Total Revenue Req ($000)**	**Incremental Impact of Preferred Resource Plan** ($000)	**Incremental Impact (%)**
2019	$3,241,019		
2020	$3,309,662	-$20,307	-0.61%
2021	$3,407,431	-$18,905	-0.55%
2022	$3,531,080	-$18,646	-0.53%
2023	$3,567,006	-$18,163	-0.51%
2024	$3,614,422	-$17,880	-0.49%
2025	$3,662,468	-$21,259	-0.58%
2026	$3,711,153	-$17,597	-0.47%
2027	$3,760,484	-$16,389	-0.44%
2028	$3,810,472	-$8,389	-0.22%
2029	$3,861,124	-$26,054	-0.67%
2030	$3,912,450	-$22,932	-0.59%
2031	$3,964,457	$78,174	1.97%
2032	$4,017,157	$41,948	1.04%
2033	$4,070,556	$47,089	1.16%
2034	$4,124,665	$4,568	0.11%
2035	$4,179,494	-$36,862	-0.88%
2036	$4,235,052	-$58,945	-1.39%
2037	$4,291,348	-$61,023	-1.42%
2038	$4,348,392	-$68,746	-1.58%
2039	$4,406,195	-$2,809	-0.06%
2040	$4,464,766	-$66,728	-1.49%

We visually portray this information in Figure 6-4 below.

Figure 6-4: Incremental Rate Impact of Preferred Plan
State of Minnesota – All Customers



A. Methodology and Calculations

We determine class revenue requirement impacts by allocating incremental costs to rate classes for each year in the planning period (2020-2034). After costs are allocated, we then calculate revenue requirement impacts for each customer class.

We apply ratemaking treatments to expense items that are impacted by the Resource Plan, as follows:

- Fuel Costs
- Purchased Energy
- Production O&M Expenses
- Property Taxes
- Deferred Income Taxes
- Tax Depreciation and Removal Expense,
- Decommissioning Accruals
- Plant In Service and Associated Depreciation, Construction Work in Progress (CWIP), and Accumulated Deferred Income Taxes

- Bulk Transmission Costs

We discuss our treatment of these expense items for purposes of this rate impact analysis below.

B. Fuel Costs and Purchased Energy

Fuel and purchased energy costs are allocated to classes using the E8760 energy allocator approved in our most recent Minnesota rate case, as provided below:[7]

Table 6-2: E8760 Energy Allocator

MN	Residential	Commercial Non-Demand	C&I Demand	Lighting
100.00%	29.27%	3.04%	67.24%	0.44%

The E8760 allocator is calculated by taking the forecast hourly load for each of the 8,760 hours of the test year for each customer class, then weighting the hourly load by the forecasted hourly marginal energy cost in each respective hour.

C. Production Expense, Property Taxes, Deferred Income Taxes, Tax Depreciation and Removal Expense and Decommissioning Accrual

These expense items are split into energy-related and capacity/demand-related components using the Company's plant stratification analysis approved in our most recent Minnesota rate case.[8] We provide the approved plant stratification analysis that we applied to production O&M expenses for each plant type below:

[7] See Docket No. E002/GR-15-826, *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, FINDINGS OF FACT, CONCLUSIONS, AND ORDER, (June 12, 2017).
[8] *Id.*

Table 6-3: Stratification Analysis by Plant Type

Plant Type	Replacement Value $/kW	Capacity Ratio	Capacity/Demand Percentage	Energy Percentage
Combustion Turbine	$825	$825 / $825	100.0%	0.0%
Fossil	$2,089	$825 / $2,089	39.5%	60.5%
Nuclear	$4,286	$825 / $4,286	19.3%	80.7%
Combined Cycle	$1,079	$825 / $1,079	76.5%	23.5%
Wind	$15,847	$825 / $15,847	5.2%	94.8%
Solar	$8,182	$825 / $8,182	10.1%	89.9%

The plant stratification approach begins by comparing the replacement cost of each type of generation plant (fossil, combined cycle, nuclear, etc.) to the replacement cost of a CT. CT are 100 percent capacity/demand-related since they are the generation source with the lowest capital cost and the highest operating cost. For each generation type, the percent of total generation costs that exceeds the cost of a CT peaking plant are classified as being energy-related. These costs are in excess of the capacity/demand-related portion, and as such, were not incurred to obtain capacity, but rather to obtain lower cost energy.

After production O&M costs originating from each type of generation plant are split into capacity-related and energy-related components based on the percentages shown in Table 6-3 above, those costs that have been classified as being energy-related are allocated to class using the E8760 energy allocator provided in *part 1* above.

The capital costs that have been classified as being capacity- or demand-related are allocated to customer class using the D10S capacity allocator approved by the Commission in our most recent rate case.[9] The D10S allocator is simply each class's load that is coincident with the NSP system peak load. We provide the approved D10S class allocator percentages below:

Table 6-4: D10S Capacity Allocator

MN	Residential	Commercial Non-Demand	C&I Demand	Lighting
100.00%	36.14%	3.28%	60.59%	0.00%

[9] *Id.*

D. Generation Rate Base Costs Including Plant in Service, Depreciation, CWIP and Accumulated Deferred Income Taxes

Rate base related costs from each type of generation plant are also split into energy-related and capacity/demand-related components using the Company's plant stratification analysis approved in our most recent Minnesota rate case.[10] As was true with the expense items listed in *part 2* above, rate base costs classified as being energy-related are allocated to class using the E8760 energy allocator. Likewise, the capital costs that have been classified as being capacity or demand-related are allocated to customer class using the D10S capacity allocator.

E. Bulk Transmission Costs

As ordered by the Minnesota Commission, all rate base and expense items related to bulk transmission are classified as being capacity or demand-related and are allocated to customer class using the Commission-approved D10S capacity allocator.[11]

IV. DETERMINING CLASS RATE IMPACTS

In order to show the estimated impacts of the Preferred Plan on customer rates and bills, we provide a breakdown by customer class for the 2020-2040 period, and in more detail for the immediate five-year 2019-2023 period at the Minnesota customer class levels.

Figure 6-5 below shows the estimated incremental impacts of our Preferred Plan over the long-term by customer class.

[10] *Id.*
[11] *Id.*

Figure 6-5: Incremental Rate Impact of Preferred Plan by Customer Class – State of Minnesota

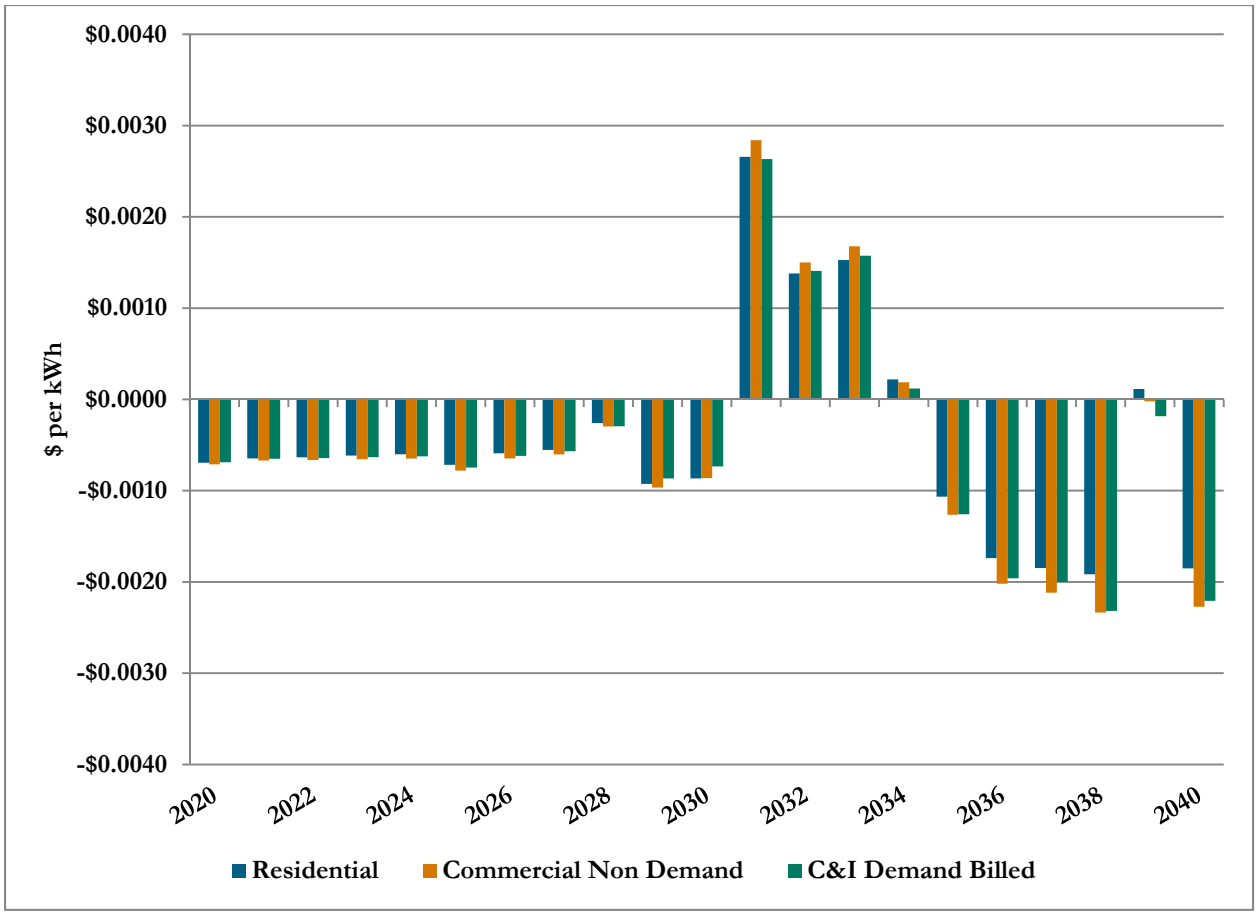


Table 6-5 below provides a more detailed view of near-term estimated rate impacts for Minnesota customer classes.

Table 6-5: Preferred Plan Estimated Rate Impacts by Class per Year

Rate Class Impacts \1	2019	2020	2021	2022	2023	2024	Comp'd Incr/Yr
Residential (avg rate, ¢/kWh)	14.488¢	14.367¢	14.506¢	14.847¢	15.377¢	15.526¢	N/A
Cumul Increase (¢/kWh)		-0.121	0.018	0.359	0.889	1.037	N/A
Cumulative Increase (%)		-0.84%	0.12%	2.48%	6.14%	7.16%	1.39%
$ Impact/Month, @ 650	($0.79)	$0.11	$2.33	$5.78	$6.74	N/A	N/A
Sm Non-Dmd (avg rate, ¢/kWh)	13.218¢	13.218¢	13.167¢	13.511¢	13.946¢	14.599¢	14.855¢
Cumul Increase (¢/kWh)		-0.052	0.293	0.727	1.380	1.636	N/A
Cumulative Increase (%)		-0.39%	2.22%	5.50%	10.44%	12.38%	2.36%
$ Impact/Month, @ 1,000	($0.52)	$2.93	$7.27	$13.80	$16.36	N/A	N/A
Demand (avg rate, ¢/kWh)	9.370¢	9.300¢	9.707¢	10.040¢	10.471¢	10.570¢	N/A
Cumul Increase (¢/kWh)		-0.070	0.336	0.669	1.100	1.199	N/A
Cumulative Increase (%)		-0.75%	3.59%	7.14%	11.74%	12.80%	2.44%
$ Impact/Month, @ 37,500	($26.30)	$126.15	$250.98	$412.56	$449.71	N/A	N/A
Street Ltg (avg rate, ¢/kWh)	25.290¢	25.027¢	24.668¢	24.917¢	25.624¢	26.079¢	N/A
Cumul Increase (¢/kWh)		-0.262	-0.622	-0.372	0.334	0.790	N/A
Cumulative Increase (%)		-1.04%	-2.46%	-1.47%	1.32%	3.12%	0.62%
$ Impact/Month, @ 60	($0.16)	($0.37)	($0.22)	$0.20	$0.47	N/A	N/A

Using the methodologies described above, the incremental costs in the last year of the period (2024) for the Preferred Plan would be expected to increase the average Residential rate by about 1.39 percent on a compounded annual basis through 2024. That is equivalent to a total increase of $6.74 per month above the current rate level.

The impact to the average Large Demand Billed rate would be an increase of about 2.44 percent on a compounded annual basis through 2023, which is equivalent to an increase of 1.199 cents per kWh above the 2019 level.

V. FACTORS IMPACTING NEAR-AND LONG-TERM RATE ESTIMATES

We note that the following factors could have an impact on the estimated rate impacts in the planning period:

Depreciation Expense for Coal Closures. The modeling and estimated rate impacts reflect accelerated depreciation associated with the early retirement of the Allen S. King and Sherco Unit 3 plants. This is consistent with the Company's current method of recovery for Sherco 1 and 2. As noted previously, however, and consistent with the Commission's actions in the approval of the early shutdown of the Benson biomass plant, a regulatory asset is another tool that could be used to accompany these early retirements. An alternative regulatory treatment such as this would impact this analysis.

Generation Ownership: Owned and Purchased Power Agreement resources will have different cost patterns, which will impact this analysis to the extent a resource addition differs in terms of ownership from what was modeled.

Taxes. This analysis is based on present tax conditions. Any tax changes will impact the modeling underlying this analysis and thus the rate impact results.

Nuclear Decommissioning Trust. There are several items regarding the NDT that may have a material impact on costs included in this resource plan.

Pending or Future Regulatory Decisions. Rate case and resource acquisition outcomes have the potential to impact rates and system needs.

Large Customer Changes. The loss or addition of a large business customer has the potential to impact both rates and system needs.

CERTIFICATE OF SERVICE

I, Jim Erickson, hereby certify that I have this day served copies or summaries of the foregoing document on the attached list of persons.

xx by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States mail at Minneapolis, Minnesota;

xx by courier; or

xx by electronic filing.

Docket Nos. **E002/RP-19-368**
E002/RP-15-21
E002/GR-15-826
Xcel Energy Miscellaneous Electric

Dated this 1st day of July 2019

/s/

_____

Jim Erickson
Regulatory Administrator

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APPENDIX A - COMPLIANCE MATRIX

Xcel Energy is committed to complying fully with all applicable statutes and rules and we believe our Plan reflects appropriate implementation of all requirements. We have prepared a matrix reflecting our inventory of requirements to be met in this Application and cross-referenced to the portion of the Plan that fulfills each compliance item.

Rules, Statutes, and Orders

Statute, Rule or Order	Subdivision or Order Point	Information Required by Statute	(7/1/2019) 2020-2034 IRP Location of Required Content
Minn. Stat. §216B.1691 Renewable Energy Objectives	Subdivision 2e.	Rate impact of standard compliance; report. Each electric utility must submit to the commission and the legislative committees with primary jurisdiction over energy policy a report containing an estimation of the rate impact of activities of the electric utility necessary to comply with this section. In consultation with the Department of Commerce, the commission shall determine a uniform reporting system to ensure that individual utility reports are consistent and comparable, and shall, by order, require each electric utility subject to this section to use that reporting system. The rate impact estimate must be for wholesale rates and, if the electric utility makes retail sales, the estimate shall also be for the impact on the electric utility's retail rates. Those activities include, without limitation, energy purchases, generation facility acquisition and construction, and transmission improvements. After the initial report, a report must be updated and submitted as part of each integrated resource plan or plan modification filed by the electric utility under section 216B.2422.	Appendix N5: Biennial Report: Renewable Energy Obligation-Renewable Energy Standard Compliance Report Appendix N6: Renewable Energy Standard: Rate Impact Report
Minn. Stat. §216B.1691 Renewable Energy Objectives	Subdivision 3.	Utility plans filed with commission. (a) Each electric utility shall report on its plans, activities, and progress with regard to the objectives and standards of this section in its filings under section 216B.2422, demonstrating to the commission the utility's effort to comply with this section. In its resource plan, each electric utility shall provide a description of: (1) the status of the utility's renewable energy mix relative to the objective and standards; (2) efforts taken to meet the objective and standards; (3) any obstacles encountered or anticipated in meeting the objective or standards; and (4) potential solutions to the obstacles.	Chapter 3: Minimum System Needs Appendix N4: Renewable Energy Compliance Positions Appendix N5: Biennial Report: Renewable Energy Obligation-Renewable Energy Standard Compliance Report
Minn. Stat. §216B.1691 Renewable Energy Objectives	Subdivision 10.	"Utility acquisition of resources. A competitive resource acquisition process established by the commission prior to June 1, 2007, shall not apply to a utility for the construction, ownership, and operation of generation facilities used to satisfy the requirements of this section unless, upon a finding that it is in the public interest, the commission issues an order on or after June 1, 2007, that requires compliance by a utility with a competitive resource acquisition process. A utility that owns a nuclear generation facility and intends to construct, own, or operate facilities under this section shall file with the commission on or before March 1, 2008, a renewable energy plan setting forth the manner in which the utility proposes to meet the requirements of this section. The utility shall update the plan as necessary in its filing under section 216B.2422. The commission shall approve the plan unless it determines, after public hearing and comment, that the plan is not in the public interest. As part of its determination of public interest, the commission shall consider the plan's impact on balancing the state's interest in: (1) promoting the policy of economic development in rural areas through the development of renewable energy projects, as expressed in subdivision 9; (2) maintaining the reliability of the state's electric power grid; and (3) minimizing cost impacts on ratepayers."	N/A - we are not proposing any specific resource acquisitions in this Resource Plan
Minn. Stat. §216B.2422. Resource Planning; Renewable Energy	Subdivision 2.	(c) As a part of its resource plan filing, a utility shall include the least cost plan for meeting 50 and 75 percent of all energy needs from both new and refurbished generating facilities through a combination of conservation and renewable energy resources.	Chapter 5: Economic Modeling Framework
Minn. Stat. §216B.2422. Resource Planning; Renewable Energy	Subdivision 2a.	Historical data and Advance Forecast. Each utility required to file a resource plan under this section shall include in the filing all applicable annual information required by section 216C.17, subdivision 2, and the rules adopted under that section. To the extent that a utility complies with this subdivision, it is not required to file annual advance forecasts with the department under section 216C.17, subdivision 2.	Appendix N1: Annual Report: Minnesota Electric
Minn. Stat. §216B.2422. Resource Planning; Renewable Energy	Subdivision 2c.	Long-range emission reduction planning. Each utility required to file a resource plan under subdivision 2 shall include in the filing a narrative identifying and describing the costs, opportunities, and technical barriers to the utility continuing to make progress on its system toward achieving the state greenhouse gas emission reduction goals established in section 216H.02, subdivision 1, and the technologies, alternatives, and steps the utility is considering to address those opportunities and barriers.	Chapter 4: Preferred Plan Appendix H: Environmental Regulations Review

Statute, Rule or Order	Subdivision or Order Point	Information Required by Statute	(7/1/2019) 2020-2034 IRP Location of Required Content
Minn. Stat. §216B.2422. Resource Planning; Renewable Energy	Subdivision 3.	Environmental Costs. (a) A utility shall use the values established by the commission in conjunction with other external factors, including socioeconomic costs, when evaluating and selecting resource options in all proceedings before the commission, including resource plan and certificate of need proceedings.	Chapter 5: Economic Modeling Framework Appendix F2: Strategist Modeling Assumptions & Inputs
Minn. Stat. §216B.2422. Resource Planning; Renewable Energy	Subdivision 4.	Preference for renewable energy facility. The commission shall not approve a new or refurbished nonrenewable energy facility in an integrated resource plan or a certificate of need, pursuant to section 216B.243, nor shall the commission allow rate recovery pursuant to section 216B.16 for such a nonrenewable energy facility, unless the utility has demonstrated that a renewable energy facility is not in the public interest. When making the public interest determination, the commission must consider: (1) whether the resource plan helps the utility achieve the greenhouse gas reduction goals under section 216H.02, the renewable energy standard under section 216B.1691, or the solar energy standard under section 216B.1691, subdivision 2f.; (2) impacts on local and regional grid reliability; (3) utility and ratepayer impacts resulting from the intermittent nature of renewable energy facilities, including but not limited to the costs of purchasing wholesale electricity in the market and the costs of providing ancillary services; and (4) utility and ratepayer impacts resulting from reduced exposure to fuel price volatility, changes in transmission costs, portfolio diversification, and environmental compliance costs.	Chapter 4: Preferred Plan Chapter 5: Economic Modeling Framework Appendix F2: Strategist Modeling Assumptions & Inputs
Minn. Stat. §216B.2422. Resource Planning; Renewable Energy	Subdivision 7.	Energy storage systems assessment. (a) Each public utility required to file a resource plan under subdivision 2 must include in the filing an assessment of energy storage systems that analyzes how the deployment of energy storage systems contributes to: (1) meeting identified generation and capacity needs; and (2) evaluating ancillary services. (b) The assessment must employ appropriate modeling methods to enable the analysis required in paragraph (a).	Appendix F7: Minnesota Energy Storage Systems Assessment
Minn. Stat. §216B.2426. Opportunities for Distributed Generation		The commission shall ensure that opportunities for the installation of distributed generation, as that term is defined in section 216B.169, subdivision 1, paragraph (c), are considered in any proceeding under section 216B.2422, 216B.2425, or 216B.243.	Chapter 5: Economic Modeling Framework
Minn. Stat. §3.8851 Legislative Energy Commission	Subdivision 4.	Nuclear reports. The public utility that owns the Prairie Island and Monticello nuclear generation facilities shall update the reports required under section 116C.772, subdivisions 3 to 5, and shall submit those updates periodically to the Public Utilities Commission with the utility's resource plan filing under section 216B.2422 and to the Legislative Energy Commission.	Appendix N9: Triennial Filing: Nuclear Decommissioning Appendix N10: Nuclear Worker Transition Plan
Minn. Rule 7843.0300, Filing Requirements and Procedures	Subpart 3.	*Completeness of filing*. The resource plan must contain the information required by part 7843.0400, unless an exemption has been granted under subpart 4.	See below:
Minn. Rule 7843.0400. Contents of Resource Plan Filings	Subpart 1.	*Advance forecasts*. A utility shall include in the filing identified in Subpart 2 its most recent annual submission to the Minnesota Department of Commerce and the Minnesota Environmental Quality Board under Minnesota Statutes, sections 216B.2422, subdivision 2a, and 216C.17, and parts 7610.0000 to 7610.0600.	Appendix N1: Annual Report: Minnesota Electric
Minn. Rule 7843.0400. Contents of Resource Plan Filings	Subpart 2.	*Resource Plan*. A utility shall file a proposed plan for meeting the service needs of its customers over the forecast period. The plan must show the resource options the utility believes it might use to meet those needs. The plan must also specify how the implementation and use of those resource options would vary with changes in supply and demand circumstances. Utility is only required to identify a resource option generically, unless a commitment to a specific resource exists at the time of the filing. Utility shall also discuss plans to reduce existing resources through sales, leases, deratings, or retirements.	Chapter 4: Preferred Plan Chapter 5: Economic Modeling Framework Appendix F3: Scenario Sensitivity Analysis: PVRR and PVSC Summary
Minn. Rule 7843.0400. Contents of Resource Plan Filings	Subpart 3.	*Supporting Information. A utility shall include in its resource plan filing information supporting selection of the proposed resource plan.*	Chapter 4: Preferred Plan Chapter 5: Economic Modeling Framework Appendix F2: Strategist Modeling Assumptions & Inputs

Statute, Rule or Order	Subdivision or Order Point	Information Required by Statute	(7/1/2019) 2020-2034 IRP Location of Required Content
Minn. Rule 7843.0400. Contents of Resource Plan Filings	Subpart 3A	A) When a utility's existing resources are inadequate to meet the projected level of resource needs, the supporting information must contain a complete list of resource options considered for addition to the existing resources. At a minimum, the list must include new generating facility of various types and sizes and with various fuel types, cogeneration, new transmission facilities of various types and sizes, upgrading of existing generation and transmission equipment, life extensions of existing generation and transmission equipment, load-control equipment, utility-sponsored conservation programs, purchases from non-utilities, and purchases from other utilities. The utility may seek additional input from the commission regarding the resource options to be included in the list. For a resource option that could meet a significant part of the need identified by the forecast, the supporting information must include a general evaluation of the option, including its availability, reliability, cost, socioeconomic effects, and environmental effects.	Chapter 4: Preferred Plan Chapter 5: Economic Modeling Framework Appendix F6: Resource Option Appendix G1: Demand Side Management Appendix I: Supporting Infrastructure: Transmission & Distribution
Minn. Rule 7843.0400. Contents of Resource Plan Filings	Subpart 3B	B) The supporting information must include descriptions of the overall process and of the analytical technique used by the utility to create its proposed resource plan from the available options.	Chapter 5: Economic Modeling Framework Appendix F2: Strategist Modeling Assumptions & Inputs
Minn. Rule 7843.0400. Contents of Resource Plan Filings	Subpart 3C	C) The supporting information must include an action plan, a description of the activities the utility intends to undertake to develop or obtain noncurrent resources identified in its proposed plan. Action plan must cover a five-year period beginning with the filing date. Action plan must include a schedule of key activities, including construction and regulatory filings.	Chapter 4: Preferred Plan
Minn. Rule 7843.0400. Contents of Resource Plan Filings	Subpart 3D	D) For the proposed resource plan as a whole, the supporting information must include a narrative and quantitative discussion of why the plan would be in the public interest, considering the factors listed in part 7843.0500, subpart 3.	Chapter 4: Preferred Plan
Minn. Rule 7843.0400. Contents of Resource Plan Filings	Subpart 4.	Nontechnical summary. A utility shall include in its resource plan filing a non-technical summary, not exceeding 25 pages in length and describing the utility's resource needs, the resource plan created by the utility to meet those needs, the process and analytical techniques used to create the plan, activities required over the next five years to implement the plan, and the likely effect of plan implementation on electric rates and bills. Minn. Stat. §216B.1612,	Appendix D: Non-Technical Summary
Docket No. E999/CI-06-159 *In the Matter of Commission Investigation and Determination under the Electricity Title, Section XII, of the Federal Energy Policy Act of 2005* **August 10, 2007 Order**	Order Point 2.	(Fossil Fuel Efficiency Standard) Investor-owned utilities shall include information in their Resource Plans generically describing how the utility is planning to address fossil fuel efficiency to meet the goals of this standard.	Appendix F2: Strategist Modeling Assumptions & Inputs Attachment A
Docket No. E999/CI-06-159 *In the Matter of Commission Investigation and Determination under the Electricity Title, Section XII, of the Federal Energy Policy Act of 2005* **August 10, 2007 Order**	Order Point 3.	Investor-owned utilities shall include information in their Resource Plans with respect to: a. The heat rates of existing plants; b. Their efforts to maintain or improve heat rates over time; and c. Modeling runs(s) of ways to improve the heat rates of either the largest existing or the lowest heat rate generation plants.	Appendix F2: Strategist Modeling Assumptions & Inputs Attachment A
Docket No. E-002/RP-10-825 In the Matter of Northern States Power Company d/b/a/Xcel Energy's Application for Approval of its 2011-2025 Resource Plan **August 5, 2013 Notice**	Page 1	The public interest determination must include whether the resource plan helps the utility achieve the greenhouse gas reduction goals under section 216H.02, the renewable energy standard under section 216B.1691, or the solar energy standard under section 216B.1691, 2f.	Chapter 4: Preferred Plan Appendix H: Environmental Regulations Review Appendix N4: Renewable Energy Compliance Positions Appendix N5: Biennial Report: REO-RES Compliance Report Appendix N7: Annual Report: Solar Energy Standard
Docket No. E-002/RP-10-825 In the Matter of Northern States Power Company d/b/a/Xcel Energy's Application for Approval of its 2011-2025 Resource Plan **August 5, 2013 Notice**	Page 2, Para 1	The Commission expects utilities to include in their resource plans filed after August 1, 2013 an explanation how the resource plan helps the utility achieve the greenhouse gas reduction goals, renewable energy standard, and solar energy standard as listed in the above-referenced legislation. Parties should also be prepared to discuss the matter in comments.	Chapter 4: Preferred Plan Appendix H: Environmental Regulations Review Appendix N4: Renewable Energy Compliance Positions Appendix N5: Biennial Report: REO-RES Compliance Report Appendix N7: Annual Report: Solar Energy Standard
Docket No. E-002/RP-10-825 In the Matter of Northern States Power Company d/b/a/Xcel Energy's Application for Approval of its 2011-2025 Resource Plan **August 5, 2013 Notice**	Page 2, Para 2	Utilities should consider adding to their initial resource plan filings the supplemental information listed at page 4 of the Commission's May 10, 2013 Order regarding its completeness review of MP's resource plan in Docket E015/RP-13-53.	See below:

Statute, Rule or Order	Subdivision or Order Point	Information Required by Statute	(7/1/2019) 2020-2034 IRP Location of Required Content
Docket No. E-002/RP-10-825 In the Matter of Northern States Power Company d/b/a/Xcel Energy's Application for Approval of its 2011-2025 Resource Plan **August 5, 2013 Notice**	E015/RP-13-53; 5/10/13 Order Page 4	1. How the addition of SO2 allowance prices would have impacted its base case and preferred plan; and	Appendix F2: Strategist Modeling Assumptions & Inputs
Docket No. E-002/RP-10-825 In the Matter of Northern States Power Company d/b/a/Xcel Energy's Application for Approval of its 2011-2025 Resource Plan **August 5, 2013 Notice**	E015/RP-13-53; 5/10/13 Order Page 4	2. How the use of unforced capacity would have impacted its base case and preferred plan;	Appendix F2: Strategist Modeling Assumptions & Inputs
Docket No. E-002/RP-10-825 In the Matter of Northern States Power Company d/b/a/Xcel Energy's Application for Approval of its 2011-2025 Resource Plan **August 5, 2013 Notice**	E015/RP-13-53; 5/10/13 Order Page 4	3. How the use of Commission-approved CO2 values from its November 2, 2012 Order affect its base case and preferred plan;	Superceded by the June 11, 2018 Order in Docket Nos. E-999/CI-07-1199 & E-999/DI-17-53 Appendix F2: Strategist Modeling Assumptions & Inputs
Docket No. E-002/RP-10-825 In the Matter of Northern States Power Company d/b/a/Xcel Energy's Application for Approval of its 2011-2025 Resource Plan **August 5, 2013 Notice**	E015/RP-13-53; 5/10/13 Order Page 4	4. How MP has considered water consumption issues and potential effects on aquatic life from water intake and discharge in its resource plan, both qualitatively and quantitatively.	Appendix H: Environmental Regulations Review Appendix F2: Strategist Modeling Assumptions & Inputs Attachment B
Docket No. E-002/RP-10-825 In the Matter of Northern States Power Company d/b/a/Xcel Energy's Application for Approval of its 2011-2025 Resource Plan **August 5, 2013 Notice**	E015/RP-13-53; 5/10/13 Order Page 4	5. How MP has taken into account possible effects of drought and high water temperature on generating plant availability in its modeling, including the results of modeling the range of these possible effects. Reference to 13-53 Order pg 4.	Appendix F2: Strategist Modeling Assumptions & Inputs Attachment B
Docket No. E-002/RP-10-825 In the Matter of Northern States Power Company d/b/a/Xcel Energy's Application for Approval of its 2011-2025 Resource Plan **August 5, 2013 Notice**	E015/RP-13-53; 5/10/13 Order Page 4	6. How MP has considered demand side management (DSM) programs in its resource plan, and the pros and cons of DSM being considered a reduction in load versus a resource to be chosen, including modeling a range of assumptions.	Chapter 3: Minimum System Needs Chapter 4: Preferred Plan Chapter 5: Economic Modeling Framework Appendix F2: Strategist Modeling Assumptions & Inputs Appendix G1: Demand Side Management
Docket No. E002/RP-10-825 In the Matter of Northern States Power Company d/b/a/Xcel Energy's Application for Approval of its 2011-2025 Resource Plan **August 5, 2013 Notice**	Page 2, Para 3	Utilities consider convening a stakeholder meeting prior to filing their initial IRPs to answer questions about assumptions used in the filing, for the purpose of responding to questions which could enhance parties' understanding of the filing and reducing the number of information requests parties may need to file.	Appendix O1: Summary of IRP Stakeholder Engagement
Docket No. E002/RP-15-21 In the Matter of Northern States Power Company d/b/a/Xcel Energy's Application for Approval of its 2016-2030 Resource Plan **January 11, 2017 Order**	Order Point 4a	4. Xcel's resource plan is modified as follows: a. to remove 400 MW of large-scale solar in 2016–2021. Xcel shall acquire approximately 650 MW of solar in 2016–2021 through a combination of the Company's community solar gardens program or other acquisitions. The Company may pursue additional, cost-effective solar resources if it is in the best interests of its customers.	Chapter 3: Minimum System Needs Appendix N8: Monthly Report: Solar Gardens June 2019
Docket No. E002/RP-15-21 In the Matter of Northern States Power Company d/b/a/Xcel Energy's Application for Approval of its 2016-2030 Resource Plan **January 11, 2017 Order**	Order Point 7	7. Xcel's schedule to retire Sherco 2 in 2023, and Sherco 1 in 2026, is approved.	Chapter 4: Preferred Plan
Docket No. E002/RP-15-21 In the Matter of Northern States Power Company d/b/a/Xcel Energy's Application for Approval of its 2016-2030 Resource Plan **January 11, 2017 Order**	Order Point 8	8. The Commission finds that more likely than not there will be a need for approximately 750 MW of intermediate capacity coinciding with the retirement of Sherco 1 in 2026.	Chapter 4: Preferred Plan
Docket No. E002/RP-15-21 In the Matter of Northern States Power Company d/b/a/Xcel Energy's Application for Approval of its 2016-2030 Resource Plan **January 11, 2017 Order**	Order Point 10	10. Xcel shall acquire no less than 400 MW of additional demand response by 2023.	Chapter 3: Minimum System Needs Chapter 4: Preferred Plan Chapter 5: Economic Modeling Framework Appendix G1: Demand Side Management

Statute, Rule or Order	Subdivision or Order Point	Information Required by Statute	(7/1/2019) 2020-2034 IRP Location of Required Content
Docket No. E002/RP-15-21 In the Matter of Northern States Power Company d/b/a/Xcel Energy's Application for Approval of its 2016-2030 Resource Plan **January 11, 2017 Order**	Order Point 12	12. Xcel shall investigate the potential for an energy-efficiency competitive bidding process for customers that have opted out of the statewide Conservation Improvement Program (CIP) under Minn. Stat. § 216B.241, subd. 1a(b).	Appendix G1: Demand Side Management
Docket No. E002/RP-15-21 In the Matter of Northern States Power Company d/b/a/Xcel Energy's Application for Approval of its 2016-2030 Resource Plan **January 11, 2017 Order**	Order Point 13	13. Xcel shall file its next resource plan on February 1, 2019.	See Docket No. E002/RP-15-21, Minnesota Public Utilities Commission's Order Extending Deadline for Filing Next Resource Plan (January30, 2019)
Docket No. E002/RP-15-21 In the Matter of Northern States Power Company d/b/a/Xcel Energy's Application for Approval of its 2016-2030 Resource Plan **January 11, 2017 Order**	Order Point 14a	14. In its next resource plan filing, Xcel shall: a. describe its plans and possible scenarios for cost-effective and orderly retirement of its aging baseload fleet, including Sherco, King, Monticello, and Prairie Island.	Appendix J1: Baseload Study
Docket No. E002/RP-15-21 In the Matter of Northern States Power Company d/b/a/Xcel Energy's Application for Approval of its 2016-2030 Resource Plan **January 11, 2017 Order**	Order Point 14b	b. evaluate combinations of supply-side (distributed and centralized), demand-side, and transmission solutions that could in the aggregate meet post-retirement energy and capacity needs as well as contribute to grid support.	Chapter 5: Economic Modeling Framework Appendix L: Sherco CC Appendix I: Supporting Infrastructure: Transmission & Distribution Appendix J1: Baseload Study
Docket No. E002/RP-15-21 In the Matter of Northern States Power Company d/b/a/Xcel Energy's Application for Approval of its 2016-2030 Resource Plan **January 11, 2017 Order**	Order Point 14c	c. explore the role of cost-effective combined heat and power solutions.	Appendix S: Combined Heat and Power Study (EPRI) Appendix F6: Resource Options
Docket No. E002/RP-15-21 In the Matter of Northern States Power Company d/b/a/Xcel Energy's Application for Approval of its 2016-2030 Resource Plan **January 11, 2017 Order**	Order Point 14d	d. report on its solar acquisition progress.	Chapter 3: Minimum System Needs Appendix N8: Monthly Report: Solar Gardens June 2019
Docket No. E002/RP-15-21 In the Matter of Northern States Power Company d/b/a/Xcel Energy's Application for Approval of its 2016-2030 Resource Plan **January 11, 2017 Order**	Order Point 14e	e. provide a full and thorough cost-effectiveness study that takes into account the technical and economic achievability of 1,000 MW of additional demand response, or approximately 20% of Xcel's system peak in total by 2025.	Appendix G1: Demand Side Management Appendix G3: DR Cost Effectiveness at NSP (Brattle)
Docket No. E002/RP-15-21 In the Matter of Northern States Power Company d/b/a/Xcel Energy's Application for Approval of its 2016-2030 Resource Plan **January 11, 2017 Order**	Order Point 14f	f. summarize its investigation and findings concerning the potential for an energy-efficiency competitive bidding process for customers that have opted out of CIP.	Appendix G1: Demand Side Management
Docket No. E002/RP-15-21 In the Matter of Northern States Power Company d/b/a/Xcel Energy's Application for Approval of its 2016-2030 Resource Plan **January 11, 2017 Order**	Order Point 15	15. In future resource plan filings, analysis and inputs must, to the extent possible, be consistent with Xcel's distribution system planning.	Chapter 5: Economic Modeling Framework Appendix F1: Load & DER Forecasting
Docket No. E999/CI-07-1199 & E999/DI-17-53 In the Matter of Establishing an Estimate of the Costs of Future Carbon Dioxide Regulation on Electricity Generation Under Minnesota Statutes § 216H.06 & In the Matter of Establishing an Updated 2016 Estimate of the Costs of Future Carbon Dioxide Regulation on Electricity Generation Under Minn. Stat. § 216H.06 **June 11, 2018 Order**	Order Point 1	1. The Commission hereby quantifies and establishes the range of regulatory costs of carbon dioxide emissions as $5 to $25 per short ton effective 2025 and thereafter.	Chapter 5: Economic Modeling Framework Appendix F2: Strategist Modeling Assumptions & Inputs

Statute, Rule or Order	Subdivision or Order Point	Information Required by Statute	(7/1/2019) 2020-2034 IRP Location of Required Content
Docket No. E999/CI-07-1199 & E999/DI-17-53 In the Matter of Establishing an Estimate of the Costs of Future Carbon Dioxide Regulation on Electricity Generation Under Minnesota Statutes § 216H.06 & In the Matter of Establishing an Updated 2016 Estimate of the Costs of Future Carbon Dioxide Regulation on Electricity Generation Under Minn. Stat. § 216H.06 **June 11, 2018 Order**	Order Point 2B	B. Incorporate, for all years, the high end of the range of environmental costs for CO2 as approved by the Commission in its January 3, 2018 order.	Chapter 5: Economic Modeling Framework Appendix F2: Strategist Modeling Assumptions & Inputs
Docket No. E999/CI-07-1199 & E999/DI-17-53 In the Matter of Establishing an Estimate of the Costs of Future Carbon Dioxide Regulation on Electricity Generation Under Minnesota Statutes § 216H.06 & In the Matter of Establishing an Updated 2016 Estimate of the Costs of Future Carbon Dioxide Regulation on Electricity Generation Under Minn. Stat. § 216H.06 **June 11, 2018 Order**	Order Point 2C	C. Incorporate the low end of the range of environmental costs for CO2 but substituting, for planning years after 2024, the low end of the range of regulatory costs for CO2 regulations, in lieu of environmental costs.	Chapter 5: Economic Modeling Framework Appendix F2: Strategist Modeling Assumptions & Inputs
Docket No. E999/CI-07-1199 & E999/DI-17-53 In the Matter of Establishing an Estimate of the Costs of Future Carbon Dioxide Regulation on Electricity Generation Under Minnesota Statutes § 216H.06 & In the Matter of Establishing an Updated 2016 Estimate of the Costs of Future Carbon Dioxide Regulation on Electricity Generation Under Minn. Stat. § 216H.06 **June 11, 2018 Order**	Order Point 2D	D. Incorporate the high end of the range of environmental costs for CO2 but substituting, for planning years after 2024, the high end of the range of regulatory costs for CO2 regulations, in lieu of environmental costs.	Chapter 5: Economic Modeling Framework Appendix F2: Strategist Modeling Assumptions & Inputs
Docket No. E999/CI-07-1199 & E999/DI-17-53 In the Matter of Establishing an Estimate of the Costs of Future Carbon Dioxide Regulation on Electricity Generation Under Minnesota Statutes § 216H.06 & In the Matter of Establishing an Updated 2016 Estimate of the Costs of Future Carbon Dioxide Regulation on Electricity Generation Under Minn. Stat. § 216H.06 **June 11, 2018 Order**	Order Point 2	Consistent with the Commission decision in the Order Updating Environmental Costs, utilities shall include at least one scenario that excludes consideration of CO2 costs.	Chapter 5: Economic Modeling Framework Appendix F2: Strategist Modeling Assumptions & Inputs
E999/CI-14-643 In the Matter of the Further Investigation into Environmental and Socioeconomic Costs Under Minnesota Statutes Section 216B.2422, Subdivision 3 **1/3/2018 Order**	Order Point 1	1. The Commission hereby quantifies and establishes the range of environmental cost of carbon dioxide emissions associated with electricity generation as follows: •The low end of the range shall reflect the global damage of the last (marginal) short ton emitted, calculated through the year 2100, with a 5.0% discount rate. •The high end of the range shall reflect the global damage of the last (marginal) short ton emitted, calculated through the year 2300, with a 3.0% discount rate.	Chapter 5: Economic Modeling Framework Appendix F2: Strategist Modeling Assumptions & Inputs
E999/CI-14-643 In the Matter of the Further Investigation into Environmental and Socioeconomic Costs Under Minnesota Statutes Section 216B.2422, Subdivision 3 **1/3/2018 Order**	Order Point 3	3. In resource-selection proceedings, utilities shall continue to analyze potential resources under a range of assumptions about environmental values—including at least one scenario that excludes consideration of environmental externalities.	Appendix F3: Scenario Sensitivity Analysis: PVRR and PVSC Summary
Docket No. E002/RP-15-21 In the Matter of Northern States Power Company d/b/a/Xcel Energy's Application for Approval of its 2016-2030 Resource Plan **January 30, 2019 Order**	Order Point 1	1. Xcel's next resource plan shall be filed by July 1, 2019.	This filing has been made July 1, 2019 in Docket No. E002/RP-19-368

Statute, Rule or Order	Subdivision or Order Point	Information Required by Statute	(7/1/2019) 2020-2034 IRP Location of Required Content
Docket No. E002/RP-15-21 In the Matter of Northern States Power Company d/b/a/Xcel Energy's Application for Approval of its 2016-2030 Resource Plan **January 30, 2019 Order**	Order Point 2	2. Xcel shall submit the files necessary to recreate the Company's 2020–2034 Reference Case, as summarized at Xcel's October 23, 2018 IRP Workshop, and shall provide the Strategist files with the same assumptions as in the Company's 2020–2034 Reference Case but using the midpoint of the Commission's most recently approved externalities and regulatory costs of carbon.	DOC IR No. 1 Docket No. IP6949, E002/PA-18-702 - submitted on November 27, 2019. See Compliance Filing submitted on May 30, 2019 in Docket No. E002/RP-19-368 regarding this Order Requirement for additional information.

APPENDIX B – ACRONYMS & TERMS

ACRONYM / TERM	DEFINITION
AC	Alternating Current
ACE	Affordable Clean Energy rule
ACI	Activated Carbon Injection
ADMS	Advanced Distribution Management System
AEO	Annual Energy Outlook
AFC	Accelerated Fleet Change
ALJ	Administrative Law Judge
AMI	Advanced Metering Infrastructure
ASHP	Air-Source Heat Pumps
AWEA	American Wind Energy Association
BA	Balancing Authority
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
BO	Buildout Scenario
BSER	Best System of Emission Reduction
C&I	Commercial and Industrial (Customers)
CAA	Clean Air Act
CAGR	Compound Annual Growth Rate
CAIDI	Net capacity factor of power plant, typically expressed as percentage, is ratio of its actual output over period of time to its potential output if it were possible for it to operate at full nameplate capacity indefinitely.
CAIR	Clean Air Interstate Rule
CAP	Competitive Acquisition Process
Capacity Factor	Measure of how often an electric generator runs for a specific period of time. Indicates how much electricity a generator actually produces relative to the maximum it could produce at continuous full power operation during the same period.
CapX2020	Coordinated transmission development effort by group of 11 regional utilities (the CapX2020 Utilities) in MN, ND, SD and WI.
C-BED	Community-Based Energy Development
CBECS	Commercial Buildings Energy Consumption Survey
CC	Combined Cycle
CCGT	Combined Cycle Gas Turbine
CCOSS	Class Cost of Service Stufy
CCRs	Coal Combustion Residuals (often referred to as coal ash)
CCS	Carbon Capture and Sequestration
CEE	Center for Energy and Environment
CEL	Capacity Export Limit
CER	Capital Project Module
CERA	Cambridge Energy Research Associates

ACRONYM / TERM	DEFINITION
CFC	Continued Fleet Change
CH_4	Methane
CHP	Combined Heat and Power
CIL	Capacity Import Limit
CIP	Conservation Improvement Program
Circuit Breaker	An electromechanical device used to configure the flow of electricity on the distribution grid. A circuit breaker is designed to open or close while electricity is flowing through the circuit. When a circuit breaker is open, no electricity is flowing through the circuit.
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CO_{2e}	Carbon Dioxide Equivalents
CON	Certificate of Need
CONE	Cost of New Entry
CPD	Coincident Peak Demand
CPNode	Commercial Pricing Mode
CRP	Certified Renewable Percentage
CSAPR	Cross-State Air Pollution Rule
CSG	Community Solar Garden
CT	Combustion Turbine
CWA	Clean Water Act
CWIP	Construction Work in Progress
DA	Day Ahead
DEM	Drive Electric Minnesota
DER	Distributed Energy Resources
DG	Distributed Generation
DIR	Dispatch Intermittent Resource Protocol
DNR	Department of Natural Resources
DOC	Department of Commerce
DOE	U.S. Department of Energy
DOI	Department of the Interior
DPP	Definitive Planning Process
DR	Demand Response
DSD	Minnesota Deemed Savings Database
DSM	Demand Side Management
E3	Energy and Environmental Economics, Inc.
ECC	Economic Carrying Charge
EE	Energy Efficiency
eGRID	Emissions and Generation Resource Integrated Database
EGU	Electric Generating Unit
EIA	Energy Information Administration
ELCC	Effective Load Carrying Capability
ELGs	Effluent Limitation Guidelines
EPA	Environmental Protection Agency

ACRONYM / TERM	DEFINITION
EPA Clean Air Act 111d Rule	Draft regulation to reduce carbon dioxide gas emissions from existing power plants that burn coal and other fossil fuels.
EPRI	Electric Power Research Institute
EQB	Environmental Quality Board
ESA	Endangered Species Act
EVs	Electric Vehicles
Externality Values	Range of environmental costs.
FAN	Field Area Networks
Fault	Abnormal condition on electric system, such as short circuit, broken wire or intermittent connection.
Feeder	Lines connecting distribution substations to taps.
FERC	Federal Energy Regulatory Commission
FERC Order 1000	Rule mandating how public utility transmission providers plan for and allocate costs of new projects on regional and interregional basis.
FIPs	Federal Implementation Plans
FL&U	Fuel Lost and Unaccounted
FLISR	Fault Location, Isolation, and Service Restoration
FWS	U.S. Fish and Wildlife Service
Gas Burn	Energy from New Natural Gas Generation
GAF	Generation Module
GHG	Greenhouse Gas
GW	Gigawatt
GWh	Gigawatt Hour
GWP	Global Warming Potential
HDVs	Heavy-Duty Vehicles
HVAC	High-Voltage Alternating Current
HVDC	High-Voltage Direct Current
IB MACT	Hazardous Air Pollutants from Industrial Boilers
IBEW	International Brotherhood of Electrical Workers
ICAP	Installed Capacity Value
ICE	Internal Combustion Engine
IDP	Integrated Distribution Plan
IDS	Interdepartmental Sales
IGCC	Integrated Gasification Combined Cycle
INPO	Institute of Nuclear Power Operations
IPCC	Intergovernmental Panel on Climate Change
IPPs	Independent Power Producers
IRP	Integrated Resource Plan
ITC	Investment Tax Credit
ISOs	Independent System Operators
JCOSS	Jurisdictional Cost of Service Study
kV	Kilovolt

ACRONYM / TERM	DEFINITION
kVA	Kilovolt Amps: 1,000 Volt-Amps. Volt is measure of force of electricity. Amp (Ampere) is measure of flow of electricity.
kWh	Kilowatt
LAF	Load Module
LBA	Load Balancing Authorities
LCM	Life Cycle Management
LCOE	Levelized Cost of Energy
LCOS	Levelized Cost of Storage
LCR	Local Clearing Requirement
LDVx	Light-Duty Vehicles
LEAP	Long-range Energy Alternatives Planning
LED	Solid State Lighting
LFC	Limited Fleet Change
LMF	Load Management Forecast
LMPs	Locational Marginal Prices
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability
LRR	Local Reliability Requirement
LRZ	Local Resource Zone
LSE	Load Serving Entities
LTRA	Long Term Reliability Assessment
MATS	National Emission Standards for Hazardous Air Pollutants for Coal- and Oil-Fired Power Plants. This rule is often referred to as the Mercury and Air Toxics Standard.
MDVs	Medium-Duty Vehicles
MEC	Mankato Energy Center
MEFF	Minnesota Energy Future Framework
MGP	Manufactured Gas Plants
MISO	Midcontinent Independent System Operator, Inc.: Non-profit organization providing reliable coordination and regional planning services including: regional planning, generation interconnection, maintenance coordination, market monitoring and dispute resolution.
MMBTU	Million British Thermal Units
MMERA	Minnesota Mercury Emissions Reduction Act
MPCA	Minnesota Pollution Control Agency
MPUC	Minnesota Public Utilities Commission
M-RETS	Midwest Renewable Energy Tracking System
MTEP	MISO Transmission Expansion Plan
MW	Megawatt
MWh	Megawatt Hour
MVA	Mega Volt Amps: 1,000,000 amps or 1,000 kVA

ACRONYM / TERM	DEFINITION
MVP	Multi Value Project: Regional transmission solutions that meet one or more of three goals: reliably and economically enable regional public policy needs, provide multiple types of regional economic value, and provide a combination of regional reliability and economic value.
N_2O	Nitrous Oxide
NAAQS	National Ambient Air Quality Standards
NDPSC	North Dakota Public Service Commission
NEEP	Northeast Energy Efficiency Partnerships
NERC	North American Electric Reliability Corporation
NGEA	Minnesota's Next Generation Energy Act
NMFS	National Marine Fisheries Service
NO_2	Nitrogen Dioxide
NO_x	Nitrogen Oxide
NOAA	National Oceanic and Atmospheric Administration
NPDES	National Pollutant Discharge Elimination System
NPV	Net Present Value
NRC	Nuclear Regulatory Commission
NREL	National Renewable Energy Laboratory
NSPM	Northern States Power Company-Minnesota
NSPW	Northern States Power Company-Wisconsin
NSPS	New Source Performance Standards
NSR	New Source Review Section of the Clean Air Act
O&M	Operating and Maintenance
O_3	Ozone
OFA	Over-Fire Air
OSPA	Sales to Public Authorities
Pb	Lead
PCBs	Polychlorinated Biphenyls
PCOR	U.S. Department of Energy's Plains Carbon Dioxide Reduction Partnership
PI	Prairie Island
PIRA	Petroleum Industry Research Associates
Plume Blight	Smoke, dust, colored gas plumes, or layered haze emitted from stacks which obscure the sky or horizon and are relatable to a single source or small group of sources.
PM	Particulate Matter
$PM_{2.5}$	Fine Particulate Matter under 2.5 micrometers
PM_{10}	Coarse Particulate Matter under 10 micrometers
PPA	Power Purchase Agreement
PPB	Parts Per Billion
PPM	Parts Per Million

ACRONYM / TERM	DEFINITION
PRC	Planning Resource Credits
PRPs	Potentially Responsible Parties
PRM	Planning Reserve Margin
PRMR	Planning Reserve Margin Requirement
Proview	Expansion Planning Module
PSD	Prevention of Significant Deterioration Section of the Clean Air Act
PSHL	Public Street and Highway Lighting
PTC	Production Tax Credit
PV	Photovoltaic
PVRR	Present Value Revenue Requirement
PVSC	Present Value of Societal Costs
RA	Resource Adequacy
RAC	Reliability Assessment Commitment
RAVI	Reasonably Attributable Visibility Impairment
RCRA	Resource Conservation and Recovery Act
RDF	Refuse Derived Fuel or Renewable Development Fund
Recloser	Circuit breaker that includes mechanism to automatically close (reconnect) after set period of time. Reclosers are used to restore service after momentary fault.
RECAP	E3's Renewable Energy Capacity model
RECs	Renewable Energy Credits: A certificate representing all of the environmental attributes of one MWh of generation from a renewable resource.
Reference Case	Baseline scenario identifying necessary resource additions.
REO	Renewable Energy Objective
REPI	Renewable Energy Production Incentive
RES	Renewable Energy Standard
RESOLVE	E3's Renewable Energy Solutions model
Retrofill	Remove contaminated oil and replace with clean oil.
RFP	Request For Proposal
RGGI	United States' Regional Greenhouse Gas Initiative
RHR	Regional Haze Rule
RIIA	Renewable Integration Impact Assessment
RPS	Renewable Portfolio Standard
RSG	Revenue Sufficiency Guarantee (Charges): Direct result of production shortfalls relative to earlier forecasts.
RTF	Resource Treatment Framework
RTO	Regional Transmission Organization
S*R	Solar Rewards (Company's Program)

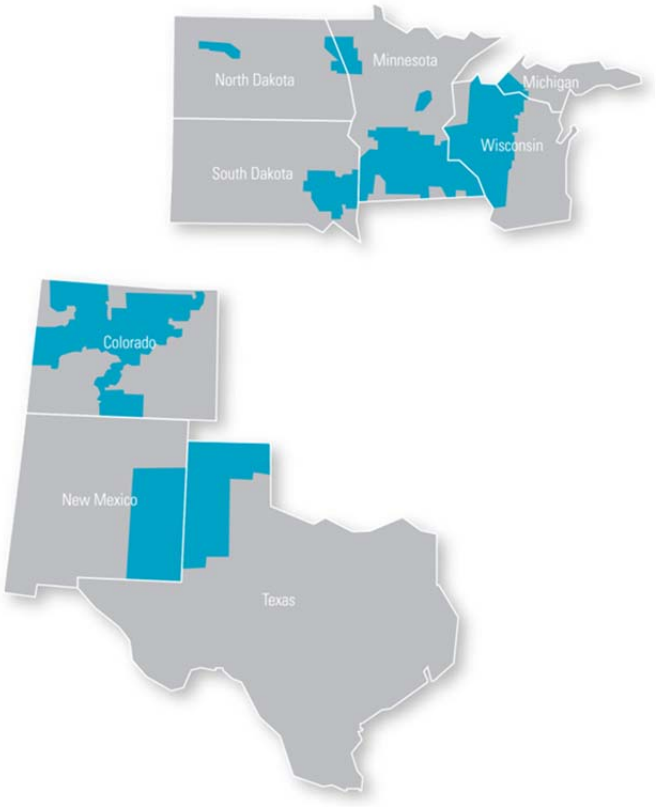
ACRONYM / TERM	DEFINITION
S*RC	Solar Rewards Community (Company's Community Solar Gardens Program)
SAIDI	System Average Interruption Frequency Index: Measures average number of times customer is interrupted over given period (usually monthly or annually). Lower values are better.
SAIFI	System Average Interruption Frequency Index: Measures average number of times customer is interrupted over given period (usually monthly or annually). Lower values are better.
SCADA	Supervisory Control and Data Acquisition
SCC	Social Cost of Carbon
SCR	Selective Catalytic Reduction
SDPUC	South Dakota Public Utilities Commission
SEPA	Solar Electric Power Association
SES	Minnesota Solar Energy Standard: Minn. Stat. § 216B.1691, subd. 2f, which requires 1.5% of retail sales to be sourced from new solar resources. SES is incremental to the Renewable Energy Standard (RES).
SFH	Single Family Housing
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
SO_x	Sulfur Oxide
SolarTAC	Solar Technology Acceleration Center
SPP	Southwest Power Pool
SQ	Status Quo
S-RECs	Solar Renewable Energy Credits: Created from a solar resource installed after August 1, 2013 and eligible to be used for compliance with the MN Solar Energy Standard.
Switch	Electromechanical devise used to configure the flow of electricity on distribution grid. A switch is designed to be opened or closed when electricity is not flowing through circuit. When switch is open, no electricity is flowing through circuit.
Tap	Final leg of distribution system before connecting to customer premises.
THI	Temperature Humidity Index
Transcos	Transmission-only entities designed to respond to the FERC Order 1000.
Transformer	Electromechanical devise that converts alternating current to higher or lower voltage.
Transmission Inadequacies	Identified deficiencies in the transmission system that need to be upgraded to keep the transmission system within its defined limits.
TRC	Total Resource Cost

ACRONYM / TERM	DEFINITION
TSD	Technical Support Document
UCAP	Production Capability Value
USACE	U.S. Army Corps of Engineers
V2G	Vehicle-To-Grid
VAr	Voltage and Reactive Power
VMT	Vehicle Miles Traveled
VOCs	Volatile Organic Compounds
W2B	Wind2Battery Project
WDNR	Wisconsin Department of Natural Resources
WOTUS	Waters of the United States
WTP	Worker Transition Plan
ZRC	Zonal Resource Credit

APPENDIX C – ABOUT XCEL ENERGY

Xcel Energy is a major U.S. electric and natural gas company based in Minneapolis, Minnesota. We have regulated operations in eight Midwestern and Western states - Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas and Wisconsin – where we provide a comprehensive portfolio of energy-related products and services to approximately 3.6 million electricity customers and 2 million natural gas customers. Our Upper Midwest service area is part of an integrated system of generation and transmission made up of two operating companies – Northern States Power Company-Minnesota (NSPM), which serves North Dakota and South Dakota in addition to Minnesota; and Northern States Power Company-Wisconsin (NSPW), which serves Wisconsin and Michigan – collectively referred to as the NSP system. Xcel Energy serves over 1.8 million customers in its NSP service territories. Figure 1 below illustrates Xcel Energy's nationwide territory.

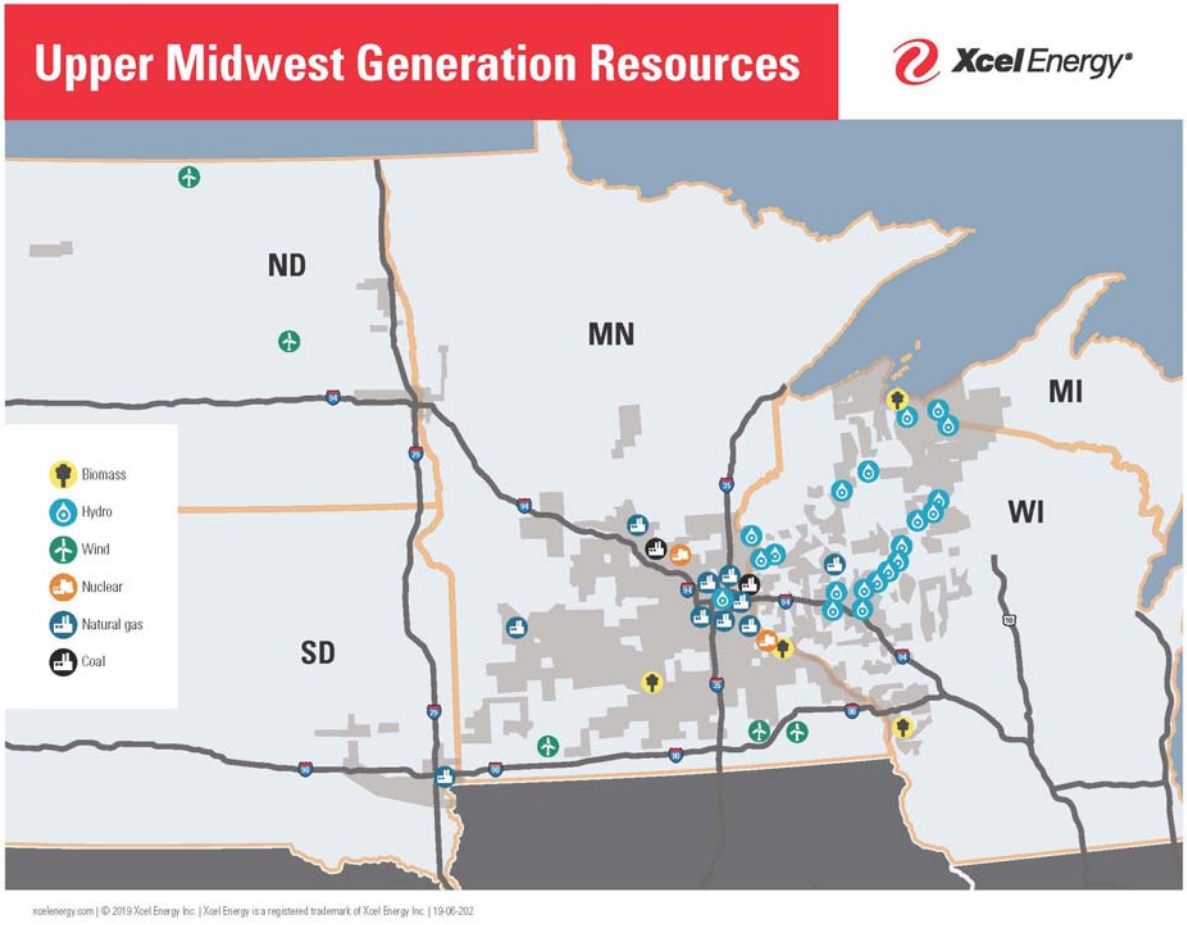
Figure 1: Xcel Energy Territory



Approximately 88 percent of our NSP customers are residential, with commercial and industrial customers comprising most of the remaining 12 percent. The distribution of electricity sales by type of customer, however, is significantly different. Residential

customers make up approximately 29 percent of electricity sales, with commercial and industrial customers making up most of the remaining 71 percent.

Figure 2: NSP System Generation Resources



NSP operates a diverse electric generating fleet, which includes facilities that use several different types of fuel: coal, natural gas, nuclear, wind, hydro, and biomass. This fleet of generating resources is illustrated by the map in Figure 2 above. The diversity of this fleet provides customers with a variety of generation options and protects them from the excessive risk of reliance on any one type of resource. Our overall strategy for purchasing our diverse generating fuels focuses on three objectives: competitive cost, diversity and reliability. Our fleet includes power plants with a net maximum capacity of over 9,500 MW, more than 8,400 miles of transmission lines, and approximately 550 transmission and distribution substations. We also have over 3,700 MW of Purchase Power Agreements (PPAs) for renewable and natural gas resources, including over 200 MW of large-scale solar and an additional expected 600 MW of Community Solar Gardens online by 2020.

Xcel Energy has long been a leader in delivering clean energy while maintaining outstanding reliability and affordability. Back in 2005, we were the leading utility wind energy provider in the country, despite the fact that wind comprised only 3 percent of our generation. By 2027, we expect renewable energy — the vast majority being wind — will account for 48 percent of our mix and will be our largest source of energy for our customers.

Along the way, we have made steady progress reducing carbon dioxide by transitioning away from fossil fuels, incorporating renewables and developing award-winning energy efficiency programs. Our 2018 carbon emissions were approximately 40 percent lower than our 2005 baseline. That progress put us on pace to hit our previous goal of reducing carbon 60 percent across all eight states in which we do business by 2030.

But a confluence of market forces — improving technology, falling prices and the risk of climate change — convinced us that we can do more, sooner. That is why in December, we became the first electric utility in the country to announce our aspiration to produce 100-percent carbon-free electricity for customers by 2050. At the same time, we announced a new interim target of reducing carbon dioxide emissions 80 percent by 2030.

Setting our sights on this ambitious vision allows us to drive the conversation rather than react to it. It also gives us time for the development of technologies not currently available that will be critical for achieving 100 percent carbon-free electricity. We are excited to make advances towards this vision and build the future together.

APPENDIX D – NON-TECHNICAL SUMMARY

I. INTRODUCTION

Northern States Power Company-Minnesota is a wholly-owned operating subsidiary of Xcel Energy, Inc. that owns and operates, in conjunction with its affiliate Northern States Power Company-Wisconsin, the integrated NSP System of generation and transmission assets that serves more than 1.8 million electric customers in Michigan, Minnesota, North Dakota, South Dakota, and Wisconsin. This 2020-2034 Upper Midwest Integrated Resource Plan builds on our strong foundation of cost-effective environmental performance and the generating fleet transition we began in our last Resource Plan.

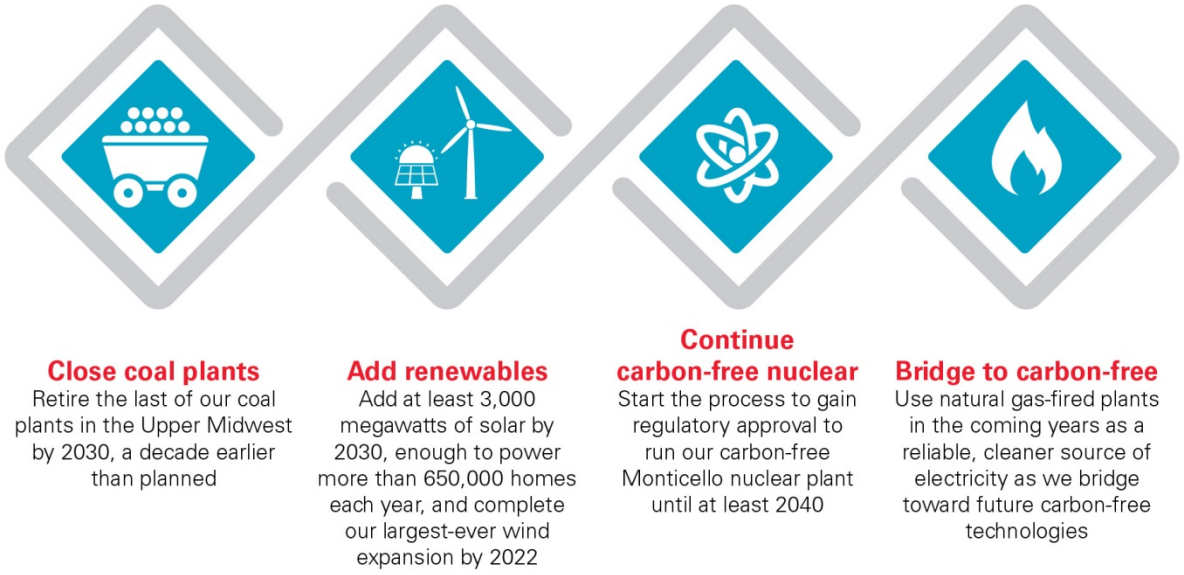
Our Resource Plan is founded on unprecedented levels of stakeholder engagement and technical analyses that examined an orderly retirement of our baseload generating units. We engaged a national expert on energy policy and economics, Dr. Susan Tierney with Analysis Group. Dr. Tierney not only brought a national perspective, but was also an independent third party that helped facilitate engaging and productive dialogue with stakeholders. We also retained Energy and Environmental Economics, Inc. (E3), to perform independent modeling and analysis of our system in order to ensure transparent work and access to the data and models for stakeholders. E3 is a recognized industry-leading firm based in San Francisco and consults extensively with utilities, developers, government agencies, and environmental groups on clean energy issues.

To develop our plan, we analyzed numerous assumptions and sensitivities to identify the plan that best meets customer needs, achieves our obligations and goals, and ensures we maintain a resilient and reliable grid. Our Preferred Plan represents the set of generation and conservation resources that we propose to meet our customers' needs over the next 15 years, which we believe is the best suite of resources that meets our planning objectives.

Figure 1: Xcel Energy Integrated Resource Plan Objectives

Our Preferred Plan includes the elimination of coal-fired generation from our system by 2030, the acquisition of at least 3,000 megawatts (MW) of utility-scale solar, a substantial increase in energy efficiency (EE) programs and Demand Response (DR), an operating extension of our carbon-free Monticello nuclear plant, and a proposal to construct a new combined cycle at our Sherco site. In total, we have an ambitious plan that supports the Company's goal of reducing carbon emissions 80 percent by 2030, and it moves us toward our ultimate vision of 100 percent carbon-free energy by 2050.

Figure 2: Preferred Plan Highlights



Our Preferred Plan will be evaluated based on its ability to: maintain or improve the adequacy and reliability of utility service; keep the customers' bills and the utility's rates as low as practicable, given regulatory and other constraints; minimize adverse socioeconomic effects and adverse effects upon the environment; enhance the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations; and limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control.[1]

II. A CHANGING PLANNING LANDSCAPE

There are key internal and external market contexts that affect how we have developed, and plan to execute on, our Preferred Plan. Below provide a contextual discussion of the planning landscape within which we developed and are presenting the results of our current resource planning efforts.

A. Regional Reliability and Market Constructs

While the regional system operator that designs many of our market and planning requirements continues to examine the effects of high renewable adoption on the grid, it has not yet developed robust and forward-looking capacity accreditation constructs to account for how renewables' contributions to peak demand will change

[1] Minn. R. 7843.0500, subp. 3

over time. This introduces complexity to designing a plan far into the future, and how we carry out those plans.

Likewise, while we are committed to substantially increasing renewables on our system to achieve our carbon reduction goals, we also anticipate facing challenges to integrating this new clean generation, given the delayed interconnection studies and current limited state of open transmission availability. Our ability to connect these new renewables in a cost-effective manner depends materially on constructs that enable careful management of our interconnection rights in the near-to-medium term as well as new transmission in the long term.

B. Distributed Energy Resources (DER)

At the same time as we work to clean our grid mix, we also recognize that customers are now exercising more choice around how and from where they consume energy. Our customers' adoption of DER and new types of load mean that consumption patterns from our centralized power system are changing. The opportunities are exciting; however, customer adoption of DER and new types of load behind the meter introduces uncertainties in our planning processes – particularly if we do not have adequate visibility into how and when that new DER or demand is coming onto our system.

Fortunately, we have made progress integrating distribution planning into our resource planning. As with other aspects of the industry that are transitioning and advancing, we are on the forefront of integrated distribution planning, and evaluating and procuring the next generation of distribution planning tools. These tools are needed to increase our forecasting and analysis capabilities and impact the integration of planning processes. Thus, while work continues to incorporate these planning processes and DER on our system, additional work and tools are needed.

C. Community and Employee Considerations

As we move forward with our carbon reduction goals, we are cognizant that phasing out some of our legacy generation assets has a significant impact not only on our energy mix, but on the economies of communities where those plants are located and the employees who work in those plants. This is particularly true of our coal facilities, where the plants are prominent places of employment and contributors to the property tax base in the community.

As we continue toward achievement of our aggressive carbon goals, we will continue to make significant clean energy investments in the states we serve. As we do so, we

will look for opportunities to create fair access to clean energy programs, jobs and economic development opportunities. Going forward, we continue to be dedicated to working with employees, communities, and stakeholders to manage community impacts throughout our clean energy transition.

D. Customer Preferences

We are increasingly hearing from our customers that they have a growing interest in increasing their energy management capabilities and desire a more customized energy mix than has been traditionally available. Residential customers tell us that they value choice and clean, affordable, and reliable energy. At the same time, municipalities within our service territory are expressing changing expectations to address their citizens' interests in achieving sustainability goals and engage residents around energy issues.

Our customers also are interested in various types of self-generation. This includes increased small-scale solar penetration through behind the meter installations or community solar gardens. Industrial customers are also interested in exploring the addition of larger scale Combined Heat and Power (CHP) installations at their facilities. The installation of self-generation on our system impacts our resource needs, planning goals, and ultimate resource mix.

We also know that customers are sensitive to rate changes. For example, our large industrial customers are energy-intensive and thus highly-sensitive to energy rates, with less sensitivity to other terms of service. These are key considerations as we plan our resource mix to meet the needs of our customers over the planning period.

E. Supply and Technology Trends

The rapid pace of advancement in energy technologies has impacted and will continue to impact the future of our industry. Emerging technologies related to grid modernization, energy storage, electric vehicles, resource extraction, renewable energy and other alternative fuels and generation methods are enabling a smarter and more resilient energy system.

While this new technology provides opportunities for a modernized energy system, operating that system is a complex matter. We are taking a measured approach to identify new and better ways to provide our customers with high quality service, meet increasing environmental requirements, and implement advancements and standardized processes that enhance the safety of our operations and overall value to customers. Our approach to these emerging technologies is to learn from the current

deployments, both internal to Xcel Energy and within the industry, and implement initiatives at the pace of value to our customers and operations.

F. Five State Integrated System

Our integrated Upper Midwest system provides service on a multi-jurisdictional basis to 1.8 million customers across five states. Through this integration, we have historically leveraged economies of scale to support needed investments. Each resource on the Upper Midwest system – whether generation or transmission – was developed in consideration of the whole system, to take advantage of the economies of scale available through integrated system planning. Indeed, planning for the varied needs of each of these five states was critical to the formation of our Preferred Plan.

G. The Evolving NSP System

This accelerated transition away from coal requires the Company to plan for the retirement of 2,400 MW of coal-fired generation in the next decade, which represents almost one-fourth of the total capacity in our current generation fleet. We will also experience a reduction in energy resources due several purchase power contracts expiring.

At the same time, we are increasing the amount of renewable generation on our system. Yet, these resources cannot alone reliably provide customers the energy they demand every hour of every day, or maintain the stability of the grid. Until such time as new technologies develop to fully transition the grid to carbon-free resources, some level of load-supporting, firm dispatchable resources is necessary for grid resilience and customer reliability. As such, our plan incorporates a Reliability Requirement as a bridge until the current planning processes adapt to recognize the transition that is underway.

Taken together, the impact of these system changes was critical to our resource planning analysis as we evaluated meeting our capacity and energy needs while maintaining reliability, retaining flexibility, and avoiding over-reliance on any one fuel source.

The planning landscape underlying this Resource Plan has greatly informed our planning efforts. We continue to believe that proactive leadership in the face of evolving industry, new and proposed environmental regulation, customer expectations, emerging technologies, and changes to the NSP System will allow us to affirmatively address these trends rather than being shaped by them. These evolving

factors also call for sufficient flexibility that allows us to adjust and react as we gain more clarity on the planning landscape.

III. KEY CONSIDERATIONS OF THE PREFERRED PLAN

Resource Planning is a complex and integrated process of planning for the capacity, energy, and emission requirements of the electric system. The process incorporates a number of key assumptions or industry projections that helps all participants develop a common vision of what the future planning environment may look like. This ongoing planning process requires utilities to examine and establish a long-term proposal for management, operation, and expansion or contraction of their generating and demand management resources to meet customer needs.

Traditionally a primary focus of resource planning has been to identify the least-cost approach to provide reliable service and meet growing demand. While this is still a part of our foundation, this Plan begins to move away from a more concentrated view of traditional thermal generation to incorporating new generation technologies, increasing carbon-free energy, reducing emission profiles, and thereby positioning the NSP System for the future.

The Preferred Plan we present was developed to address the planning landscape in which it was developed and in consideration of our four key planning objectives: (1) Environmental Benefits and Innovation (2) Reliability (3) Cost (4) Risk Mitigation and Flexibility. Underscoring all of these objectives is our commitment to our employees and the communities within which we operate.

A. Environmental and Innovation

Environmental benefits and the technological innovations that will help us achieve them are front and center in this Resource Plan process. We have made a bold commitment to achieve 80 percent carbon reduction from 2005 levels by 2030, and have considered this target a modeling pillar for all of our potential scenarios. Our Preferred Plan achieves this goal in several ways. First, our Preferred Plan eliminates coal from our system by 2030, extends our carbon-free Monticello plant to 2040, adds at least 4,000 MW of new renewable resources, including substantial new solar capacity additions, and maintains the wind levels committed to in our previous Resource Plan by replacing renewables with renewables when they reach the end of their operating lives.

Many of these resource additions are not needed for a number of years. We therefore expect technological advancements and innovations will create opportunities in

future planning and procurement processes if we are able to retain the flexibility we seek with this plan.

B. Reliability

Our responsibility to ensure a reliable electricity supply for our customers is a fundamental underpinning of our Preferred Plan. We therefore developed a Reliability Requirement that establishes a minimum level of firm dispatchable resources that is required to serve our customers' needs in every hour of every day. We developed the Reliability Requirement through analysis of industry trends and careful study of our system's performance and the broader Midcontinent Independent System Operator (MISO) system's performance during both winter and summer days when renewables were unavailable – sometimes for lengthy durations.[2]

This Requirement does not drive any firm dispatchable load supporting resource additions in our Preferred Plan until after 2030. Prior to 2030, our Preferred Plan relies on two primary sources to ensure reliability: (1) combined cycle (CC) generating plants – specifically the Mankato Energy Center (MEC) that we have proposed to acquire, one at our Sherco location near Becker, Minnesota (Sherco CC), and (2) our Monticello and Prairie Island nuclear units. Combined cycle generating units are intermediate natural gas resources that efficiently address reliability challenges associated with the variability of wind and solar and customer needs, because they can vary their output to adapt as demand for electricity changes over the course of the day and year. With respect to nuclear generation, our proposed extension of the Monticello operating license not only represents a carbon-free workhorse of a resource, it also enhances fuel diversity and provides a generation resource that is not subject to seasonal fuel supply limitations.

C. Cost

Along with leading the clean energy transition and enhancing the customer experience, keeping customer costs low is one of Xcel Energy's central, guiding objectives. Since our last Resource Plan, renewable technology costs – and in particular, solar costs – have continued to decline; we expect this trend to continue

[2] MISO is an independent, not-for-profit organization that delivers safe, cost-effective electric power across 15 U.S. states and the Canadian province of Manitoba. The NSP System is part of MISO, which is part of the Eastern Interconnection that connects the generation and transmission assets of the electrical grids from the Rocky Mountains to the East Coast and from Canada to the Gulf of Mexico. This interconnected network of generating resources and transmission infrastructure works together to seamlessly respond and adjust to dynamic and sometimes adverse circumstances to provide an adequate and reliable supply of electricity to customers.

going forward. Taking advantage of technological advancements is one reason that we can deliver a Preferred Plan that achieves deep carbon reductions for a nominal customer cost of just over one (1) percent Compound Annual Growth Rate (CAGR) over the planning period. And over the long run, our Preferred Plan is expected to yield net present value savings – yielding $203 million of benefits on present value revenue requirements (PVRR) basis and $461 million of benefits on a present value societal costs (PVSC) basis.

D. Risk and Flexibility

Finally, we also seek to mitigate customer risk by ensuring fuel diversity, maintaining appropriate capacity length in our portfolio, and maintaining flexibility in our plans. Portfolio fuel diversity is essential to risk mitigation – especially so, as we transition away from coal. Incorporating a mix of nuclear, load management, intermediate and peaking natural gas capacity, and renewables into our long-term plans ensures that our portfolio is adequately diverse – mitigating the risk associated with overdependence on any one fuel source. Further, the proposed resource additions identified in our Preferred Plan result in a capacity position that is between 500-1,000 MW long in any given year. We believe this modest length is prudent, particularly as we propose to substantially increase renewable resources – adding more than 4,000 MW of incremental new renewable capacity, in addition to our already large wind fleet.

Both MISO and independent analyses suggest that capacity accreditation for solar in particular will decline substantially as more capacity is added. We expect MISO will ultimately recognize this conclusion from its ongoing study of issues associated with integration of high levels of renewables in its planning construct.[3] Therefore, what we believe today to be a long capacity position may actually erode over time.

Maintaining a significant amount of flexibility in our future plans is essential to reliably and affordably navigating the transition of our fleet. To that end, we are deferring a decision on pursuing a license extension at the Prairie Island nuclear plant to subsequent resource plans, thereby preserving flexibility to respond to market conditions at that time.

Underscoring all four of our objectives is our commitment to our employees and the communities within which we operate. We do not make plant closure decisions lightly, and we are committed to supporting our employees at the Sherco and King plants as we prepare to retire these facilities. We also know that the Company is a

[3] We discuss MISO's *Renewable Integration Impact Assessment* (RIIA) in more detail in our Baseload Study, provided as Appendix J1.

major presence in terms of employment and local tax revenues in Becker and Oak Park Heights and the surrounding areas. We also have partners at our Sherco site with Liberty Paper and SMMPA (Southern Minnesota Municipal Power Agency). We are currently participating, alongside Minnesota Power, in a Host Community Impact study, to better understand the potential impact of power plant retirements on host communities. We are committed to continue to work with our employees and communities to navigate this transition together.

IV. THE PREFERRED PLAN

To develop the Preferred Plan, we first developed a Reference Case plan that continues the path we set out in our 2015 Resource Plan, with respect to operation of our baseload generating units. This Reference Case provides an opportunity to at least achieve the carbon reduction goals set-out in our previous Resource Plan, while meeting our minimum system needs and compliance obligations. Our Reference Case provides a base line from which we measured the emission reduction benefits, renewable and other energy additions and estimated cost impacts of our Preferred Plan.

A. Determining Customer Needs

Determining our customers' needs for electricity is a key component of any resource plan, and provides the foundation for determining the type and amount of resources that will be needed over the 15 year planning period. To this, we forecast of customers' needs starts in terms of capacity, or peak demand, which informs the total amount of generating capacity (in megawatts, or MW) needed to meet our customers' needs in the highest demand hour (i.e. peak-hour) in each year of the planning period. We also assess the amount of total energy (measured in megawatt hours or MWh) we expect customers to consume in each year of the planning period. Together, the peak demand and total energy needs inform the type of generating resources that will best meet customer needs.

To this, we add a "reserve margin" prescribed by MISO, which is intended to cover potential uncertainties in the availability of resources or level of demand. We then subtract the resources we already have or expect to have, to determine our net surplus or need. We illustrate this concept and discuss each of the components below.

Figure 3: Net Resource Need/Surplus Calculation

Customer Needs Forecast
Plus MISO Reserve Margin
Equals **Total Capacity Obligation**
Minus Demand Response Capability
Minus Generation Capacity (measured by UCAP)
Minus Generation Adjustments
Equals **Net Resource Need/Surplus**

This analysis yields our net generation capacity surplus or deficit over the planning period, shown below:

Table 1: Reference Case Load and Resources[4] 2020-2034 Planning Period

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
System needs (MW)															
Forecasted gross load	10,499	10,559	10,621	10,684	10,755	10,820	10,886	10,954	11,140	11,232	11,320	11,418	11,518	11,619	11,717
Forecasted EE[5] (reduction to load)*	(1,386)	(1,472)	(1,517)	(1,609)	(1,707)	(1,822)	(1,921)	(1,992)	(2,125)	(2,215)	(2,278)	(2,366)	(2,352)	(2,324)	(2,415)
Forecasted net load	**9,112**	**9,087**	**9,103**	**9,075**	**9,048**	**8,998**	**8,965**	**8,963**	**9,014**	**9,016**	**9,042**	**9,052**	**9,166**	**9,295**	**9,301**
MISO System Coincident	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
Coincident Load	8,657	8,633	8,648	8,621	8,595	8,548	8,517	8,514	8,564	8,565	8,590	8,599	8,708	8,831	8,836
MISO PRM	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%
NSP Obligation	**9,384**	**9,358**	**9,374**	**9,345**	**9,317**	**9,266**	**9,232**	**9,230**	**9,283**	**9,285**	**9,312**	**9,321**	**9,439**	**9,572**	**9,579**
Reference Case resources (MW, unforced capacity)[6]															
Load Management *(existing)*	940	955	970	989	1,007	1,023	1,038	1,053	1,066	1,054	1,043	1,032	1,021	1,010	1,000
Load Management* *(potential study)*	270	290	312	322	339	380	392	406	421	438	456	476	497	527	550
Coal	2,390	2,390	2,390	2,390	1,699	1,699	1,699	1,017	1,017	1,017	1,017	1,017	1,017	1,017	1,017
Nuclear	1,603	1,603	1,603	1,603	1,603	1,603	1,603	1,603	1,603	1,603	1,603	992	992	992	484
Natural Gas/Oil	3,295	3,295	3,295	3,295	3,141	2,829	2,624	2,136	2,018	2,018	2,018	2,018	1,765	1,765	1,765
MEC*	627	627	627	627	627	627	627	627	627	627	627	627	627	627	627
Sherco CC*	0	0	0	0	0	0	0	727	727	727	727	727	727	727	727
Biomass/RDF	110	110	110	86	86	63	63	63	22	22	22	22	22	22	22
Hydro	877	997	989	989	989	162	162	162	162	162	162	162	156	152	152
Wind	596	650	696	670	659	642	637	622	616	594	593	578	575	511	492
Grid-scale solar	182	182	181	180	179	178	177	176	175	174	174	173	172	171	170
Solar*Rewards Community Solar	335	339	344	348	352	356	360	365	369	373	377	381	385	389	393
Distributed Solar	42	48	55	60	66	72	78	83	89	95	100	105	111	116	121
Existing Resources	**11,267**	**11,486**	**11,571**	**11,559**	**10,746**	**9,634**	**9,460**	**9,040**	**8,913**	**8,905**	**8,920**	**8,311**	**8,066**	**8,026**	**7,521**
Net Resource (Need)/Surplus	**1,884**	**2,128**	**2,196**	**2,213**	**1,429**	**368**	**228**	**(190)**	**(370)**	**(380)**	**(392)**	**(1,010)**	**(1,373)**	**(1,546)**	**(2,058)**

From this point, the modeling underlying our resource planning identifies the best combination to meet any net resource deficiencies and the resulting energy mix.

[4] In addition to existing and approved resources, those indicated with a * include pending or proposed resources that we have included across all Scenarios, including the Reference Case.
[5] Includes EE savings from historically installed measures, as well as future EE from bundles modeled in this Resource Plan, achieving 2-3% savings levels. Also includes minimal EV and coincidence adjustments.
[6] Unforced Capacity (UCAP) is a measure of resource adequacy value that we use in modeling to ensure we have sufficient resources to cover our full obligation. These values are discounted based on actual or expected average performance, per MISO, relative to the installed capacity values presented in our expansion plans.

B. Reference Case Expansion Plan and Energy Mix

Table 2: Reference Case Annual Expansion Plan (MW)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Grid-Scale Solar	0	0	0	0	0	500	0	1000	500	500	0	1000	500	0	0
Battery	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CC	0	0	0	0	0	0	0	835	0	0	0	0	0	0	0
Firm Dispatch-able	0	0	0	0	0	0	0	0	0	0	0	0	232	374	374
DR	270	20	21	10	17	41	12	14	15	17	19	20	21	22	23
EE	115	130	116	133	143	145	154	157	155	140	138	136	129	126	126
Wind	0	0	0	126	45	70	66	72	10	107	16	56	31	523	1581
Distributed Solar	154	22	22	21	21	21	21	20	20	20	20	20	20	20	19
Total	540	172	159	290	226	777	252	2,098	700	784	193	1,232	932	1,065	2,123

C. Developing the Preferred Plan

We use a modeling tool called Strategist, which allows us to explore how we best meet our customer and policy requirements under a variety of conditions and at a reasonable cost. We work with internal and external subject matter experts to develop starting assumptions that reflect their expert opinion of likely future conditions. We then test the robustness of the plans through sensitivity analyses by individually changing key assumptions and re-running the plans under these changed assumptions.

Beginning with our Reference Case to meet our minimum system needs, we created 15 scenarios. Because one of our requirements with this Plan was to examine a potential schedule for a cost-effective and orderly retirement of baseload generating units not already scheduled to retire early (King, Sherco 3, Monticello, and Prairie Island Units 1 and 2), we performed technical studies as part of an overall Baseload Study that informed these scenarios and their costs.

These scenarios examined different combinations and timing of baseload unit retirements, and the resulting size, type, and timing of new resources we would need to add in order to continue meeting customers' needs, achieve our 2030 carbon reduction goals, and maintain affordable rates. Key scenario groupings analyzed include:

- *Early Coal.* Analyses to evaluate the economics (i.e. revenue requirement impacts) of retiring King and/or Sherco 3 early.
- *Early Nuclear.* Analyses to test the economics of retiring Monticello and/or Prairie Island early, either alone or together and with the combination of early coal retirements.

- *Extend Nuclear.* Analyses to test the economics of re-licensing Monticello and/or Prairie Island and extending the operational life by ten years over the current retirement date.

Based on these analyses, we believe that our Preferred Plan meets all of our key planning objectives, positions us well to meet customers' needs, reasonably balances outcomes and costs – all while providing us with the necessary strategic flexibility to address the planning landscape.

D. Preferred Plan

Key components of our Preferred Plan include:

- ***Coal Resources*** – Retire our last two units early: King in 2028 (nine years early) and Sherco 3 in 2030 (ten years early). Additionally, continue our plan to retire Sherco 1 and 2 in 2026 and 2023, respectively, and commit to offering Sherco Unit 2 into MISO on a seasonal basis until its retirement.
- ***Nuclear Resources*** – Operate our Monticello unit through 2040 (10 years longer than its current license) and operate both Prairie Island units through the end of their current licenses (PI Unit 1 to 2033 and PI Unit 2 to 2034).[7]
- ***Renewable Resources*** – While the exact wind and solar mix could vary based on a variety of reasons, at this time we propose to add 4,000 MW of cumulative utility scale resources by 2034 (the first being in 2025) and approximately 1,200 MW of cumulative wind by 2034 to replace wind that is set to retire from our system during that period.
- ***Combined Cycle Resources*** – Acquire and operate MEC and build, own and operate Sherco CC to satisfy significant capacity and operational needs created by coal closures.
- ***Firm Load Supporting Resources*** – Starting in 2031, add approximately 1,700 MW of cumulative firm dispatchable, load-supporting resources by 2034.
- ***Demand Side Management*** – Include energy efficiency (EE) programs representing an approximately 780 GWh of savings annually through 2034 (compared to average annual energy savings of 444 GWh in our last Resource Plan) and the addition of 400 MW of incremental Demand Response (DR) by 2023, achieving a total of over 1,500 MW DR by 2034.

[7] Given that our operating licenses for Prairie Island run until 2033 and 2034, we believe there is sufficient time to address the future of that plant in upcoming resource plans.

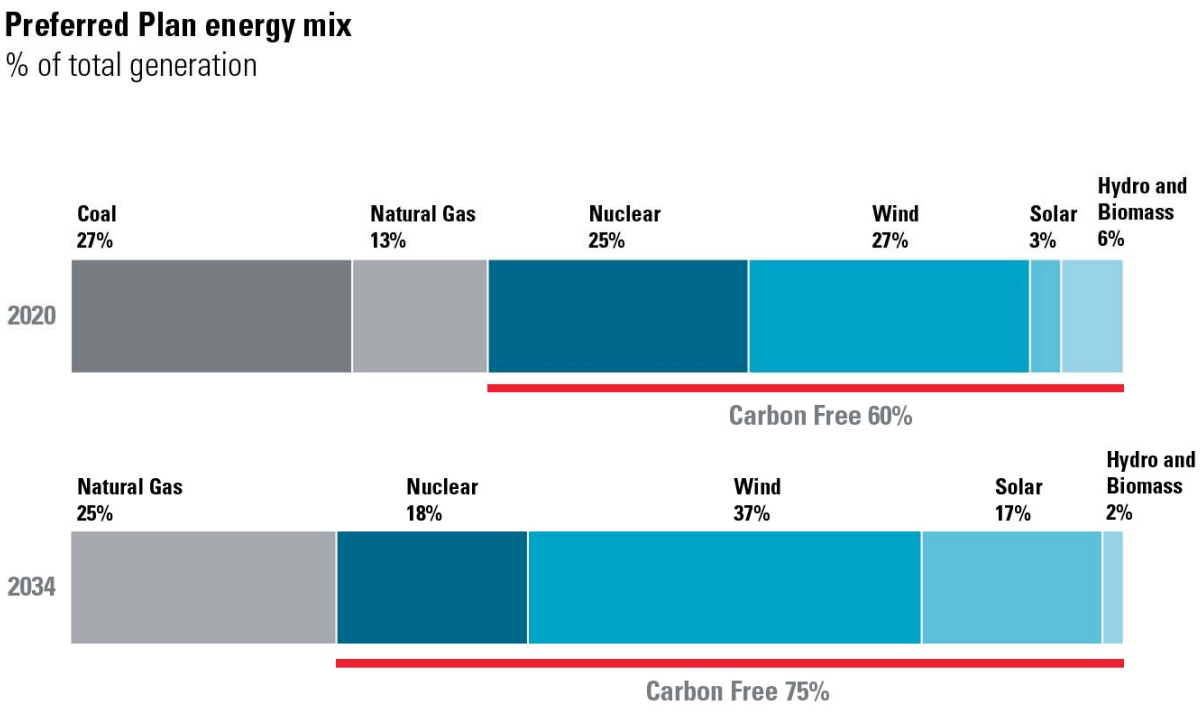
Table 3 below outlines the proposed timing, type, and size of resource additions comprising our Preferred Plan.

Table 3: Preferred Plan Resource Additions (MW)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Grid-Scale Solar	0	0	0	0	0	500	500	1000	500	500	500	0	500	0	0
Battery	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CC	0	0	0	0	0	0	0	835	0	0	0	0	0	0	0
Firm Dispatch-able	0	0	0	0	0	0	0	0	0	0	0	606	0	374	748
DR	270	20	21	10	17	41	12	14	15	17	19	20	21	22	23
EE	115	130	116	133	143	145	154	157	155	140	138	136	129	126	126
Wind	0	0	0	126	45	70	66	72	10	107	16	56	31	523	81
Distributed Solar	154	22	22	21	21	21	21	20	20	20	20	20	20	20	19
Total	**540**	**172**	**159**	**290**	**226**	**777**	**752**	**2,098**	**700**	**784**	**693**	**838**	**700**	**1,065**	**997**

Our Preferred Plan outlined above would result in the energy mix shown in Figure 4 below.

Figure 4: Preferred Plan Energy Mix



Our Preferred Plan achieves several important goals:

Reliability. Our Preferred Plan maintains the safe and reliable service we have been providing for many years, and ensures that the NSP System has sufficient capacity and energy available during the planning period.

Environmental Outcomes. Implementing our Preferred Plan will allow us to reduce our carbon emissions over 80 percent from 2005 levels by 2030. Additionally, our Preferred Plan adds significant renewable energy to the NSP System.

Strategic Flexibility. Our Preferred Plan positions the Company well in the current planning landscape – meeting near-term needs and creating flexibility for the future. As we have described, planning constructs, policies, and technology costs are all creating uncertainty, which leads us to prioritize strategic flexibility in our plans to preserve the most value for our customers

Affordability. As discussed below in the Rate Impact section, we estimate that our Preferred Plan can be implemented at reasonable cost to our customers.

V. FIVE-YEAR ACTION PLAN

Our Preferred Plan does not identify any incremental capacity needs through 2024. Thus, our actions in the next five years primarily address previously approved or pending resource additions and retirements, wind repowering and procurement to meet specific customer needs, and continuing to achieve reductions in energy demand and load through ambitious DSM programs. We also plan to make targeted investments in supporting infrastructure to accommodate increased renewable energy and DER on the grid, and to gain operational experience with technologies that may play a larger role on our grid in the future. Key highlights are as follows:

Wind. We expect that the 1,850 MW of wind generation resulting from our recent acquisitions and RFPs will achieve commercial operation by 2022. We expect to replace wind capacity that will expire, and we are committed to pursuing repowering and/or contract extension opportunities for this capacity, as part of our "no going back" renewables strategy. Further, we intend to pursue incremental renewable resources as needed to meet customer needs in growing customer programs like Renewable*Connect.

Solar. Our Preferred Plan includes significant amounts of large scale solar, with the initial addition of 500 MW occurring in 2025 – just outside of the five-year Action Plan window. We expect to implement a competitive acquisition process in the 2023 to 2024 timeframe and bring these resources online by the end of 2025. On the distributed solar side, we have included forecasted growth in our plan. If actual distributed solar capacity additions exceed our expectations, we anticipate this will displace a portion of our proposed utility-scale solar resources.

Nuclear. Our Preferred Plan includes a request to operate our Monticello nuclear unit for an additional 10 years beyond its current license. While the license does not end until 2030, we expect to begin a proceeding with the Commission within the next five years and also begin working toward license extension with the Nuclear Regulatory Commission during this timeframe.

Natural Gas/Oil Peaking. We anticipate extending the life of Blue Lake Units 1-4 through 2020-2023,[8] which provides 153 MW of peaking capacity to the NSP System. Our Preferred Plan further includes our acquisition of MEC, which is currently pending Commission consideration. Finally, we plan to continue development activities associated with the Sherco CC during the next five years.

In addition, as discussed in our last Resource Plan, system retirements will impact our current blackstart plans and we are currently analyzing our blackstart path to determine the best fit for our system needs. While we do not propose any action related to the system blackstart at this time, we anticipate addressing this in our next Resource Plan or earlier, if system needs dictate the need to do so.
Coal. As approved in our last Resource Plan, we will take action with MISO and retire Sherco Unit 2 in 2023, and intend to offer it into MISO on a seasonal basis until that time. Though outside the five-year action window, we are proposing to retire the remainder of our coal units (Sherco 2, Sherco 3 and King) before 2030. As with our previous plant retirements, we plan to begin working with our employees and host communities to prepare for this transition.

Demand Response. Our Preferred Plan proposes to acquire 400 MW of DR resources by 2023.

Supporting Infrastructure. Aside from the grid-scale and DER additions included in our Plan, sufficient supporting infrastructure is essential to facilitate our fleet transformation, ensure grid resilience and reliability, and to enable greater DER and DR resources on our system. We expect further and substantial transmission infrastructure development will be necessary over the long-term, which will involve planning in the near-term. We also are continuing to refine our advanced grid strategy and intend to propose implementation of foundational grid modernization investments – and continue our work to integrate planning processes at all levels of the grid.

Resource treatment across states. We continue to explore options with the North Dakota

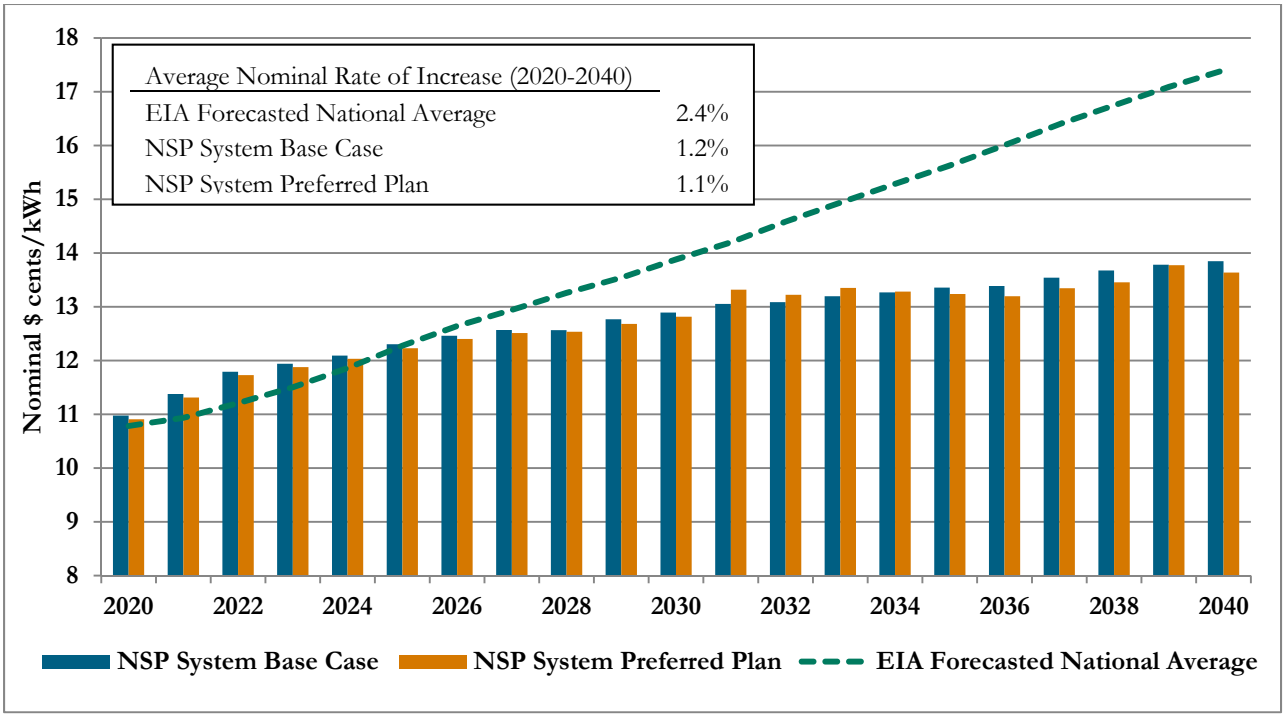
[8] Pending decision in Docket E,G002/D-19-161

Public Service Commission to create a resource planning process can more formally accommodate generation portfolio preferences. We believe additional discussions with all of our state Commissions will be necessary during the five-year action planning period to address differing energy policies and changes in cost allocations that may result.

VI. RATE IMPACTS

Overall, our Preferred Plan results in an estimated average annual increase in revenue requirements less than the Reference Case and just over 1 percent overall. In other words, we can achieve significant CO_2 emissions reductions, with cost impacts that are roughly half the expected national average increase in electricity prices. This is demonstrated in Figure 5 below.

Figure 5: Preferred Plan Average Nominal Cost Comparison
NSP System

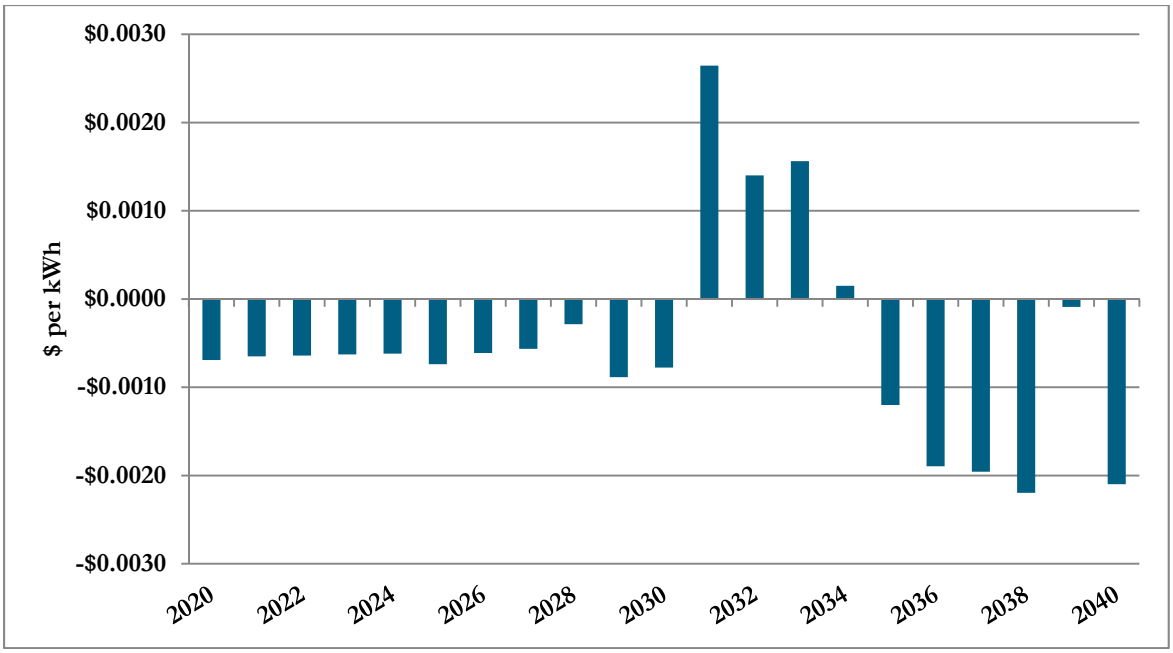


* *Notes: National energy cost forecast from Energy Information Administration (EIA) Annual Energy Outlook 2019, Table Energy Supply, Disposition, Prices and Emissions – Reference Case. End use prices, all sector average.*[9] The Preferred Plan and Reference *Plan lines include the costs of Solar Rewards*Community.*

[9] *See* https://www.eia.gov/outlooks/aeo/data/browser/#/?id=8-AEO2019&region=0-0&cases=ref2019&start=2017&end=2050&f=A&linechart=~ref2019-d111618a.70-8-AEO2019&ctype=linechart&sid=ref2015-d021915a.70-8-AEO2015~ref2019-d111618a.70-8-AEO2019&sourcekey=0 The EIA's Annual Energy Outlook was published in January 2019. The report is available at https://www.eia.gov/outlooks/aeo/pdf/aeo2019.pdf.

Figure 6 below demonstrates the actual impact implementation of our Preferred Plan would have on our customers' bills. We note that the Preferred Plan's average estimated rate impact, relative to the Reference Case, in any given is well under $0.01 per kWh.

Figure 6: Incremental Rate Impact of Preferred Resource Plan
State of Minnesota – All Customers



VII. CONCLUSION

The Preferred Plan we propose in this 2020-2034 Upper Midwest Resource Plan reflects extensive collaboration with stakeholders as well as independent expert analysis. Our Preferred Plan proposes to eliminate coal, add even more renewables, and continue our industry-leading energy efficiency and demand response programs, all while preserving reliability and affordability for our customers. It also meets the varied interests of our five-state Upper Midwest region. By planning ahead and charting an orderly, gradual transition of our generation fleet, we believe we can achieve all of these goals while managing the impacts to our host communities and employees, preserving the reliability and stability of our system, and maintaining affordability for our customers. For these reasons, as discussed throughout this filing, we believe our Preferred Plan is in the public interest and merits Commission approval.

Xcel Energy®

Building a Carbon-free Future | CARBON **REPORT**

To our **Stakeholders:**

Xcel Energy is committed to serving customers, and that includes responding to the concerns of many customers around the risk of climate change. National and international studies paint a sobering picture about this risk and call for nothing less than a transformation of our industry to help address it. While that transformation will be challenging, we see an opportunity for our company and those we serve to significantly reduce greenhouse gas emissions reliably, safely and at a low cost.

In 2018, we reduced carbon emissions from the electricity that serves our customers by 38 percent compared to 2005 levels and plan to do even more. As technologies have improved and costs have fallen, we are making significant changes — more than we imagined possible a decade ago — without compromising the reliability or affordability that our customers expect. We need all three components — clean, reliable and affordable — to make this transition work.

As we carry out Xcel Energy's vision to be a preferred and trusted energy provider, leading the clean energy transition continues to be a strategic priority for us. It's helping to achieve our other two strategic priorities as well — to keep customer bills low and enhance the customer experience.

We're a national leader in wind energy and are harnessing it through our Steel for Fuel strategy, which we expect to reduce costs for customers. We also offer a leading portfolio of energy efficiency and renewable choice programs because an increasing number of customers want to power their homes and businesses with clean energy and take steps to reduce their own carbon footprints.

While our existing efforts are significant, we want to do even more and do it sooner than anticipated. That is why I set an ambitious vision to reduce our carbon emissions 80 percent from 2005 levels by 2030. Longer term, we aspire to serve our customers with carbon-free electricity by 2050. The technology to achieve this aspiration isn't commercially available yet, but I believe it can be available if we make it a priority today.

In this report, we discuss our vision, including the opportunities, risks and challenges we face getting there. We describe how our carbon transition can have an even larger impact in other sectors, such as transportation. We also show how our commitment compares to the targets of international climate agreements.

Xcel Energy is leading the clean energy transition. We know from experience that our goals are ambitious. This change will require collaborative, long-term solutions that are cost effective as well as advanced clean energy technologies. Broad stakeholder support, smart public policy and favorable economics are essential factors in this ongoing transformation.

We can't achieve this transition alone — it will take all of us working together. I look forward to your partnership.

Sincerely,

Ben Fowke
Chairman, President and CEO

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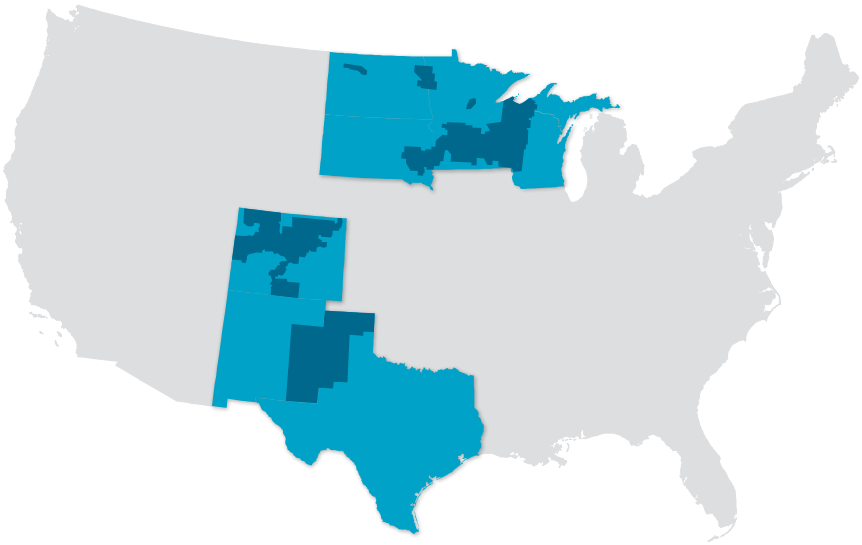
About Us

Xcel Energy is a major U.S. electricity and natural gas company with annual revenues of $11.4 billion. Based in Minneapolis, we operate in eight states and provide a comprehensive portfolio of energy-related products and services to 3.6 million electricity customers and 2 million natural gas customers.

Addressing climate change is a priority for many of our customers, investors and key stakeholders, and is a priority for us as well. In delivering on our strategic focus to lead the clean energy transition, we are successfully reducing carbon emissions and providing clean energy solutions from a variety of renewable sources, reliably and affordably for customers.

More information on our clean energy strategy, corporate governance and risk management is available at **xcelenergy.com** in our corporate reports, including Xcel Energy's Annual Report, Proxy Statement, Corporate Responsibility Report and EEI Environmental, Social, Governance and Sustainability Report.



Forward Looking Statements

The material in this report contains forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements include projections related to emission reductions, changes in our generation portfolio, planned retirements, and planned capital investments and are identified in this document by the words "aim", "aspire", "assuming", "believe", "could", "expect", "may", and similar expressions. Actual results may vary materially. Factors that could cause actual results to differ materially include, but are not limited to: general economic conditions, including the availability of credit, actions of rating agencies and their impact on capital expenditures; business conditions in the energy industry: competitive factors; unusual weather; effects of geopolitical events; including war and acts of terrorism; changes in federal or state legislation; regulation; actions of regulatory bodies; and other risk factors listed from time to time by Xcel Energy in its Annual Report on Form 10-K for the fiscal year ended Dec. 31, 2018 (including the items described under Factors Affecting Results of Operations) and the other risk factors listed from time to time by Xcel Energy Inc. in reports filed with the SEC.

Aspiration for a **Carbon-free** Energy Future

For more than a decade, Xcel Energy has demonstrated leadership on clean energy — proactively reducing carbon emissions at levels that currently surpass state and federal goals. This environmental commitment is woven into our company's strategy, governance, executive compensation and daily operations.

To respond to growing stakeholder expectations, we have regularly established and achieved increasingly ambitious carbon reduction goals.

Where We Aim to Be

Our vision for the future includes industry-leading goals shown in Figure 1. In this report, we demonstrate how our goals align with an emissions trajectory needed for the electric power sector to meet the goals of the Paris climate agreement.

By 2030, we aim to reduce carbon dioxide emissions 80 percent below 2005 levels company-wide. This means that by 2030, our annual carbon emissions from the electricity that serves our customers will be about 17 million tons, or 80 percent lower than in 2005. We believe these emission reductions can be achieved cost effectively with continued fleet transition and operational changes, and with the renewable, carbon-free generation and energy storage technologies available today.

By 2050, we aspire to provide our customers across all states with 100 percent carbon-free electricity. In the next 30 years, we will transition to serve our customers with electric resources that emit zero carbon dioxide emissions. To fulfill this aspiration, we will continue to increase renewable energy sources on our system, as well as technologies that enable renewable integration. We will need new carbon-free dispatchable technologies — technologies not yet commercially available at the cost and scale needed to achieve our 2050 aspiration. Because of this, there needs to be significant research and development to ensure we have these technologies to deploy in the coming decades.

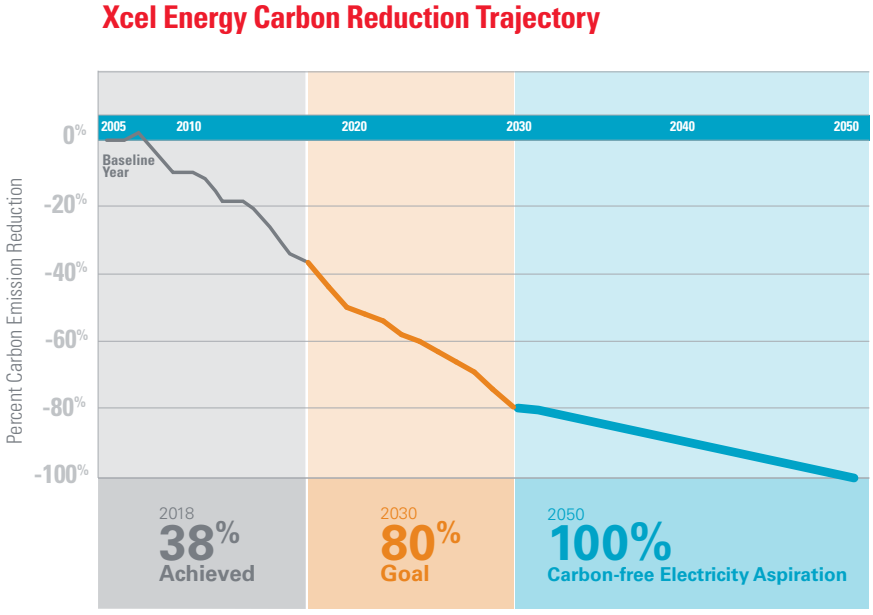


Figure 1: Our vision for the clean energy transition 2030 and 2050

The Path to Get There

We know that climate change is an urgent issue for many of our policy makers and a growing concern of our customers who want to help make a difference. Planning for the transition to a clean energy future today will allow us to deliver the product our customers want and achieve reductions that our policy makers are increasingly demanding. By acting now, we increase our chances to achieve these goals while assuring that our system remains reliable and our prices affordable. These last two points are critical to our success. The electricity we deliver is an essential service that powers the economy and keeps our customers comfortable and safe.

While we move through this transition, we need to make sure that power will be there when our customers need it and that the prices we charge are affordable to all customers , both residential and commercial. To accomplish this, we will build upon four focus areas that are transforming our system and delivering clean, reliable, low-cost power to customers today.

These focus areas include:

- Investing in wind and solar under our Steel for Fuel strategy and offering customers more renewable energy options
- Helping customers manage their energy usage and bills through efficiency and rebate programs and encouraging strategic electrification of other sectors, such as transportation
- Maintaining our carbon-free nuclear plants in the Upper Midwest
- Transforming the energy grid by retiring or reducing the operation of aging coal plants and replacing their energy with low-carbon natural gas, renewables and advanced technologies

Looking ahead to 2030 and 2050, we plan to continue this progress. Our vision is not a single plan or initiative. Instead, it will guide the policies that we support and the resource plans that we expect to file in our states over the coming decades. As we advance these efforts, stakeholders are essential and will help to influence the outcomes. Because of this, we plan to continue working collaboratively with customers, nongovernmental organizations, policy makers and others to identify and implement pragmatic solutions to make our goals possible.

In setting our goals, we did sensitivity analysis to identify key elements and variables that could affect our plans. There are a variety of cost-effective pathways to an 80 percent carbon reduction by 2030, and resource plans in our jurisdictions will determine the exact resource mix. However, through the pathways we explored, we have identified the following common elements that we know will be part of the plans:

- We anticipate adding thousands of megawatts of wind and solar power to our system and incorporating both natural gas and storage resources to help balance high levels of renewables
- Strategic electrification of certain end uses will help create flexible demand
- We will seek to operate our nuclear plants through at least the remainder of their licenses, and we will need to retire additional coal units or change their operations to minimize emissions affordably and reliably
- In addition, we will need to make critical investments in supportive infrastructure, such as transmission

As we transition our system and retire plants, we will need to assure that we do so in a way that our company remains financially healthy and that acknowledges the financial impacts of plant retirements and the replacement investment on our investors. Just as we serve other stakeholders, we must provide our investors with value to encourage them to provide the capital necessary to support these plans. There are many ways to accomplish our carbon vision, but the ability to own these replacement resources is clearly an important consideration, as investors support companies that grow their earnings power. This ownership also helps to reduce risk to customers and is fundamental to ensuring our financial viability and ongoing ability to efficiently invest in day-to-day infrastructure needs as well as clean energy.

To reach our 2050 aspiration, there must be more action around the research, innovation and demonstration of advanced technologies. We need, clean technologies that can be dispatched to balance the peaks when customer use exceeds renewable generation and valleys when renewable generation exceeds customer use. Cost-effective, low-carbon and carbon-free dispatchable resources will be required to remove the remaining carbon from the system to serve customers with carbon-free electricity. Technology advancement is key to the long-term success of our strategy.

Analysis Related to **Our Vision**

In planning our future carbon transition, we have reviewed the research on climate science to confirm the effectiveness of our goals. A trio of climate reports — from the Intergovernmental Panel on Climate Change (IPCC), the U.S. Global Change Research Program and the UN Environment Program — examine potential climate change impacts and the greenhouse gas reductions needed to meet the targets of the Paris climate agreement. While providing broad context for our analysis, none of these reports includes actionable guidance for utility decision making or for individual company greenhouse gas goals.

We also participate in an Electric Power Research Institute (EPRI) project that is analyzing the science around climate scenario analysis and emission goal setting. While providing useful insights about global, regional and electric sector emissions consistent with limiting temperature increases to 2 C, the EPRI project does not provide company-specific comparisons to the Paris climate targets.

To bridge this gap, we hired experienced climate modelers at the University of Denver to compare Xcel Energy's goals to the Paris climate targets. We compared our goals to electric power sector emissions in industrialized countries, in IPCC scenarios consistent with a high probability of achieving the 2 C and 1.5 C temperature goals in the Paris climate agreement.

The Paris Climate Agreement

In December 2015, the international negotiations of the United Nations Framework Convention on Climate Change (UNFCCC) produced the Paris climate agreement, with the goal of "holding the increase in the global average temperature to well below 2 C above preindustrial levels and pursuing efforts to limit the temperature increase to 1.5 C above preindustrial levels, recognizing that this would significantly reduce the risks and impacts of climate change."[1]

The Paris climate agreement does not establish goals, mandates or even guidance for individual economic sectors or companies. This makes it challenging to address the relationship between the agreement's goals and company-level targets. Its temperature goals represent a global ambition, pursued through nationally determined contributions and subsequent national and sub-national (e.g., state) policy decisions about how to allocate the emission reduction burden across sectors, industries and individual companies.

IPCC Special Report

The IPCC in October 2018 published a Special Report on Global Warming of 1.5 °C. The IPCC estimates that warming to date is about 1 C above average preindustrial temperatures and that warming is likely to reach 1.5 C between 2030 and 2052.[2] The report evaluates human and natural impacts of climate change associated with global warming of 1.5 C and compares these to impacts at 2 C or more. The IPCC then explores what global greenhouse gas reductions would be needed, on what timeframe, to limit warming to 1.5 C. It estimates that global net human-caused carbon dioxide emissions would need to peak within the next few years, then fall dramatically, reaching net zero by around 2050 (meaning that after that point, carbon emissions are balanced by carbon removal.) The report indicates that allowing global temperatures to temporarily overshoot 1.5 C, but return below 1.5 C by 2100, would require greater reliance on negative emission technologies after mid-century. To stay below or only temporarily exceed 1.5 C, global emissions in 2050 would have to be between 71 percent and 129 percent below 2010 levels.[3]

US Fourth National Climate Assessment (NCA4)

The U.S. Global Change Research Program in November 2018 released its Fourth National Climate Assessment, summarizing the latest scientific understanding of climate change impacts, risks, mitigation and adaptation, both nationally and by regions of the United States. The report finds that climate change is having significant impacts on U.S. communities, the economy, trade, water, public health, ecosystems, infrastructure, energy systems, agricultural productivity, oceans and coastlines. Potential impacts on the electric sector include reduced generation efficiency at thermal plants, power outages, grid reliability challenges, fuel transport, changing wind patterns, increased electricity demand for cooling and reduced natural gas demand for heating.

Under a high emissions future, NCA4 finds that "climate change is projected to impose substantial damages on the U.S. economy, human health and the environment. Under scenarios with high emissions and limited or no adaptation, annual losses in some sectors are estimated to grow to hundreds of billions of dollars by the end of the century."[4] However, NCA4 also finds that greenhouse gas reductions sufficient to keep the world on a lower warming pathway could still avoid or significantly reduce these damages — and that the earlier the reductions, the greater the chance of avoiding the worst impacts.

UN Emissions Gap Report

The U.N. Environment Programme (UNEP) in November 2018 released its annual Emissions Gap Report, which assesses the status of countries' "nationally determined contributions" under the Paris climate agreement. The report finds that global carbon dioxide emissions increased in 2017 after staying relatively flat for three years, reaching 53.5 billion metric tonnes CO2e (GtCO2e) and show no signs of peaking in the near term. Without additional efforts, UNEP predicts global warming of about 3 C by 2100. UNEP estimates a gap of 13 GtCO2e per year by 2030 between global emissions under the nationally determined contributions and the annual emissions needed to achieve the 2 C target (for the 1.5 C target, a gap of 29 GtCO2e.) UNEP finds it is still possible to bridge the gap and contain warming below 2 C and 1.5 C, but this will require aggressive reductions by 2030, particularly in emission scenarios that are more pessimistic about the potential for negative emissions (i.e., carbon removal technologies) later on.

EPRI Research

Because the reports summarized above do not include guidance specific to electric utilities or other industries, Xcel Energy also participates in a multi-utility project convened by EPRI to examine the current state of the science around climate scenario analysis and company greenhouse gas goals.[5] EPRI released a report in fall 2018 that takes stock of current scientific understanding and provides analytical guidance, titled Grounding Decisions: A Scientific Foundation for Companies Considering Global Climate Scenarios and Greenhouse Gas Goals. We outline here a few key findings from the report.

Figure 2 illustrates the many variables defining the relationship between global temperature goals and company-level greenhouse gas emissions. Uncertainties in the relationships between each variable result in ranges of global, country, sector and individual company emissions consistent with a temperature goal. This means there is no single or uniform target that can be applied to all companies and is appropriate in all plausible futures. Nonetheless, ranges can be identified that are consistent with achieving the temperature goals.

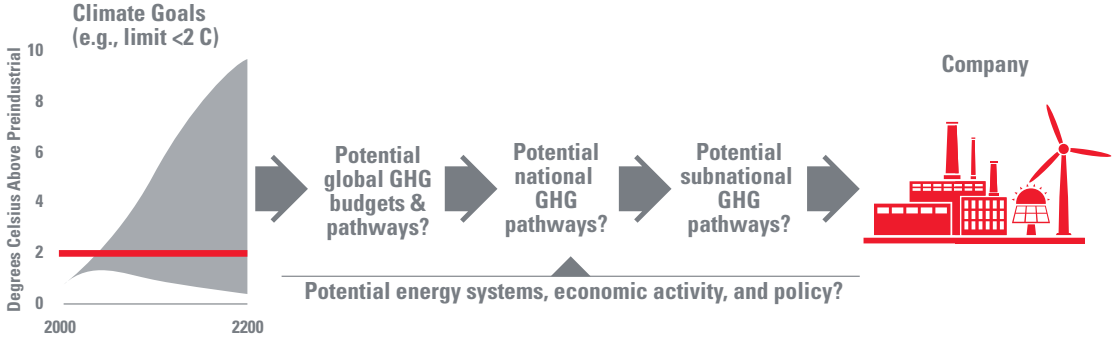


Figure 2: The relationship between global climate goals and company-level targets. Reproduced from EPRI 2018, page 2-1.

EPRI draws on the IPCC Fifth Assessment Report (AR5) emission scenario database and other scenarios to characterize current understanding of these relationships. Among other things, the EPRI study identifies sets of global, regional and electric power sector emission scenarios consistent with different probabilities of limiting global average temperature increase to 2 C.[6]

Figure 3, reproduced from the EPRI report, shows the range of global carbon dioxide scenarios consistent with a 40 percent or greater chance of limiting global warming to 2 C. The left-hand chart shows that a broad range of scenarios, rather than a single scenario, is consistent with this temperature goal. It also shows that scenarios that increase emissions in the near term generally require significant negative emissions after mid-century to offset the near-term increase and achieve the temperature goal.[7] The right-hand chart shows the much smaller range of scenarios that can achieve the temperature goal with the same 40 percent probability, if negative emissions technologies are unavailable.

The EPRI study also presents sets of regional and electric sector emissions pathways consistent with 2 C. However, as discussed by EPRI, these results are dependent upon global assumptions — in particular, global economy-wide policy design and technology availability assumptions that facilitate reducing carbon with electricity. These are important uncertainties for electric power companies to evaluate, and sub-global scenario results should be used with caution and with these uncertainties in mind.

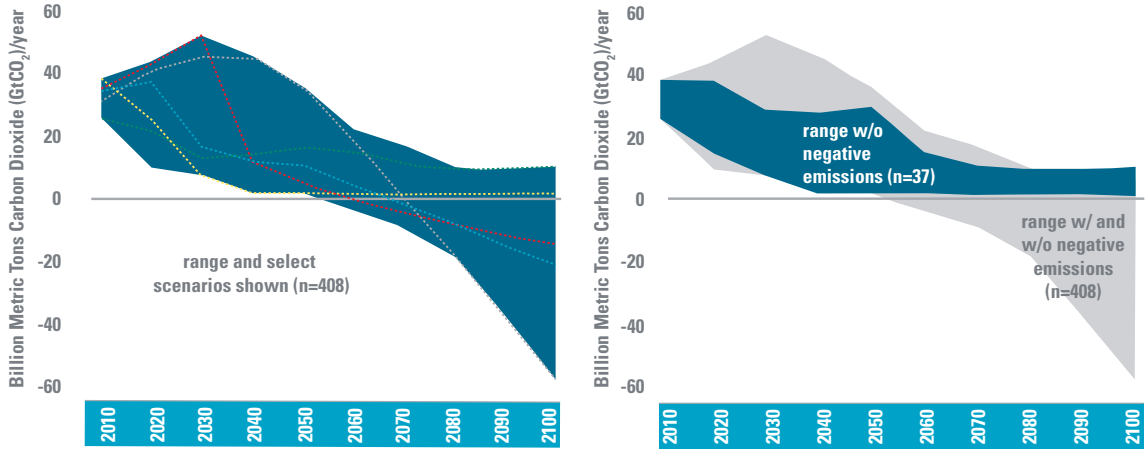


Figure 3: Global net carbon dioxide pathway ranges consistent with a 40 percent or greater chance of limiting warming to less than 2 C. Reproduced from EPRI 2018 and supporting material.

EPRI's report provided key insights for our subsequent work with the University of Denver. First, there is a broad range of emissions pathways consistent with a given probability of achieving a temperature goal. We need to consider our carbon goals relative to this range and the uncertainties it represents, including uncertainties about policy, technology availability and reductions assumed to be achieved in sectors other than electricity. Second, we can choose to compare ourselves to pathways with higher likelihood of achieving temperature goals, as well as compare to Xcel Energy to sub-global pathways such as electric power sector emissions. However, in doing so, it is important to recognize the assumptions, challenges and uncertainties embedded in such an analysis and their implications for our goals.

Finally, many IPCC scenarios assume the availability of significant negative emissions after mid-century, in some cases offsetting emission increases in the near term, to achieve the temperature goal. This is particularly true of the 1.5 C scenarios. Because negative emissions electricity technologies are not commercially available today, to be conservative we compared ourselves only to carbon scenarios that do not include negative emissions technologies within the electric power sector in industrialized countries (but may include negative emissions in other regions and sectors.) If negative emissions electricity technologies become available, we would consider them along with other options for providing customers reliable, affordable clean energy. Because our analysis does not rely on these technologies to reach our goals, we plan to continue to reduce carbon emissions aggressively in the near term, consistent with cost (which is also influenced by need) as well as reliability.

Comparing Xcel Energy to the Paris Climate Agreement Goals

EPRI did not attempt to identify company-specific emission trajectories corresponding to the global temperature goals because of the increasing uncertainty at higher levels of resolution. However, investors and others routinely ask Xcel Energy to compare company-specific emissions to the temperature goals, so we needed to go a step further. We commissioned an analysis by experienced climate modelers at the University of Denver, including a lead author on the IPCC's forthcoming Sixth Assessment Report, to compare our goals to electric sector carbon dioxide emission scenarios consistent with limiting warming to both 2 C and 1.5 C. We provided the modelers our carbon emission forecast and goals, and had them compare these to electric sector carbon emission scenarios consistent with 2 C and 1.5 C. We set three constraints on their analysis:

- Focus on scenarios categorized by the IPCC as having a high probability of achieving the temperature goals
- Compare Xcel Energy to the electric power sector in industrialized countries
- Exclude scenarios that rely on negative emissions technologies within the electric sector

On pages 11 to 13, the University of Denver modelers summarize briefly their approach and findings.

Xcel Energy targets and limiting warming to less than 2 C and 1.5 C

By Dr. Brian O'Neill and Steve Hedden

Climate researchers have carried out a large number of studies of how much and how fast greenhouse gas emissions would have to be reduced in order to achieve the Paris climate targets of limiting warming to less than 2 C, or even to below 1.5 C. We drew on the results of those studies to compare Xcel Energy's emissions reduction goals to emissions pathways consistent with the Paris climate targets. In those pathways, global carbon emissions generally decline to zero (in net terms) by around 2070 or later to stay below 2 C and by around 2050 to stay below 1.5 C.

However, emissions associated with one company in one country are just a fraction of global emissions, so we compared Xcel Energy's goals to a more detailed and more relevant set of results from these studies: net carbon emissions from the electric power sector in industrialized countries. We found that Xcel Energy's goals represent reductions that are consistent with, and in most cases larger than, those that occur in this sector in scenarios that achieve the Paris climate targets.

Approach

The Intergovernmental Panel on Climate Change report from October 2018[8] assessed the scientific literature on emissions scenarios consistent with the Paris climate targets. To support that assessment, researchers created a database of 416 published emissions scenarios.[9] The scenarios were developed using computer models that calculate the greenhouse gas emissions and warming that would result from the production and consumption of energy, food, transportation and other goods in regions around the world over the coming decades. The future is uncertain, so these scenarios investigate a wide range of possibilities about how fast population, incomes and energy demand may grow and what kinds of climate policies may be pursued to achieve the Paris climate targets.

We compared the Xcel Energy goals to a subset of these scenario results. First, we selected two sets of global greenhouse gas emission scenarios from the database: those that would be likely (defined as having a greater than 66 percent chance) to stay below 2 C, and those that would be more likely than not (defined as having a greater than a 50 percent chance) to stay below 1.5 C or to only slightly (and temporarily) exceed that level.[10]

Next, we extracted results from these scenarios for carbon dioxide emissions from the electric power sector in industrialized countries.[11] These outcomes from the scenario database are the best comparison available to Xcel Energy goals. Models that produce emissions scenarios do not represent individual companies, nor even individual countries. Results are reported in the database as totals for groups of countries for different sectors of the economy. By using results for the electric sector in industrialized countries, we can compare Xcel Energy goals to emissions pathways that occur on average across the same sector of countries at similar levels of economic development to the United States.

Finally, we excluded scenarios in which net carbon dioxide emissions from the industrialized country electric sector are negative at any time in the future, through 2100. (Note that these scenarios could still include negative emissions in other sectors and regions.) In the electric sector, net negative emissions could result from technologies like biomass energy with carbon capture and storage (BECCS) that generate electricity while removing carbon from the atmosphere. Scenarios with these technologies often allow for higher global emissions in the first few decades that are compensated for by negative emissions later in the century. However, these technologies are unproven at large scales and involve possible risks to biodiversity and food prices due to the large amount of land that may be required for growing biofuels.

Our selection process left us with 17 scenarios consistent with the 2 C target and five scenarios consistent with the 1.5 C target, a reflection that achieving the lower target without net negative emissions in the electric power sector is relatively uncommon in the scientific literature.

Results

The comparison in Figure 4 shows that Xcel Energy's 2030 and 2050 goals represent emissions reductions that are larger than those that occur in the electric sector of industrialized countries in most of the global emissions scenarios likely to limit warming to below 2 C. Xcel Energy's goals are also within the range of reductions that occur in the limited number of scenarios achieving the 1.5 C target. These figures show scenario results to 2050. Beyond 2050, these scenarios generally indicate low or zero net carbon emissions continuing through the end of the century.

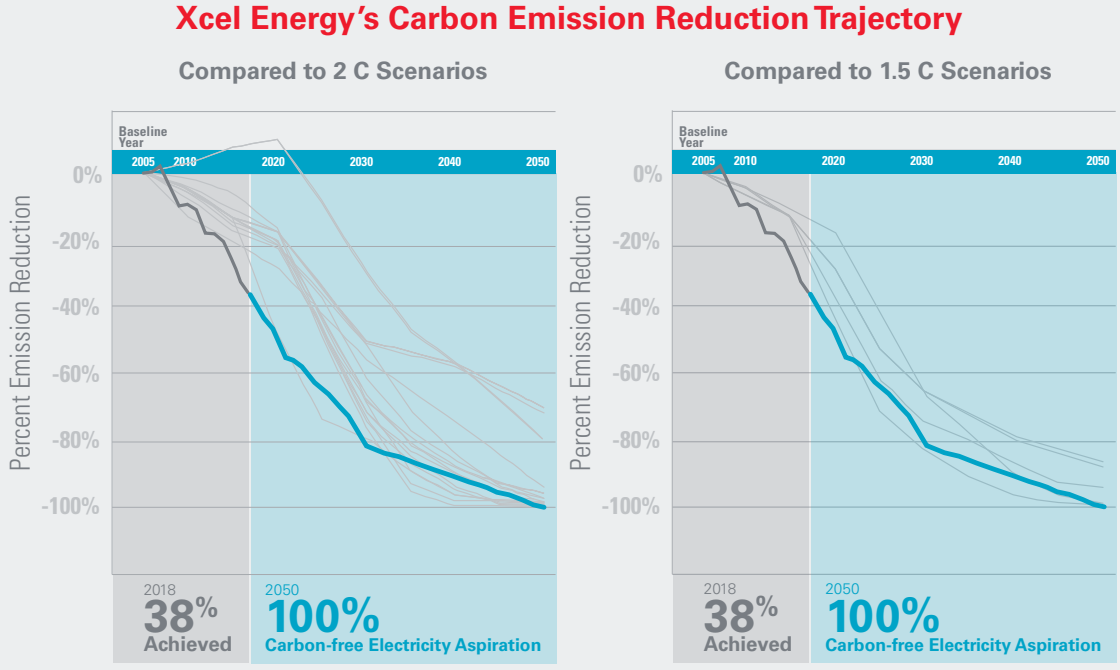


Figure 4: Xcel Energy carbon emissions reduction goals (in blue, with historical emissions in dark gray) compared to scenarios of emissions from the industrialized country electric power sector (in light gray). Emissions scenarios are from global scenarios likely to remain below 2 C warming (left) or more likely than not to avoid 1.5 C warming (right) without significantly exceeding that level. Emissions expressed as a percent reduction relative to levels in 2005.

Caveats to this analysis

To date, most company-level greenhouse gas scenario analysis has focused on 2 C rather than 1.5 C, in part because of the much greater uncertainty about the attainability of limiting warming to 1.5 C. The IPCC notes that limiting warming to 1.5 C may involve unprecedented actions.[12] Without taking a position on the attainability of 1.5 C, in this analysis we have assessed Xcel Energy's goals in relation to both temperature goals. We have chosen to include the 1.5 C scenarios because while that goal is unquestionably harder to attain than 2 C, experience shows that the scale and pace of technological change often outpaces our expectations today. Because of this — and because the IPCC Special Report makes clear that climate risks and damages, while not zero at 1.5 C, are substantively less than at 2 C — we believe it makes sense to include it in our analysis.

Any multi-decade analysis of company- or sector-level carbon dioxide emission trajectories relative to the global temperature goals involves inherently uncertain assumptions about economic growth, technologies, policy and global coordination or lack thereof. If those assumptions are not borne out — e.g., technologies do not develop as expected, economic growth is more carbon intensive than assumed, emission reductions (or negative emissions) assumed to occur in other sectors or regions do not materialize, etc. — then the industrialized country electric sector emissions consistent with a given probability of achieving the temperature goals could change.

We have endeavored to make conservative assumptions in this analysis. For example, we focus only on scenarios with relatively high likelihoods of achieving the temperature goals and exclude scenarios that rely on net negative emissions technologies within the electric sector. Also, we examined our conclusions to ensure that they do not change fundamentally when varying key assumptions, such as allowing net negative emissions in the electric sector, and that they do not rely on unreasonably large assumed reductions in other regions. For a fuller discussion of these issues, see our full report.[13]

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Our Conclusions on the Analysis

Participating in the EPRI research, and subsequently engaging University of Denver climate modelers to compare our carbon vision against the Paris climate targets, helped to validate that our goals are consistent with electric sector emissions in scenarios likely to achieve the targets. Our goal to reduce carbon emissions 80 percent by 2030 and aspiration to serve customers with carbon-free electricity by 2050 appear largely consistent with the industrialized country electric sector carbon reductions in scenarios that achieve the Paris climate targets, even acknowledging the many uncertainties and embedded assumptions in any such analysis.

More specifically, Figure 4 shows that our carbon dioxide reductions achieved to date (shown by the dark gray line) fall below all the scenarios corresponding to a high probability of achieving the 2 C and 1.5 C goals. Our trajectory from today to 2030 falls below all but one of the scenarios for both temperature goals. Our aspiration for 2050 lies well within the range of emission scenarios for both temperature goals. In addition, we note that our carbon dioxide emission reduction trajectory from 2030 to 2050 is represented as a simple straight-line projection since we have no resource plans that extend to 2050. Our actual reductions will not likely follow that smooth line and depending on cost and technology developments, and the future of our nuclear plants, could either decline or increase from the line in any given year.

Any climate scenario analysis has embedded assumptions and necessary simplifications. For our analysis, these include:

- Our actual carbon emissions will depend on our resource mix, renewable energy and natural gas prices, total load, degree of electrification of end uses currently reliant on other fuels, and many other factors. We typically run sensitivities for these and many other variables in our resource plans.

- Depending on the amount of electrification assumed, a very low-carbon electric power sector may enable significant greenhouse gas reductions in transportation, buildings and other sectors. Our strategy contemplates significant electrification of the economy. The scenarios shown here virtually remove carbon from the electric sector, but there could be scenarios in which it is cost effective for the electric sector to emit slightly more carbon while reducing carbon in other sectors and still achieving the economy-wide reductions necessary for the temperature goals.
- The cost effectiveness of any greenhouse gas reduction pathway depends to some extent on climate policy, which is not addressed here. If adopted, climate policy frameworks will determine costs to our customers, flexibility in achieving greenhouse reductions, and linkages to or coordination with other emitting sectors. Xcel Energy will continue to advocate for climate strategies that achieve greenhouse gas reductions at the lowest possible cost to customers while maintaining reliability. Since many IPCC scenarios envision significantly increased electricity use in transportation, buildings and industry in order to achieve economy-wide reductions, keeping electricity affordable will be crucial.
- The achievability and cost effectiveness of any greenhouse gas goal will also depend on how technology evolves, which we cannot predict for 2050 or even 2030. Our carbon transition will depend on a mix of renewable energy, energy storage, carbon-free dispatchable technologies and flexible demand that could enable us to achieve deep carbon reductions affordably and reliably.

Reporting and **Measuring Progress**

As an energy provider, we emit greenhouse gases as we provide electricity to our customers. The primary source of these emissions is from the combustion of fossil fuels to generate electricity, which makes up 99 percent of our total greenhouse gas emissions. Nearly all of our generation-related emissions are carbon dioxide. Because of this, it makes sense that we focus our strategy, goals and reporting on reducing carbon emissions.

The carbon emissions discussed in this report and other Xcel Energy reporting are from electric generating plants that we own and from electricity that we purchase from others. Xcel Energy sells a small portion of the electricity we generate into the market, and the carbon emissions from these off-system sales are excluded from our goal and goal reporting because the energy does not serve our customers. Also, it is likely that many companies purchasing the energy account for the emissions in their reporting, so including them in our reporting could result in double counting.

Our goal to reduce carbon emissions 80 percent by 2030 is based on absolute, company-wide emissions from the electricity that serves our retail and wholesale customers, measured from a 2005 baseline. Likewise, our aspiration to serve customers with carbon-free electricity by 2050 is company-wide.

Xcel Energy supports timely, transparent public reporting of carbon dioxide and other greenhouse gas emissions. Our comprehensive greenhouse gas reporting, from all parts of our business, is based on The Climate Registry and its Electric Power Sector Protocol, which aligns with the World Resources Institute and ISO 14000 series standards. Our company joined The Climate Registry as a founding member in 2007 to help establish a consistent and transparent standard for calculating, verifying and reporting greenhouse gases. Through The Climate Registry, we annually third-party verify, register and publicly disclose our greenhouse gas emissions.

Managing the Risks Associated with **Climate Change**

Over the next several decades as we make our carbon transition, we will continue to monitor and take steps to mitigate any risks along the way. Changing weather patterns, extreme weather conditions and other events, such as flooding, droughts, wildfires and snow or ice storms, can all impact our system in terms of system operability, customer demand, revenues, cost recovery and the health of regional economies.

We rely on routine business processes to identify and address these types of risks and emerging challenges. These include our risk management, resource planning and daily operations, as well as our continuous improvement and innovation initiatives.

Integrated Risk Management

Our integrated, multi-disciplinary risk management process creates accountability for managing risk across the company — from employees who are responsible for business compliance and adhering to our Code of Conduct, to senior executives and the board of directors who oversee risk management. Annually, executive leadership conducts a key risk assessment, considering materiality, timing and likelihood and controllability of risks. Management also identifies and analyzes risk through its business planning process and development of goals and key performance indicators, which include risk identification to determine barriers to implementing our strategy. While the assessment is broad, it includes the operational, policy and weather-related risks potentially associated with climate change. Findings are presented to the board of directors, which assigns oversight of critical risks among the board's four standing committees to ensure they are well understood and managed on an ongoing basis. We provide more information on our risk management process, including discussion of climate-related risks, in Xcel Energy's annual form 10-K.

Resource Planning

Our resource planning process is designed to manage capital-intensive investments over decades-long time horizons. Through this regulated process, we evaluate a range of scenarios and stress test our energy portfolio against important variables, including fuel prices, renewable energy and storage costs, transmission constraints and a variety of others. We use load forecasts to account for changing weather patterns, a key variable in explaining actual loads and in forecasting future loads. Load forecast sensitivities can also ensure our portfolio is sufficient to meet different needs created by electrification, which is likely to become more prevalent in a carbon-constrained future. Our resource planning also considers the costs and risks of potential carbon regulation and potential damages from climate change by applying a carbon proxy, allowing regulatory costs, and in some cases, externality damages to be considered in selecting resources.[14]

Operations

Maintaining reliable and resilient operations across generation, transmission and distribution means we constantly prepare for the unexpected. We use a suite of techniques to maintain a resilient system from water management to emergency preparedness. For example, our Monitoring and Diagnostics Center watches the operation of major generating units in real time, identifying potential issues before they occur. We also have predictive analytics and software tools that help avoid plant failures and can even address issues which may result in higher emissions or compromise reliability. Further, we have specific procedures in place to deal with extreme weather, flooding, drought or other conditions that may impact the operability of our plants. To better understand and address climate-related vulnerabilities on our system, we joined the Department of Energy's Partnership for Energy Sector Climate Resilience to work with others in the industry.

A Focus on Grid Resiliency

We continually invest and innovate to maintain and improve the resiliency of our energy grid. The following are several highlights from the many programs we are implementing to address potential system risks.

Under our Advanced Grid Intelligence and Security (Advanced Grid) program, we are upgrading the energy grid to better serve customers and enhance our ability to efficiently restore power and improve reliability. The program builds a platform that provides enhanced visibility and control of the energy grid through the integration of modern information system technology and traditional distribution systems.

In addition to maintaining emergency plans at all of our power plants and planning for extreme weather, we are also focused on successfully managing major storm events, responding quickly and providing information to customers as we restore service. The Edison Electric Institute has recognized Xcel Energy multiple times with its Emergency Recovery Award for outstanding storm response. These efforts extend beyond our service territory, with our crews on standby to help with recovery efforts across the country when hurricanes or other natural disasters strike.

To better integrate high levels of renewable energy, we have deployed sophisticated modeling tools to better dispatch our system. Working with the National Center for Atmospheric Research and its affiliate company Global Weather Corp., we helped develop the Wind WX system that utilities around the globe now use to make better commitment and dispatch decisions. It uses real-time, turbine-level operating data and applies sophisticated algorithms to forecast the amount of wind power that will be produced. Forecasts for a 168-hour period are provided every 15 minutes across Xcel Energy's entire service territory. As we integrate more solar on our system, we are working on similar innovations for solar forecasting.

Our vegetation management program is generally performed on a four- to five-year cycle for our distribution and transmission lines. In Colorado, we have established a Mountain Hazard Tree Program that helps us stay ahead of the tree mortality caused by Mountain Pine Beetles.

Since we provide electricity in drought-prone areas, water is a precious resource that we must carefully manage. A co-benefit of our transition to renewable energy is that we are also lowering our water footprint. Beyond this, we have a comprehensive water management program to minimize the risks of continued water usage, including innovative partnerships to access water during extreme drought periods. For example, we use treated effluent to cool power plants in Texas and New Mexico. This effluent is water that would otherwise not be used and is available during drought.

Opportunities to Lead the **Carbon Transition**

Utilities can play a key role in helping solve the challenges of climate change. According to the Energy Information Administration, the electric power industry collectively reduced carbon emissions 28 percent from 2005 to 2017.[15] This includes Xcel Energy's progress — having reduced emissions 38 percent already, we have plans underway to achieve more, as explained in this report.

As an industry leader in renewable energy and reducing carbon emissions, we have a strategic advantage in continuing to lead this transition. We have been able to provide scalable solutions to reduce the carbon footprint of the energy we provide, while continuing to deliver energy in a manner that is safe, reliable and affordable. As we continue to implement solutions to address emissions across our system, we can also provide customers with options to reduce their carbon emissions and help other sectors reduce carbon through strategic electrification.

Investing for the Future to Reduce Emissions

We must achieve our carbon transition while maintaining a modern, viable electric system, which is dependent on our ability to attract capital and investors. Transitioning to cleaner sources of energy to achieve our carbon reduction goals should consider utility ownership of replacement resources, as we need our investors to support this transition. Our capital plans also envision the need for additional transmission and advanced grid technology. By investing in these assets, we can improve service to our customers, introduce new options and support greater reliability and flexibility in the way energy is delivered. This financial component is important to our plans.

Xcel Energy operates in regions with some of the best wind and solar resources in the United States, and we are capitalizing on this. Our Steel for Fuel strategy calls for adding renewable resources at a net savings because the capital costs of projects are more than offset by future avoided fuel costs. Customers benefit from the clean energy that also helps to keep their electricity bills low.

These renewable projects are just one component of the resource plans that determine new investments. Through the resource planning process with state regulators, we develop comprehensive, cost-effective plans to transform our system, serve customers and advance our transition to clean energy.

Empowering Customers to Reduce Carbon Emissions

We know customers want cleaner energy and more renewable options, but also expect electricity that is affordable and reliable. The great advantage of our system-wide clean energy transition is that all customers are receiving lower-carbon electricity over time — our reductions are their reductions — at an affordable cost.

Some of our customers — from residential customers to corporations and cities — desire to go further faster, accelerating the system transition by setting goals to meet up to 100 percent of their own demand with renewable electricity or to reduce their overall emissions. To meet this demand from customers, we provide an increasing array of voluntary renewable choice products, including cost-effective options to procure up to 100 percent renewable electricity and a comprehensive portfolio of industry-leading energy efficiency programs.

Through our 2030 and 2050 carbon reduction vision, we can further help customers achieve their goals. They will continue to reduce the portion of emissions from their electricity consumption, while we transition our overall system to a diverse mix of cost-effective, low-carbon and carbon-free generation resources.

In addition, we expect that our planned investments in technologies to modernize the energy grid will enable us to deliver new solutions for customers and create a flexible energy grid that allows for two-way power flows from customer-connected devices or distributed energy resources.

Electrification of our Economy

As the nation's electricity supply becomes cleaner, attention has increasingly turned to other sectors of the economy to address climate change.

The transportation sector is now the nation's leading source of greenhouse gas emissions according to the Energy Information Administration.[16] This also applies to the states Xcel Energy serves. For example, data from Minnesota indicates transportation has surpassed electricity as the leading carbon emitter, and that carbon emissions from transportation are declining far slower than electricity — a clear indicator of the opportunity for transportation electrification.[17]

We believe that strategic electrification of certain end uses will be a key component — though not the only solution — for achieving economy-wide greenhouse gas reduction goals. If we continue to electrify transportation and power vehicles with carbon-free electricity by 2050, we can help address the climate challenge for that sector.

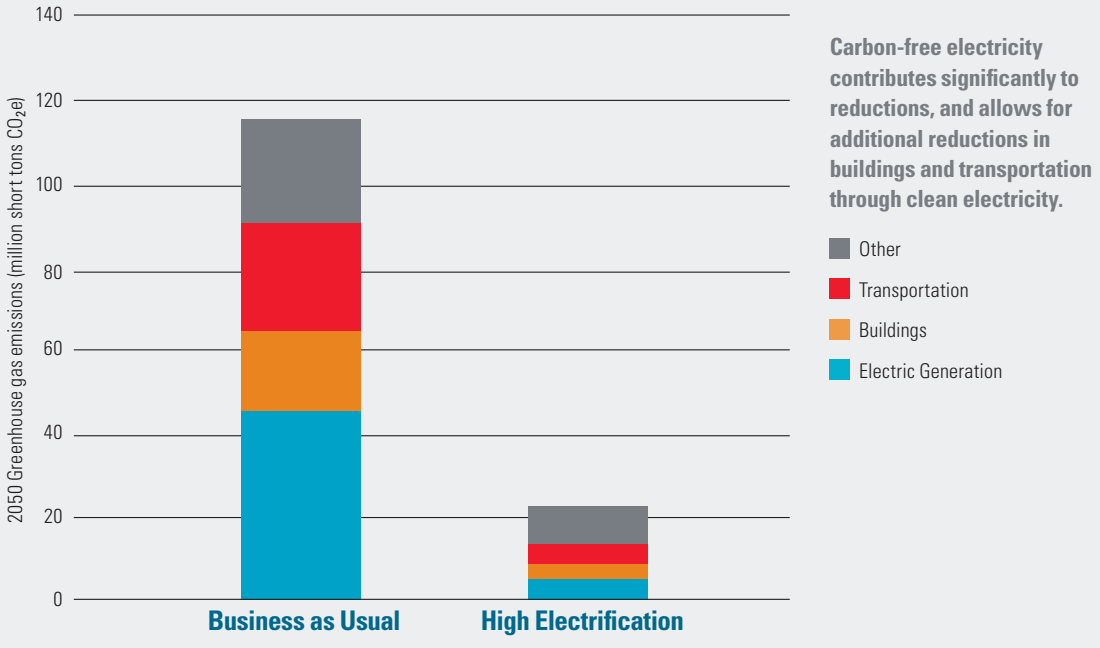
Low-carbon electricity and electrification: a Minnesota example

Removing carbon from electricity and electrifying other parts of the economy can be mutually reinforcing. Low-carbon electricity allows transportation, buildings and other major emitting sectors to reduce emissions. At the same time, flexible loads, such as electric vehicles and appliances that can charge at times of high renewable generation, may allow us to integrate more renewable resources than we could otherwise.

Xcel Energy engaged Energy+Environmental Economics (E3) to explore the feasibility of deep carbon reductions, both for the Xcel Energy system and for Minnesota statewide. E3 created a Minnesota PATHWAYS model looking at how the state could achieve its statutory economy-wide goal to reduce greenhouse gas emissions 80 percent from 2005 levels by 2050, with a primary focus on electricity, transportation and buildings.

The chart below illustrates this potential, focusing on 2050. It compares a business-as-usual scenario in which carbon is not reduced from electricity, and there is little or no electrification of other sectors, to what could be achieved in a "high electrification" scenario designed to meet the state's economy-wide 80 percent reduction goal. In this scenario, virtually all vehicles, space heating and water heating switch to electric alternatives by 2050. To supply these new loads, total statewide electricity demand in 2050 is 60 percent higher than 2015. Meanwhile, the electric sector reduces carbon, supplying over 90 percent carbon-free electricity in 2050. As a result, direct carbon emissions from electricity are reduced by about 40 million tons, as shown by the blue bars. Emissions from buildings, transportation and other sectors also decrease dramatically, with electrification enabling 35 million tons of that reduction through low-carbon electricity. Just as electricity is an essential service, natural gas service is as well, as it plays a critical role in keeping our customers comfortable and safe. When we review these options, we need to keep the affordability of space heating a primary objective along with the affordability of our electric business.

Carbon Reductions in the Electric Sector Drive Compounding Reductions throughout the Economy



Credit: Energy+Environmental Economics.

Xcel Energy's Electric Vehicle Strategy

The future of transportation is dramatically changing to include more electric-powered transportation options than ever before — as well as more autonomous features in vehicles and new (often shared) mobility services. Utilities are uniquely positioned to work with customers, communities and electric vehicle (EV) stakeholders to ensure this change benefits all customers, the environment and the energy grid that we all rely upon.

Through our current EV strategy, we are focused on:

- Making it easier for customers — from individual households to public and private sector fleets — to adopt EVs
- Creating the infrastructure needed to charge EVs
- Establishing time-varying rates and technological controls to ensure that EVs can charge as much as possible on low-cost, low-carbon energy

While EVs create a significant opportunity for drivers and fleet operators to save on fuel and other costs, barriers exist to wider-scale adoption, such as customer awareness, high up-front costs and the availability of charging infrastructure. Our plans will help overcome these barriers by developing new services, piloting them and then rolling out our most successful ideas to customers on a broader scale.

In Minnesota, we are engaging customers who are interested in adopting electric vehicles and buses. We hope to better understand their needs and barriers to adoption so we can work collaboratively toward solutions that could benefit all customers down the road. We expect these discussions will provide opportunities for us to pilot a variety of solutions that will inform our stakeholders and policy makers so we can scale solutions best suited to benefit all Minnesotans in the coming years.

As we pursue our EV Plan, we are focused on these objectives:

- Empower customers with information, tools and options
- Increase access to electricity as a transportation fuel in an equitable manner
- Encourage efficient use of the power grid and integrate renewable energy
- Improve air quality and decrease carbon emissions
- Ensure reliability, interoperability and safety of equipment
- Leverage public and private funding opportunities
- Provide benefits to all customers, both EV drivers and non-EV drivers
- Ensure transparency and measure results

Driving **Change**

By mid-century, we aspire to serve customers with carbon-free electricity. Even though this goal is decades away, we are a long lead time business and should begin now to identify and address the barriers to reaching it — especially if we are to maintain the affordable, reliable service that customers need and expect.

After reviewing national and international studies on climate change and through our going work with stakeholders, we believe reducing carbon emissions reliably and affordably is a top priority and must be the primary focus of our clean energy transition. To effectively achieve this shared objective, we must remain disciplined and concentrate on those efforts that produce the greatest carbon reductions at the lowest cost to customers.

We are optimistic that by staying focused we can make this transition and have identified the following drivers that will make the change possible:

- Protect energy reliability and affordability
- Support from our states and stakeholders
- A constructive policy environment and framework
- Availability of cost-effective, carbon-free dispatchable technologies

While our vision is ambitious, we believe these drivers implemented together will make it possible to transform our operations and the industry overall. Our plan is to continue working proactively and collaboratively in all these areas and to advance the solutions that emerge.

Protect Energy Reliability and Affordability

Cost is a major consideration for our clean energy strategy, and so far, we have successfully reduced carbon emissions while keeping energy costs low for customers. In fact, the average Xcel Energy residential customer electric bill has decreased 3 percent in the past five years. Our residential electric bills are on average about $28 lower per month than the national average. In our largest service territories, Minnesota and Colorado, customer electric bills are 22 percent and 36 percent below the national average respectively. We must continue to develop and invest in cost-effective transformative plans and in technologies with proven economic value for customers.

Energy reliability is also a fundamental requirement. Today, we are achieving far greater levels of renewable energy on our system than the industry ever believed possible. There are hours on our system when renewable generation delivers more than 50 percent of customers' electricity, and at the end of 2018, we achieved an hourly renewable generation record of 72 percent on our Colorado system. We expect these hourly records to increase under our current plans, we project that renewables will generate almost half of our power on an annual basis by 2021. As we deploy more renewable energy resources, managing the stability and reliability of the energy grid becomes increasingly difficult with fewer resources that can be dispatched to manage the variability of wind and solar energy. We will be focused on how to make sure that we take care to have sufficient resources to meet swings in load and generation as our integration of more renewable energy becomes more challenging.

Support from our States and Stakeholders

By working with the states we serve, we have successfully executed our clean energy strategy and plans.

Our four operating companies work under regulated conditions largely determined by state public utilities commissions. Every few years, we go through a process to determine the resources necessary to serve customers' future energy needs. This state resource planning process is critical to ensuring reliable energy and maintaining reasonable customer bills. Our carbon vision is not a single resource plan. Implementing our clean energy transition and achieving our goals will happen through many iterations of resource planning before our state utilities commissions between now and 2050.

Stakeholder participation is an important component to resource planning, and stakeholder support is essential to our clean energy progress. We will continue constructive engagement with our customers, investors, regulators, environmental groups, community leaders, policy makers and others to develop solutions and implement plans to achieve our goals.

We believe this model of state leadership can go even further in driving cost-effective emission reductions and clean energy investment. If advanced, federal policy should encourage utilities to work with states and invest as the conditions are right — when customers and the economics and technology are ready and without imposing significant, unnecessary costs on utility customers.

A Constructive Policy Environment and Framework

We are proving that the vertically integrated utility model with regulatory oversight is a cost-effective way to transition the energy system and achieve significant carbon reductions. This model provides inherent system value through efficiency, optimization and economies of scale that benefit all customers. It also balances the allocation of risks and benefits between the utility, its customers and even different customer classes.

Every customer on the energy grid shares in the transition to clean energy and can credibly claim the same carbon reduction. Policies that enable large businesses to sign direct contracts with renewable developers, may help individual companies to achieve their goals. However, they do not provide all customers with affordable, carbon-free energy and may even result in a more expensive energy system overall.

We have seen remarkable examples of the transformation that is possible and know from experience that our ambitious carbon transition is achievable if stakeholders and policy makers continue to recognize the economic and environmental benefits that utilities provide. As we continue this transition and go above and beyond in reducing carbon emissions, there may be opportunities to provide appropriate incentive to encourage and reward the industry's progress toward carbon reductions economy-wide.

Large-scale, universal resources — conventional, renewable and advanced — are by far the most cost-effective electricity generating resources available. While distributed energy resources are important for customers who want to invest in them and may play important roles at the distribution system level, these resources cannot accomplish what large-scale resources do in terms of carbon reduction at scale. Public policy should recognize the economic benefits that large, universal resources provide to achieve our ambitious goals affordably and reliably for customers. Hidden and unfair subsidies to support high-priced resources only serve to increase the cost of clean energy and reduce the ability of the nation to make this transition.

Similarly, nuclear generation plays a vital role in our carbon transition and provides a significant portion of our carbon-free energy in the Upper Midwest. We need policies at the state and federal levels that allow us to continue the cost-effective operation of these important assets at least through the end of their current operating licenses.

We must also address emissions from fossil plants, especially from our remaining coal generation. We need policies that support coal operations which reduce emissions and offer investment recovery for the remaining value of coal plants which retire early. We also need help to minimize the impact on communities that depend on these plants.

All of these resources belong to the larger energy grid, which is enabling our carbon transition. As stewards of the grid, utilities own, operate and maintain this asset; raise and deploy capital to finance its growth and operation; and work with regulators to manage the risks associated with investments made on behalf of customers. Regulatory policy should ensure utilities continue to perform these critical functions to maintain the reliability, security and resilience of the energy grid during this transition.

Availability of Cost-effective, Carbon-free, Dispatchable Technologies

New cost-effective technologies have enabled our company and industry's progress in transitioning the nation's generating fleet and reducing carbon emissions. For at least the next decade, existing wind, solar, battery and natural gas technologies will continue to serve a growing portion of our energy needs while reducing carbon emissions and saving our customers money.

However, renewable generation and storage alone face significant technical and economic challenges if relied on exclusively to achieve carbon-free electricity. For example, the relatively short duration energy storage available today and anticipated in the future does not address seasonal challenges that arise when a system dependent on renewable resources experiences several days or weeks with low wind or solar generation. Even with continually declining prices, variable wind and solar resources are expected to provide diminishing value at high saturations. Fully relying on renewable sources could result in a costly overbuilding of the system where each incremental megawatt provides less capacity value, renewable curtailments reach high levels and massive investments in transmission and storage are required.

We need a suite of new, carbon-free resources that can be dispatched to complement our continued adoption of renewable energy, energy efficiency and demand response. Our research shows that these new resources will be the key to achieving a carbon-free generation fleet without a costly overbuilding of the energy grid. Others studying this issue have reached similar conclusions, including the MIT Energy Initiative, Energy+Environmental Economics and Vibrant Clean Energy.[18] These technologies may include carbon capture and storage, power to gas, seasonal energy storage, advanced nuclear or small modular reactors, deep rock geothermal and others not yet imagined.

Each of these options holds promise, but they will require considerable investment and further research and demonstration to become viable solutions at the cost and scale at which the electric sector will need them. Federal and state policies must support this development. We can also send clear signals to the market around price, capabilities and timing for when these technologies will be needed. In this way, utility resource plans provide the market signal — the "technology pull" — from which the private sector and national laboratories and federal agencies can align their investments, research and assets.

Conclusion

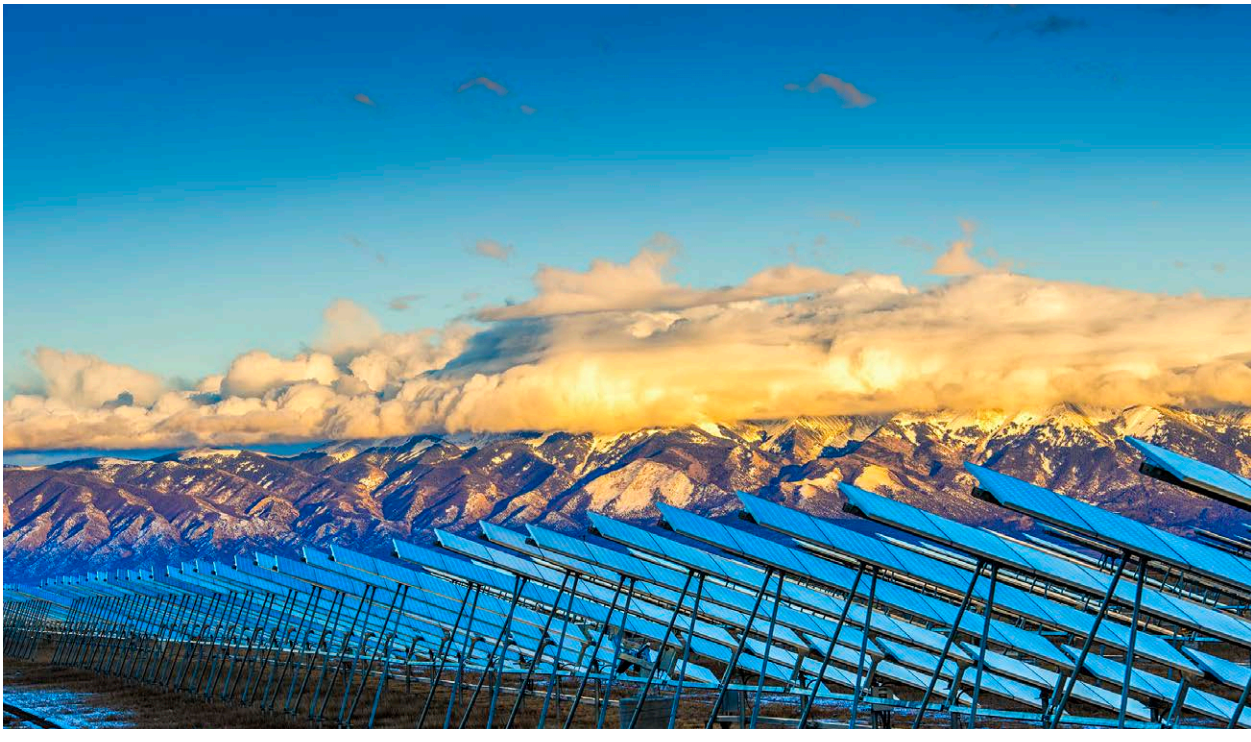
The finish line is clear — we aim to serve all customers by 2050 with carbon-free electricity. Through our analysis with the University of Denver, we are confident that both our interim and 2050 goal are the right goals for our customers but also to help limit warming to 2 C and possibly even 1.5 C.

Our vision is just the start. We will begin work now even though 2050 is decades away. Today, the technology and market exists to reach our interim goal and reduce carbon emissions 80 percent by 2030, but significant changes are needed to achieve reliable, affordable carbon-free electricity to serve our customers. We look to our partners to help us drive the advancements in technology and constructive policy to make it happen. While there may be differences of opinion around the details of how we get there, we are all in the same race together to reduce and eventually eliminate carbon.

Reducing carbon emissions should be the ultimate and shared objective. We must remain focused on this outcome and the drivers that will get us there as efficiently and cost effectively as possible.

As we work to make this vision possible, we will position our company and customers for success in a low-carbon future and provide greater long-term value for all stakeholders. We believe we can manage both the risks and capture the opportunities presented by this transition, and in the end, provide what our customers and other stakeholders want and need from us.

We are optimistic that through collaboration and with ingenuity and innovation, we will realize our vision for a carbon-free energy future.



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1 A summary of the Paris climate agreement, ratification status and text of the agreement are available at https://unfccc.int/process-and-meetings/the-paris-agreement/the-paris-agreement.

2 IPCC Special Report, Summary for Policymakers, page SPM-4.

3 IPCC Special Report, Summary for Policymakers, pages SPM-15 to SPM-24, and EPRI analysis of IPCC Special Report.

4 U.S. Global Change Research Program, Volume II: Impacts, Risks, and Adaptation in the United States - Report-in-Brief. Chapter 29, Reducing Risks through Emissions Mitigation, page 168. Available at https://nca2018.globalchange.gov.

5 EPRI is a non-advocacy, nonprofit, scientific research organization with a public benefit mandate. See http://eea.epri.com/ and www.epri.com/sustainability to learn more about EPRI's efforts to better understand the technical dimensions of company climate scenario analysis and GHG goal setting.

6 EPRI focused on the 2 C goal because the IPCC's AR5 database is the largest source of peer-reviewed scenarios available with over 1,000 scenarios. The IPCC Special Report on Global Warming of 1.5 °Celsius, and accompanying emission scenario database, were not available at the time EPRI began its work. As discussed in the EPRI study, 2 C pathways are extremely challenging — geophysically, technologically, economically, and politically — which creates uncertainty about their attainability. Uncertainty about the attainability of 1.5 C pathways is even greater.

7 Negative emissions technologies include biomass energy with carbon capture and storage, large-scale afforestation, direct air capture or other technologies yet to be developed. All face significant technology, cost, land use and social constraints at present.

8 IPCC, 2018: Global warming of 1.5°C. An IPCC Special Report on the impacts of global warming of 1.5°C above pre-industrial levels and related global greenhouse gas emission pathways, in the context of strengthening the global response to the threat of climate change, sustainable development, and efforts to eradicate poverty [V. Masson-Delmotte, P. Zhai, H. O. Pörtner, D. Roberts, J. Skea, P.R. Shukla, A. Pirani, W. Moufouma-Okia, C. Péan, R. Pidcock, S. Connors, J. B. R. Matthews, Y. Chen, X. Zhou, M. I. Gomis, E. Lonnoy, T. Maycock, M. Tignor, T. Waterfield (eds.)]. In Press. Hereafter, "IPCC SR 1.5 C."

9 Huppmann, D. et al. IAMC 1.5°C Scenario Explorer and Data hosted by IIASA. Integrated Assessment Modeling Consortium & International Institute for Applied Systems Analysis, 2018. doi: 10.22022/SR15/08-2018.15429 | url: data.ene.iiasa.ac.at/iamc-1.5c-explorer.

10 These categories follow the grouping used in the IPCC report in ref. 1. The lower likelihood of achieving the target in the 1.5 C case (50 percent) is used because of the difficulty of achieving it with higher likelihood. "Slightly exceeding" the target is defined as staying below 1.6 C.

11 We use the phrase "industrialized countries" to refer to the region defined in the IPCC database as "OECD90+EU," which contains countries that were members of the OECD as of 1990, as well as current EU member countries and candidates. Note this does not include Russia and other members of the Former Soviet Union (the "REF" region in the database). Specific countries included are: Albania, Australia, Austria, Belgium, Bosnia and Herzegovina, Bulgaria, Canada, Croatia, Cyprus, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Japan, Latvia, Lithuania, Luxembourg, Malta, Macedonia, Montenegro, Netherlands, New Zealand, Norway, Poland, Portugal, Romania, Serbia, Slovakia, Slovenia, Spain, Sweden, Switzerland, Turkey, United Kingdom, United States of America.

12 See IPCC Special Report, Summary for Policymakers, page SPM-21: "Pathways limiting global warming to 1.5°C with no or limited overshoot would require rapid and far-reaching transitions in energy, land, urban and infrastructure (including transport and buildings), and industrial systems (high confidence). These systems transitions are unprecedented in terms of scale, but not necessarily in terms of speed, and imply deep emissions reductions in all sectors, a wide portfolio of mitigation options and a significant upscaling of investments in those options (medium confidence)… The rates of system changes associated with limiting global warming to 1.5°C with no or limited overshoot have occurred in the past within specific sectors, technologies and spatial contexts, but there is no documented historic precedent for their scale (medium confidence)."

13 Xcel Energy carbon emissions targets and limiting warming to less than 2 degrees C. Brian O'Neill and Steve Hedden, December 31, 2018. Frederick S. Pardee Center for International Futures - Josef Korbel School of International Studies at the University of Denver.

14 Under integrated resource planning statutes in Minnesota, utilities must apply both a range of proxy prices for future carbon dioxide regulatory costs, and ranges for externality damages for carbon dioxide and other pollutants. Under Colorado public utilities commission rules, utilities apply carbon dioxide regulatory costs; there is no general requirement to apply carbon dioxide externality values, but Xcel Energy in its latest Electric Resource Plan cycle was ordered to include a sensitivity using an externality value.

15 See https://www.eia.gov/todayinenergy/detail.php?id=37392.

16 See https://www.eia.gov/totalenergy/data/monthly/, Environment section, and compare tables 12.5 and 12.6. Transportation CO_2 emissions surpassed electricity in 2016 and remained higher in 2017 and the first nine months of 2018.

17 Minnesota Pollution Control Agency, January 2019. Greenhouse gas emissions in Minnesota: 1990-2016. Page 6. Available at https://www.pca.state.mn.us/sites/default/files/lraq-2sy19.pdf.

18 Sepulveda, Jenkins et al., "The Role of Firm Low-Carbon Resources in Deep Decarbonization of Power Generation," Joule, November 2018, available at https://doi.org/10.1016/j.joule.2018.08.006; Jenkins, Luke and Thernstrom, "Getting to Zero Carbon Emissions in the Electric Power Sector," Joule, December 2018, available at https://doi.org/10.1016/j.joule.2018.11.013; Energy+Environmental Economics, "Deep Decarbonization Scenarios in Minnesota – Minnesota PATHWAYS: Updated Results," October 23, 2018 Xcel Energy Upper Midwest Integrated Resource Plan stakeholder workshop; Vibrant Clean Energy, "Minnesota's Smarter Grid: Pathways Toward a Clean, Reliable and Affordable Transportation and Energy System," August 2018, available at https://www.vibrantcleanenergy.com/media/reports/.

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APPENDIX F1 – LOAD AND DISTRIBUTED ENERGY RESOURCE FORECASTING

I. LOAD FORECAST METHODOLOGY

This Appendix discusses the methodology we used in conjunction with this Resource Plan to forecast customer need, including the requirements specified in Minn. R. 7610.0320. We also note that, while this Appendix documents our load and energy demand forecasting process, we have taken additional steps with respect to the treatment of energy efficiency (EE) forecasting in this Resource Plan, to model it as a supply-side resource. Where relevant, we include explanations of these steps in order to provide transparency, and explain how this base forecast correlates to the load and energy demand forecasting discussed in Chapter 3: Minimum System Needs, and Appendix F2: Strategist Modeling Assumptions and Inputs.

The Company relies on econometric models and other statistical techniques to develop the sales forecast. The econometric models relate our historical electric sales to demographic, economic and weather variables. We develop sales forecasts for each major customer class, in each state of our service area. The individual class forecasts for each state are summed to derive a total system sales forecast.

We convert the sales forecast into energy requirements at the generator level by adding energy losses. The forecasted losses are based on forecasted loss factors, which are developed using actual historical loss factors and are held constant over the forecast period. We develop the peak demand forecast using a regression model that relates historical monthly base peak demand to energy requirements and weather. The median energy requirements forecast and normal peak-producing weather are used in the model to create the median base peak demand forecast. We provide a detailed discussion of the forecast methodology later in this Appendix.

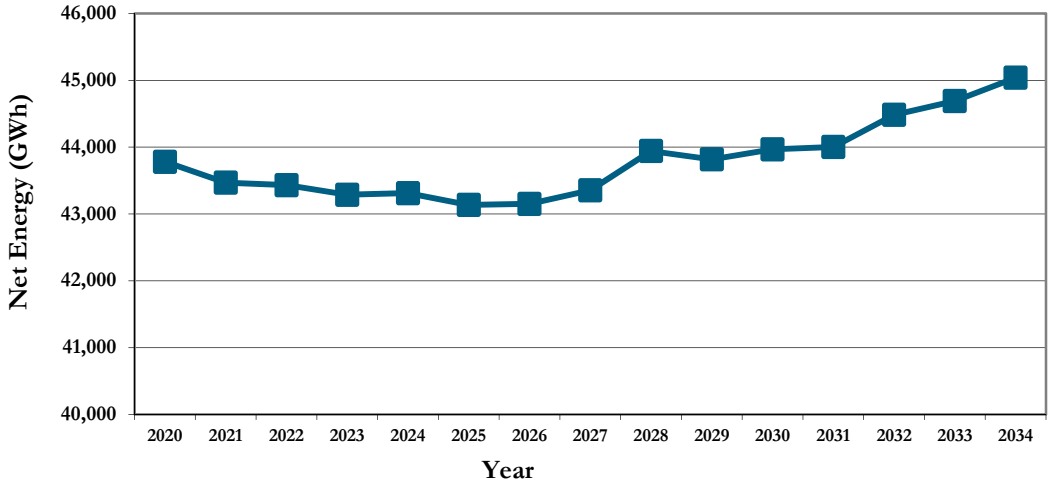
The forecasts are based on projections of economic activity for our various service areas provided by IHS Global Insight, Inc. (Global Insight). Global Insight projects continued growth in key economic indicators. For example, for the Minneapolis-St. Paul metropolitan area, households are expected to increase at an average annual rate of 0.8 percent during the 2020-2034 planning period. Real personal income is expected to increase 0.8 percent per year on average, and employment is expected to gain an average of 0.2 percent per year. Minnesota real gross state product is expected to increase at an average annual rate of 1.8 percent.

A. Energy Forecast

1. Base Forecast Methodology

The base energy forecast increases at an average annual growth rate of 0.2 percent over the 2020 – 2034 planning period, net of the 1.5 percent energy savings level approved in the Company's last Resource Plan, forecasted distributed solar, and electric vehicle charging projections. Electric energy requirements are expected to increase at an annual average of 90 gigawatt-hours (GWh), starting with 43,781 GWh in 2020 to 45,038 GWh in 2034. See Figure 1 below.

Figure 1: NSP System Total Median Net Energy (GWh)
(Includes 1.5 Percent EE Adjustment)



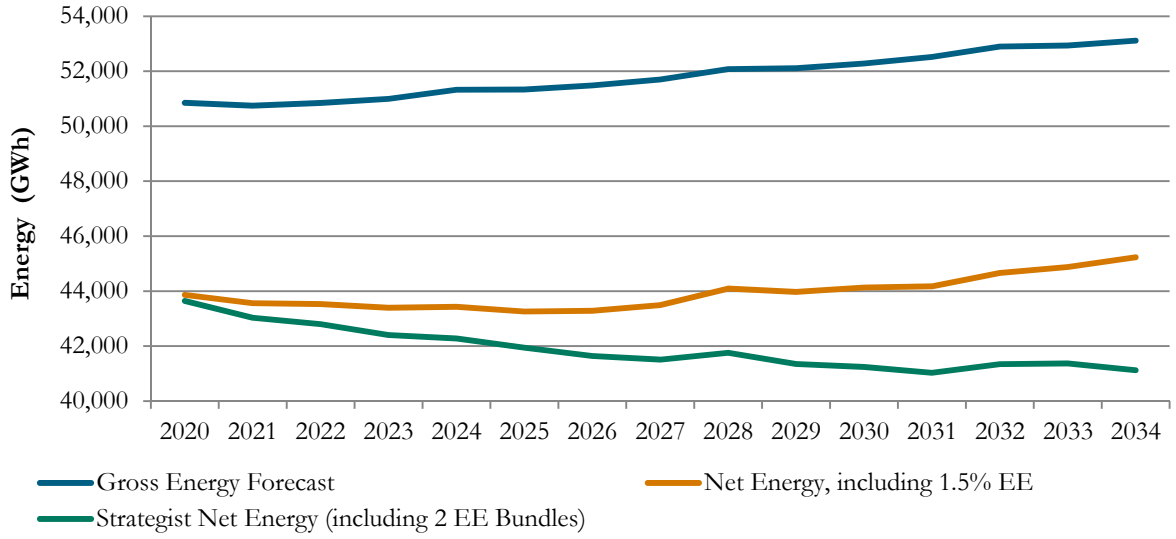
The projected 0.2 percent average annual growth in electric energy requirements is stronger than the actual growth seen over the past few years. After adjusting for unusual weather, electric energy requirements decreased at an average annual rate of *negative* 0.3 percent from 2014 to 2017.

2. Modifications for Use in Strategist

As noted in Chapter 3: Minimum System Needs, we undertook additional steps to allow EE to be modeled as a supply-side resource. This required that we adjust the base energy forecast (discussed in Part 1 above) to remove the embedded EE adjustment that projects the effects of 1.5 percent energy savings to the end of the Planning Period. This resulted in an NSP System Gross Energy Requirements forecast. In a separate process, we formulated annual EE savings amounts into

"Bundles" that we made available in the Strategist model along with other supply-side resources used to model EE as a supply-side resource in Strategist. We show these adjustments in Figure 2 below.

Figure 2: Gross Energy Requirements Forecast Compared to Net Energy Requirements Forecast



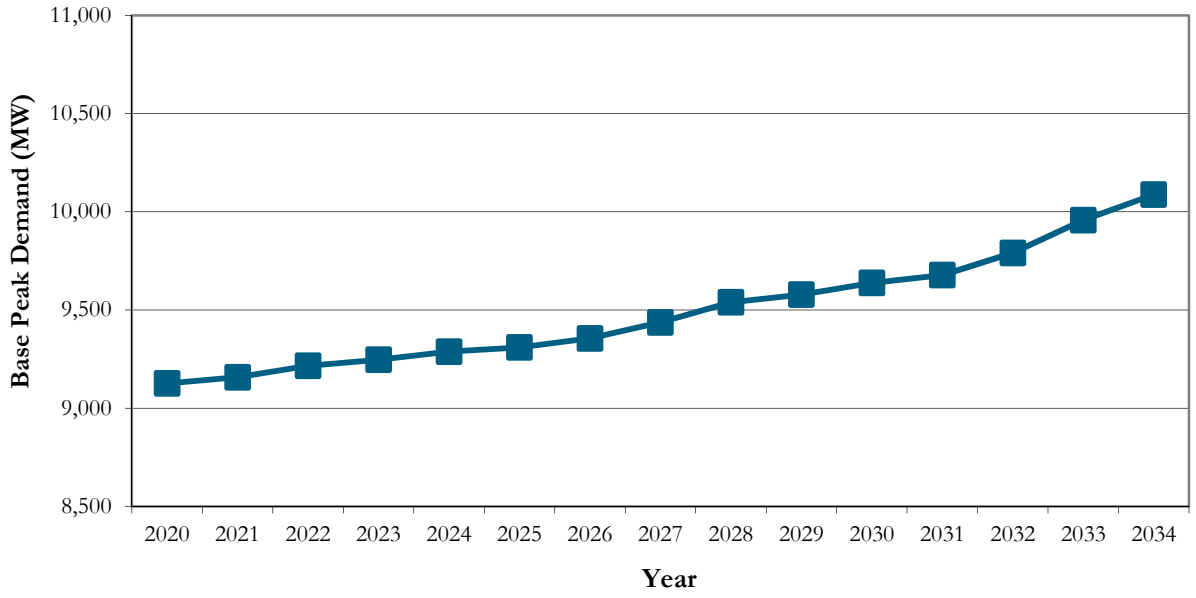
We discuss the EE Bundle modeling further in Appendix F2: Strategist Modeling and Appendix F6: Resource Options.

B. System Peak Demand Forecast

1. Base Forecast Methodology

During the 2020 – 2034 planning period, the median base peak increases at an average annual growth rate of 0.7 percent. As demonstrated in Figure 3 below, annual peak demand increases at an average of 69 MW each year, starting with 9,126 MW in 2020 to 10,087 MW in 2034.

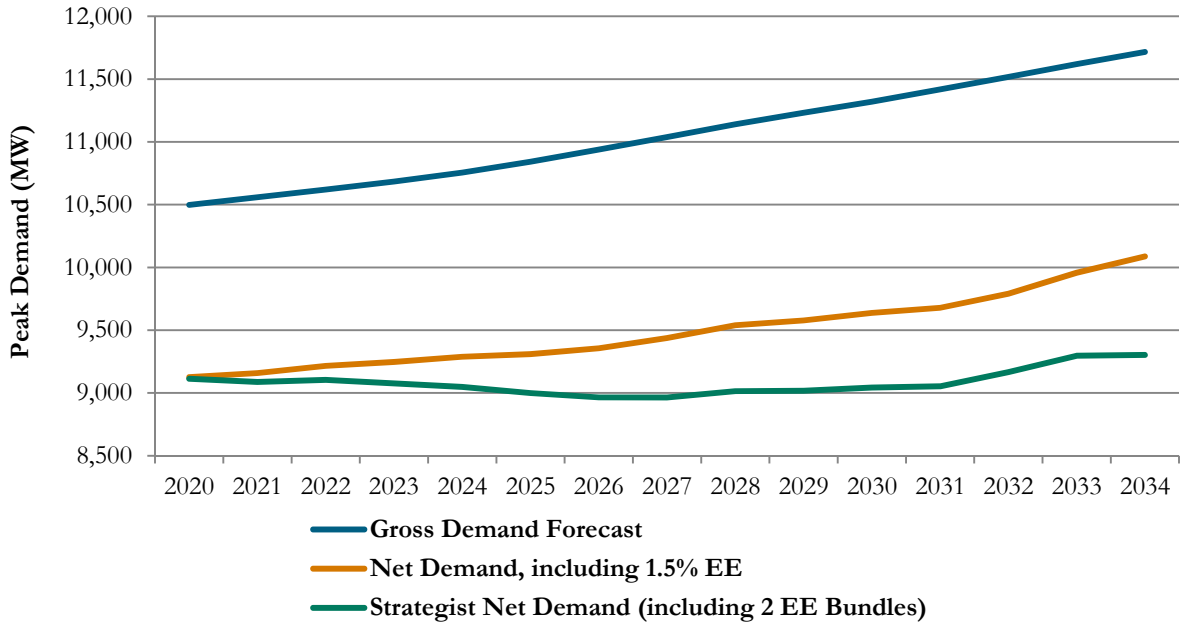
Figure 3: NSP System Median Base Summer Peak Demand (MW)
(Includes 1.5 Percent EE Adjustment)



2. Modifications for Use in Strategist

For modeling demand levels in Strategist, we took the same approach as noted in reference to the energy forecasts. Again here, for Strategist modeling purposes, we start with the base forecast and remove 1.5 percent EE adjustment in order to reflect gross load. This process enables us to model the system considering EE as a supply-side resource.

Figure 4: Gross Peak Demand Forecast Compared to Net Peak Demand Forecast



The balance of this Appendix discusses the energy and peak load forecasting methodologies, assumptions, analytics, adjustments, etc. to derive the System Energy Forecast presented in Part A.1 and Figure 1 above and the System Base Peak Demand Forecast presented in Part B.1 and Figure 3.

C. Key Demand and Energy Forecast Variables

Below we discuss some of the key variables that are included in the 2019 Resource Plan forecasts.

1. Demographics

Demographic projections are essential to the development of the long-range forecasts. The consumption of electricity is closely correlated with demographic statistics. The number of residential customers, weather data and economic indicators are key variables in the residential energy sales forecast. Over 99 percent of the variability in historical electric residential customer counts in our service territory can be explained through an econometric model that contains either population or households as key drivers. The forecasts for population and households are provided by Global Insight.

We forecast an average annual growth rate for total residential customers on our system of 0.6 percent, with the addition of 10,246 residential customers on average per year from 2020 through 2034.

2. Economic Indicators

Xcel Energy uses estimates of key economic indicators to develop electric sales forecasts. These variables include gross state product, employment and real personal income. The variables used are specific to the jurisdiction and are statistically significant in the sales models for the residential and commercial and industrial customer classes. Growth in electric energy consumption in the residential and commercial and industrial sectors closely follows trends in economic activity. Global Insight provided the economic forecasts used in our regression models.

For the planning period, the economy is expected to continue to grow, resulting in growth in electric energy consumption.

3. Weather

The peak demand for electric power is heavily influenced by hot and humid weather. As the temperature and humidity rise, the demand for cooling rises steeply. Our approach to forecasting peak demand includes using a weather variable that consists of the mean of an index of heat and humidity referred to as the temperature humidity index (THI). Simply stated, the THI is an accurate measure of how hot it really feels when the effects of humidity are added to the high temperature.

We have tracked the THI at the time of the system peak demand over the past 20 years. Because of the 20 years of smoothing, the weather variable does not drastically affect our median forecasts; however, it becomes a key factor in assessing the potential peak demand if and when hot and humid weather extremes are encountered. Since Xcel Energy must have adequate generating resources available during hotter than normal circumstances, planning for the extreme is important.

D. Forecast Methodology

Xcel Energy serves customers in five jurisdictions in the upper Midwest: Minnesota, North Dakota, South Dakota, Wisconsin and Michigan. We develop a forecast for each major customer class and jurisdiction using a variety of statistical techniques.

We first develop our system sales forecasts by using a set of econometric models at

the jurisdictional level for the Residential and Small Commercial and Industrial sectors for all jurisdictions, the Large Commercial and Industrial sector for Minnesota, and the Minnesota Public Street and Highway Lighting and Public Authority sectors. These models relate our historical electric sales to demographic, economic and weather variables as detailed in the prior section of this document.

For the remaining customer classes, Large Commercial and Industrial, Public Street and Highway Lighting, and Public Authority in all states but Minnesota, and Interdepartmental, we use trend analysis and customer specific data. We compile our system sales by summing the individual forecasts for each sector in each jurisdiction.

Since some energy is lost, mostly in the form of heat created in transmission and distribution conductors, we use loss factors to convert the sales forecasts into energy production requirements at the generator. The forecasted loss factors are developed using actual historical loss factors and are held constant over the forecast period.

We have developed a regression model to relate Xcel Energy's historical uninterrupted monthly peak demand to energy requirements and weather at the time of the peak in the winter and summer seasons. The median energy requirements forecast (50/50 forecast) and normal peak-producing weather are used in the model to create the peak demand forecast. (*Note*: Section II of this Appendix contains a comprehensive summary of the regression modeling process utilized to develop the energy and demand forecasts.)

Once the NSP System peak demand forecast is complete, a forecast is developed for the NSP System demand coincident with the Midcontinent Independent System Operator (MISO) system peak demand. The coincident demand forecast is developed using a regression model that determines the relationship between the NSP System demand coincident with the MISO peak demand and the NSP System peak demand (not coincident with the MISO peak demand). MISO only requires an annual coincident demand forecast for the next planning year. The current resource plan forecast is for the NSP System demand coincident to the MISO annual peak demand during the 2019-20 planning year (June 2019 – May 2020).

E. Forecast Adjustments

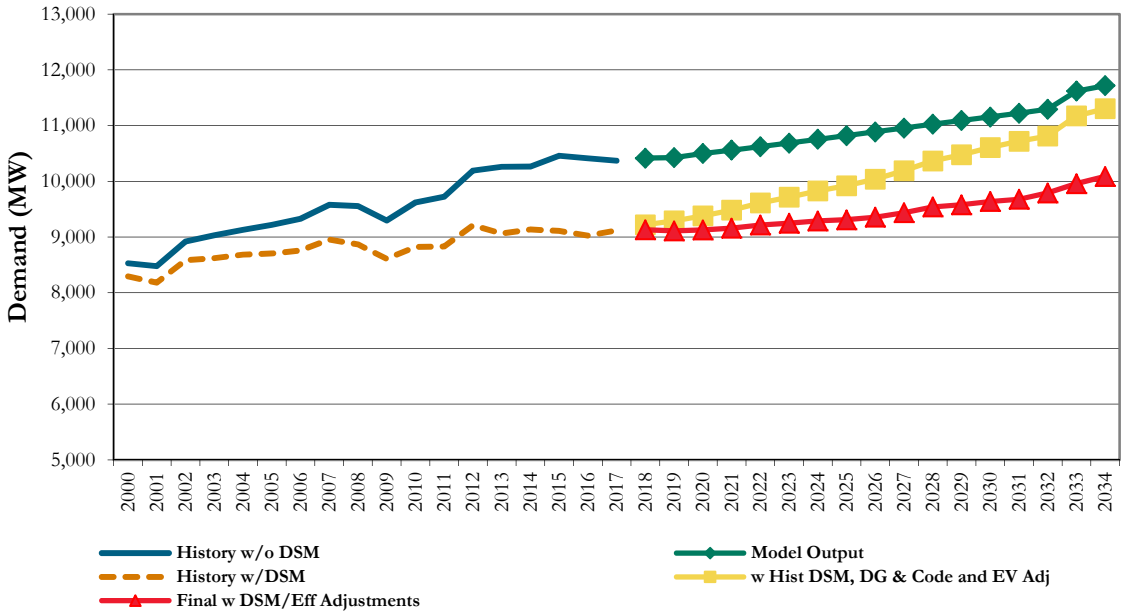
Our demand and energy forecasts are developed using a number of key forecast variables as described in this Appendix. One important adjustment to the forecasts is to take into account our conservation programs.

The EE methodology implemented for the State of Minnesota uses the same method for projecting the impacts of EE and its load management effects on the sales forecast as was used in our 2015 Resource Plan filing. There are three distinct steps to this process:

- Collect and calculate historical and current effects of EE on observed sales
- Project the forecast using observed data with the impact of EE removed (i.e. increase historical sales to show hypothetical case without EE)
- Adjust the forecast to show the impact of all planned EE in future years.
- Also adjust the forecast to account for codes and standards changes resulting in decreased sales that are in addition to Company-sponsored EE.

These EE adjustments are based on the Company's current Triennial Plan goals, which were based on the savings level approved in the resource planning process. The Commission approved an average annual energy savings level of 444 GWh for all planning years in our 2015 Resource Plan in Docket No. E002/RP-15-21.[1] Figure 5 below graphically illustrates the EE adjustment.

Figure 5: Illustration of EE Adjustment – NSP System Demand (MW)



For the State of South Dakota, the impacts from all conservation program

[1] *See* Order, Ordering Point No. 11 (January 11, 2017).

installations prior to 2018 are assumed embedded in the historical demand and energy data at a rate equal to the annual program installations from 2013 through 2017. To accurately predict future supply needs, the energy and demand forecasts must be reduced by an estimate of the incremental future conservation savings. For the base forecast, we adjust the demand and energy forecast by assuming all future annual conservation achievement equal to achievement of our 2018 goal as approved in the 2016 South Dakota DSM Status Report and 2018 DSM Plan filing (Docket No. EL17-019).

In response to the establishment of a Solar Energy Standard (SES) by the Minnesota Legislature, an increased emphasis has been placed on distributed solar generation. We developed a forecast of the expected impact on demand and energy based on new programs designed to meet goals established for the SES. We adjusted the Minnesota class-level sales forecasts and the system peak demand forecast to account for the impacts of customer-sited behind-the-meter solar installations on the NSP System. We discuss the distributed solar forecast methodology below.

After determining the base forecast, we develop net forecasts that include all adjustments, including future EE, distributed solar generation, electric vehicle charging, and the effects of our EE programs over time.

F. Additional Forecast Adjustments

We made additional adjustments to the energy and demand forecasts to account for expected changes in specific large customers' electricity usage. These additional adjustments include:

- Customers adding self-generation combined heat and power capabilities, which reduce energy consumption and peak demand,
- Increases or reductions in usage due to new customers in our service territory, or planned expansions or reductions of load by existing customers, and increasing use of plug-in electric vehicle charging, which we discuss in Part II.D below.

G. Forecast Variability

As with any forecast, our forecasts of energy requirements and peak demand depend on other forecasts of key variables. Changes in these variables will affect our forecasts. For instance, if the number of households in our service territory is lower than Global Insight has predicted, electric consumption in the residential sector will

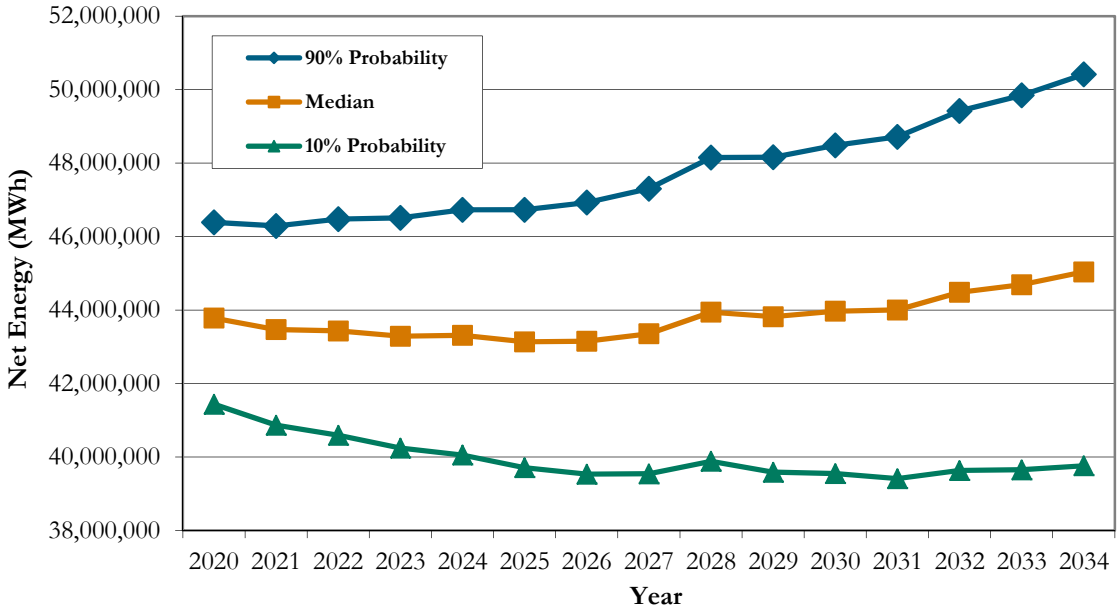
be lower. The peak demand for electric power each year is very sensitive to weather conditions and can vary considerably as the result of abnormal weather conditions.

Other forecast uncertainties include potential increases in loads due to new customers and potential losses in loads due to changes in customers' operations. For example, the potential exists for large increases in loads in the middle of the planning period due to increased mining activities in Northern Wisconsin. However, at this time there is still uncertainty around this potential increase and, therefore, we have not made an adjustment to the forecast.

Given that there is uncertainty in any long-term forecast, we supplement the median forecasts with forecasts developed using statistical techniques to reflect the potential variability in energy requirements and peak demand. These probability distributions were developed using a Monte Carlo stochastic simulation of peak demand (MW) and a simulation of energy (MWh). For example, the peak demand simulation involved taking 10,000 random draws from the weather probability distributions as well as 10,000 random draws from the 12-month sum of the energy probability distribution. The random draws produce 10,000 forecasts of peak demand and thus generate a probability distribution around the mean peak demand. We provide a more detailed description of the probability distribution methodology in Section II, and discuss summary results below.

The probability distributions developed for this forecast yielded a 90 percent probability that the net energy will be less than 50,416,762 MWh in 2034 – or alternatively, there is a 10 percent probability that the net energy will be less than 39,760,413 MWh. See Figure 6 below.

Figure 6: NSP System Total Net Energy (MWh)
(Includes 1.5 Percent EE Adjustment)



Figures 7 and 8 below show the higher and lower variations of the 2020 to 2034 long-range forecasts of base and net summer peak demand. [2]

[2] Where net summer peak demand includes adjustments form the base forecast to account for interruptible load.

Figure 7: NSP System Total Base Summer Peak Demand (MW)
(Includes 1.5 Percent EE Adjustment)

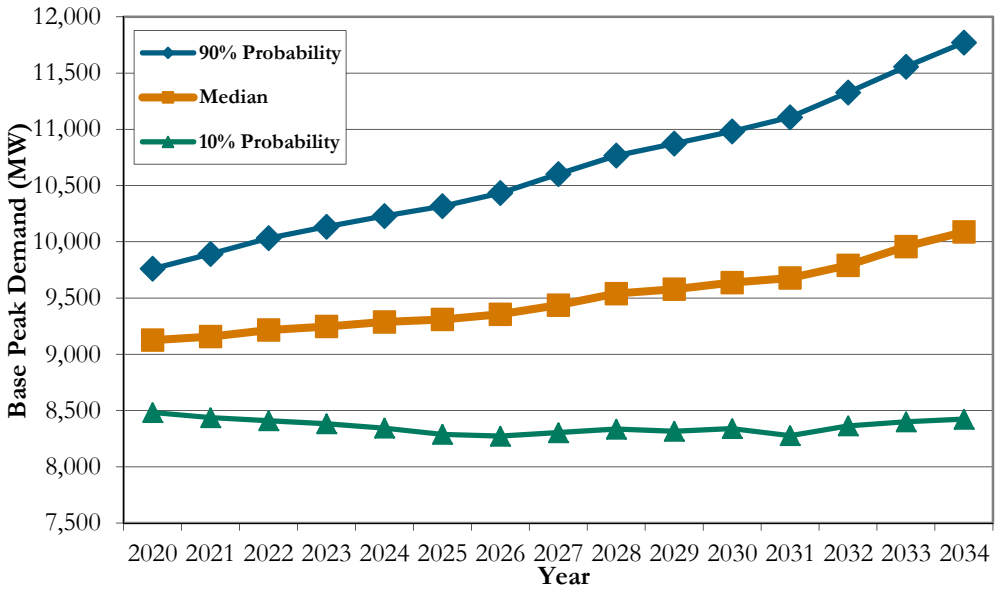
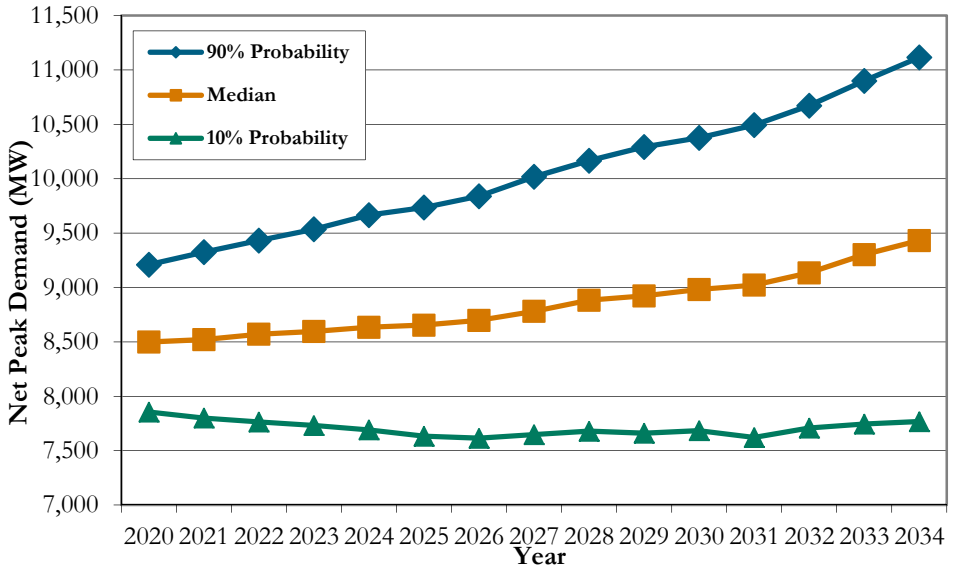


Figure 8: NSP System Total Net Summer Peak Demand (MW)
(Includes 1.5 Percent EE Adjustment)



Tables 1, 2, and 3 below provide the data underlying Figures 6, 7, and 8, respectively.

Table 1: Annual Net Energy (MWh)

(Including 1.5 Percent EE Adjustment)

Year	90% Probability	Median	10% Probability
2020	46,387,135	43,780,715	41,434,501
2021	46,289,330	43,467,677	40,864,878
2022	46,475,233	43,430,233	40,590,345
2023	46,508,251	43,287,395	40,240,549
2024	46,727,937	43,311,190	40,052,004
2025	46,728,197	43,135,149	39,706,759
2026	46,927,693	43,150,544	39,530,565
2027	47,302,668	43,354,456	39,539,672
2028	48,151,679	43,942,185	39,881,494
2029	48,158,669	43,817,294	39,583,487
2030	48,484,779	43,967,558	39,546,151
2031	48,714,578	44,001,712	39,410,068
2032	49,421,682	44,482,912	39,632,078
2033	49,845,815	44,689,679	39,649,954
2034	50,416,762	45,038,288	39,760,413
Average Annual Growth 2020 - 2034	**0.6%**	**0.2%**	**-0.3%**

Table 2: Annual Base Summer Peak Demand (MW)

(Includes 1.5 Percent EE Adjustment)

Year	90% Probability	Median	10% Probability
2020	9,761	9,126	8,483
2021	9,892	9,158	8,437
2022	10,032	9,216	8,409
2023	10,134	9,247	8,383
2024	10,229	9,288	8,344
2025	10,317	9,309	8,288
2026	10,433	9,356	8,272
2027	10,602	9,437	8,303
2028	10,766	9,539	8,334
2029	10,873	9,578	8,316
2030	10,982	9,638	8,340
2031	11,107	9,678	8,277
2032	11,327	9,791	8,364
2033	11,556	9,958	8,400
2034	11,771	10,087	8,423
Average Annual Growth 2020 - 2034	**1.4%**	**0.7%**	**-0.1%**

Table 3: Annual Net Peak Demand (MW)
(Includes 1.5 Percent EE Adjustment)

Year	90% Probability	Median	10% Probability
2020	9,210	8,498	7,855
2021	9,325	8,520	7,800
2022	9,432	8,571	7,764
2023	9,535	8,596	7,731
2024	9,666	8,635	7,691
2025	9,736	8,654	7,633
2026	9,839	8,698	7,614
2027	10,018	8,781	7,647
2028	10,166	8,883	7,679
2029	10,292	8,922	7,660
2030	10,376	8,982	7,684
2031	10,493	9,022	7,621
2032	10,671	9,135	7,708
2033	10,900	9,302	7,745
2034	11,115	9,432	7,767
Average Annual Growth 2020 - 2034	**1.3%**	**0.7%**	**-0.2%**

H. Forecast Vintage Comparison

As described above, projections of energy and demand are fundamental to identifying the need for resources to meet expected customer needs. Thus, these forecasts are an important component in determining the size, type and timing of new generation resources. As a result, ensuring robust forecasts with fully analyzed assumptions and variables is a key component to supporting a Resource Plan or resource acquisition.

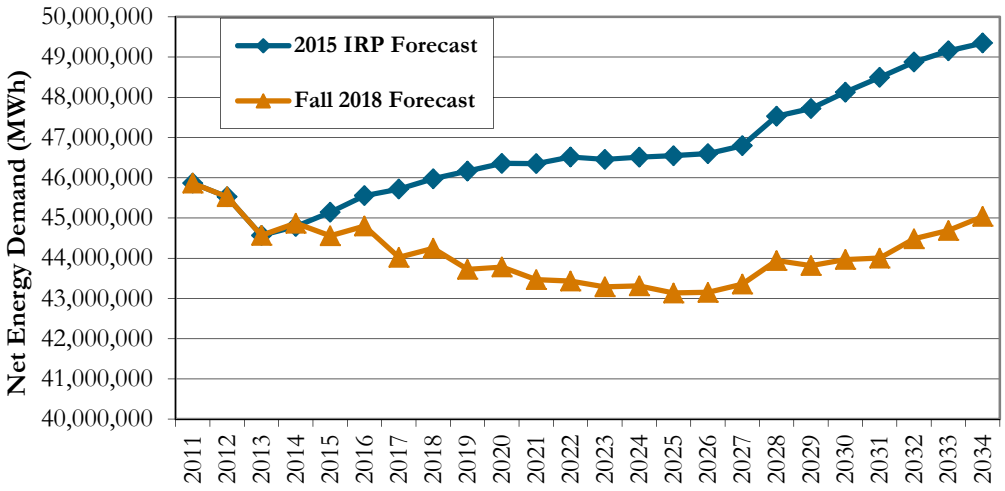
1. Forecast Vintage and Comparison

The review process for a Resource Plan or a resource acquisition typically takes a significant amount of time and effort to complete. During this time, forecasts can change as economic conditions, business operations, and technology changes occur. The graphs below compare the peak demand and energy of the Company's current forecast with the forecasts filed 2015 Resource Plan.

Figure 9 below indicates that the Fall 2018 energy forecast is lower than the Fall 2014 forecast provided in our 2015 Resource Plan due to lower and declining actual sales in 2015, 2016, and 2017. In particular, 2015-2017 weather normalized actual sales were lower for the NSPM residential sector and the NSPM small and large commercial and industrial sectors. In the residential sector, while the actual number of customers was slightly higher than estimated in the Fall 2014 forecast, the larger driver of the weaker-than-expected sales was lower use per customer. The NSPM small commercial and

industrial sector also experienced lower-than expected use per customer. The NSPM large commercial and industrial sector was projected to grow in the Fall 2014 forecast, but actual sales declined due to customers installing combined heat and power plants and loss of other load to locations outside Xcel's service territory.

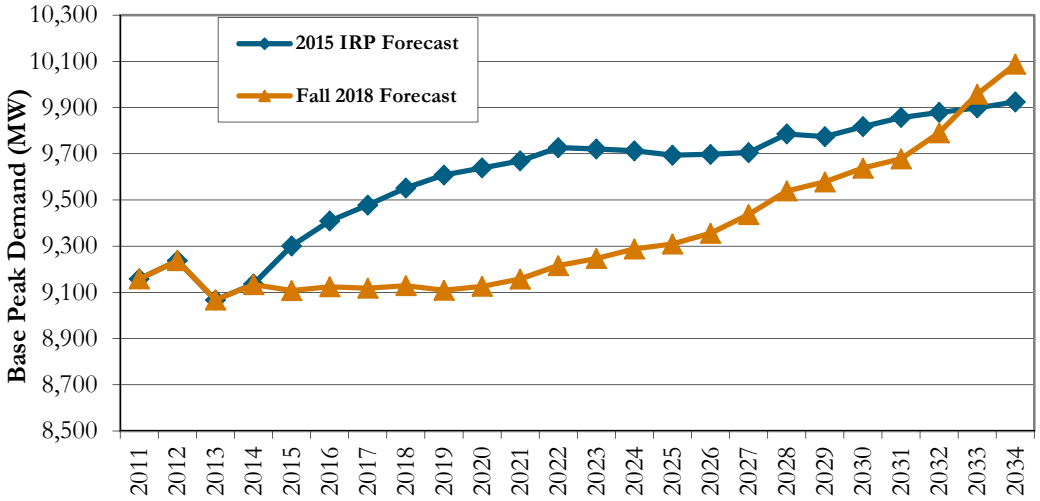
Figure 9: Net Energy Requirements (MWh) – Comparison of Current and Previous Energy Forecast
Median (50th Percentile) Forecast



In addition, the projected rate of growth of key economic indicators is lower now than when the Fall 2014 forecast was produced. For example, the average annual growth rate during the planning period for Minnesota real personal income is 1.8 percent, compared to a projected 3.6 percent in the Fall 2014 forecast. As another example, the average annual growth rate during the planning period for Minneapolis-St. Paul total employment is 0.4 percent, compared to the projected 1.1 percent in the Fall 2014 forecast.

Figure 10 below shows a comparison of the base peak demand forecast to the Fall 2014 forecast. Similar to the energy forecast, the current demand forecast is lower than the Fall 2014 forecast underlying the 2015 Resource Plan for most of the planning period. While actual sales from 2011 to 2017 have trended downward, the NSP system peak demand has remained fairly flat, but well below the Fall 2014 forecast. The current forecast calls for peak demand to increase and surpass the Fall 2014 forecast as energy gains turn positive in the outer years of the planning period.

Figure 10: Base Peak Demand (MW) – Comparison of Current and Previous Demand Forecast
Median (50th Percentile) Forecast



II. OVERALL METHODOLOGICAL FRAMEWORK

In this Section, we outline the technical details regarding our forecast, consistent with the requirements of Minn. R. 7610.0320.

Xcel Energy prepares its forecast by major customer class and jurisdiction, using a variety of statistical and econometric techniques. The NSP System serves five jurisdictions: Minnesota, North Dakota and South Dakota are served by Northern States Power Company, a Minnesota corporation (NSPM); Wisconsin and Michigan are served by Northern States Power Company, a Wisconsin corporation (NSPW). The overall methodological framework is "model oriented." The NSPM and NSPW Systems operate as an integrated NSP System. The forecast is referred to as the 2018v2.1 Forecast (August 2018).

A. Specific Analytical Techniques

1. Econometric Analysis

Xcel Energy uses econometric analysis to develop jurisdictional MWh sales forecasts at the customer meter for the following sectors:

a) Residential without Space Heating;
b) Residential with Space Heating;

c) Small Commercial and Industrial;
d) Large Commercial and Industrial (Minnesota);
e) Public Street and Highway Lighting (Minnesota);
f) Other Sales to Public Authorities (Minnesota).

Xcel Energy also uses econometric analysis to develop the total system MW peak demand forecast.

2. Trend Analysis

Trend analysis is used for the "Other" sectors, which include Public Street and Highway Lighting (all states except Minnesota), Other Sales to Public Authorities (Michigan, North Dakota and Wisconsin), Interdepartmental sales (Michigan, Minnesota and Wisconsin), and Large Commercial and Industrial (Michigan, North Dakota, South Dakota, and Wisconsin).

3. Loss Factor Methodology

Loss factors by jurisdiction are used to convert the sales forecasts into system energy requirements (at the generator).

4. Judgment

Whenever possible, Xcel Energy uses quantitative models to structure its judgment in the forecasting process. However, judgment is inherent to the development of any forecast. The sales forecasts are estimates of MWh levels measured at the customer meter. They do not include line or other losses. The various jurisdictional class forecasts are summed to yield the total system sales forecast. Native energy requirements are measured at the generator and include line and other losses. Xcel Energy creates native energy requirements based on the sales forecasts.

A system loss factor for each jurisdiction, developed based on average historical losses, is applied to the jurisdictional sales forecast to calculate total losses. The sum of the jurisdictional MWh sales and losses equals native energy requirements. The native energy requirements, along with peak producing weather and binary variables, are then used as independent variables within an econometric model to forecast MW peak demand for the NSP System.

B. Models Used

1. Residential Econometric Models

Sales to the residential sectors represent 29.7 percent of total NSP System electric retail sales in 2018. Residential sales are divided into with space heating and without space heating customer classes for each jurisdiction. Regression models using historical data are developed for each residential sector. A variety of independent variables is used in the models, including:

- Number of customers;
- Real Personal Income for respective jurisdiction;
- Employment for the respective jurisdiction;
- Gross State Product for respective jurisdiction;
- Actual heating and temperature humidity index (THI) degree days;
- Number of monthly billing days.

2. Small Commercial and Industrial Econometric Models

The small commercial and industrial sector represents 43.7 percent of NSP System electric retail sales in 2018. The models are regressions using historical data. The models include a combination of variables, including the following:

- Number of small commercial and industrial customers;
- Gross State or Metro Product for respective jurisdiction;
- Employment for respective jurisdiction;
- Real Personal Income for respective jurisdiction;
- Actual heating and temperature humidity index (THI) degree days;

3. Large Commercial and Industrial Econometric Models

Sales to the large commercial and industrial sector represent 26.0 percent of NSP System electric retail sales in 2018. The models are regressions using historical data and a combination of variables, including the following:

- Industrial Production for respective jurisdiction;
- Number of monthly billing days;
- Indicator variables such as CI reclassification.

4. Others

Sales to the "Others" sector represent 0.6 percent of NSP System electric retail sales

in 2018. This sector includes Public Street and Highway Lighting (PSHL), Sales to Public Authorities (OSPA) and Interdepartmental (IDS) sales. Because this class represents a very small portion of the total sales, trend analysis is used and very little growth is forecast. Exceptions to this are the Minnesota Street Lighting and Other Public Authority classes. Minnesota Street Lighting sales are based on population in the Minneapolis-St. Paul MSA. Minnesota Other Public Authority sales are based on the Minnesota Other Public Authority customer forecast.

5. Peak Demand Model

An econometric model is developed to forecast base peak demand for the entire planning period. The model includes a combination of variables, including the following:

- Weather normalized native energy requirements
- Peak producing weather by month
- Binary variables

C. Methodology Strengths and Weaknesses

The strength of the process Xcel Energy uses for this forecast is the richness of the information obtained during the analysis. Xcel Energy's econometric forecasting models are based on sound economic and statistical theory. Historical modeling and forecast drivers are based on economic and demographic variables that are easily measured and analyzed. The use of models by class and jurisdiction gives greater insight into how the NSP System is growing, thereby providing better information for decisions to be made in the areas of generation, transmission, marketing, conservation, and load management.

With respect to accuracy, forecasts of this duration are inherently uncertain. Planners and decision makers must be keenly aware of the inherent risk that accompanies long-term forecasts. They must also develop plans that are robust over a wide range of future outcomes.

D. Data Definitions

The following is a list of definitions of the variables considered in Xcel Energy's econometric models.

Table 4: Jurisdiction Abbreviations

Mi or MI	State of Michigan
M or MN	State of Minnesota
N or ND	State of North Dakota
S or SD	State of South Dakota
W or WI	State of Wisconsin

Table 5: Monthly MWh Sales Series

SLSReswo(Juris)	Residential without space heating for given jurisdiction
SLSResSH(Juris)	Residential with space heating for given jurisdiction
SLSSmCI(Juris)	Small commercial and industrial for given jurisdiction
SLSLgCI(Juris)	Large commercial and industrial for given jurisdiction

Table 6: Monthly Customer Series

CustReswo(Juris)	Residential without space heating for given jurisdiction
CustResSH(Juris)	Residential with space heating for given jurisdiction
CustSmCI(Juris)	Small commercial and industrial for given jurisdiction
CustLgCI(Juris)	Large commercial and industrial for given jurisdiction

Table 7: Monthly Economic and Demographic Series

HH_(Juris)	Number of Households in given jurisdiction
NR_(Juris)	Total Population in given jurisdiction
GMP_(MSA)	Gross Metro Product for given metropolitan statistical area
GSP_(State)	Gross State Product for given state
EE_(Juris)	Total Employment in given jurisdiction
IPMFG_(Juris)	Industrial Production Index - manufacturing in given jurisdiction
CYP_(Juris)	Real Personal Income in given jurisdiction
(Juris)TotRes_RAP	Real Average Price for electric sales to residential customers

Table 8: Monthly Data Variables used in Demand Model

THI12(Month)Cust	Temperature Humidity Index @12:00 noon on the peak day multiplied by total retail customers
THI15(Month)Cust	Temperature Humidity Index @3:00 PM on the peak day multiplied by total retail customers.
HDD(Season)	Normal Heating Degree Days on the day of the Peak multiplied by a binary variable for the season (winter - Wtr, shoulder month - sh)
WNActEnergy_LpYrAdj_12MoSum	12 month rolling sum of the weather normalized net energy requirements adjusted to remove the effect of leap years

Table 9: Monthly Weather Variables used in Sales Models

H65_bill (Juris)(Month)	HDD base 65 for given jurisdiction and month
T65_bill(Juris)(Month)	THI DD base 65 for given jurisdiction and month

Table 10: Other Monthly Variables

BillDaysCellnet21	Billing Month Days

Table 11: Monthly Binary Variables

Jan	Binary variable for the month of January
Feb	Binary variable for the month of February
Mar	Binary variable for the month of March
Apr	Binary variable for the month of April
May	Binary variable for the month of May
Jun	Binary variable for the month of June
Jul	Binary variable for the month of July
Aug	Binary variable for the month of August
Sep	Binary variable for the month of September
Oct	Binary variable for the month of October
Nov	Binary variable for the month of November
Dec	Binary variable for the month of December

E. Data Sources

MWh sales and MW peak demand. Xcel Energy uses internal and external data to create its MWh sales and MW peak demand forecast.

Historical MWh sales. Historical MWh sales are taken from Xcel Energy's internal company records, fed by its billing system. Historical coincident net peak demand

data is obtained through company records. The load management estimate is added to the net peak demand to derive the base peak demand.

Weather data. Weather data (dry bulb temperature and dew points) were collected from www.weatherunderground.com and the National Oceanic and Atmospheric Administration for the Minneapolis/St. Paul, Fargo, Sioux Falls, and Eau Claire areas. The heating degree-days and THI degree-days are calculated internally based on this weather data.

Economic and demographic data. Economic and demographic data is obtained from the Bureau of Labor Statistics, U.S. Department of Commerce, and the Bureau of Economic Analysis. Typically they are accessed from IHS Global Insight, Inc. data banks, and reflect the most recent values of those series at the time of modeling.

F. Energy Efficiency Programs

The regression model results for the residential classes and commercial and industrial classes are reduced to account for the expected impacts of energy efficiency programs.

The EE methodology implemented for the State of Minnesota utilizes a transparent method to project the impacts of energy efficiency (including the energy savings impacts from our current demand response programs) in sales forecasts. There are three distinct steps to this process:

- Collect and calculate historical and current effects of EE on observed sales
- Project the forecast using observed data with the impact of EE removed (i.e. increase historical sales to show hypothetical case without EE)
- Adjust the forecast to show the impact of all planned EE in future years.

The first step involves collecting data involving any measure that would cause an impact on the time period utilized in the sales forecast. In this model, we use the time period from 2003 to 2017, and therefore the historical EE would include any measure that results in decreased sales in any (or all) years from 2003 through 2017.

Since the vast majority of EE measures have a lifetime greater than one year (exceptions include but are not limited to behavioral energy savings programs), the impact on sales will include the year that a measure is installed as well as any years that follow until the measure has reached the end of its useful life. For example, a residential lighting measure that was installed in 2008 and has a life of six years will result in a sales reduction from 2008 to 2013 (six full calendar years). Though a measure may be installed in June of 2008 and, thus, would persist until May of 2013,

the Company believes that the simplifying case in which all measures are installed for the entire calendar year is sufficient.

Due to the wide variation of measures available to customers, the Company sums the savings for each year by EE program to optimize the level of detail and depth of history included in the model. As a result of limitations in the quality of data prior to 1996, the Company has taken the conservative approach and omitted the impacts of achievements before 1996. While this may seem inconsequential, some programs have a 20-year lifetime, and EE from 1998 could therefore affect the 2017 usage. Achievement data are from the approved Conservation Improvement Program (CIP) Status Reports filed annually for each year since 1996.

Once the total impact of EE in effect is calculated for each year, a hypothetical sales data set is created. This series consists of the observed sales from 2003 through May 2017 plus the effective EE calculated for all EE measures installed in that year as well is achieved savings from programs in prior years that are still within the useful measure life.

The hypothetical sales data is used to generate a sales forecast that has entirely excluded the impacts of company-sponsored EE. It is important to note that customer-initiated EE or EE due to codes and standards (naturally-occurring EE) is not calculated as part of the CIP.

Once the sales forecast based on hypothetical sales has been generated, the Company subtracts the projected future EE from the total to determine the EE-adjusted sales. In addition, codes and standards changes resulting in decreased sales not documented within CIP may have separate adjustment factors applied in addition to the company-sponsored EE. The source for company-sponsored EE adjustments will be based on the CIP Plan in effect at the time of the forecast.

Exogenous adjustments were made to the Minnesota sales model output for future years to account for codes and standards changes for lighting in the Residential and Business segments. These adjustments are in addition to the adjustments made for future EE program achievement. The sales model implicitly accounts for some portion of changes in customer use, due to conservation and other influences, by basing projections of future consumption on past customer class energy consumption patterns. However, when technologies driving code and standard changes are adopted at an accelerated pace but can no longer be incentivized through EE programs, the sales forecast is not able to adequately adapt to future changes due to the difference between past and projected customer use, and the future changes are

not accounted for in the exogenous adjustments made for EE program achievement.

As a result of recent changes in business and residential lighting practices, two new additional adjustments have been added to the sales forecast. The first is for residential customers only, and takes into account the new standard efficiency for general service lamps (also known as EISA standards). For the adjustment to the sales forecast, this only calculates the difference between a standard incandescent and an EISA-compliant halogen bulb, since additional efficiency will still be captured through EE programs. The second adjustment projects business class sales reductions resulting from accelerated technological improvements in the business lighting sector due to improvements in solid state lighting (LED).

A monthly forecast of the impact of new EE programs is developed by Xcel Energy's DSM Regulatory Strategy and Planning Department, and is used to reduce the class level sales forecasts that result from the regression modeling process. Impacts from all program installations through 2017 are assumed to be imbedded in the historical data, so only new program installations are included in the EE adjustment.

The Company's demand response programs result in short-term interruptions of service designed to reduce system capacity requirements rather than permanent reductions in energy use, so it is not considered here.

G. Behind-the-Meter Distributed Solar Generation

In response to the establishment of a Solar Energy Standard (SES) by the Minnesota Legislature an increased emphasis has been placed on distributed solar generation. A forecast of the expected impact on demand and energy has been developed based on new programs designed to meet goals established for the SES. The process of incorporating behind-the-meter distributed solar generation into the forecast process is similar to how EE program savings are incorporated in the sales and peak demand forecasts. Historical behind-the-meter distributed solar generation is added-back to the historical sales and peak demand modeling data, similar to how historical company-sponsored EE programs savings are added back to the historical sale and peak demand modeling data. The forecast output, based on the hypothetical sales and peak demand data with behind-the-meter solar generation added back to the historical sales and peak demand data, is then reduced for the future impacts of behind-the-meter installations on the class level sales in Minnesota and South Dakota and the NSP System peak demand.

H. Forecast Adjustments

Adjustments have been made to the forecast to account for planned changes in production levels for several large customers in Minnesota and Wisconsin. The most significant of these changes is the reduction of sales and demand related to the scheduled installation of customer-owned Combined Heat and Power generating facilities in 2017 and 2018.

I. Overview of Probability Distributions

Xcel Energy uses a straightforward extension of the peak demand econometric model to assess risk around the expected value of the peak demand by conducting a Monte Carlo simulation on the main drivers of the peak model (weather and native energy requirements). For the Monte Carlo energy probability distribution model, the main drivers are weather, Minnesota Households (HH_MN), and Minnesota Real Gross State Product (CGSP_MN).

The Monte Carlo stochastic simulation of peak demand (MW) or energy (MWh) involves taking 10,000 random draws from the weather probability distributions as well as 10,000 draws from the 12-month sum of energy probability distribution (or HH_MN and CGSP_MN probability distributions), which, in turn, produces 10,000 forecasts of peak demand (or energy), and thus generates a probability distribution around the mean peak demand (or mean energy).

For example, if the econometric model forecasts that the mean peak demand for 2025 is 9,309 MW, then using the same econometric model, the Monte Carlo simulation method forecasts that there is a 90 percent probability that the 2025 peak demand will be less than 10,317 MW, or alternatively, a 10 percent chance that the peak will be less than 8,288 MW.

In summary, the Monte Carlo stochastic simulation method adequately captures the effect of extreme weather on monthly peak demand and monthly energy usage, while preserving the expected value or mean forecast of peak demand and energy.

J. Data Adjustments and Assumptions

Weather Adjustments. Xcel Energy adjusts the monthly weather data to reflect billing schedules. Therefore, the monthly weather data corresponds exactly with the billing month schedule.

Economic Adjustments. All Consumer Price Index data is deflated to 1982=1 and related economic series are deflated to 2009 constant dollars.

K. Assumptions and Special Information

The data used in Xcel Energy's forecasting process has already been discussed in a general way. Descriptions and citations of sources for the data sets have been mentioned within this documentation under different sections.

Xcel Energy believes that its process is a reasonable and workable one to use as a guide for its future energy and load requirements. The underlying assumptions used to prepare Xcel Energy's median forecast are as follows:

- *Demographic Assumption.* Population or household projections are essential in the development of the long-range forecast. The forecasts of customers are derived from population and household projections provided by IHS Global Insight, Inc., and reviewed by Xcel Energy staff. Xcel Energy customer growth mirrors demographic growth over the forecast period.
- *Weather Assumption.* Xcel Energy assumes "normal" weather in the forecast horizon. Normal weather is defined as the average weather pattern over the 20-year period from 1998-2017. The variability of weather is an important source of uncertainty. Xcel Energy's energy and peak demand forecasts are based on the assumption that the normal weather conditions will prevail in the forecast horizon. Weather-related demand uncertainties are not treated explicitly in this forecast.
- *Loss Factor Assumptions.* The loss factors are important to convert the sales forecast to energy requirements. Xcel Energy uses a historical average loss factor for each jurisdiction, and assumes it will not change in the future.

L. MISO Coincident Peak Demand Forecast

Once we complete the NSP System Peak Demand Forecast, we develop a forecast for the NSP System Peak Demand coincident with the MISO system peak. MISO has published the date and time of the MISO system peak for each of the four summer months (June – September) of 2005 – 2017. Company records were queried to determine the NSP System uninterrupted peak at the time of each of the MISO monthly peak days.

We then develop a forecast of the NSP System peak demand coincident with the MISO peak using a regression model based on the NSP System peaks coincident with

MISO, the NSP System peaks not coincident with MISO, and the weather variable representing the temperature-humidity index at 3:00 PM on the MISO coincident peak day for each summer month. MISO only requires an annual coincident peak forecast for the next planning year. The current forecast is for the NSP System peak coincident to the MISO annual peak during the 2019-20 planning year (June 2019 – May 2020).

M. Forecast Coordination

Xcel Energy reports its energy and peak demand forecasts to MISO, who then combines the forecasts of all its member utilities. Xcel Energy also reports its forecast to the Public Service Commission of Wisconsin as part of its Strategic Energy Assessment (SEA) process. In this process, the Wisconsin portion of the total Xcel Energy system load is combined with other Wisconsin electric utilities to form a statewide Wisconsin forecast.

III. DISTRIBUTED ENERGY RESOURCES FORECAST

A. Distributed Solar

We offer several programs to customers interested in solar as a renewable opportunity. Specifically we provide incentives under our Solar*Rewards program, and the opportunity to earn bill credits for community solar gardens in our Solar*Rewards Community program. In addition, we offer a net-metering option for customers installing incentivized small scale solar. We have factored all of these distributed solar PV options into our Reference Case, Medium, and High distributed solar forecast.[3] We note that the methodology used to forecast distributed solar for this Resource Plan is consistent with what we used in our November 2018 Integrated Distribution Plan, filed in Docket No. E999/CI-18-251.

1. Reference Case Assumptions

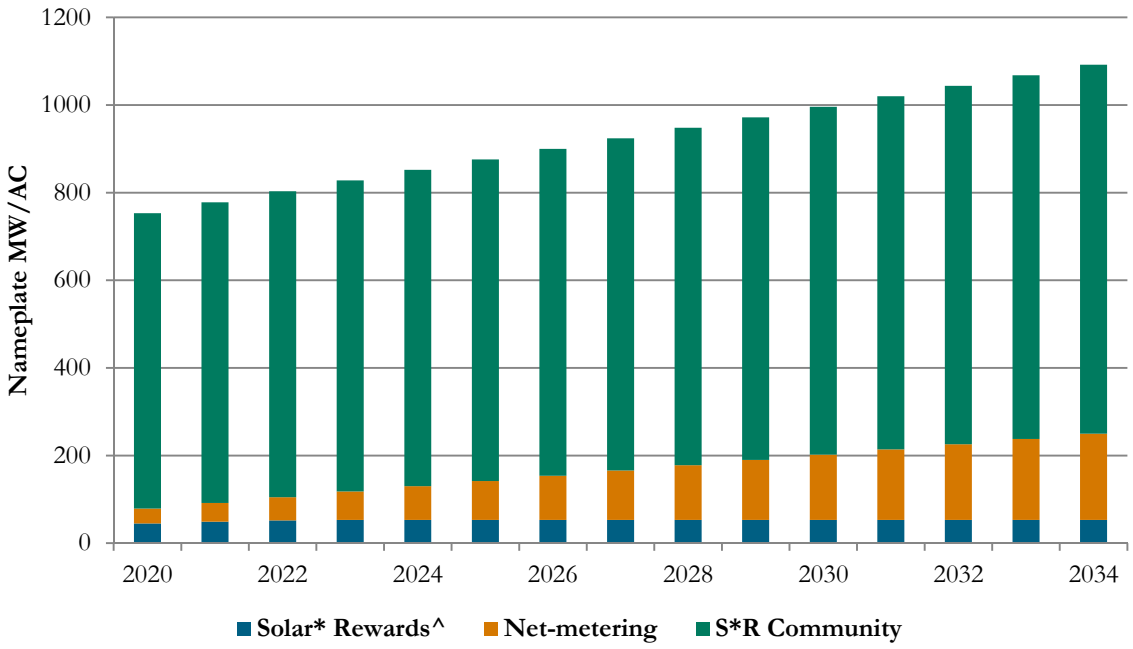
In determining our Reference Case, we updated our goals to be consistent with 2017 legislative outcomes that: (1) increased 2018-2020 Solar*Rewards incentive funding, (2) eliminated new Made in Minnesota awards after 2017, with final installations completed by October 2018, and 3) eliminated new Solar*Rewards systems after 2021, with final installations completed by 2023. We assumed net-metering only system additions would continue at current annual levels through 2021 and increase in 2022 to accommodate for demand from the elimination of the Solar*Rewards program in

[3] We note that we provide information specific to just Solar*Rewards Community as Appendix N8.

this scenario. We based attrition and completion lag rates on historical analysis of cancelled and completed projects, and applied these to program application forecasts to derive final installation estimates.

Due to the large response to our Solar*Rewards Community program, which has no statutory budget or capacity limit, we are forecasting additions of 673 MW through 2019 in this filing. For our Reference Case assumptions through the Resource Plan planning period, we assume Solar*Rewards Community adjusts to approximately 12 MW per year after 2021 to account for significant early adoption of CSGs and reduction in tax benefits. The graph below reflects the Reference Case forecast of distributed solar PV forecast.

Figure 11: Reference Case – NSP System Distributed Solar PV Forecast (Nameplate MW/AC)



^Includes Made in Minnesota

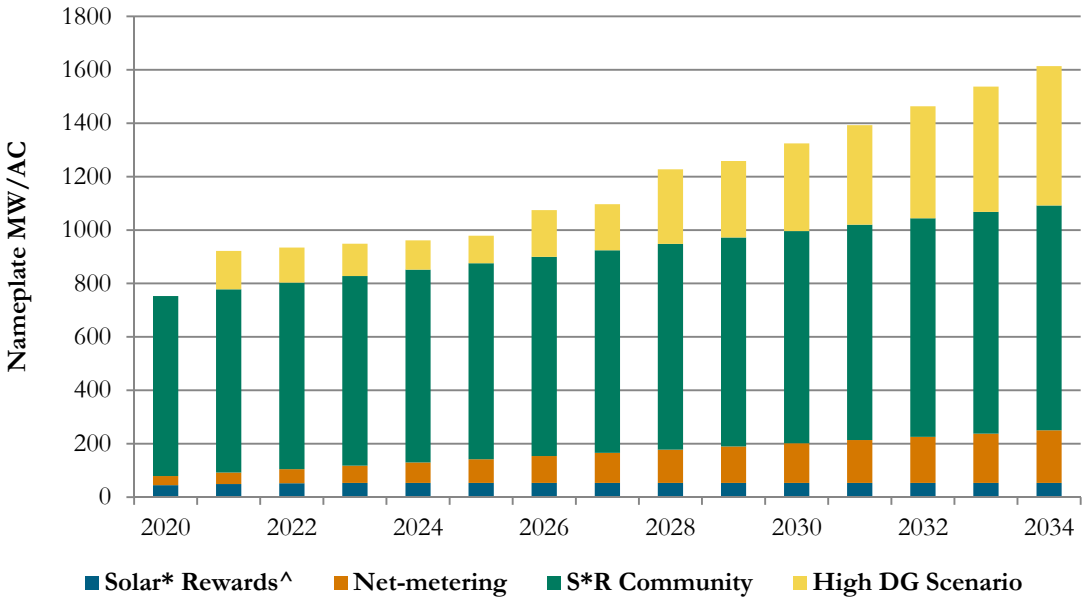
2. Reference vs High Forecasts

The Reference and High scenarios hold the levels of Solar*Rewards and Made in Minnesota constant for the reasons discussed above. For net metering and CSG, we assume that customers that participate in solar programs would consider, in the majority of cases, that these programs are substitutes for each. Therefore the incremental growth in one category is interchangeable with another category. For

example, we are estimating that total solar PV in 2034 is approximately 1,100 MW – of which, approximately 850 MW is net metering and CSG.

For the High scenario, we used a Payback adoption model with lower installation costs. We also applied a 10 percent reduction to the solar installation cost curve starting in 2020. Solar installation costs in the High scenario are set to be higher for the first year due to new import tariffs and contracts already in place. Hence, there is a low probability that the solar installation prices will drop significantly below the Reference scenario for 2019. The adoption of solar is flat in the early 2020s, because the decline in solar installation cost is offset by the decline in Investment Tax Credit (ITC). The Payback model results indicate around 1,600 MW for total installed distributed solar by 2034. The graph below reflects the high forecast of distributed solar PV forecast.

Figure 12: High Forecast Case – NSP System Distributed Solar PV Forecast (Nameplate MW/AC)



B. Distributed Wind

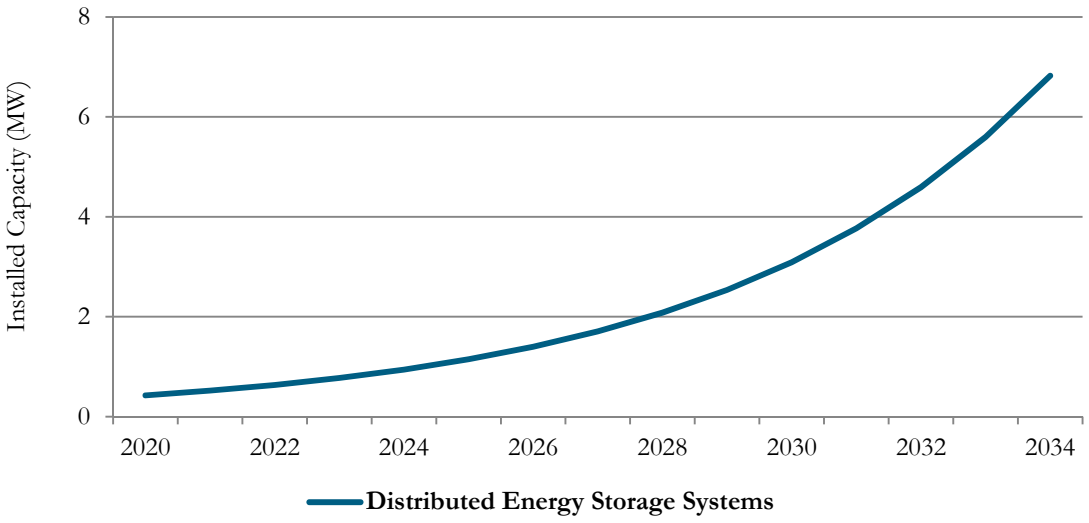
We presently have a small number of distributed wind projects on our system, with a total of 59 projects that comprise 14 MW. We believe distributed wind will continue to be a very small proportion of DER on our distribution system, largely due to the rapid development of solar and storage markets – and their relative ease of adoption, compared to wind. Additionally, there is little information available in the industry

regarding the adoption of distributed wind. For these reasons, we are not providing a forecast in conjunction with this Resource Plan.

C. Distributed Storage

Navigant Research's Global DER Overview, 2Q 2019, projects a growth rate of 21.9 percent for Distributed Energy Storage Systems (DESS). From 2017 through April 2019, we received approximately 50 interconnection applications for energy storage on our distribution system. Of these 50 applications, 32 are complete and in operation, comprising approximately 350 kW. Figure 13 below extrapolates the current installations at the Navigant projected rate of growth.

Figure 13: NSP System Distributed Energy Storage Systems Forecast



The impact of DESS is, currently, not incorporated into demand forecasting or as a specific supply side resource. We discuss the utility-scale storage as it applies to the modeling underlying this Resource Plan in Appendix F6: Resource Options.

D. Electric Vehicles

Our customers are procuring EVs in greater numbers than ever before. In our Upper Midwest service area, the total number of EVs is currently approximately 9,500.[4] Nationally, annual sales of EVs increased by 81 percent from 2017 to

[4] IHS Markit, 2019. The IHS Markit data is provided at the zip code level for zip codes within the Company's service territory. Utility jurisdictions do not exactly follow zip code boundaries, so there may be some margin

2018.[5] Forecasts suggest that we may see increased adoption as EVs are poised to grow into a more mainstream new vehicle option, with over 40 models of EVs available in the United States today. The nascent nature of this market however, makes the possibility of significantly more or less adoption a large variable, and thus difficult to forecast.

The approach we took in this Resource Plan to forecast EVs allows for consideration of a wide range of potential futures, and represents an advancement and change from our approach in our November 1, 2018 Integrated Distribution Plan (IDP). The IDP used a forecast based on national level adoption that had informed early- to mid-2018 filings in other dockets.[6] At that time we noted our intent to improve, benchmark, and validate our forecasting models and assumptions, which is underway. We also noted that we were doing work around electrification to support our upcoming Resource Plan.

That said, for the purposes of this Resource Plan, we made an exogenous adjustment for a base level of light duty electric vehicle adoption in both our energy and demand forecasts. We then worked with E3 to develop a high "electrification" load forecast sensitivity, which includes a broader range of EV adoption – as well as other electrification impacts.[7] This creates a wide band of possible outcomes to inform our modeling. We believe that by limiting the modeling of a highly dynamic external factor to a Base and High view, we are better able to examine the base needs of the system, while also considering the long-term impacts of potential high electrification across Minnesota's economy.

We illustrate the Base and High Electrification forecasts that informed this Resource Plan in Figure 14 below. We additionally show the Base EV forecast for this Resource Plan to give perspective on the magnitude of electrification the High Electrification sensitivity affords the modeling in this Plan.

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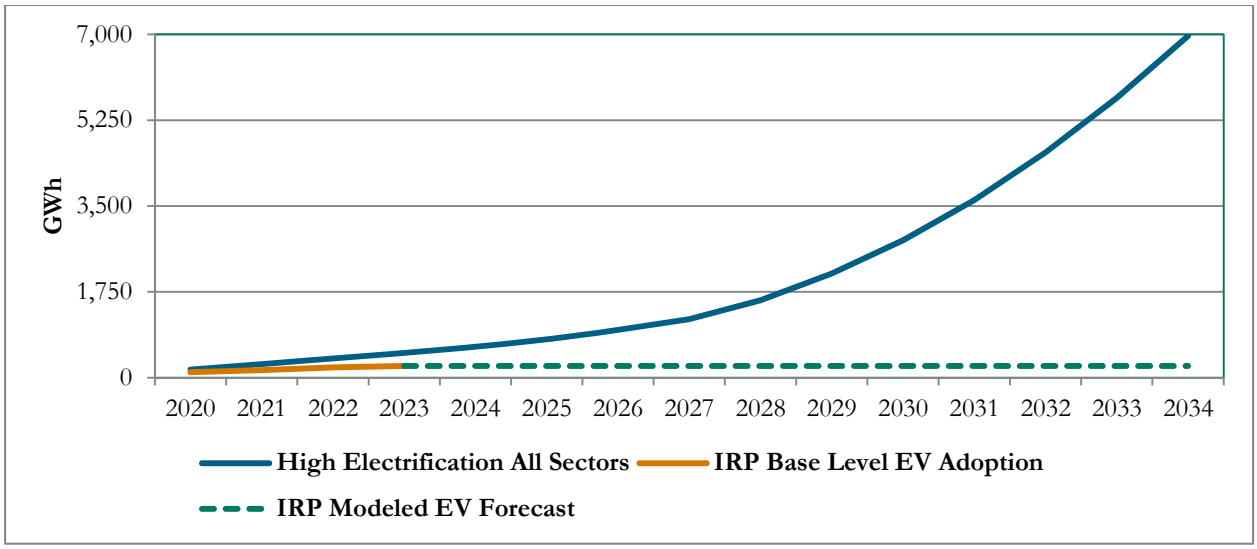
of error in this value.

[5] InsideEVs PEV Scorecard, https://insideevs.com/monthly-plug-in-sales-scorecard/.

[6] June 1, 2018 filing in Docket No. E002/M-15-111 and a January 11, 2018 response to Minnesota Commission Staff Information Request No. 8 in our hosting capacity proceeding in Docket No. E002/M-17-777.

[7] We provide a full discussion of the E3 high electrification sensitivity as Appendix F4.

Figure 14: NSP System Base Level Compared to High Electrification Sensitivity – 2020-2034



We discuss our development of the Base Forecast below. We discuss the details of the High Electrification Sensitivity in Appendix F4: High Electrification Sensitivity and note that it was developed as part of E3's PATHWAYS study, provided as Appendix P3: Minnesota PATHWAYS Report June 2019 (E3).

1. Base EV Adoption

The Base EV forecast projects adoption of light duty vehicles in the first five-years of the planning period and then holds constant from year six through the remainder of the planning period. This Base level of light duty EV adoption is used in all modeling scenarios, and is consistent with the likely forecast from the IDP. The rate and level of EV adoption impacts the energy forecast, and customer charging behavior assumptions impact the demand forecast, which we discuss in turn below.

a. EV Adoption Levels

Our Base EV forecast is based on an internally-developed methodology that incorporates both economic payback and Bass diffusion (technology adoption) model.[8] Key variables informing our adoption estimates for the base energy forecast

[8] The Bass Model or Bass Diffusion Model was developed by Frank Bass. It consists of a simple differential equation that describes the process of how new products get adopted in a population. The model presents a rationale of how current adopters and potential adopters of a new product interact. The basic premise of the model is that adopters can be classified as innovators or as imitators and the speed and timing of adoption

include:

- Electricity Prices
- Vehicle Battery Prices
- Gasoline Prices
- Car ownership
- Car usage
- Efficiency

In addition to EV adoption, customer charging behavior is an important consideration to factor into our load forecasts. Because we are reflecting adoption of only light duty EVs in our base forecast, our primary considerations are the share of charging done at homes, and penetration of managed charging stations. Our source for this was the DOE EV Project Data Set.

Forecasting is very sensitive to various assumptions, especially for new technologies like EVs that are in early stages of adoption. Forecasts are also sensitive to several externalities like policy changes (such as incentives), technology changes (such as battery improvements and autonomous vehicles), geopolitical issues (such as trade and tariff issues), availability of raw materials (such as shortages of lithium or cobalt), etc. Additionally, many of the inputs change frequently and could produce significant swings in the model outputs.

2. *High Electrification Sensitivity*

We worked with E3 to develop a High Electrification load forecast sensitivity, derived from the E3 statewide decarbonization analysis using PATHWAYS,[9] which we ran for each Resource Plan modeling scenario. The objective of this sensitivity was to create a "bookend," examining the possible impacts on load growth and peak demand growth on our Upper Midwest NSP System service area, under a scenario with electrification sufficiently aggressive to achieve Minnesota's economy-wide goal of an 80 percent reduction in greenhouse gas (GHG) emissions below 2005 levels by 2050.[10]

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depends on their degree of innovativeness and the degree of imitation among adopters. The Bass model has been widely used in forecasting, especially new products' sales forecasting and technology forecasting.

[9] In summary, for the PATHWAYS study, E3 developed a set of long-term economy-wide, deep decarbonization scenarios for the state of Minnesota. These scenarios provide an exploration of the cross-sectoral implications of meeting economy-wide carbon reduction goals, and highlight the role of Xcel Energy, and the electric sector as a whole, in meeting the state's economy-wide carbon goal. For details, see the E3 Minnesota PATHWAYS Report as Appendix P3.

[10] Minn. Stat. 216H.02, Subd. 1. *See* https://www.pca.state.mn.us/air/state-and-regional-initiatives.

Without suggesting this much electrification will or should occur, this sensitivity asks: If there were very aggressive electrification of transportation, buildings, and other end uses, what are the potential impacts on energy consumption and peak demand during the planning period?

We summarize the E3 High Electrification sensitivity in Appendix F4, and provide as Attachment A to that Appendix, E3's detailed discussion of their methodology.

3. Summary

We believe planning for electrification must contemplate a variety of future state scenarios, but also that EVs and electrification broadly are not a primary driver that will influence resource decisions in this Resource Plan. We are continuing to refine our EV forecasting methods as we learn more about the EV industry and adoption trends nationally. We expect to provide updated EV-specific forecast scenarios in our November 2019 IDP.

APPENDIX F2 – STRATEGIST MODELING ASSUMPTIONS & INPUTS

A. Discount Rate and Capital Structure

The discount rate used for levelized cost calculations and the present value of modeled costs is 6.53 percent. The rates shown below were calculated by taking a weighted average of each NSP jurisdiction's last allowed/settled electric retail rate case.

Table 1: Discount Rate and Capital Structure

Discount Rate and Capital Structure				
	Capital Structure	Allowed Return	Before Tax Electric WACC	After Tax Electric WACC
Long-Term Debt	46.16%	4.80%	2.22%	1.60%
Common Equity	52.35%	9.35%	4.90%	4.90%
Short-Term Debt	1.49%	3.65%	0.05%	0.04%
Total			**7.17%**	**6.53%**

B. Inflation Rates

The inflation rates are used for existing resources, generic resources, and other costs related to general inflationary trends in the modeling and are developed using long-term forecasts from Global Insight. The general inflation rate of 2% is from their long-term forecast for "Chained Price Index for Total Personal Consumption Expenditures" published in the second quarter of 2018.

C. Reserve Margin

The reserve margin at the time of MISO's peak is 8.4 percent from the 2018-2019 LOLE Study Report published November 2017. The coincidence factor between the NSP System and MISO system peak is 5 percent. Therefore, the effective reserve margin is:

$$(1 - 5\%) * (1 + 8.4\%) - 1 = 2.98\%.$$

D. CO_2 Costs

The PVSC Base Case CO2 values are based on the high environmental cost values for CO2 through 2024 (page 31 of the Minnesota Public Utilities Commission's Order Updating Environmental Cost Values in Docket No. E999/CI-14-643 issued January 3, 2018.). All prices are converted to 2018 real dollars using the 2017 GPDIPD of

113.416 and then escalate at general inflation thereafter.

The PVSC Base Case values starting in 2025 are based on the "high" end of the range of regulated costs (see page 12 of MPUC Order Establishing 2018 and 2019 Estimate of Future Carbon Dioxide Regulation Costs in Dockets No.E999/CI-07-1199 and E-999/DI-17-53 issued June 11, 2018). All prices escalate at general inflation.
The Order Establishing 2018 and 2019 Estimate of Future Carbon Dioxide Regulation Costs requires four alternative scenarios to be run in addition to the PVSC Base Case. The Order Extending Deadline for Filing Next Resource Plan issued January 30, 2019 also requires a scenario using the midpoint of the Commission's most recently approved externalities and regulatory costs of carbon. The values in the PVSC Base Case and alternative scenarios are set out below.

Table 2: CO2 Costs

CO2 Costs ($ per short ton)						
Year	Low Environmental Cost	High Environmental Cost	Low Environmental/ Regulatory Costs	Mid Environmental/ Regulatory Costs	PVSC - High Environmental/ Regulatory Costs	PVRR - Omitting CO2 Cost Considerations
2018	$9.09	$42.76	$9.09	$25.92	$42.76	$0.00
2019	$9.49	$44.58	$9.49	$27.04	$44.58	$0.00
2020	$9.90	$46.45	$9.90	$28.18	$46.45	$0.00
2021	$10.32	$48.39	$10.32	$29.35	$48.39	$0.00
2022	$10.77	$50.38	$10.77	$30.57	$50.38	$0.00
2023	$11.22	$52.43	$11.22	$31.82	$52.43	$0.00
2024	$11.69	$54.55	$11.69	$33.12	$54.55	$0.00
2025	$12.16	$56.72	$5.00	$15.00	$25.00	$0.00
2026	$12.67	$58.97	$5.10	$15.30	$25.50	$0.00
2027	$13.17	$61.29	$5.20	$15.61	$26.01	$0.00
2028	$13.70	$63.67	$5.31	$15.92	$26.53	$0.00
2029	$14.24	$66.12	$5.41	$16.24	$27.06	$0.00
2030	$14.80	$68.64	$5.52	$16.56	$27.60	$0.00
2031	$15.37	$71.24	$5.63	$16.89	$28.15	$0.00
2032	$15.97	$73.91	$5.74	$17.23	$28.72	$0.00
2033	$16.57	$76.67	$5.86	$17.57	$29.29	$0.00
2034	$17.21	$79.50	$5.98	$17.93	$29.88	$0.00
2035	$17.85	$82.41	$6.09	$18.28	$30.47	$0.00
2036	$18.52	$85.41	$6.22	$18.65	$31.08	$0.00
2037	$19.20	$88.50	$6.34	$19.02	$31.71	$0.00
2038	$19.91	$91.68	$6.47	$19.40	$32.34	$0.00
2039	$20.62	$94.96	$6.60	$19.79	$32.99	$0.00
2040	$21.38	$98.32	$6.73	$20.19	$33.65	$0.00
2041	$22.14	$101.78	$6.86	$20.59	$34.32	$0.00
2042	$22.94	$105.34	$7.00	$21.00	$35.01	$0.00
2043	$23.74	$109.00	$7.14	$21.42	$35.71	$0.00
2044	$24.58	$112.76	$7.28	$21.85	$36.42	$0.00
2045	$25.43	$116.63	$7.43	$22.29	$37.15	$0.00
2046	$26.33	$120.61	$7.58	$22.73	$37.89	$0.00
2047	$27.23	$124.71	$7.73	$23.19	$38.65	$0.00
2048	$28.17	$128.92	$7.88	$23.65	$39.42	$0.00
2049	$29.12	$133.24	$8.04	$24.13	$40.21	$0.00
2050	$30.12	$137.69	$8.20	$24.61	$41.02	$0.00
2051	$31.14	$142.26	$8.37	$25.10	$41.84	$0.00
2052	$32.18	$146.97	$8.53	$25.60	$42.67	$0.00
2053	$33.26	$151.80	$8.71	$26.12	$43.53	$0.00
2054	$34.36	$156.76	$8.88	$26.64	$44.40	$0.00
2055	$35.50	$161.87	$9.06	$27.17	$45.28	$0.00
2056	$36.66	$167.11	$9.24	$27.71	$46.19	$0.00
2057	$37.86	$172.51	$9.42	$28.27	$47.11	$0.00

E. All Other Externality Costs

The values of the criteria pollutants are derived from the high and low values for each of the 3 locations, as determined in the Minnesota Commission Order Updating Environmental Cost Values in Docket No. E999/CI-14-643 issued January 3, 2018.

The midpoint externality costs are the average of the low and high values. All prices are escalated to 2018 real dollars using the 2017 GPDIPD of 113.416. The high, low and midpoint externality costs will be used in the CO2 sensitivities as described above.

Table 3: Externality Costs

MPUC Low Externality Costs 2018 $ per short ton				
	Urban	Metro Fringe	Rural	<200mi
SO2	$6,116	$4,829	$3,643	$0
NOx	$2,934	$2,622	$2,110	$28
PM2.5	$10,697	$6,856	$3,654	$872
CO	$1.65	$1.17	$0.31	$0.31
Pb	$4,857	$2,562	$624	$624

MPUC High Externality Costs 2018 $ per short ton				
	Urban	Metro Fringe	Rural	<200mi
SO2	$15,288	$12,030	$8,878	$0
NOx	$8,390	$7,798	$6,771	$158
PM2.5	$26,721	$17,091	$8,973	$1,327
CO	$3.51	$2.08	$0.63	$0.63
Pb	$6,011	$3,094	$695	$695

MPUC Midpoint Externality Costs 2018 $ per short ton				
	Urban	Metro Fringe	Rural	<200mi
SO2	$10,702	$8,430	$6,261	$0
NOx	$5,662	$5,210	$4,441	$93
PM2.5	$18,709	$11,974	$6,313	$1,099
CO	$2.58	$1.63	$0.47	$0.47
Pb	$5,434	$2,828	$659	$659

F. Demand and Energy Forecast

The Company's fall 2018 load forecast is used as the base assumption and assumes that EV impacts grow through 2023 are then held constant for the remaining forecast period. The energy efficiency (EE) forecast included in this forecast assumes impacts at a 75 percent rebate level which equals roughly 1.5 percent of sales through the planning period.

The "Load Forecast with 1.5% EE" shown in Table 4 below is the starting point for the Strategist load inputs. In all modeling scenarios, the "1.5% EE" is removed - the removal of these EE program effects, which have a 14-year life, impacts the load forecast through 2047. In its place, three EE Bundles (discussed below) are included

in Strategist as Proview Alternatives and any number of these bundles (from 0 to all 3) is allowed to be selected as part of the optimization process. The resulting forecast, before the optimized EE bundles are added, is shown below in Table 4 as "Forecast Without 1.5% EE." The forecasts shown do not include the impact of DG solar, as DG solar is modeled as a resource in Strategist, not a load modifier.

Table 4: Strategist Demand and Energy Forecast

Demand and Energy Forecast				
	Demand (MW)		Energy (GWh)	
Year	Forecast with 1.5% EE	Forecast without 1.5% EE	Forecast with 1.5% EE	Forecast without 1.5% EE
2018	9,152	9,152	43,914	43,914
2019	9,136	9,136	43,798	43,798
2020	9,156	9,227	43,865	44,310
2021	9,191	9,333	43,560	44,447
2022	9,251	9,464	43,529	44,860
2023	9,285	9,569	43,394	45,168
2024	9,329	9,684	43,425	45,650
2025	9,354	9,780	43,257	45,919
2026	9,403	9,900	43,281	46,386
2027	9,487	10,055	43,493	47,042
2028	9,593	10,262	44,089	48,093
2029	9,635	10,403	43,972	48,408
2030	9,697	10,567	44,130	49,010
2031	9,740	10,713	44,172	49,496
2032	9,856	10,956	44,661	50,445
2033	10,005	11,211	44,875	51,087
2034	10,137	11,343	45,232	51,443
2035	10,248	11,368	45,534	51,302
2036	10,374	11,408	46,042	51,382
2037	10,482	11,430	46,126	51,006
2038	10,576	11,438	46,287	50,723
2039	10,674	11,449	46,541	50,534
2040	10,777	11,467	46,946	50,505
2041	10,873	11,476	46,975	50,081
2042	10,964	11,481	47,143	49,805
2043	11,057	11,488	47,407	49,626
2044	11,169	11,514	47,823	49,603
2045	11,241	11,500	47,879	49,210
2046	11,328	11,500	48,076	48,964
2047	11,424	11,510	48,372	48,816
2048	11,536	11,536	48,977	48,977
2049	11,626	11,626	48,811	48,811
2050	11,715	11,715	49,042	49,042
2051	11,804	11,804	49,274	49,274
2052	11,893	11,901	49,640	49,640
2053	11,982	11,992	49,736	49,736
2054	12,071	12,083	49,968	49,968
2055	12,160	12,174	50,199	50,199
2056	12,249	12,265	50,567	50,567
2057	12,339	12,356	50,662	50,662

The low load sensitivity includes high customer-adoption-based DG/DER growth and higher EE savings, which reduces load. The high load sensitivity includes high electrification load. These assumptions are shown in Table 5 and Table 6, and are incremental/decremental to the forecast shown in Table 4.

Table 5: High Load Sensitivity

High Electrification		
Year	Energy (GWh)	Demand (MW)
2018	35	8
2019	46	6
2020	59	7
2021	166	20
2022	276	33
2023	390	47
2024	507	62
2025	627	77
2026	785	96
2027	976	117
2028	1,194	141
2029	1,579	171
2030	2,122	207
2031	2,802	250
2032	3,622	302
2033	4,593	362
2034	5,706	430
2035	6,969	509
2036	8,320	592
2037	9,751	681
2038	11,248	772
2039	12,797	866
2040	14,387	961
2041	15,950	1,055
2042	17,472	1,146
2043	18,940	1,245
2044	20,341	1,930
2045	21,665	2,660
2046	22,904	3,318
2047	24,054	3,945
2048	25,112	4,800
2049	26,076	5,056
2050	26,947	5,554
2051	28,051	6,093
2052	29,061	6,564
2053	30,072	7,041
2054	31,083	7,528
2055	32,093	8,021
2056	33,104	8,496
2057	34,115	8,984

**Demand values are coincident to system peak*

Table 6: Low Load Sensitivity

High DER Growth			
Year	Energy (GWh)	ELCC (MW)	Demand (Nameplate MW)
2018	0	0	0
2019	0	0	0
2020	0	0	0
2021	189	72	144
2022	173	66	131
2023	159	60	121
2024	144	55	109
2025	135	51	103
2026	230	87	175
2027	228	87	173
2028	369	140	280
2029	377	143	286
2030	432	164	328
2031	490	186	373
2032	553	210	420
2033	617	235	469
2034	687	261	522
2035	760	289	578
2036	840	319	637
2037	920	350	700
2038	1,007	383	766
2039	1,099	418	836
2040	1,200	455	910
2041	1,225	466	931
2042	1,187	451	902
2043	1,148	437	873
2044	1,112	422	844
2045	1,070	407	814
2046	1,014	385	771
2047	974	370	740
2048	935	354	709
2049	891	339	677
2050	850	323	646
2051	799	304	607
2052	759	287	575
2053	701	266	532
2054	657	249	498
2055	607	230	461
2056	559	211	422
2057	506	192	383

G. Energy Efficiency Bundles

The EE "Program" and "Maximum" Bundles are based on the Minnesota Department of Commerce's Minnesota Energy Efficiency Potential Study: 2020-2029 published December 4, 2018. The "Optimal" Bundle was developed by the Company. The bundles are incremental to the "Forecast without 1.5% EE" shown in Table 4. They are also dependent on the Bundle before it being selected (i.e. Bundle 2 cannot be selected if Bundle 1 is not selected). The Bundles are included in Strategist as Proview Alternatives and any number of these Bundles (from 0 to all 3) is allowed to be selected as part of the optimization process.

Table 7: Energy Efficiency Bundles

	Energy(MWh)			Demand (MW)			Costs ($000)		
Year	Bundle 1: Program	Bundle 2: Optimal	Bundle 3: Max	Bundle 1: Program	Bundle 2: Optimal	Bundle 3: Max	Bundle 1: Program	Bundle 2: Optimal	Bundle 3: Max
2018	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0	0
2020	621	43	231	97	18	36	100,989	12,598	148,331
2021	1,326	91	493	207	38	77	113,525	13,905	167,221
2022	1,913	148	702	301	60	113	121,239	21,425	177,197
2023	2,555	211	928	407	86	154	133,614	23,931	196,474
2024	3,094	279	1,110	520	116	197	148,406	26,120	217,388
2025	3,629	346	1,289	635	146	241	152,433	26,077	223,293
2026	4,330	414	1,533	759	176	289	160,445	26,236	233,779
2027	5,054	482	1,785	886	206	338	167,718	26,637	242,963
2028	5,785	551	2,040	1,012	235	387	174,161	27,018	249,373
2029	6,454	606	2,280	1,127	259	432	162,170	23,442	233,114
2030	7,110	659	2,516	1,241	283	477	162,170	23,442	233,114
2031	7,753	710	2,748	1,354	307	522	162,170	23,442	233,114
2032	8,339	760	2,960	1,460	329	564	162,170	23,442	233,114
2033	8,909	808	3,168	1,564	352	605	162,170	23,442	233,114
2034	9,464	857	3,370	1,667	374	646	162,170	23,442	233,114
2035	9,250	846	3,294	1,648	370	638	0	0	0
2036	8,739	835	3,073	1,579	366	600	0	0	0
2037	8,088	789	2,829	1,470	347	557	0	0	0
2038	7,450	741	2,590	1,369	327	517	0	0	0
2039	6,841	685	2,372	1,267	304	475	0	0	0
2040	6,197	626	2,144	1,154	278	430	0	0	0
2041	5,543	562	1,919	1,036	250	384	0	0	0
2042	4,871	499	1,685	916	221	337	0	0	0
2043	4,220	434	1,457	796	191	291	0	0	0
2044	3,561	377	1,218	678	165	245	0	0	0
2045	2,912	318	990	562	139	201	0	0	0
2046	2,276	265	761	451	116	156	0	0	0
2047	1,746	212	573	349	93	117	0	0	0
2048	1,216	159	384	248	70	79	0	0	0
2049	686	106	195	146	46	40	0	0	0
2050	156	53	7	45	23	1	0	0	0
2051	0	0	0	0	0	0	0	0	0
2052	0	0	0	0	0	0	0	0	0
2053	0	0	0	0	0	0	0	0	0
2054	0	0	0	0	0	0	0	0	0
2055	0	0	0	0	0	0	0	0	0
2056	0	0	0	0	0	0	0	0	0
2057	0	0	0	0	0	0	0	0	0

***Demand values are coincident to system peak*

H. Demand Response Forecast

The base demand response forecast was developed by the Company and is included in all scenarios and sensitivities. The three demand response "Bundles" are from the Brattle Potential Study provided as Appendix G2. The Bundles are incremental to the base demand response forecast and, the same as for EE, are dependent on the Bundle before it being selected (i.e. Bundle 2 cannot be selected if Bundle 1 is not selected). These Bundles are included in Strategist as Proview Alternatives and any number of

the Bundles (from 0 to all 3) is allowed to be selected as part of the optimization process.

Table 8: Demand Response Forecast

Demand (MW) Adjusted For Reserve Margin					Costs ($000)		
Year	Base Demand Response Forecast	Bundle 1	Bundle 2	Bundle 3	Bundle 1	Bundle 2	Bundle 3
2018	848	0	0	0	0	0	0
2019	924	0	0	0	0	0	0
2020	940	270	107	89	14,380	7,659	11,311
2021	955	290	112	97	15,724	8,150	12,587
2022	970	312	116	106	17,212	8,676	14,016
2023	989	322	120	110	18,124	9,137	14,758
2024	1007	339	132	101	19,512	10,277	13,829
2025	1023	380	145	92	22,305	11,459	12,858
2026	1038	392	151	93	23,475	12,207	13,326
2027	1053	406	159	95	24,786	13,080	13,845
2028	1066	421	168	97	26,245	14,086	14,418
2029	1054	438	178	99	27,859	15,231	15,047
2030	1043	456	189	101	29,637	16,522	15,734
2031	1032	476	201	104	31,551	17,926	16,467
2032	1021	497	214	106	33,612	19,451	17,251
2033	1010	519	227	109	35,832	21,109	18,088
2034	1000	542	242	112	38,224	22,911	18,984
2035	990	567	257	116	40,802	24,870	19,943
2036	981	594	274	119	43,582	26,999	20,971
2037	972	630	293	125	46,580	29,313	22,072
2038	963	660	312	129	49,814	31,829	23,253
2039	954	692	332	133	53,305	34,564	24,522
2040	945	726	353	138	57,073	37,537	25,884
2041	937	726	353	138	58,215	38,288	26,402
2042	929	726	353	138	59,379	39,054	26,930
2043	921	726	353	138	60,566	39,835	27,468
2044	913	726	353	138	61,778	40,632	28,018
2045	906	726	353	138	63,013	41,444	28,578
2046	898	726	353	138	64,274	42,273	29,150
2047	891	726	353	138	65,559	43,118	29,733
2048	884	726	353	138	66,870	43,981	30,327
2049	876	726	353	138	68,208	44,860	30,934
2050	869	726	353	138	69,572	45,758	31,552
2051	862	726	353	138	70,963	46,673	32,183
2052	854	726	353	138	72,382	47,606	32,827
2053	847	726	353	138	73,830	48,558	33,484
2054	839	726	353	138	75,307	49,530	34,153
2055	832	726	353	138	76,813	50,520	34,836
2056	825	726	353	138	78,349	51,531	35,533
2057	817	726	353	138	79,916	52,561	36,244

**Demand values are coincident to system peak.*

I. Fuel Price Forecasts

The natural gas prices are developed using a blend of market information (New York Mercantile Exchange futures prices) and long-term fundamentally-based forecasts from Wood Mackenzie, Cambridge Energy Research Associates (CERA) and Petroleum Industry Research Associates (PIRA).

Coal price forecasts are developed using two major inputs: the current contract volumes and prices combined with current estimates of required spot volumes and prices to cover non-contracted coal needs. Typically coal volumes and prices are under contract on a plant by plant basis for a one to five year term with annual spot volumes filling the estimated fuel requirements of the coal plant based on recent unit dispatch. The spot coal price forecasts are developed from price forecasts provided by Wood Mackenzie, JD Energy, and John T Boyd Company, as well as price points from recent Request for Proposal (RFP) responses for coal supply. Added to the spot coal forecast, which is just for the coal commodity, are: transportation charges, SO_2 costs, freeze control and dust suppressant, as required.

In addition to resources that exist within the NSP System, the Company is a participant in the MISO Market. Electric power market prices are developed from fundamentally-based forecasts from Wood Mackenzie, CERA and PIRA using a similar methodology as is used for the gas price forecast. Table 9 below shows the market prices under zero CO_2 cost assumptions. The market purchases and sales limit for transaction volume between the Company and MISO is 1,350 MWh/h in 2018, 1,800 MWh/h from 2019-2022, and 2,300 MWh/h for 2023 and beyond.

High and low price sensitivities were performed by adjusting the growth rate up and down by 50 percent from the base forecast starting in year 2022.

Table 9: Fuel and Market Price Forecasts

	Base Price Forecast				Low Price Forecast				High Price Forecast			
	Fuel Price ($/mmBTu)		Market Price ($/MWh)		Fuel Price ($/mmBTu)		Market Price ($/MWh)		Fuel Price ($/mmBTu)		Market Price ($/MWh)	
Year	Generic Coal	Ventura Hub	Minn Hub On-Peak	Minn Hub Off-Peak	Generic Coal	Ventura Hub	Minn Hub On-Peak	Minn Hub Off-Peak	Generic Coal	Ventura Hub	Minn Hub On-Peak	Minn Hub Off-Peak
2018	$2.19	$2.74	$28.60	$21.61	$2.19	$2.74	$28.60	$21.61	$2.19	$2.74	$28.60	$21.61
2019	$2.08	$2.67	$27.10	$21.12	$2.08	$2.67	$27.10	$21.12	$2.08	$2.67	$27.10	$21.12
2020	$2.11	$2.44	$24.36	$18.97	$2.11	$2.44	$24.36	$18.97	$2.11	$2.44	$24.36	$18.97
2021	$2.14	$2.37	$23.37	$17.97	$2.14	$2.37	$23.37	$17.97	$2.14	$2.37	$23.37	$17.97
2022	$2.23	$2.52	$24.93	$19.30	$2.19	$2.44	$24.18	$18.72	$2.26	$2.59	$25.68	$19.88
2023	$2.29	$2.82	$28.39	$22.16	$2.24	$2.59	$26.08	$20.36	$2.34	$3.06	$30.80	$24.04
2024	$2.37	$3.07	$30.69	$23.93	$2.29	$2.70	$27.02	$21.07	$2.45	$3.47	$34.66	$27.03
2025	$2.42	$3.26	$32.82	$25.48	$2.34	$2.79	$28.06	$21.79	$2.51	$3.79	$38.13	$29.61
2026	$2.48	$3.42	$34.50	$27.03	$2.38	$2.85	$28.81	$22.58	$2.59	$4.06	$41.02	$32.14
2027	$2.55	$3.51	$35.03	$27.53	$2.43	$2.89	$28.86	$22.68	$2.68	$4.24	$42.22	$33.19
2028	$2.62	$3.60	$35.52	$27.78	$2.48	$2.93	$28.90	$22.60	$2.77	$4.40	$43.35	$33.90
2029	$2.69	$3.82	$37.34	$29.17	$2.54	$3.02	$29.53	$23.07	$2.87	$4.79	$46.83	$36.59
2030	$2.76	$4.09	$39.20	$30.60	$2.59	$3.13	$29.95	$23.38	$2.97	$5.31	$50.84	$39.69
2031	$2.84	$4.26	$41.18	$32.22	$2.64	$3.19	$30.85	$24.13	$3.07	$5.63	$54.45	$42.60
2032	$2.92	$4.47	$42.61	$33.54	$2.70	$3.27	$31.17	$24.53	$3.18	$6.05	$57.66	$45.38
2033	$3.00	$4.74	$45.01	$35.50	$2.75	$3.37	$31.99	$25.24	$3.30	$6.60	$62.64	$49.41
2034	$3.08	$4.93	$46.64	$37.01	$2.81	$3.44	$32.51	$25.80	$3.42	$6.99	$66.15	$52.51
2035	$3.17	$4.94	$46.91	$37.38	$2.87	$3.44	$32.65	$26.02	$3.54	$7.02	$66.64	$53.11
2036	$3.26	$5.00	$46.72	$37.35	$2.93	$3.46	$32.33	$25.85	$3.67	$7.15	$66.75	$53.37
2037	$3.35	$5.17	$48.19	$38.46	$2.99	$3.52	$32.81	$26.19	$3.81	$7.51	$69.97	$55.84
2038	$3.44	$5.40	$49.56	$40.01	$3.06	$3.60	$33.03	$26.67	$3.95	$8.00	$73.47	$59.32
2039	$3.51	$5.65	$51.50	$41.70	$3.11	$3.68	$33.54	$27.16	$4.05	$8.57	$78.09	$63.23
2040	$3.61	$5.90	$53.12	$43.28	$3.18	$3.76	$33.87	$27.60	$4.20	$9.14	$82.24	$67.00
2041	$3.69	$6.08	$54.73	$44.58	$3.24	$3.82	$34.39	$28.01	$4.31	$9.55	$85.97	$70.04
2042	$3.77	$6.27	$56.47	$46.00	$3.30	$3.88	$34.93	$28.46	$4.42	$10.01	$90.07	$73.38
2043	$3.85	$6.46	$58.13	$47.35	$3.36	$3.94	$35.44	$28.88	$4.53	$10.45	$94.04	$76.61
2044	$3.93	$6.57	$59.12	$48.17	$3.43	$3.97	$35.75	$29.12	$4.65	$10.72	$96.46	$78.59
2045	$4.02	$6.66	$59.90	$48.80	$3.49	$4.00	$35.99	$29.32	$4.77	$10.93	$98.37	$80.14
2046	$4.11	$6.77	$60.93	$49.63	$3.56	$4.03	$36.29	$29.57	$4.89	$11.21	$100.88	$82.19
2047	$4.20	$6.96	$62.70	$51.07	$3.63	$4.09	$36.82	$29.99	$5.02	$11.69	$105.27	$85.75
2048	$4.29	$7.17	$64.55	$52.57	$3.70	$4.15	$37.37	$30.44	$5.15	$12.21	$109.93	$89.54
2049	$4.38	$7.25	$65.25	$53.15	$3.77	$4.17	$37.57	$30.60	$5.29	$12.41	$111.72	$91.01
2050	$4.48	$7.37	$66.39	$54.08	$3.85	$4.21	$37.90	$30.87	$5.43	$12.73	$114.66	$93.38
2051	$4.58	$7.52	$67.67	$55.12	$3.92	$4.25	$38.27	$31.17	$5.57	$13.10	$117.97	$96.08
2052	$4.68	$7.66	$68.99	$56.19	$4.00	$4.29	$38.64	$31.47	$5.72	$13.49	$121.42	$98.90
2053	$4.79	$7.81	$70.33	$57.28	$4.08	$4.33	$39.02	$31.78	$5.87	$13.88	$124.95	$101.77
2054	$4.89	$7.96	$71.68	$58.39	$4.16	$4.38	$39.39	$32.08	$6.03	$14.28	$128.56	$104.71
2055	$5.00	$8.12	$73.07	$59.51	$4.25	$4.42	$39.77	$32.39	$6.18	$14.69	$132.28	$107.74
2056	$5.11	$8.27	$74.48	$60.67	$4.33	$4.46	$40.16	$32.71	$6.34	$15.12	$136.13	$110.87
2057	$5.21	$8.43	$75.92	$61.83	$4.41	$4.50	$40.54	$33.02	$6.49	$15.55	$140.05	$114.06

**Coal prices are delivered prices, while gas and market prices are hub prices.*

J. Baseload Retirement "Leave Behind" Costs

Based on the MISO Y2 retirement studies performed on existing coal and nuclear resources, the Company developed transmission reinforcement or "leave behind" estimates, which reflect costs required to mitigate localized grid impacts of the retirement of major baseload resources. The reinforcement costs are included as a one-time charge based on the timing of the resource retirement.

Specifically, we have included the following proxy leave behind costs related to our baseload resource retirements as estimated from the MISO studies. We applied these costs in the modeling as soon as the resource is retired, over a three year period, to reflect the estimated local transmission reinforcement costs assumed to be required upon retirement. All numbers below are in real dollar terms ($2020).

- King: $48 million
- Sherco 3: $48 million
- Monticello: $96 million
- Prairie Island 1: $96 million
- Prairie Island 2: $96 million

K. Surplus Capacity Credit

The surplus capacity credit of up to 500 MW is applied for all twelve months of each year and is priced at the avoided capacity cost of a generic brownfield H-Class combustion turbine on an economic carrying charge basis.

Table 10: Surplus Capacity Credit

Surplus Capacity Credit																				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
$/kw-mo	4.62	4.71	4.81	4.90	5.00	5.10	5.20	5.31	5.41	5.52	5.63	5.74	5.86	5.98	6.10	6.22	6.34	6.47	6.60	6.73
	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057
$/kw-mo	6.87	7.00	7.14	7.29	7.43	7.58	7.73	7.89	8.04	8.20	8.37	8.54	8.71	8.88	9.06	9.24	9.42	9.61	9.80	10.00

L. Effective Load Carrying Capability (ELCC) Capacity Credit for Wind, Solar, and Battery Resources

The ELCC for existing wind units is based on current MISO accreditation. The ELCC for generic wind is equal to 15.6% of their nameplate rating per MISO 2017/2018 Wind Capacity Report. The ELCC for generic solar is 50% of the AC nameplate capacity. The ELCC for a generic 4-hour battery is equal to 100% of their AC equivalent capacity.

M. Spinning Reserve Requirement

Spinning reserve is the on-line reserve capacity that is synchronized to the grid to maintain system frequency stability during contingency events and unforeseen load swings. The level of spinning reserve modeled is 137 MW and is based on a 12 month rolling average of spinning reserves carried by the NSP System within MISO.

N. Emergency Energy

Emergency energy is $500/MWh and is used to cover events where there are not enough resources available to meet system energy requirements.

O. Transmission Delivery Costs and Interconnection Costs

Transmission delivery costs for generic resources were developed by the Company. They are based on evaluation of recent and historical MISO studies and queue results. These costs represent "grid upgrades" to ensure deliverability of energy from these facilities to the overall bulk electric system.

We note additionally that interconnection costs for generic resources are included in the capital costs in Table 14 in Part U of this Appendix, and represent "behind the fence" costs associated with substation and representative gen-tie construction.

Table 11: Transmission Delivery Costs

Transmission Delivery Costs				
	CC	CT	Wind	Solar
$/kw	500	200	400	140

P. Integration and Congestion Costs

Integration costs are taken from studies conducted by Enernex and apply to new wind and solar resources only. Congestion costs were developed by the Company using the MISO MTEP 2018 models and looking at the average congestion costs between representative wind bus locations and NSP.NSP. Congestion costs are applied to new wind projects only.

Table 12: Integration and Congestion Costs

Integration and Congestion Costs ($/MWh)				
Year	Integration		Congestion	
	Wind	Solar	Wind	Solar
2018	0.00	0.00	0.00	0.00
2019	0.00	0.00	0.00	0.00
2020	0.41	0.41	3.43	0.00
2021	0.42	0.42	3.50	0.00
2022	0.43	0.43	3.57	0.00
2023	0.44	0.44	3.64	0.00
2024	0.45	0.45	3.71	0.00
2025	0.46	0.46	3.79	0.00
2026	0.47	0.47	3.86	0.00
2027	0.48	0.48	3.94	0.00
2028	0.49	0.49	4.02	0.00
2029	0.49	0.49	4.10	0.00
2030	0.50	0.50	4.18	0.00
2031	0.51	0.51	4.27	0.00
2032	0.53	0.53	4.35	0.00
2033	0.54	0.54	4.44	0.00
2034	0.55	0.55	4.53	0.00
2035	0.56	0.56	4.62	0.00
2036	0.57	0.57	4.71	0.00
2037	0.58	0.58	4.80	0.00
2038	0.59	0.59	4.90	0.00
2039	0.60	0.60	5.00	0.00
2040	0.62	0.62	5.10	0.00
2041	0.63	0.63	5.20	0.00
2042	0.64	0.64	5.30	0.00
2043	0.65	0.65	5.41	0.00
2044	0.67	0.67	5.52	0.00
2045	0.68	0.68	5.63	0.00
2046	0.69	0.69	5.74	0.00
2047	0.71	0.71	5.86	0.00
2048	0.72	0.72	5.97	0.00
2049	0.74	0.74	6.09	0.00
2050	0.75	0.75	6.22	0.00
2051	0.77	0.77	6.34	0.00
2052	0.78	0.78	6.47	0.00
2053	0.80	0.80	6.60	0.00
2054	0.81	0.81	6.73	0.00
2055	0.83	0.83	6.86	0.00
2056	0.84	0.84	7.00	0.00
2057	0.86	0.86	7.14	0.00

Q. Distributed Generation and Community Solar Gardens

The distributed solar inputs are based on the most recent Company forecasts. Annual additions are modeled assuming a degradation of half a percent annually in generation, and a twenty five year service life. After a "vintage" of additions reach end of life, it is assumed 90% of the capacity is replaced at then-current costs. The Company expects

a transition from Solar*Rewards to non-incentivized DG over time due to the end of statutory provisions.

Table 13: Distributed Solar Forecast

Distributed Solar (Nameplate MW)				
Year	Solar Rewards	Net Metered	Community Gardens	Total
2018	29	18	246	293
2019	41	27	504	573
2020	49	37	641	727
2021	53	47	649	749
2022	56	58	657	771
2023	57	70	665	792
2024	57	83	673	813
2025	56	96	681	834
2026	56	109	689	854
2027	56	122	697	875
2028	55	135	705	895
2029	55	147	713	915
2030	55	160	720	935
2031	55	172	728	955
2032	54	185	736	975
2033	54	197	744	995
2034	51	212	751	1,014
2035	45	229	759	1,033
2036	39	247	766	1,052
2037	34	262	774	1,070
2038	27	280	781	1,088
2039	16	301	789	1,106
2040	8	319	796	1,123
2041	4	333	804	1,141
2042	0	346	808	1,154
2043	0	358	796	1,154
2044	0	368	781	1,149
2045	0	379	776	1,155
2046	0	389	783	1,171
2047	0	399	789	1,188
2048	0	409	795	1,205
2049	0	419	802	1,221
2050	0	429	808	1,237
2051	0	439	814	1,254
2052	0	449	821	1,270
2053	0	459	827	1,286
2054	0	469	833	1,302
2055	0	479	839	1,318
2056	0	488	845	1,334
2057	0	498	852	1,350

R. Owned Unit Modeled Operating Characteristics and Costs

Company owned units are modeled based upon their tested operating characteristics and projected costs. Below is a list of typical operating and cost inputs for each

company owned resource.

a. Retirement Date
b. Maximum Capacity
c. Current Unforced Capacity (UCAP) Ratings
d. Minimum Capacity Rating
e. Seasonal Deration
f. Heat Rate Profiles
g. Variable O&M
h. Fixed O&M
i. Maintenance Schedule
j. Forced Outage Rate
k. Emission rates for SO_2, NO_x, CO_2, Mercury and particulate matter (PM)
l. Contribution to spinning reserve
m. Fuel prices
n. Fuel delivery charges

S. Thermal Power Purchase Agreement (PPA) Operating Characteristics and Costs

PPAs are modeled based upon their tested operating characteristics and contracted costs. Below is a list of typical operating and cost inputs for each thermal PPA.

a. Contract term
b. Maximum Capacity
c. Minimum Capacity Rating
d. Seasonal Deration
e. Heat Rate Profiles
f. Energy Schedule
g. Capacity Payments
h. Energy Payments
i. Maintenance Schedule
j. Forced Outage Rate
k. Emission rates for SO_2, NO_x, CO_2, Mercury and PM
l. Contribution to spinning reserve
m. Fuel prices
n. Fuel delivery charges

T. Renewable Energy (PPAs and Owned) Operating Characteristics and Costs

PPAs are modeled based upon their tested operating characteristics and contracted costs. Company owned units are modeled based upon their tested operating characteristics and projected costs. Below is a list of typical operating and cost inputs for each renewable energy unit.

a. Contract term
b. Name Plate Capacity
c. Accredited Capacity
d. Annual Energy
e. Hourly Patterns
f. Capacity and Energy Payments
g. Integration Costs

Wind hourly patterns are developed through a "Typical Wind Year" process where individual months are selected from the years 2014-2017 to develop a representative typical year. Actual generation data from the selected months is used to develop the profile for each wind farm. For farms where generation data is not complete or not available, data from nearby similar farms is used.

Solar hourly patterns are taken from the ELCC Study from Fall 2013 and updated to reflect the ELCC as stated above.

U. Generic Assumptions

Generic resources are modeled based upon their expected operating characteristics and projected costs. Generic thermal costs are developed by the Company. Generic battery costs are based on Public Service of Colorado All-Source Solicitation bids (Nov 28, 2017) with a 10% annual price improvement rate. Generic renewable costs and capacity factors are from National Renewable Energy Laboratory's 2018 Annual Technology Baseline data. Utility-scale wind and solar costs shown in Tables 16-18 include transmission costs from Table 10, while DG/distributed solar does not.

The Reference Case assumes "no going back" on renewables, meaning that we are committed to pursuing repowering and/or contract extension opportunities for renewable resources that will expire , and renewable resources are replaced "in-kind" when they reach end of life. Starting in 2023, generic solar is added to maintain at a minimum the 2015 IRP Preferred Plan solar levels. In 2023, there is approximately 1,800 GWhs of solar (both utility scale and DG solar) on the system which will grow to approximately 4,500 GWhs by 2028. The Company has already procured the levels

of wind contemplated in the previous Resource Plan, so no minimum level of generic wind additions are needed. Additional renewables are included as Proview Alternatives.

In addition to base cost data for renewables, low and high costs are used for various sensitivities. Low and high wind and solar costs are based on the National Renewable Energy Laboratory's 2018 Annual Technology Baseline data. Low and high battery costs are based the percent difference in the NREL ATB low / high battery costs compared to the NREL ATB base costs, with this percent difference applied to the Company's base battery cost forecast. Below is a list of typical operating and cost inputs for each generic resource.

Thermal

a. Retirement Date
b. Maximum Capacity
c. UCAP Ratings
d. Minimum Capacity Rating
e. Seasonal Deration
f. Heat Rate Profiles
g. Variable O&M
h. Fixed O&M
i. Maintenance Schedule
j. Forced Outage Rate
k. Emission rates for SO_2, NO_x, CO_2, Mercury and PM
l. Contribution to spinning reserve
m. Fuel prices
n. Fuel delivery charges

Renewable

a. Contract term
b. Name Plate Capacity
c. Accredited Capacity
d. Annual Energy
e. Hourly Patterns
f. Capacity and Energy Payments
g. Integration Costs

Table 14: Thermal Generic Information (Costs in 2018 Dollars)

Thermal Generic Information					
Resource	**Sherco CC**	**Generic CC**	**Generic CT**	**Generic CT**	**Generic CT**
Technology	7H	7H	7H	7F	7H
Location Type	Brownfield	Greenfield	Brownfield	Brownfield	Greenfield
Cooling Type	Wet	Dry	Dry	Dry	Dry
Book life	40	40	40	40	40
Nameplate Capacity (MW)	835	901	374	232	374
Summer Peak Capacity (MW)	750	856	331	206	331
Capital Cost ($000) 2018$	$837,068	$906,588	$174,700	$114,766	$193,500
Electric Transmission Delivery ($000) 2018$	NA	$410,505	NA	NA	$74,804
Ongoing Capital Expenditures ($000-yr) 2018$	$6,200	$6,200	$1,784	$892	$1,784
Gas Demand ($000-yr) 2018$	$15,000	$19,058	$2,165	$1,342	$2,165
Gas Pipeline CIAC ($000) 2018 $	$192,000	NA	NA	NA	NA
Capital Cost ($/kW) 2018$	$1,002	$1,006	$467	$495	$517
Electric Transmission Delivery ($/kW) 2018$	NA	$455	NA	NA	$200
Ongoing Capital Expenditures ($/kW-yr) 2018$	$7.42	$6.88	$4.77	$3.85	$4.77
Gas Demand ($/kW-yr) 2018$	$17.96	$21.14	$5.79	$5.79	$5.79
Fixed O&M Cost ($000/yr) 2018$	$6,592	$6,592	$1,253	$1,203	$1,253
Variable O&M Cost ($/MWh) 2018$	$1.04	$1.04	$0.99	$1.03	$0.99
Levelized $/kw-mo (All Fixed Costs) $2018	$14.46	$16.19	$5.96	$6.27	$8.14
Summer Heat Rate 100% Loading (btu/kWh)	6,359	6,848	9,264	10,025	9,264
Summer Heat Rate 75% Loading (btu/kWh)	6,547	6,874	9,738	10,581	9,738
Summer Heat Rate 50% Loading (btu/kWh)	6,985	7,334	11,120	12,515	11,120
Summer Heat Rate 25% Loading (btu/kWh)	8,004	8,404	11,558	13,430	11,558
Forced Outage Rate	3%	3%	3%	3%	3%
Maintenance (weeks/yr)	5	5	2	2	2
CO2 Emissions (lbs/MMBtu)	118	118	118	118	118
SO2 Emissions (lbs/MWh)	0.00	0.00	0.00	0.00	0.00
NOx Emissions (lbs/MWh)	0.05	0.05	0.90	0.32	0.90
PM10 Emissions (lbs/MWh)	0.02	0.02	0.03	0.03	0.03
Mercury Emissions (lbs/MMWh)	0.00	0.00	0.00	0.00	0.00

Table 15: Renewable Generic Information (Costs in 2018 Dollars)

Renewable Generic Information				
Resource	**Wind**	**Utility Scale Solar**	**Distributed Solar Commercial**	**Distributed Solar Residential**
ELCC Capacity Credit (%)	15.6%	50.0%	50.0%	50.0%
Capacity Factor	50.0%	17.7%	14.0%	14.8%
Book life	25	25	25	25
Electric Transmission Delivery ($/kW)	400	140	0	0

Table 16: Storage Generic Information (Costs in 2018 Dollars)

Storage Generic Information	
Resource	**Battery**
Technology	Li Ion
Location Type	NA
Book life	40
Nameplate Capacity (MW)	321
Summer Peak Capacity (MW)	321
Storage Volume (hrs)	4
Cycle Efficiency (%)	88
Equivalent Full Cycles per Year	156
Electric Transmission Delivery ($000) 2018$	0
Levelized $/kw-mo (All Fixed Costs) $2023	$10.53

Table 17: Levelized Capacity Costs by In-Service Year

Levelized Capacity Costs by In-Service Year ($/kw-mo)								
COD	CT - 7H Greenfield	CT - 7F Brownfield	CT - 7H Brownfield	CC	Sherco CC	Base Battery	Low Battery	High Battery
2018	$8.14	$6.27	$5.96	$16.19	$14.46			
2019	$8.31	$6.40	$6.08	$16.51	$14.75			
2020	$8.47	$6.53	$6.20	$16.84	$15.04			
2021	$8.64	$6.66	$6.33	$17.18	$15.35			
2022	$8.81	$6.79	$6.46	$17.52	$15.65			
2023	$8.99	$6.93	$6.58	$17.88	$15.97	$10.53	$8.03	$13.71
2024	$9.17	$7.07	$6.72	$18.23	$16.28	$9.48	$6.99	$12.51
2025	$9.35	$7.21	$6.85	$18.60	$16.61	$8.91	$6.35	$11.92
2026	$9.54	$7.35	$6.99	$18.97	$16.94	$8.53	$5.90	$11.41
2027	$9.73	$7.50	$7.13	$19.35	$17.28	$8.24	$5.53	$11.04
2028	$9.93	$7.65	$7.27	$19.74	$17.63	$8.02	$5.20	$10.73
2029	$10.13	$7.80	$7.41	$20.13	$17.98	$7.83	$4.92	$10.49
2030	$10.33	$7.96	$7.56	$20.53	$18.34	$7.68	$4.65	$10.28
2031	$10.53	$8.12	$7.71	$20.94	$18.71	$7.54	$4.51	$10.19
2032	$10.75	$8.28	$7.87	$21.36	$19.08	$7.42	$4.39	$10.13
2033	$10.96	$8.44	$8.03	$21.79	$19.46	$7.31	$4.27	$10.08
2034	$11.18	$8.61	$8.19	$22.23	$19.85	$7.22	$4.16	$10.05
2035	$11.40	$8.79	$8.35	$22.67	$20.25	$7.13	$4.05	$10.02
2036	$11.63	$8.96	$8.52	$23.12	$20.65	$7.05	$3.94	$10.02
2037	$11.86	$9.14	$8.69	$23.59	$21.07	$6.98	$3.83	$10.03
2038	$12.10	$9.32	$8.86	$24.06	$21.49	$6.91	$3.73	$10.05
2039	$12.34	$9.51	$9.04	$24.54	$21.92	$6.85	$3.63	$10.07
2040	$12.59	$9.70	$9.22	$25.03	$22.36	$6.79	$3.53	$10.09
2041	$12.84	$9.89	$9.40	$25.53	$22.80	$6.73	$3.44	$10.11
2042	$13.10	$10.09	$9.59	$26.04	$23.26	$6.68	$3.36	$10.13
2043	$13.36	$10.29	$9.78	$26.56	$23.72	$6.63	$3.28	$10.15
2044	$13.63	$10.50	$9.98	$27.09	$24.20	$6.58	$3.20	$10.17
2045	$13.90	$10.71	$10.18	$27.63	$24.68	$6.54	$3.12	$10.20
2046	$14.18	$10.92	$10.38	$28.19	$25.18	$6.50	$3.10	$10.13
2047	$14.46	$11.14	$10.59	$28.75	$25.68	$6.46	$3.09	$10.07
2048	$14.75	$11.37	$10.80	$29.33	$26.19	$6.42	$3.07	$10.01
2049	$15.05	$11.59	$11.02	$29.91	$26.72	$6.38	$3.06	$9.96
2050	$15.35	$11.82	$11.24	$30.51	$27.25	$6.35	$3.04	$9.91
2051	$15.65	$12.06	$11.46	$31.12	$27.80	$6.31	$3.03	$9.85
2052	$15.97	$12.30	$11.69	$31.74	$28.35	$6.28	$3.01	$9.80
2053	$16.29	$12.55	$11.93	$32.38	$28.92	$6.25	$3.00	$9.76
2054	$16.61	$12.80	$12.16	$33.03	$29.50	$6.22	$2.98	$9.71
2055	$16.94	$13.06	$12.41	$33.69	$30.09	$6.19	$2.97	$9.66
2056	$17.28	$13.32	$12.66	$34.36	$30.69	$6.16	$2.95	$9.62
2057	$17.63	$13.58	$12.91	$35.05	$31.30	$6.13	$2.94	$9.58

Table 18: Base Renewable Levelized Costs by In-Service Year

Levelized Costs by In-Service Year $/MWh (LCOE)				
COD	Wind	Utility Scale Solar	Distributed Solar Commercial	Distributed Solar Residential
2018				
2019				
2020	$29.79	$40.00	$73.92	$97.93
2021	$29.65	$40.00	$71.77	$91.35
2022	$34.04	$40.00	$70.71	$88.46
2023	$38.61	$49.48	$69.59	$87.04
2024	$43.39	$49.90	$68.41	$85.55
2025	$52.15	$50.32	$67.18	$83.98
2026	$52.55	$50.74	$65.88	$82.34
2027	$52.98	$51.17	$64.53	$80.63
2028	$53.42	$51.59	$63.11	$78.83
2029	$53.89	$52.01	$61.62	$76.95
2030	$54.39	$52.43	$60.07	$74.98
2031	$54.95	$53.10	$60.66	$75.15
2032	$55.54	$53.78	$61.25	$75.28
2033	$56.16	$54.47	$61.84	$75.40
2034	$56.80	$55.16	$62.43	$75.49
2035	$57.47	$55.86	$63.02	$75.56
2036	$58.17	$56.57	$63.61	$75.60
2037	$58.91	$57.28	$64.20	$75.61
2038	$59.67	$58.00	$64.78	$75.60
2039	$60.47	$58.72	$65.37	$75.56
2040	$61.30	$59.45	$65.95	$75.49
2041	$62.17	$60.13	$66.88	$76.33
2042	$63.07	$60.81	$67.82	$77.18
2043	$64.01	$61.50	$68.77	$78.04
2044	$64.99	$62.18	$69.74	$78.89
2045	$66.01	$62.87	$70.71	$79.76
2046	$67.07	$63.57	$71.70	$80.62
2047	$68.17	$64.27	$72.70	$81.49
2048	$69.32	$64.97	$73.71	$82.36
2049	$70.52	$65.68	$74.73	$83.24
2050	$71.76	$66.38	$75.76	$84.07
2051	$73.20	$67.71	$77.28	$85.75
2052	$74.66	$69.07	$78.83	$87.47
2053	$76.16	$70.45	$80.40	$89.22
2054	$77.68	$71.86	$82.01	$91.00
2055	$79.23	$73.29	$83.65	$92.82
2056	$80.82	$74.76	$85.32	$94.68
2057	$82.43	$76.25	$87.03	$96.57

**Distributed Solar costs represent at the meter values before grossing up for losses.*

Table 19: Low Renewable Levelized Costs by In-Service Year

Low Levelized Costs by In-Service Year $/MWh (LCOE)				
COD	Wind	Utility Scale Solar	Distributed Solar Commercial	Distributed Solar Residential
2018				
2019				
2020	$25.51	$35.18	$56.57	$94.61
2021	$24.43	$35.18	$51.50	$85.46
2022	$27.80	$35.18	$50.18	$81.18
2023	$31.28	$43.52	$48.81	$78.32
2024	$34.89	$43.21	$47.40	$75.38
2025	$42.41	$42.88	$45.95	$72.34
2026	$41.50	$42.54	$44.44	$69.21
2027	$40.53	$42.17	$42.89	$65.98
2028	$39.52	$41.79	$41.28	$62.65
2029	$38.00	$41.39	$39.63	$59.22
2030	$37.80	$40.97	$37.93	$55.69
2031	$37.66	$41.28	$37.65	$53.91
2032	$38.06	$41.58	$37.35	$52.04
2033	$38.48	$41.88	$37.03	$50.07
2034	$38.90	$42.28	$36.68	$48.02
2035	$39.34	$42.25	$36.30	$45.87
2036	$39.80	$42.39	$35.90	$43.62
2037	$40.26	$42.52	$35.47	$41.27
2038	$40.75	$42.64	$35.01	$38.81
2039	$41.24	$42.75	$34.52	$36.25
2040	$41.75	$42.85	$33.99	$33.57
2041	$42.27	$43.27	$34.47	$34.11
2042	$42.80	$43.39	$34.95	$34.64
2043	$43.35	$43.37	$35.44	$35.19
2044	$43.92	$43.33	$35.94	$35.75
2045	$44.50	$44.15	$36.44	$36.31
2046	$45.09	$43.34	$36.95	$36.88
2047	$45.70	$43.39	$37.46	$37.46
2048	$46.32	$43.42	$37.98	$38.05
2049	$46.96	$43.44	$38.50	$38.65
2050	$47.62	$43.97	$39.04	$39.22
2051	$48.57	$44.85	$39.82	$40.00
2052	$49.54	$45.74	$40.61	$40.80
2053	$50.53	$46.66	$41.43	$41.62
2054	$51.54	$47.59	$42.25	$42.45
2055	$52.57	$48.54	$43.10	$43.30
2056	$53.63	$49.51	$43.96	$44.17
2057	$54.70	$50.50	$44.84	$45.05

**Distributed Solar costs represent at the meter values before grossing up for losses.*

Table 20: High Renewable Levelized Costs by In-Service Year

High Levelized Costs by In-Service Year $/MWh (LCOE)				
COD	Wind	Utility Scale Solar	Distributed Solar Commercial	Distributed Solar Residential
2018				
2019				
2020	$34.70	$50.52	$88.96	$124.70
2021	$35.40	$50.52	$91.58	$127.20
2022	$40.61	$50.52	$93.41	$128.14
2023	$46.03	$62.48	$95.28	$130.70
2024	$51.64	$63.73	$97.19	$133.32
2025	$61.25	$65.01	$99.13	$135.98
2026	$62.49	$66.31	$101.11	$138.70
2027	$63.76	$67.63	$103.14	$141.48
2028	$65.06	$68.99	$105.20	$144.30
2029	$66.38	$70.37	$107.30	$147.19
2030	$67.72	$71.77	$109.45	$150.13
2031	$69.10	$73.21	$111.64	$153.14
2032	$70.50	$74.67	$113.87	$156.20
2033	$71.93	$76.17	$116.15	$159.32
2034	$73.39	$77.69	$118.47	$162.51
2035	$74.88	$79.24	$120.84	$165.76
2036	$76.39	$80.83	$123.26	$169.08
2037	$77.94	$82.45	$125.72	$172.46
2038	$79.52	$84.09	$128.24	$175.91
2039	$81.13	$85.78	$130.80	$179.42
2040	$82.77	$87.49	$133.42	$183.01
2041	$84.45	$89.24	$136.09	$186.67
2042	$86.16	$91.03	$138.81	$190.41
2043	$87.90	$92.85	$141.58	$194.21
2044	$89.68	$94.70	$144.42	$198.10
2045	$91.49	$96.60	$147.30	$202.06
2046	$93.34	$98.53	$150.25	$206.10
2047	$95.23	$100.50	$153.25	$210.22
2048	$97.15	$102.51	$156.32	$214.43
2049	$99.12	$104.56	$159.45	$218.72
2050	$101.12	$106.65	$162.63	$223.09
2051	$103.14	$108.79	$165.89	$227.55
2052	$105.21	$110.96	$169.21	$232.10
2053	$107.31	$113.18	$172.59	$236.75
2054	$109.46	$115.44	$176.04	$241.48
2055	$111.65	$117.75	$179.56	$246.31
2056	$113.88	$120.11	$183.15	$251.24
2057	$116.16	$122.51	$186.82	$256.26

**Distributed Solar costs represent at the meter values before grossing up for losses.*

ATTACHMENT A: HEAT RATE UPDATED

In Docket No. E999/CI-06-159 (In the Matter of Commission Investigation and Determination under the Electricity Title, Section XII, of the Federal Energy Policy Act of 2005), the Minnesota Commission required the Company to file information on the fossil fuel efficiency (heat rate) of our generation units, and actions we are taking to increase the fuel efficiency of those units.

Heat rate data for the Company's owned generating units is provided publicly in our annual Federal Energy Regulatory Commission (FERC) Financial Report, FERC Form No. 1. We include a copy of the pertinent unit heat rate data from FERC Form No. 1 for 2018 in Table 21 below.

Table 21: 2018 FERC Heat Rates

Unit	Heat Rate
AS King	10,013
Sherco	10,546
Monticello	10,505
Prairie Island	10,487
Black Dog (NG)	7,870
High Bridge	6,863
Riverside	7,172
French Island	23,570
Wilmarth	10,637

The Company's Performance Monitoring department performs routine heat rate testing and conducts heat balances of its generating units. In addition, testing, assessments, and reporting on boilers, air heaters, cooling towers, and enthalpy drop tests on steam turbines are also conducted. These tools factor into our assessment of the condition of these individual components, as well as how their respective performance levels will impact the overall efficiency of a given generating unit. Table 22 below shows a summary of NSP System heat rate testing from 2015-2018.

Table 22: Heat Rate Tests – 2015-2018

Plant/Unit	Type of Unit Test	Type of Test	Year Tested
Sherco U1	Coal Boiler	Heat Rate	2015
Bayfront U4	Combustion Turbine	Calculated Adjustment for Fuel Change	2016
King U1	Coal Boiler	Heat Rate	2016
Sherco U2	Coal Boiler	Heat Rate	2015, 2016
Black Dog U5/U2	Combined Cycle	Heat Rate	2015, 2017
High Bridge CC	Combined Cycle	Heat Rate	2017, 2018
Sherco U3	Coal Boiler	Heat Rate	2017
Black Dog U6	Combustion Turbine	Heat Rate	2018
Riverside U7,U9,U10	Combined Cycle	Heat Rate	2017,2018

As part of its heat rate testing and reporting protocol, the Performance Monitoring group identifies potential heat rate improvement opportunities and validates actual performance enhancements. The Company does not look at heat rate improvements in isolation when considering plant improvement projects; rather, we perform a collective assessment of potential safety, efficiency, and environmental performance improvements as well as overall economics in developing our generation asset management objectives. Looking forward, the Company plans to continue our proactive cycle of heat rate testing and overall unit assessments at our generation units and implement improvements as opportunities arise.

ATTACHMENT B: WATER AND PLANT OPERATIONS

The Minnesota Commission's August 5, 2013 Notice of Information in Future Resource Plan Filings in Docket No. E002/RP-10-825 suggested utilities should consider adding to their initial resource plan filings the supplemental information listed at page 4 of the Commission's May 10, 2013 Order in Minnesota Power Docket No. E015/RP-13-53 (Order Point No. 4).

The Company's generating units are geographically positioned along major Minnesota waterways. The access to water accommodates the thermal needs of these generating units. As such, the Company's plant operations are governed by and comply with all applicable cooling water intake and discharge rules and regulations, which may indirectly affect Strategist modeling as discussed below.

The Clean Water Act Section 316(a) sets thermal limitations for discharges and the criteria and processes for allowing thermal variances. The Company's power plant discharge temperature limits and allowances for thermal emergency provisions are

outlined in the plants' National Pollutant Discharge Elimination System (NPDES) permits. Additionally, Xcel Energy has policies which outline the conditions and procedures to implement during periods of energy emergencies that allow for limited thermal variances.

Section 316(b) of the Clean Water Act governs the design and operation of intake structures in order to minimize adverse environmental impacts to aquatic life. EPA issued new rules in August 2014 that will impact all plants that withdraw water for cooling purposes. The new rules require improvements to intake screening technology to minimize the number of aquatic organisms that are killed due to being stuck to the screens (referred to as "impingement). The rules also created a process for the state permitting agency to evaluate and determine if additional improvements are required to minimize the number of smaller organisms that pass through the intake screens and enter the plant cooling water system (referred to as "entrainment"). While the costs associated with the impingement compliance requirements are definable, the costs associated with the entrainment compliance requirements are uncertain.

Timing of the compliance requirements is site-specific and is determined by each site's NPDES permit renewal timeline.

While specific conditions, such as high water discharge temperatures, are not directly modeled in Strategist, the model reflects the impact of reducing plant output due to high water temperatures. Modeling in Strategist includes two methods to account for impacts due to changes in plant operations: each resource is modeled using a unit specific median unforced capacity rating, and the system needs are modeled with a planning reserve margin. By modeling the system needs with a planning reserve margin, the base level of required resources is assumed to be higher than those needed to meet the forecasted peak system demand. By modeling all units with an assumed level of forced outage, the base level of all available resources, modeled in aggregate, is assumed to be sufficient to represent resource availability due to emergency changes in plant operations. Thus the impact of reducing plant output due to high water temperatures is reflected through corrections to both obligation and resource adjustments.

ATTACHMENT C: ICAP LOAD AND RESOURCES TABLE

The following table shows load and resources using Installed Capacity Rating (ICAP) for the planning period, in compliance with the Minnesota Commission's August 5, 2013 Notice of Information in Future Resource Plan Filings.[1]

Table 23: Load and Resources Tables, 2020-2034 Planning Period

ICAP Rating - Load and Resources 2020-2034 Planning Period															
Determination of Need	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Forecast Load	9,112	9,087	9,103	9,075	9,048	8,998	8,965	8,963	9,014	9,016	9,042	9,052	9,166	9,295	9,301
MISO System Coincident (ICAP)	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Coincident Load	9,112	9,087	9,103	9,075	9,048	8,998	8,965	8,963	9,014	9,016	9,042	9,052	9,166	9,295	9,301
MISO Planning Reserve	17.1%	17.1%	17.1%	17.1%	17.1%	17.1%	17.1%	17.1%	17.1%	17.1%	17.1%	17.1%	17.1%	17.1%	17.1%
Obligation	10,670	10,641	10,660	10,627	10,595	10,537	10,498	10,495	10,556	10,558	10,589	10,599	10,733	10,885	10,892
Existing and Approved Resources	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Load Management, Existing	940	955	970	989	1,007	1,023	1,038	1,053	1,066	1,054	1,043	1,032	1,021	1,010	1,000
Load Management, Potential Study	270	290	312	322	339	380	392	406	421	438	456	476	497	527	550
Coal	2,471	2,471	2,471	2,471	1,773	1,773	1,773	1,062	1,062	1,062	1,062	1,062	1,062	1,062	1,062
Nuclear	1,697	1,697	1,697	1,697	1,697	1,697	1,697	1,697	1,697	1,697	1,697	1,053	1,053	1,053	527
Natural Gas/Oil	3,511	3,511	3,511	3,511	3,347	3,032	2,784	2,260	2,139	2,139	2,139	2,139	1,858	1,858	1,858
MEC	720	720	720	720	720	720	720	720	720	720	720	720	720	720	720
Sherco CC	0	0	0	0	0	0	0	786	786	786	786	786	786	786	786
Biomass/RDF	107	107	107	84	84	60	60	60	19	19	19	19	19	19	19
Hydro	887	1,009	1,002	1,002	1,002	152	152	152	152	152	152	152	145	142	142
Wind	3,954	4,200	4,200	4,054	4,054	4,034	4,012	3,913	3,848	3,739	3,735	3,439	3,372	2,984	2,620
Distributed Solar	42	48	55	60	66	72	78	83	89	95	100	105	111	116	121
Solar*Rewards Community	335	339	344	348	352	356	360	365	369	373	377	381	385	389	393
Grid Scale Solar	182	182	181	180	179	178	177	176	175	174	174	173	172	171	170
Existing Resources	15,117	15,530	15,569	15,438	14,620	13,477	13,243	12,732	12,543	12,448	12,460	11,536	11,200	10,837	9,968
Existing and Approved Net Resource (Need)/Surplus	4,446	4,889	4,909	4,811	4,025	2,941	2,745	2,237	1,987	1,890	1,871	937	466	-48	-924
Reference Plan Resource Additions/Retirements	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Natural Gas/Oil	0	0	0	0	0	0	0	0	0	0	0	0	220	570	920
Wind	0	0	0	126	171	242	307	379	389	496	512	568	598	1,122	2,702
Solar	0	0	0	0	0	251	251	752	1,002	1,252	1,253	1,753	2,004	2,004	2,004
Reference Plan Resource Adjustments	0	0	0	126	172	492	558	1,131	1,391	1,749	1,765	2,321	2,822	3,696	5,627
Reference Plan Net Resource (Need)/Surplus	4,446	4,889	4,909	4,937	4,197	3,433	3,303	3,367	3,379	3,639	3,636	3,258	3,288	3,647	4,702

[1] *See* Docket No. E002/RP-10-825. In addition to noting amendments to Minn. Stat. § 216B.2422, subd. 4, the Notice suggested utilities should consider adding to their initial resource plan filings the supplemental information listed at page 4 of the Commission's May 10, 2013 Order in Minnesota Power Docket No. E015/RP-13-53 (Order Point No. 2).

APPENDIX F3 - SCENARIO SENSITIVITY ANALYSIS: PVRR & PVSC SUMMARY

	A	B	C	D	E	F	G	I	J	K	L	M	N	ECF	DBF
	PVSC	PVRR	Low Gas/Coal/ Mkts	High Gas/Coal/ Mkts	Low Load	High Load	Low Resource Cost	High Resource Cost	Low Externality	Low Externality, Low Regulatory	Mid Externality, Mid Regulatory	High Externality	No Reg or Externality Costs	Market sales off	High Load High Gas/Coal/Mkts Low Resource Cost	Low Load Low Gas/Coal/Mkts Low Resource Cost
1- REFERENCE	$45,657	$37,679	$45,216	$46,360	$46,328	$49,952	$44,760	$46,813	$40,949	$39,008	$42,541	$52,890	$37,276	$45,260	$49,797	$45,359
2- EARLY KING	$45,450	$37,495	$44,909	$46,347	$46,258	$49,795	$44,703	$46,499	$40,570	$38,811	$42,319	$52,001	$37,064	$44,896	$49,787	$45,276
3- EARLY SH3	$45,563	$37,662	$45,018	$46,420	$46,373	$49,940	$44,828	$46,593	$40,643	$38,975	$42,418	$51,868	$37,235	$44,993	$49,935	$45,396
4- EARLY COAL	$45,449	$37,632	$44,882	$46,394	$46,274	$49,777	$44,758	$46,475	$40,435	$38,934	$42,324	$51,128	$37,202	$44,859	$49,968	$45,311
5- EARLY MONTI	$45,824	$37,782	$45,347	$46,570	$46,498	$50,093	$44,907	$47,034	$41,021	$39,111	$42,673	$52,931	$37,356	$45,325	$49,953	$45,470
6- EARLY PI	$46,345	$38,281	$45,847	$47,119	$46,892	$50,741	$45,222	$47,704	$41,558	$39,584	$43,177	$53,636	$37,847	$45,739	$50,392	$45,715
7- EARLY All NUCLEAR	$46,491	$38,292	$45,956	$47,306	$47,000	$50,782	$45,329	$47,873	$41,586	$39,620	$43,267	$53,725	$37,857	$45,840	$50,503	$45,768
8- EARLY BASELOAD	$46,251	$38,144	$45,561	$47,366	$46,985	$50,646	$45,341	$47,462	$41,006	$39,488	$43,002	$51,915	$37,710	$45,306	$50,747	$45,734
9- EARLY COAL; EXTEND MONTI	$45,173	$37,476	$44,705	$45,966	$46,084	$49,419	$44,628	$46,065	$40,250	$38,757	$42,098	$50,829	$37,050	$44,646	$49,701	$45,327
10- EARLY KING; EXTEND MONTI	$45,124	$37,286	$44,684	$45,877	$46,010	$49,444	$44,552	$46,054	$40,322	$38,590	$42,044	$51,601	$36,860	$44,628	$49,601	$45,258
11- EARLY COAL; EXTEND PI	$44,788	$37,134	$44,395	$45,449	$45,711	$49,020	$44,327	$45,595	$39,885	$38,406	$41,731	$50,394	$36,705	$44,239	$49,551	$45,100
12- EARLY COAL; EXTEND All NUCLEAR	$44,655	$37,240	$44,460	$45,018	$45,589	$48,794	$44,194	$45,462	$39,977	$38,455	$41,696	$50,435	$36,813	$44,356	$49,324	$45,177
13- EXTEND MONTI	$45,268	$37,316	$44,833	$45,978	$46,130	$49,577	$44,690	$46,181	$40,516	$38,635	$42,156	$52,315	$36,884	$44,720	$49,665	$45,394
14- EXTEND PI	$44,830	$36,906	$44,440	$45,455	$45,757	$49,158	$44,379	$45,618	$40,080	$38,219	$41,729	$51,800	$36,471	$44,266	$49,382	$45,157
15- EXTEND All NUCLEAR	$44,749	$37,065	$44,541	$45,116	$45,678	$48,852	$44,316	$45,508	$40,209	$38,333	$41,744	$51,812	$36,636	$44,394	$49,255	$45,281
REFERENCE ADJ (ADD DR)	$45,974	$38,055	$45,534	$46,677	$46,679	$50,276	$45,077	$47,131	$41,267	$39,327	$42,859	$53,204	$37,595	$45,579	$50,121	$45,711
PREFERRED PLAN	$45,513	$37,851	$45,046	$46,307	$46,416	$49,757	$44,969	$46,405	$40,591	$39,099	$42,439	$51,168	$37,392	$44,990	$50,040	$45,660
ND PLAN	$45,892	$37,598	$44,869	$45,901	$46,833	$50,123	$45,231	$46,904	$40,415	$38,892	$42,208	$51,021	$37,208	$44,817	$49,443	$45,356

	A	B	C	D	E	F	G	I	J	K	L	M	N	ECF	DBF
DELTAS	PVSC	PVRR	Low Gas/Coal/ Mkts	High Gas/Coal/ Mkts	Low Load	High Load	Low Resource Cost	High Resource Cost	Low Externality	Low Externality, Low Regulatory	Mid Externality, Mid Regulatory	High Externality	No Reg or Externality Costs	Market sales off	High Load High Gas/Coal/Mkts Low Resource Cost	Low Load Low Gas/Coal/Mkts Low Resource Cost
1- REFERENCE	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$
2- EARLY KING	($207)	($184)	($307)	($12)	($71)	($156)	($56)	($315)	($379)	($197)	($222)	($889)	($213)	($365)	($10)	($83)
3- EARLY SH3	($93)	($17)	($198)	$60	$45	($12)	$69	($220)	($306)	($33)	($124)	($1,022)	($41)	($267)	$137	$37
4- EARLY COAL	($208)	($47)	($334)	$35	($54)	($174)	($1)	($339)	($513)	($74)	($217)	($1,762)	($75)	($401)	$170	($48)
5- EARLY MONTI	$167	$103	$131	$210	$170	$142	$147	$220	$72	$103	$131	$42	$80	$65	$156	$111
6- EARLY PI	$689	$602	$631	$759	$564	$789	$462	$891	$609	$576	$636	$746	$571	$479	$595	$356
7- EARLY All NUCLEAR	$834	$613	$740	$947	$672	$831	$569	$1,060	$637	$612	$726	$835	$581	$580	$706	$409
8- EARLY BASELOAD	$594	$465	$345	$1,006	$656	$695	$582	$649	$57	$480	$460	($975)	$433	$46	$950	$375
9- EARLY COAL; EXTEND MONTI	($484)	($204)	($510)	($394)	($245)	($533)	($131)	($748)	($699)	($251)	($443)	($2,060)	($226)	($614)	($96)	($32)
10- EARLY KING; EXTEND MONTI	($532)	($393)	($532)	($482)	($318)	($508)	($207)	($759)	($626)	($418)	($498)	($1,288)	($416)	($632)	($197)	($101)
11- EARLY COAL; EXTEND PI	($868)	($545)	($821)	($911)	($617)	($931)	($433)	($1,218)	($1,064)	($602)	($811)	($2,496)	($571)	($1,022)	($247)	($259)
12- EARLY COAL; EXTEND All NUCLEAR	($1,001)	($439)	($756)	($1,342)	($740)	($1,158)	($566)	($1,352)	($972)	($553)	($846)	($2,455)	($463)	($904)	($473)	($182)
13- EXTEND MONTI	($388)	($363)	($383)	($381)	($198)	($375)	($70)	($632)	($433)	($373)	($386)	($575)	($393)	($540)	($133)	$34
14- EXTEND PI	($827)	($773)	($776)	($905)	($571)	($794)	($381)	($1,195)	($868)	($789)	($813)	($1,090)	($805)	($995)	($416)	($202)
15- EXTEND All NUCLEAR	($908)	($614)	($675)	($1,244)	($650)	($1,099)	($444)	($1,305)	($739)	($675)	($797)	($1,078)	($640)	($867)	($542)	($79)
REFERENCE ADJ (ADD DR)	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$	$
PREFERRED PLAN	($461)	($203)	($488)	($371)	($263)	($519)	($109)	($726)	($675)	($228)	($420)	($2,037)	($203)	($588)	($81)	($51)
ND PLAN	($83)	($456)	($665)	($777)	$154	($153)	$154	($227)	($852)	($435)	($652)	($2,184)	($388)	($761)	($678)	($355)

APPENDIX F4 – HIGH ELECTRIFICATION SCENARIO DESCRIPTION

We worked with Energy and Environmental Economics (E3) to develop a High Electrification load forecast sensitivity, derived from the E3 statewide decarbonization analysis using PATHWAYS.[1] The objective of this sensitivity was to create a "bookend," examining the possible impacts on load growth and peak demand growth on our Upper Midwest NSP System service area, under a scenario with electrification sufficiently aggressive to achieve Minnesota's economy-wide goal of an 80 percent reduction in greenhouse gas (GHG) emissions below 2005 levels by 2050.[2] The Company does not suggest this amount of electrification is likely to occur, absent additional policy measures. We note that an 80 percent economy-wide reduction could theoretically be achieved with less electrification and more of other measures.

Without suggesting this much electrification will or should occur, the sensitivity asks: if there were very aggressive electrification of transportation, buildings, and other end uses, what are the potential impacts on energy consumption and peak demand during the planning period?

I. METHODS

E3 details its methodology in Attachment A to this Appendix. In summary, E3 began with the High Electrification scenario developed in its Minnesota PATHWAYS analysis.[3] In that analysis, E3 created two scenarios, High Electrification and High Biofuels, both targeting the 80 percent by 2050 economy-wide goal. The High Electrification scenario assumes low-carbon electricity (48 percent zero-carbon generation by 2025, 90 percent by 2050) and a high amount of energy efficiency – including high-efficiency appliances and building shell weatherization. All light, medium, and heavy-duty vehicle sales are electric by 2050; sales of electric heat pump equipment reach 95 percent by 2050, replacing electric, natural gas and LPG alternatives; and 50 percent of liquid fuels used in agriculture are electrified by 2050. As a result, statewide total electricity demand grows 60 percent by 2050, relative to 2015. Load growth is especially pronounced in the latter years (2035-2050).

E3 then developed hourly load shapes for each electrified end use, using simulated

[1] In summary, for the PATHWAYS study, E3 developed a set of long-term economy-wide, deep decarbonization scenarios for the state of Minnesota. These scenarios provide an exploration of the cross-sectoral implications of meeting economy-wide carbon reduction goals, and highlight the role of Xcel Energy, and the electric sector as a whole, in meeting the state's economy-wide carbon goal. For details, see the E3 Minnesota PATHWAYS Report as Appendix P3.

[2] Minn. Stat. 216H.02, Subd. 1. *See* https://www.pca.state.mn.us/air/state-and-regional-initiatives.

[3] This analysis is summarized in E3 presentations from September 24 and October 23, 2018. *See* https://www.xcelenergy.com/company/rates_and_regulations/resource_plan_overview/midwest_energy_plan and, under Current Status, the 9/24/18 and 10/23/18 Workshop Materials.

demand by year based on a 2009 weather year. Water heating, which becomes dominated by heat pump water heaters, is assumed to be a "managed" load capable of being limited largely to off-peak hours. Passenger EVs are assumed to be mostly (90 percent) managed to avoid peak demand impacts. This is based on the experience of Xcel Energy and other utilities, that most charging happens at home and that it will likely be feasible, with a combination of technological controls and time-sensitive rates, to incentivize EV owners to mostly avoid on-peak charging. Heavier EVs and agricultural electrification are conservatively assumed to be flat across hours, i.e. an unmanaged load.

Electrified space heating, however, has a significant potential impact on total energy and peak demand, and is less amenable to being managed to off-peak hours. E3 assumed an increasing share of space heating is served by electric air-source heat pumps (ASHPs), which face special challenges in cold climates. Because efficiency of ASHPs decreases as outdoor air temperature drops, ASHPs are paired with backup electric resistance and thermal heating in this scenario. Below 0° Fahrenheit, there is a non-linear increase in input energy needs as an increasing share of heat is provided by electric resistance backup. See Attachment A to this Appendix for greater detail.

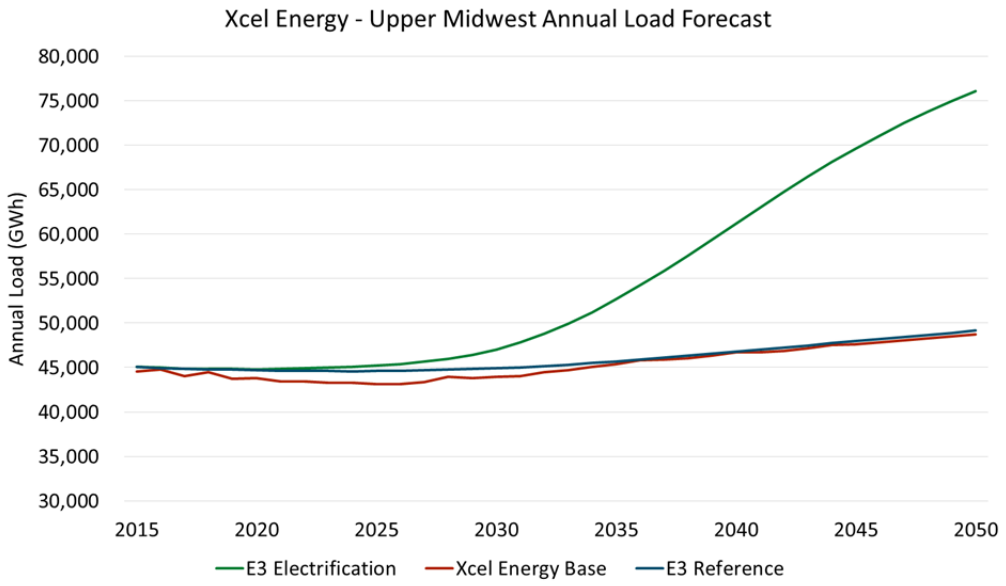
Finally, E3 scaled the Minnesota-wide results to the NSP System, i.e. Xcel Energy's service territory across five Upper Midwest states. Based on historical energy data, in recent years Xcel Energy's retail sales in those five states have been on average 67 percent of total retail sales in Minnesota, so E3's forecast of load and peak demand Minnesota-wide is multiplied by 67 percent to derive load and peak demand for the NSP System under this High Electrification sensitivity. This approach assumes that the scaling of Minnesota loads to the NSP System stays constant over the forecast period. If electrification of transportation, water, and space heating has a different growth rate in our Upper Midwest service territories than in Minnesota as a whole, then both energy and demand impacts could be significantly different for Xcel Energy.

II. RESULTS

Even with aggressive electrification of transportation, water heating and space heating, impacts on incremental energy and peak demand needs are relatively slight during the 2020-2034 Resource Plan planning period – but much more significant by 2050. This is primarily because adoption of EVs and electrified appliances reaches its "hockey stick" phase only near the end of the planning period. Further, even once electric alternatives dominate new sales, the stock of vehicles and appliances takes time to turn over.

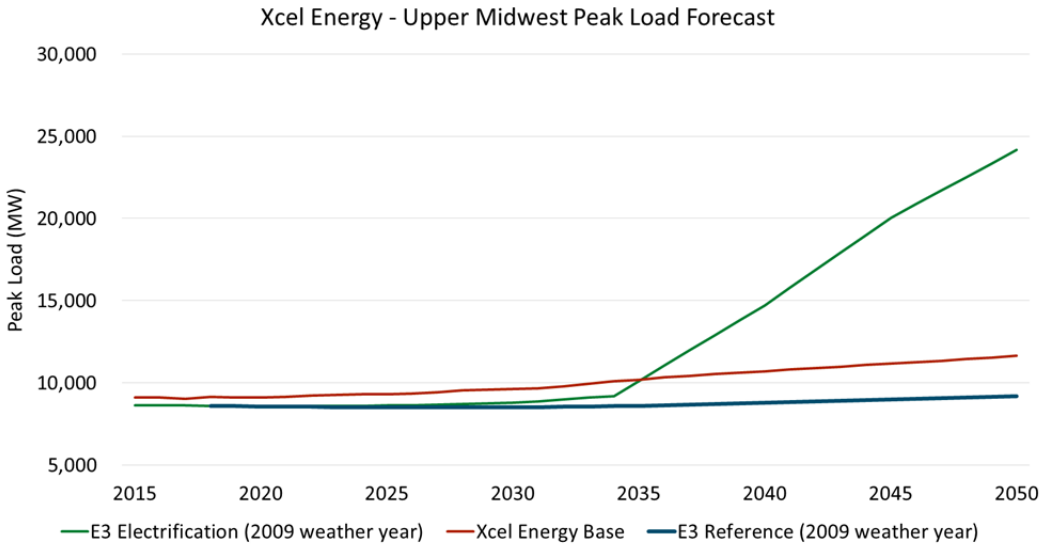
Load Impacts. When compared to E3's reference scenario, the high electrification scenario requires incremental energy on our Upper Midwest system of about 2,000 GWh in 2030 and 5,700 GWh by 2034. Incremental energy requirements increase dramatically thereafter, reaching 14,000 GWh in 2040 and almost 27,000 GWh by 2050. See Figure 1 below.

Figure 1: Incremental Annual Load under a High Electrification Scenario



Peak Demand Impacts. Impacts on peak demand under a high electrification scenario likewise come primarily after the planning period. For example, incremental peak demand requirements due to electrified loads are only 430 MW by 2034, but escalate dramatically thereafter, reaching over 5 GW of incremental peak demand by 2040 and almost 15 GW by 2050. See Figure 2 below.

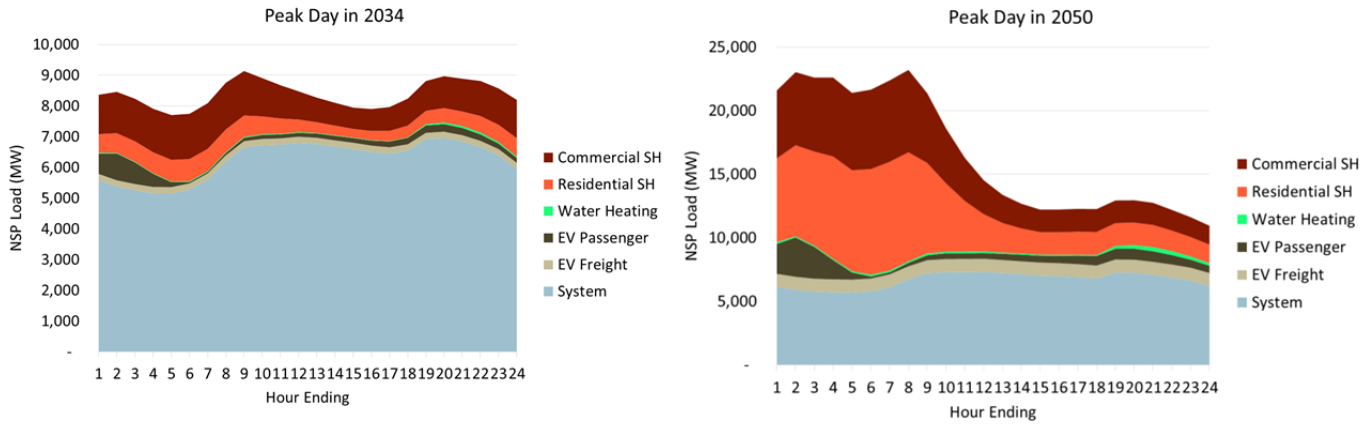
Figure 2: Incremental Peak Demand under a High Electrification Scenario



While some electrified loads, such as passenger EVs and water heating, are able to be managed mostly to off-peak hours, space heating has a significant peak demand impact since heating is needed round-the-clock. Figure 3 below shows peak demand in 2034 and 2050, illustrating both that the bulk of peak demand needs are from residential and commercial space heating – and, that space heating imposes incremental peak demand needs in all hours. After about 2034, our Upper Midwest NSP System becomes a winter peaking utility in this scenario.

Figure 3: Electricity Demand on a Peak Day in 2034 (Left) and 2050 (Right) under a High Electrification Sensitivity

Note difference in y-axis scale



III. IMPLICATIONS

Achieving Minnesota's goal of an 80 percent economy-wide GHG reduction will be challenging. Because of the progress the electricity sector has made to-date in reducing emissions, and its expected continued progress by 2050, there is significant potential to reduce emissions from other economic sectors using low-carbon electricity, which could help Minnesota achieve its statutory GHG goals. However, if electricity use by other sectors is to grow significantly, it is all the more important to maintain affordable and reliable electricity – highlighting the need to take advantage of economies of scale in pursuing low- and zero-carbon electricity options.

While most of the High Electrification sensitivity's impacts on load and peak demand come beyond the planning period, it is important to avoid a myopic view in planning the energy system to serve this potential demand beyond 2034. Firm capacity needs would increase dramatically just beyond the end of the planning period in this sensitivity. This strengthens the rationale for the Reliability Requirement – a minimum amount of firm, dispatchable resources to meet customers' energy needs whenever they peak, as discussed in Appendix J2: Reliability Requirement. Incremental peak capacity needs can be mitigated to some degree by putting in place time-sensitive rates and technological controls needed to manage electrified loads (EVs, water heating) to off-peak hours and match these flexible loads to hours of high renewable generation. However, as discussed in conjunction with the Reliability Requirement, renewable generation is not always available. Additionally, not all electrified loads are amenable to shifting off-peak, so it will be important to plan the system with a view beyond 2034.

Finally, a strategic electrification (or "beneficial electrification") approach may be preferable to an "electrify everything" approach. Considering cold climate challenges of some types of electrification, the difficulty of managing some electrified loads to off-peak hours, and the relative efficiency of the natural gas local distribution system in providing heat, it makes sense to focus electrification efforts on those end uses where electrification meets criteria such as:

- Reducing system costs for all utility customers;
- Reducing net CO_2 emissions; and
- Providing for a more efficient utilization of grid resources.[4]

[4] As adopted in Colorado Senate Bill 19-236, and similar to the definition of beneficial electrification proposed by the Regulatory Assistance Project in https://www.raponline.org/knowledge-center/beneficial-electrification-ensuring-electrification-public-interest/.

Xcel NSP High Electrification Scenario

June 26, 2019

Prepared for Xcel Energy

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1 Background

This study investigates the potential future of Minnesota's energy economy. We model Minnesota's energy economy on an annual time scale, with key outputs including annual emissions, electric loads, and electric supply changes.

We model two evolutions: the evolution of energy demands and energy supply. To model energy demands we use LEAP, the Long-range Energy Alternatives Planning system. LEAP is an energy accounting framework that provides annual economy-wide energy and emissions results, including a stock roll-over component for major equipment categories (energy uses in buildings and transportation fleet). E3, in partnership with Xcel Energy - Upper Midwest, developed a LEAP model to represent the energy economy of Minnesota (Minnesota PATHWAYS). This model includes developing representation of the Minnesota economy as it exists today, and a series of transformations that reduce economy-wide emissions consistent with achieving the Next Generation Energy Act goal of 80% below 2005 emissions levels by 2050.

We take annual electricity loads from Minnesota PATHWAYS, downscale them to the Xcel Energy - Upper Midwest service territory, and pass them to RESOLVE, E3's electricity capacity expansion and operations model. We use RESOLVE to develop least-cost optimal expansion plans of the electricity grid. Together, the models allow us to track the change in composition of the Minnesota energy economy annually, as well as evaluate how the Xcel Energy - Upper Midwest electric supply could change in a decarbonized future. This document highlights the methods and data surrounding this modeling effort, with a focus on the High Electrification scenario.

The scope of our analysis does not focus on the full scope of greenhouse gas (GHG) emissions, which include agricultural and waste water emissions; we focus on direct energy consumption and energy supply.

Energy forecasting methodology

We begin by tracking the high level economic drivers: population, housing units, square footage, and total vehicle miles traveled (VMT). These data are sourced primarily from various federal and state data sources, including the Census and 2018 AEO. From these economic drivers, we forecast energy demands by using either a stock rollover approach, or a total energy approach.

When infrastructure data is available (such as the number of vehicles) we use a stock rollover approach to model the number of devices and track the improvements in efficiency or change in energy usage as newer, more efficient devices replace retiring devices.

A stock rollover approach allows us to track sales and retirements of devices by technology, track efficiency improvements explicitly, and see the physical lag in the energy system as devices are bought and consumed throughout their lifetimes before being replaced. Note shorter lived technologies, such as lighting and hot water heaters, might roll over multiple times during the study period whereas longer lived technologies, such as power plants and building shells, might roll over only once.

Using a stock rollover approach, the Minnesota PATHWAYS model tracks energy demand associated with existing devices from prior years that have not reached the end of their life. We establish the on-site energy demand associated with these devices by multiplying the number of devices from each vintage with the per-unit energy demand applicable to each vintage.

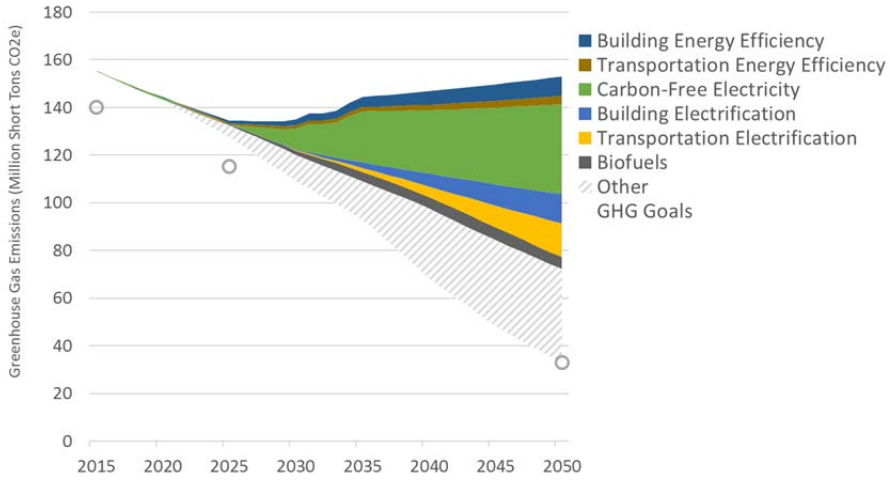
Secondly, we model the number of new devices that are added to each subsector every year. Every year sales of new devices are set to a quantity sufficient to replace retiring devices and meet the demand for new growth (new growth tracks the economic drivers such as housing units or population). Similar to the existing devices, we establish the on-site energy demand associated with new devices by multiplying the number of devices with the appropriate energy usage per device applicable to the new devices' vintage.

When data are limited or of poor quality (such as the industrial sector), we use a total energy approach in which we directly specify the energy demand by fuel, and forecast future energy demands benchmarking to fundamental economic drivers, such as population or AEO energy demand forecasts.

2 Summary of the "High Electrification" scenario:

The High Electrification scenario forecasts a pathway for Minnesota to achieve 80% decarbonization of the energy economy relative to a 2005 base year by 2050. This scenario leans heavily on electrification of end uses wherever practical. An electrification heavy pathway is dependent on carbon-free electricity that is used to displace fossil fuels in buildings and vehicles (Figure 1).

Figure 1. GHG Reductions by Measure: High Electrification Scenario



The high electrification scenario increases load by **60%** in 2050, relative to 2015. Load growth is especially pronounced in the latter years (2035-2050) as load growth from vehicle and space heating electrification exceed energy efficiency gains (Figure 2). For more details on key assumptions see Table 1, below.

Figure 2. Minnesota Load in the High Electrification Scenario

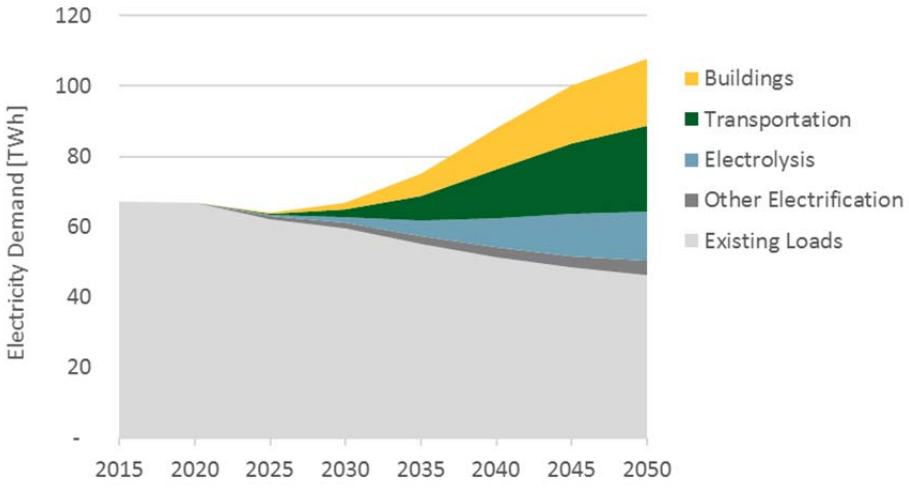


Table 1. Key scenario assumptions

	High Electrification (and low EE)
Electricity generation	
Zero-carbon generation	48% by 2025, 90% by 2050
Nuclear power	Assume nuclear is relicensed or replaced with other carbon-free generation
Buildings	
Energy Efficiency	50% of appliance sales are high-efficiency by 2030 No smart appliances and conservation by 2050 No reduction in demand in nonstock (Residential Other and Commercial Other) demand by 2030, and 30% reduction by 2050
Building Shell and Weatherization	100% adoption of efficient building shell/weatherization measures by 2030
Sales of Electric Heat Pump Equipment	50% by 2030, 95% by 2050, replacing electric, natural gas and LPG
Transportation	
Sales of Zero-Emission Vehicles	LDVs: 50% by 2030, 100% by 2050 MDVs: 50% by 2030, 100% by 2050 HDVs: 40% by 2030, 100% by 2050
Efficiency	Federal CAFÉ standards for LDVs through 2026
Other	50% of Residual Fuel Oil is electrified by 2050
Industry and Other	
Energy Efficiency	No efficiency improvements below baseline
Agriculture Electrification	50% of liquid fuels (Diesel, Gasoline, LPG) are electrified in Agriculture by 2050, at a 50% efficiency improvement due to electrification

3 Electrification load shapes

3.1 Load shapes for water heating and electric vehicles

In developing hourly electric load shapes, this study investigates the electric power system impacts of electrifying a variety of end uses including space heating, water heating, transportation electrification, and others. The next section discusses our space heating load shaping methodology in greater detail. Here we briefly cover the methodology used to create shapes for water heating, transportation electrification, and other electrification.

Water heating: In the High Electrification scenario there is a move towards increased heat pump water heater penetration. E3 used a set of managed heat pump and electric resistance water heating shapes from the Xcel Energy team. The managed resistance water heater shapes are controlled to have no demand from 7am through 6PM. Heat pump water heater shapes are sourced from a broader electricity and decarbonization study commissioned in part by Great River Energy and performed by Brattle in 2016[1]. To capture a representative split of years we use an 80%/20% split of heat pump water heaters / electric resistance water heaters and calculate a blended managed water heating profile. We calculate this profile for a single day that is applied to all the days in a year.

Passenger EV: In the High Electrification scenario there is a move towards increased vehicle electrification, of both passenger and freight. To calculate the load impact of electric passenger EV, E3 used a set of EV load profiles provided by Xcel Energy. These load profiles are sourced from the EV Project, and include both managed and unmanaged charging shapes[2]. For this analysis, we use a blended profile of 90% managed and 10% unmanaged charging. We again calculate this profile for a single day that is applied to all the days in a year.

Freight EV and Agriculture: The final major sources of incremental electrification in the High Electrification scenario are freight vehicles and agriculture. Public data on freight vehicle electric load shapes are sparse. Without accurate, publicly available charging data it is difficult to calculate a representative charging profile for these end uses, so E3 used a flat block across all hours – this indicates that charging demand is consistent across all hours. This is likely not to be accurate, especially if real-time electricity prices fluctuate strongly in future years as these vehicles might exhibit more sophisticated and price responsive charging behavior than the average residential passenger vehicle. Nevertheless, without more data we use a flat charging profile for this study.

In addition to the three categories mentioned above, space heating is the last significant source of electric load growth in the High Electrification scenario. Since space heating has the potential to create operational challenges due to its peaky nature in cold weather, we discuss space heating load shaping in more detail below.

[1] https://greatriverenergy.com/wp-content/uploads/2015/10/Appendices-H-L.pdf
[2] https://www.energy.gov/sites/prod/files/2014/02/f8/nissan_leaf_driving_charging_2011.pdf

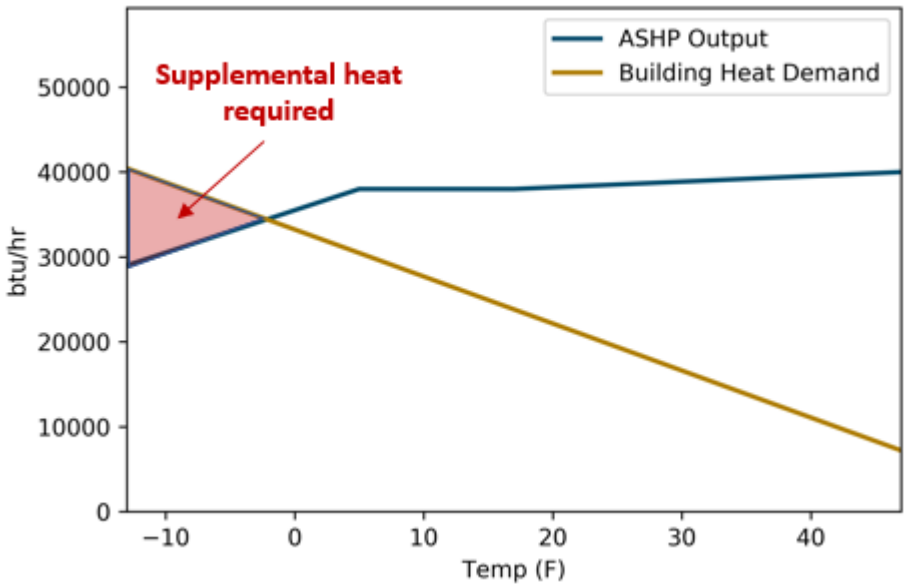
3.2 E3 space heating load shaping methodology

The E3 High Electrification scenario assumes that an increasing share of space-heating loads in Minnesota are served by electric air-source heat pumps (ASHP). ASHPs are relatively rare in Minnesota today, but in the High Electrification scenario adoption of ASHP technologies approaches 90% of state-wide floorspace by 2050. Such a large-scale adoption of ASHPs would add large new, and weather dependent, loads to the state's electricity system.

ASHPs and weather

The efficiency and output capacity of an ASHP decrease as outdoor air temperature drops. When an ASHP can no longer provide enough heat to maintain building comfort, supplemental sources of heat are required (Figure 3**Error! Reference source not found.**). There are two sources of supplemental heat typically used in combination with an ASHP: electric resistance and thermal. For the purposes of the High Electrification scenario we assume that all supplemental heat is served by electric resistance. Where a heat pump can have a coefficient of performance of higher than 2 cold temperatures, the COP of electric resistance heat is 1. The combination of decreasing heat pump efficiency and increasing reliance on electric resistance heat means that ASHPs require non-linear amounts of input power to keep buildings warm in cold weather.

Figure 3: Building Loads and Heat Pump Output

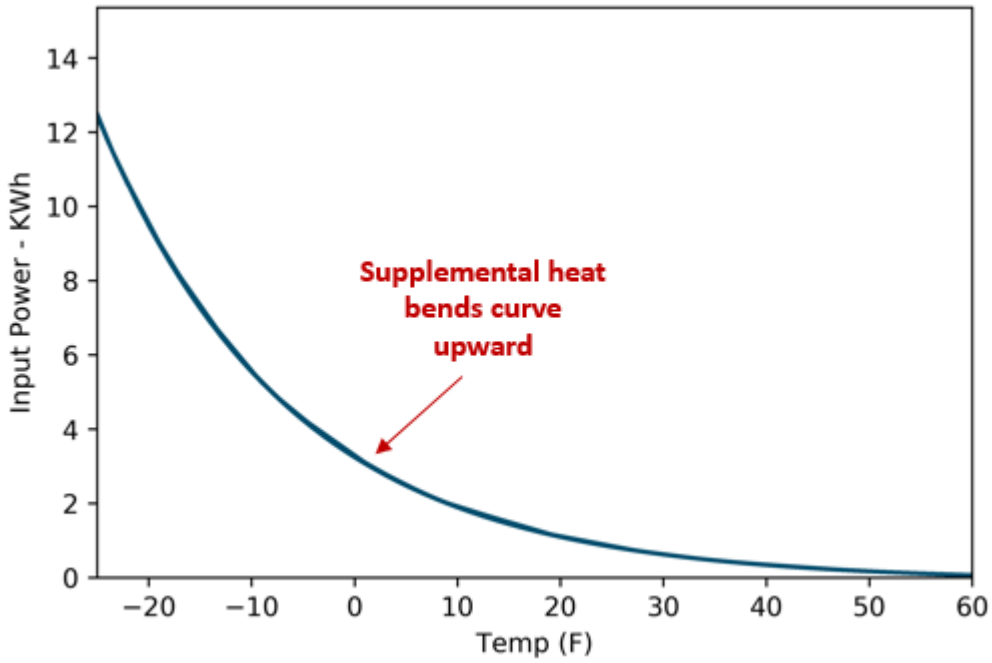


Building simulations and benchmarking

E3 developed relationships between temperature and ASHP loads for both residential and commercial buildings through simulations in the building science software EnergyPlus. E3 used a combination of Federal and local sources (EIA RECS 2015, EIA CBECS 2012, CEE 2018, CEE 2017, Edwards et al 2018) to benchmark the simulations to MN building heat demands.

Figure 4 shows the derived relationship between temperature and a cold climate ASHP load for a typical residential home in Minnesota[3]. The heat pump can cover all of the building's load until 0F, at which point an increasing share of heat is provided by the electric resistance element. By -25F, the ASHP has a COP of 1, the point at which buildings are assumed to be entirely heated by electric resistance.

Figure 4: Residential Heat Pump Load & Temperature



Weather matching

ASHP loads are weather dependent. On a very cold day outdoor air temperatures across Minnesota can vary by a wide margin (Figure 5). For instance, on January 16, 2009 the minimum outdoor air temperature was -5F in Cottonwood County but was -38F during the same hour in Koochinching County. This temperature gradient can lead to very different per-building loads across the state. For instance, a residential building in Cottonwood County with design load of 38 kbtu per hour requires 4 kW of input power to stay warm. That figure for an equivalent building in Koochinching County quadruples to over 16 kW because the heat pump is running entirely in electric resistance back-up mode.

In order to account for the diversity of weather impacts, E3 used a combination of NOAA historical weather data and Census county-level household data. E3 matched NOAA weather stations to their nearest county neighbor in order to develop a geographically explicit per-building load prediction (Figure 5). These shapes were then multiplied by the number of fuel-switching households per county and summed to develop a diversified ASHP shape for Minnesota as a whole. Figure 6 shows the cumulative 2050 loads from ASHP space heaters under a 2009 weather year on both an annual and peak week basis.

[3] The performance of this heat pump is consistent with a top performing 48 kbtu/hr (4-ton) heat pump on the NEEP Cold Climate Heat Pump Product Specification listing.

Figure 5: Minimum Temperatures on January 16, 2009

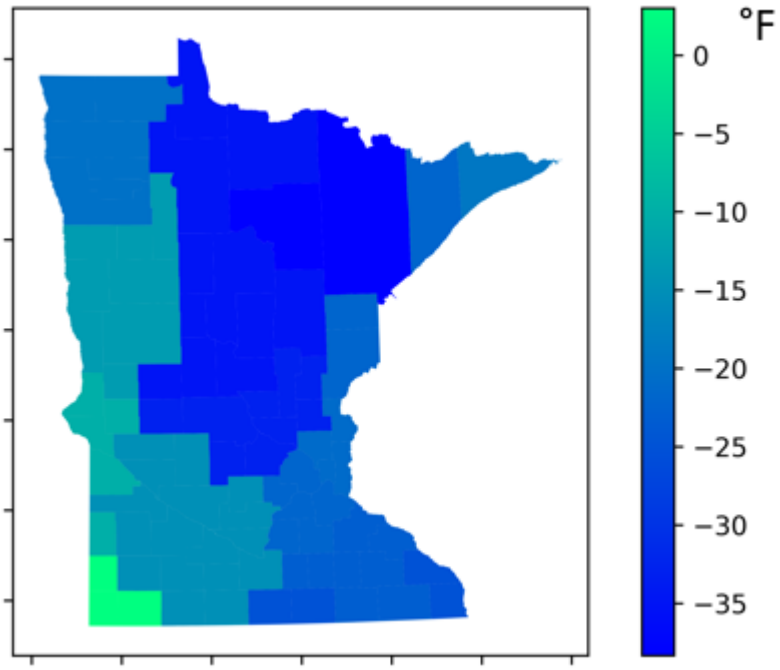
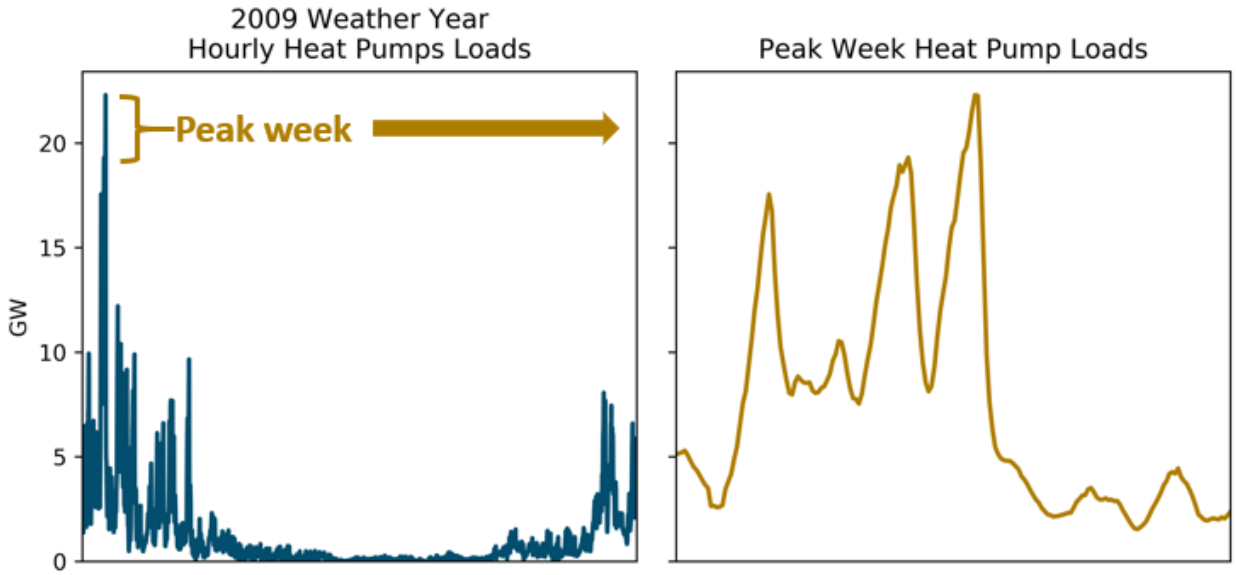


Figure 6: 2050 Residential Space Heat Load



Caveats and limitations

The load shapes developed through the above methodology offer an initial estimation of the scale of loads that follow from a near-complete electrification of space-heating in Minnesota. There are several factors that could make these loads higher or lower. Loads, particularly peak loads, could be higher if homes and businesses do not adopt cold-climate heat pump technologies. Loads could be lower if heat pump technologies continue to improve in cold-climate performance and if buildings heating loads are reduced through weatherization measures. Reduced heating loads decrease the amount of load in peak hours that must be covered by electric resistance back-up heat. Doing so pushes the non-linear portion of the load curve shown on Figure 4 to lower temperatures.

4 Simulating hourly loads

4.1 Forecasting hourly loads

In forecasting the Reference scenario, we project hourly loads by scaling up a historical year of Xcel Energy - Upper Midwest hourly loads according to the total energy in the forecast year. This methodology assumes that the load mix in the Reference scenario changes slowly enough that using a historical load shape will represent the Reference load shapes in the future. Although the Reference scenario has some changes in load across classes, the net load growth is small (0.24%/year) especially in comparison to the High Electrification scenario. Thus, we project hourly loads for the Reference scenario by scaling up each hour according to the total energy in the forecast year. For example, in 2009 the Xcel Energy - Upper Midwest annual load was 44.9 TWh; if the forecast year had an Xcel Energy - Upper Midwest load of 60 TWh we would scale up each hour by 1.33 (60/44.9 = 1.33) to calculate the hourly load for the Reference scenario in the forecasted year.

High electrification load

In calculating the High Electrification scenario load shape, we forecast the annual shape by layering on the incremental amount of electrification we expect in each of the load shaping categories. See Table 2 for the annual incremental electric load in the High Electrification scenario. In earlier years there is some amount of negative load due to efficiency gains[4], but in most categories we see load growth due to electrification.

Table 2. High Electrification scenario incremental annual electric load over Reference scenario (TWh)

	2015	2020	2025	2030	2034	2040	2045	2050
Space Heating	0.0	0.0	0.0	0.2	1.2	3.8	6.1	7.8
Water Heating	0.0	0.0	-0.1	-0.3	-0.2	0.2	0.6	0.8
Passenger EV	0.0	0.0	0.0	0.5	1.6	4.1	5.8	6.5
Other (Freight EV, Agriculture)	0.0	0.1	0.7	1.7	3.1	6.3	9.2	11.8

4.2 Downscaling Minnesota loads for the Xcel Energy - Upper Midwest service territory

[4] This is especially the case for water heaters. Transitioning to heat pump water heaters causes lower load growth than the Reference scenario through 2034

To calculate hourly load shapes for the Xcel Energy - Upper Midwest system, E3 scaled the Minnesota hourly load shapes to Xcel Energy's service territory across five Upper Midwest states. Based on historical energy data, in recent years Xcel Energy's retail sales in those five states have been on average 67% of total retail sales in Minnesota (Table 2). So E3's forecast of load and peak demand Minnesota-wide is multiplied by 67% to derive load and peak demand for the Xcel Energy - Upper Midwest system under this High Electrification sensitivity.

This approach assumes that the scaling of Minnesota loads to the Xcel Energy - Upper Midwest system stays constant over the forecast period. If electrification of transportation, water, and space heating has a different growth rate in our Upper Midwest service territories than in Minnesota as a whole, then both energy and demand impacts could be significantly different for Xcel Energy.

Space heating loads have a significant impact on the estimated peak load, especially in the 2040-2050 timeframe. Using this load shaping methodology for the Xcel Energy – Upper Midwest territory, the incremental peak impact of the High Electrification scenario over the Reference scenario grows from 430 MW in 2034 to over 14 GW in 2050, as the utility shifts from a summer peaking utility to a winter peaking utility due primarily to space heating demands. As noted in the load shaping section above, technology choice matters – foregoing building weatherization and cold climate heat pump technologies could make this peak demand even greater. Other peak mitigation options include non-electric thermal backup sources of heat, or managed load programs (like DR).

Table 2. Minnesota to Xcel Energy - Upper Midwest Scaling Factor[5]

	Xcel Energy - Upper Midwest Annual Load (MWh)	Minnesota Annual Retail Sales (MWh)	Load Share	
2009	44,923,739	64,004,463	70%	
2010	46,188,165	67,799,706	68%	
2011	46,133,452	68,532,708	67%	
2012	45,550,281	67,988,535	67%	
2013	45,177,181	68,644,103	66%	
2014	45,197,106	68,719,367	66%	
2015	44,565,009	66,579,234	67%	
2016	44,670,394	66,546,492	67%	
			67%	**Average**

[5] Source for Minnesota load: EIA state profile on retail sales for 2009 to 2016

APPENDIX F5 – GENERATION INTERCONNECTION COSTS METHODOLOGY

Xcel Energy Transmission Planning – White Paper
Generation Interconnection Costs using Random Placement Techniques
June 27, 2018

I. PURPOSE

The purpose of this paper is to articulate Transmission Planning's efforts to create a process to identify interconnection costs associated with renewable generation on the Northern States Power (NSP) System using Monte Carlo simulations.

A. Background

Resource Planning approached Transmission Planning to see if there was a way to identify average transmission upgrade costs associated with solar installations. Running individual cases to create a statistically significant amount of results using the Siemen's PSSE program would be time consuming. Transmission Planning decided to try and develop a Monte Carlo type process to see if we could speed up the process to allow for a large amount of generation placed randomly around the system.

The runtime for each case depend on the amount of contingencies that are chosen to run and the portion of the system you choose to monitor. In addition the case chosen based on its size will greatly affect the runtime (MISO cases vs equivalized MNTACT cases). MNTACT cases used for local NERC reliability have been reduced in size by taking remote areas of the eastern interconnection and equivalizing them into a simple load and gen on one bus representing their system. This has the effect of reducing the overall case size and improves runtime.

The sample size needs to be of significant number to be considered statistically significant to produce a believable average. Typically the confidence interval (CI) is affected by the size of the statistical sample. The larger your sample size the lower the margin of error is. Since the number of possible random generation configurations is infinite a sample size of 100 was chosen based on size and time considerations.

B. Analysis

To create a large amount of random topology cases for analysis purposes Transmission Planning proposed incorporating the Python Coding interface with Siemens PSSE program using the API.
The process steps are outlined below:

1. Choose the amount of Monte Carlo runs (a minimum amount for statistical significance)
2. Identify and solve two benchmark cases to mimic the MISO process (MISO generation assumptions are used to dispatch)
    a. Summer peak (solar 100%)
    b. Shoulder (solar 50%)
3. Choose the random amount of new solar generation to be studied
    a. 69 kV: 3-20 MW
    b. 115-230 kV: 50-100 MW
    c. 345 kV: 200 MW
4. Use Python Code to randomly place solar generation around the NSP and GRE systems up to the amount chosen
    a. Python Code will then readjust MISO system generation down to accommodate the new generation addition. This process chooses generation units that are already on-line to be readjusted down in small increments to prevent the area swing bus from taking the full amount of new generation and thus reducing solving errors.
5. The two new summer and shoulder cases are created with new generation mix
6. ACCC is run on both new created cases
7. A compare is run against output from new cases compared to benchmark cases
8. Thermal overload costs are assigned based on newly created overloads or 3% greater difference than benchmark case
    a. Voltage issue costs were not tracked due to the difficulty in determining validity of identified voltage issues
9. Output thermal overload costs are plotted on scatter graph and a mean is identified for Monte Carlo run

C. Business Benefits

Monte Carlo analysis is used in most other industries to examine probabilistic outcomes using random input variable assumptions. It is heavily used in the finance industry to test financial models over good and bad markets. Traditional transmission planning studies involve a large amount of time in both the model development and the output analysis. Verification of all identified transmission issues and verification of contingencies consume a large amount of time. This type of analysis is typically what is required for reliability projects to comply with NERC standards.

Applying Monte Carlo simulation to the power systems will allow us to test future scenarios over a wide range of inputs and develop likely outcomes. The Monte Carlo approach will not replace the traditional reliability studies currently run to meet NERC criteria, but instead will allow us to develop probabilistic futures for changing generation or load mixes based on future assumptions.

D. Summary

When considering the rapidly changing world related to the power system, Monte Carlo simulations will allow Transmission Planning to develop future probabilistic models to help give insights into future assumptions. This type of random analysis will allow for a large amount of future assumptions to be screened quickly. For the generation example above it can be replicated for any amount of generation, type, or general location.

Future applications for stability are a possibility requiring further examination.

APPENDIX F6 – RESOURCE OPTIONS

I. INTRODUCTION

The main goal of resource planning is to evaluate the size, type, timing and sometimes location of resources we plan to procure to meet customer needs over the next several years. To do this, we take into account key planning considerations, such as carbon reduction goals, reliability, affordability and potential future risk. Over the course of the 2020-2034 planning horizon, our customers' gross peak demand needs are expected to grow from approximately 10,500 MW to just over 11,700 MW, before accounting for Demand Side Management (DSM) adjustments. While we are currently long capacity, a substantial portion of our resources will either reach planned retirement or end of contract dates over the planning period, per our Preferred Plan. As a result, our modeling shows a capacity deficiency in the mid-2020s timeframe. Our Resource Plan addresses how the Company proposes to fill this gap by identifying an appropriate mix of future resource additions.

To identify this mix the Company developed a set of generic resources for inclusion in Strategist modeling, with size, cost, and performance assumptions that reflect updated information from project experience, public stakeholder meeting input, and independent third party studies. Future resource options can be generally categorized as supply-side resources, and demand-side resources. We also evaluated potential transmission cost implications associated with supply-side centralized resources, given current transmission capacity constraints in MISO. Paired with existing owned resources and contracts, this set of generic resources was evaluated in Strategist modeling to determine optimal future resource portfolios, in light of the different scenarios and sensitivities we tested.

II. EXISTING RESOURCES

The Company owns and has under contract approximately 13,500 MW of capacity currently, although as stated above, many of our current resources are slated to retire over the planning period. Below we include discussion of each resource type, and tables showing: each generating unit, whether it is owned or contracted, capacity we own or contract,[1] and the retirement year if known, as reflected in the Strategist model. These numbers have been rounded to the nearest whole number for simplicity, where applicable. It should be noted that the capacity numbers provided below are the maximum values included in the Strategist modeling, and may differ

[1] Expected as of 2020.

marginally from official nameplate or ICAP values.

A. Coal

The Company owns and operates four coal-fired power plants, with a total capacity of 2,390 MW. Planned retirement dates for Sherco 1 in 2026 and Sherco 2 in 2023 were approved in our last Resource Plan, and existing retirement dates for King and Sherco 3 are 2037 and 2040 respectively. As part of our Preferred Plan, we are proposing to retire these two facilities a decade early; where AS King and Sherco 3 would retire in in 2028 and 2030, respectively.

Table 1: Existing Coal Resources

Name of Unit or Contract	Type	Owned or Contracted (PPA)	Capacity (MW)	Existing Retirement/Contract Expiration
Allen S King	Steam Turbine (ST)	Own	511	2037
Sherco 1	ST	Own	680	2026
Sherco 2	ST	Own	682	2023
Sherco 3[2]	ST	Own	517	2040

B. Nuclear

The Company owns and operates three nuclear power plants with a total capacity of 1,738 MW. These units operate at very high capacity factors and provide nearly 30 percent of the energy for our system. They have also both achieved operating costs reductions of over 20 percent from 2015 levels, and both produce energy for our system for under $30/MWh. The existing retirement dates for the nuclear facilities are reflected in the table below. In our Preferred Plan, we propose to extend Monticello plant operation to 2040.

[2] This represents the portion of Sherco 3 under our ownership.

Table 2: Existing Nuclear Resources

Name of Unit or Contract	Type	Owned or Contracted (PPA)	Capacity (MW)	Existing Retirement/Contract Expiration
Monticello	Boiling Water Reactor	Own	646	2030
Prairie Island 1	Pressurized Water Reactor (PWR)	Own	546	2033
Prairie Island 2	PWR	Own	546	2034

C. Natural Gas and Oil

The Company owns or maintains Purchase Power Agreements (PPAs) with many natural gas facilities. Our current natural gas generators are configured as either simple-cycle Combustion Turbines (CTs) or a Combined Cycle Gas Turbine (CCGTs or CCs). The CTs are located at seven different sites and provide peaking capacity meaning they are only typically dispatched a limited number of times a year during peak demand and/or net load conditions. The CCs are located at five sites and provide intermediate capacity, meaning they tend to operate at higher capacity factors due to better efficiencies and lower dispatch prices when compared to CTs.

Our current natural gas and oil fleet provides nearly 4,780 MW of dispatchable capacity. Resource portfolio provides a combined with varying retirement dates In the list of resource below, we provide the capacity and anticipated retirement dates for the Mankato CC assuming we own the resource, per our proposed acquisition in Docket No. IP6949, E002/PA-18-702; however, the Company currently has a PPA for energy and capacity with each of the Mankato CC units. The second unit began commercial operation in June 2019.

Table 3: Existing Natural Gas and Oil Resources

Name of Unit or Contract	Type	Owned or Contracted (PPA)	Capacity	Existing or Planned Retirement/Contract Expiration
Black Dog 52	CC	Own	298	2032
High Bridge	CC	Own	606	2048
Riverside	CC	Own	508	2049
Mankato Energy Center[3]	CC	Own	762	2046, 2054
LSP – Cottage Grove	CC	PPA	245	2027
Angus Anson 2-4	CT	Own	386	2034
Black Dog 6	CT	Own	232	2058
Blue Lake 7,8	CT	Own	351	2034
Inver Hills 1-6	CT	Own	369	2026
Wheaton 1-4	CT	Own	241	2025
Cannon Falls Energy Center	CT	PPA	358	2025
Blue Lake 1-4	Oil	Own	191	2023
French Island 3,4	Oil	Own	160	2027
Wheaton 6	Oil	Own	70	2025

D. Biomass

The company owns and operates, and maintains PPAs with, various biomass facilities. Refuse-derived fuel (RDF), landfill (LND) and digester (DIGT) resources are also generally considered biomass resources and therefore included in this category. These facilities total nearly 160 MW of capacity on our system.

[3] Note: As stated above, we have modeled Mankato Energy Center as an owned resource. Approval of this acquisition is pending in Docket No. IP6949, E002/PA-18-702.

Table 4: Existing Biomass Resources

Name of Unit or Contract	Type	Owned or Contracted (PPA)	Capacity (MW)	Retirement/Contract Expiration
Bayfront 5,6	Bio	Own	26	2035
French Island 1,2	Bio	Own	15	2027
Red Wing 1,2	Bio	Own	18	2027
Wilmarth 1,2	Bio	Own	17	2027
KODA Energy	Bio	PPA	12	2019
St. Paul Cogen	Bio	PPA	24	2023
WM Renewable Energy	LND	PPA	4	2020
Gunderson	LND	PPA	1	
Barron County	RDF	PPA	2	2022
Hennepin Energy Recovery Center	RDF	PPA	34	2024
Diamond K. Dairy[4]	DIGT	PPA	0.4	2023
Greenwhey	DIGT	PPA	3	
Heller Dairy	DIGT	PPA	0.5	

E. Hydroelectric

The Company owns, operates and maintains PPAs for hydropower resources with a number of different counterparties, totaling over 680 MW. The majority of our current hydro capacity is provided by our PPAs with Manitoba Hydro, which expire in 2025. We also have an additional 125 MW PPA with Manitoba Hydro that is slated to start in 2021. Further, the Company has a 350 MW Diversity Agreement with Manitoba Hydro, wherein we receive 350 MW of capacity in the summer and Manitoba Hydro receives 350 MW of capacity in the winter. Due to the unique nature of the agreement, it is not included in the list below or reflected in the total hydro capacity specified above.

[4] Note: This unit is included in Strategist modeling, but its PPA was terminated as of April 2019.

Table 5: Existing Hydroelectric Resources

Name of Contract or Unit	Type	Owned or Contracted (PPA)	Capacity (MW)	Retirement/Contract Expiration
Byllesby	Hydro	PPA	2	2021
Hastings	Hydro	PPA	4	2033
St. Cloud	Hydro	PPA	9	2021
Dairyland	Hydro	PPA	4	-
Eau Galle	Hydro	PPA	0.3	2026
DG Hydro	Hydro	PPA	0.4	-
LCO Hydro	Hydro	PPA	3	2021
Neshonoc	Hydro	PPA	0.4	2020
Rapidan	Hydro	PPA	5	2020
SAF Hydro	Hydro	PPA	9	2031
WTC Angelo Dam	Hydro	PPA	0.2	2024
MN Grouped Hydro	Hydro	Own	14	-
WI Grouped Hydro	Hydro	Own	260	-
Manitoba Hydro	Hydro	PPA	371	2025
Manitoba Hydro	Hydro	PPA	125	2025 (2021 start)

F. Wind

The Company owns or contracts for over 2,600 MW of wind power. Over the next two to three years, the Company intends to add 1,850 MW of wind generation from recent acquisitions and Requests for Proposal (RFPs), as well additional capacity to serve other customer programs.

Table 6: Existing and Near Term Wind Resources

Name of Contract or Unit	Type	Owned or Contracted (PPA)	Capacity (MW)	Retirement/Contract Expiration
Big Blue	Wind	PPA	36	2032
Chanarambie	Wind	PPA	86	2023
Community Wind North	Wind	PPA	26	2044
Fenton	Wind	PPA	206	2032
McNeilus Group	Wind	PPA	37	2028
Jeffers	Wind	PPA	44	2044
MinnDakota	Wind	PPA	150	2022
Moraine II	Wind	PPA	50	2029
Community Wind South (Zephyr)	Wind	PPA	31	2032
Lake Benton I	Wind	PPA	104	2028
Lake Benton II[5]	Wind	PPA	104	2019
Odell	Wind	PPA	200	2035
Prairie Rose	Wind	PPA	200	2032
FPL Mower Co	Wind	PPA	99	2026
Ridgewind	Wind	PPA	25	2031
Border	Wind	Own	150	2040
Courtenay	Wind	Own	200	2041
Grand Meadows	Wind	Own	100	2033
Nobles	Wind	Own	200	2035
Pleasant Valley	Wind	Own	200	2040
Crowned Ridge (Owned)	Wind	Own	300	2044
Freeborn	Wind	Own	200	2045
Foxtail	Wind	Own	150	2044
Blazing Star I	Wind	Own	200	2044
Blazing Star II	Wind	Own	200	2045
Lake Benton Repower	Wind	Own	100	2044
Dakota Range 1 & 2	Wind	Own	300	2046
Dakota Range 3	Wind	PPA	150	2032
Clean Energy	Wind	PPA	100	2039
Crowned Ridge (PPA)	Wind	PPA	300	2044
Small Wind[6]	Wind	PPA	285	Various

[5] Note: this unit is being repowered; the repower is reflected as a separate line item in this table ("Lake Benton Repower").
[6] Includes PPAs of 20 MW or less

G. Solar

By 2020 the Company anticipates it will maintain a total of 990 MW of solar capacity, via PPA, to serve our customers. This includes approximately 260 MW of large grid-scale solar, over 640 MW of Community Solar Gardens (anticipated by 2020), and nearly 90 MW of small-scale distributed solar.

Table 7: Existing Solar Resources

Name of Contract or Unit	Type	Owned or Contracted (PPA)	Capacity (MW)	Retirement/Contract Expiration
Slayton	PV	PPA	2	2033
St. John's	PV	PPA	0.4	2030
School Sisters of Notre Dame	PV	PPA	0.7	2036
Other RDF Solar	PV	PPA	2	
Aurora	PV	PPA	99	2036
Marshall	PV	PPA	62	2042
North Star	PV	PPA	99	2041
DG Solar[7]	PV		86 (2020)	Various
Community Solar Garden	PV	PPA	641(2020)	Various

III. GENERIC FUTURE RESOURCE OPTIONS

Consistent with past resource plans, we have developed generically-defined resources to use in Strategist modeling, from which the model can select when resource retirements or PPA expirations result in our remaining portfolio falling short of future projected demand. Cost and performance data for these resources was developed using a mix of third party studies and forecasts such as the National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB), consultant estimates, and internal Company data. Generic resources are intended to help identify the general size, type, and timing of resource needs in the future and do not typically represent a specific resource at a specific location, or whether such a resource would be owned or contracted. Rather, these specific details are determined via a competitive acquisition process that is held after the general size, type and timing has been established and approved in the Resource Plan proceeding.

[7] Includes Solar*Rewards and Made in MN Solar

It is important to highlight that the Company worked closely with and solicited feedback from stakeholders to select the best sources and methodologies to employ in developing generic resource options. Our stakeholder interactions, and direction from our regulators, resulted in a number of refinements to our past assumptions. We believe these adjustments improved the quality of our modeling and highlight the benefit of our proactive approach to stakeholder engagement.

A. Supply Side Resources

Supply-side centralized resources are traditional large-scale thermal and renewable generation facilities. We have included a number of supply-side centralized fuel types in our modeling; large-scale wind and solar, a variety of natural gas resource options, and battery energy storage. Their attributes, and the method by which we developed each one, are described further. We also detail specific resource cost and performance assumptions in Appendix F2, unless otherwise noted.

1. Wind

Our generic wind resource option was sized at 750 MW on nameplate capacity basis. While the size of this generic wind resource may seem relatively large, we account for the MISO accredited capacity value for new wind resources as 15.6 percent[8] of this total, or about 117 MW. Given our modeling selects resources on the basis of their accredited capacity, and given the size of our system, and magnitude of future capacity needs, we feel this sizing represents an appropriate approach to modeling generic wind additions.

We derived forecasted wind costs used in our modeling from publicly available data from the NREL 2018 ATB Levelized Cost of Electricity (LCOE) data. This cost has been further adjusted for tax credit effects in relevant years, and converted to nominal dollar terms. We have also added estimated transmission costs associated with a greenfield generation facility, as described further below.

2. Solar

Our generic supply-side large-scale solar resource is sized at 500 MW on a nameplate capacity basis. Similar to wind resources, it is important to note that the MISO accredited capacity value for solar is discounted by 50 percent, thus the Strategist model considers generic solar additions in 250 MW firm capacity increments. This

[8] Reflecting the wind capacity accreditation value for Planning Year 2018/2019.

accredited capacity size increment is comparable to other generic resource assumptions, and thus evaluating solar in this size increment is appropriate. We derived forecasted solar costs from the publicly available LCOE data in the NREL ATB as well. Similar to the adjustments for wind resources, this cost has been adjusted for tax credit impacts in the relevant years, and converted to nominal dollar terms. We have also added estimated transmission costs associated with greenfield generation facilities, as described further below.

Our modeling also includes a forecast of distributed solar adoption, applied as a supply-side resource with an assumed adoption rate. In addition to these static forecasts, we had planned to include distributed residential and commercial solar as generic resource options in the modeling. However, we ultimately found these resources would not be selected by the model and eliminated them from the optimization exercise. We feel this is justified, as generic distributed solar continues to be significantly more expensive, on a levelized cost of energy (LCOE) basis, than large-scale solar. This cost delta exists even when including transmission costs for large-scale solar, and as a result, it would be highly unlikely that distributed solar would be selected in our scenario optimizations where the model could choose less expensive large scale solar instead. Therefore, to improve model runtimes and reduce truncation issues, as discussed in Chapter 4: Preferred Plan, distributed solar was included at an assumed adoption rate and not further optimized in the Strategist model.

Please see Appendix F1 for more information regarding distributed solar forecasts.

3. Natural Gas

We have included three potential generic resource configurations for natural gas, given the different types of generator and location types. Specifically, we have included options for both CT and CC generic units. Based on our pre-screening review of cost and performance data available from major equipment suppliers and construction contractors, we developed generic resource options based on those we felt had the best economic viability in our system.

For CTs we developed two generic options, differing in size, configuration, and whether the site would be green- or brown-field, based on the available external data noted above and internal engineering assessments. For CCs, we developed one generic option, and applied similar methods to identify appropriate generator cost and performance assumptions from external sources and internal engineering assessments. Here, however, we depended upon an external consultant analysis to better understand potential interconnection costs across several greenfield sites, given

increased complexity of siting a several hundred MW gas generation unit and navigating the current MISO generator interconnection process.

4. Battery Energy Storage

For the first time in this IRP process, we have developed a generic four-hour battery energy storage resource to include in our Strategist modeling. The unit is sized at 331 MW, which we selected based on both our understanding of our system's future capacity needs and to ensure size parity with one of our generic CT options. Our resource cost assumptions are based on bids our Public Service Company of Colorado operating company received in response to a late 2017 all-source solicitation. To forecast future costs, we applied NREL ATB estimated technology learning curves to these internal cost estimates. For more discussion on storage, see the Minnesota Energy Storage Assessment in Appendix F7.

B. Demand Side Management (DSM)

Based on external studies and stakeholder feedback, we have updated our approach to modeling DSM resources in this Resource Plan, as compared to past years. The Company utilized a *Demand Response Potential Study* provided by the Brattle Group (Appendix G2) and a *Minnesota Energy Efficiency Potential Study*[9] prepared for the Minnesota Department of Commerce, Division of Energy Resources to convert DSM resources into supply-side option "Bundles," which could compete against other resource alternatives in Strategist modeling. Our approach to developing Bundles from the information provided in the study is described below.

1. Energy Efficiency (EE)

Based on external studies and internal expertise, the company developed three Bundles, termed Program, Optimal, and Maximum. Internal experts provided detailed cost, and energy and demand avoidance characteristics, for the three Bundles by year. Each Bundle is included in Strategist as a supply-side resource the model could potentially select. The Program and Maximum Bundles are based on the 2018 *Minnesota Energy Efficiency Potential Study* findings. The Optimal Bundle was developed by the Company using the study results for optimal demand reduction (as opposed to energy reduction). Each Bundle included in our resource modeling is incremental to the last, and selection of any Bundle is dependent on the Bundle before it being

[9] Study available at: https://www.mncee.org/MNCEE/media/PDFs/MN-Potential-Study_Final-Report_Publication-Date_2018-12-04.pdf

selected (i.e. Bundle 2 cannot be selected if Bundle 1 is not selected).

2. Demand Response (DR)

Similar to the process for EE, we developed Demand Response (DR) Bundles, so that DR could be treated as a supply-side resource in the Strategist modeling. Consistent with past practice, the Company developed a Base DR Forecast from existing programs, which was included in all baseline resource modeling. The Company then developed three DR Bundles incremental to the Base DR Forecast, based on the Brattle Study noted above. The DR Bundles were designed by taking a point-in-time supply curve of DR options in the study, and developing more detailed annual demand reduction and cost characteristics by year. The Bundles were generally sized to account for supply curve price thresholds, with Bundle 1 achieving demand reduction of 270 to 542 MW; Bundle 2 achieving an incremental 107 to 242 MW; and Bundle 3 achieving an incremental 89 to 112 MW during the planning period. Similar to EE, the DR Bundles are incremental to each other and dependent on the preceding Bundle being selected (i.e. Bundle 2 cannot be selected if Bundle 1 isn't selected).

C. Transmission Costs for Greenfield Resources

In addition to generating resource assumptions, our Strategist modeling also includes transmission cost considerations for new greenfield resources. These values are intended to capture the transmission expansion and/or interconnection costs required to successfully integrate new greenfield resources into the system. Given current challenges with the MISO interconnection process, and shrinking available transmission capacity on the system, significant study delays and major upgrade costs are likely to result in elevated transmission costs for future resources. Therefore, the Company engaged in a number of internal and external studies in order to appropriately represent anticipated transmission costs associated with new greenfield CT, CC, wind and solar resources. To assess CC transmission delivery costs, the Company hired Excel Engineering, a third party consultant, to perform a study that evaluated potential costs for six different locations on the system. The study identified the potential for high interconnection costs at all of the potential site locations, ranging from a low of $263 million to a high of $1,354 million. Cost levels in this study are dependent in part on the percentage of planned projects that withdraw from the MISO queue. Excel Engineering's Interconnection Cost Estimates is included in Appendix R.

To assess wind and solar transmission delivery costs, the Company's internal Transmission Planning Group performed a random placement technique study. This study identified and solved two benchmark cases to mimic the MISO process. Next,

new solar capacity was added at random locations, in order to study the modeled effect on the transmission system. These results were then compared back to the "benchmark" study, to help identify transmission system violations. Finally, interconnection cost estimates were developed by estimating the costs necessary to remedy the violations identified in the study. This methodology is further explained in Appendix F5.

IV. POTENTIAL RESOURCES NOT CONSIDERED IN MODELING

The Company considered several additional technologies in the initial screening process that, in the end, were not included in modeling. We discuss these resources and why they were not included below. We will continue to monitor and screen these options for possible inclusion in future Resource Plans, and/or allow them to compete in future competitive resource acquisition processes, in order to gain additional information on their potential costs and operating characteristics.

A. Biomass

New biomass resources were excluded from consideration as generic options, primarily due to cost. Generic estimates for biomass resources from the U.S. Energy Information Administration (EIA), and other sources, indicate that the capital costs of biomass resources are substantially higher than those associated with generic wind, solar, and natural gas resource options. As a result, the Company did not include a generic biomass resource for consideration in the modeling.

We anticipate, however, that future acquisition processes may allow biomass resources to compete in resource solicitations. There are also existing biomass resources in our region that may be available to help meet our future resource needs. If found to be cost competitive, they could be selected to displace other generic options identified in our Plan.

B. Combined Heat and Power (CHP)

CHP was not included as a generic resource option, as studies indicated it will have limited economic potential during the planning period. The Company engaged the Electric Power Research Institute (EPRI) and ICF International to evaluate the technical and economic potential for CHP applications in our Minnesota service area. The study estimates a total of 319 MW of technical potential from 239 sites and 145 MW of economic CHP potential in Xcel Energy's Minnesota service territory. Under the base scenario, CHP adoption is estimated at 43 MW through 2039. We provide the study as Appendix S.

C. Nuclear

Nuclear is an important, reliable resource that helps contribute to our carbon-free portfolio. There are a number of existing and new nuclear technologies currently being considered for future deployment; however, while these technologies appear promising, there remain commercial barriers to adoption such that we did not include them as generic resource options for our plan. Outstanding commercial uncertainties include:

- Technological maturity and component manufacturing experience
- Risks and costs related to construction delays and/or budget overruns
- Options for disposal of spent nuclear fuel from new facilities
- State and federal regulatory barriers or uncertainty

Of note, Minnesota state statute currently prohibits the Commission from issuing a Certificate of Need for the construction of a new nuclear facility.[10] We further discuss emerging nuclear technologies in Section V below.

D. Pumped Hydro

Pumped hydro is a mature flexible-duration storage technology with a relatively long operational life; however, environmental challenges and resource economics have generally limited its growth. Further, pumped hydro unit configurations and costs are highly site specific, which makes it a difficult resource to represent generically. As a result, the Company did not include a generic pumped hydro resource for consideration in modeling. Similar to biomass resources, the Company remains willing to evaluate pumped hydro projects in future resource solicitations, and if cost effective, pumped hydro resources could displace generic resource options identified in this Plan.

E. Coal

New generic coal resources were eliminated from the list of resource options due to cost, environmental challenges, and non-alignment with our strategic goals. Capital costs for generic coal resources are high relative to new gas and renewable resource options. Low natural gas prices, increased renewable penetration, and regulatory risk

[10] Laws of Minnesota 1994, Chapter 641, Article 2, Section 1, Subd. 3b.

create additional challenges and major risks for new coal resources. Furthermore, adding coal resources with high carbon emission levels would not align with our commitment to deep carbon reduction on our electric system. For these reasons, we have excluded new coal resources from our modeling. While the Company will continue to monitor carbon capture and sequestration technology developments, we do not expect to consider new coal resources in future resource plans.

V. EMERGING TECHNOLOGIES

As we have previously stated, we can achieve our 2030 carbon reduction goals with existing technologies; however, achieving our vision of a carbon-free electricity supply by 2050 will require significant technology developments that either do not yet exist or are not yet commercialized. In particular, our system will need stable baseload and dispatchable carbon-free generation, and energy storage technologies that can help us maintain reliability for every hour of every day while also keeping our electricity affordable for customers. We are continually assessing new technologies that may be viable options for future resource planning cycles. Below we present a non-exhaustive list of example technologies we are currently tracking.

A. Allam Cycle Application for Emissions Capture in Natural Gas Plants

The Allam Cycle uses natural gas to produce power, but in a different fuel burning process than traditional CTs. Instead of using ambient air for combustion directly, the plants burn natural gas with pure oxygen generated within an Air Separation Unit. This "oxy-combustion" produces CO2, which is then used in the plant's electricity generation process. Using pure oxygen rather than ambient air eliminates nitrogen oxide emissions from the plant's process. The CO_2 released from the combusted natural gas is captured within the plant's process and reused to support additional cycles of fuel combustion. Heat energy is also recovered and used in the process. Excess CO_2 not needed for energy generation can be stored or used in other industrial processes.

NET Power, a company working to commercialize this technology, has recently finished a demonstration project in Texas that is providing power to local customers and undergoing testing to connect to the broader transmission system. They are also working to develop a larger commercial facility with Occidental Petroleum.[11] While this technology remains more expensive than conventional gas plants, we will

[11] *See* Patel, Sonal. "Insite NET Power: Gas Power Goes Super-critical." Power Mag (April 2019). Available at: https://www.powermag.com/inside-net-power-gas-power-goes-supercritical/

continue to monitor this and other potential developments in carbon capture and storage for potential future application in our system.

B. Hydrogen for Power Generation

Hydrogen is another fuel with potential to support dispatchable carbon-free generation as burning hydrogen, by itself, does not produce any carbon emissions. In existing applications; however, hydrogen is typically mixed with natural gas, which has the effect of lowering a plant's CO_2 emissions levels. Introducing hydrogen into the fuel mix for an existing gas plant does not always require substantial plant retrofits. In fact, some conventional gas turbines are already capable of burning hydrogen in low-to-medium concentrations. For higher concentrations, more significant plant configuration changes are likely required.[12]

There are several methods of producing the hydrogen that would be burned in these units, from using existing industrial process byproduct hydrogen to producing it in dedicated water electrolysis facilities. Current methods like water electrolysis are, in themselves, energy intensive, and as such can make using hydrogen for electricity generation expensive. As the share of variable renewables on the electric grid increases, however, these processes may be able to use inexpensive (or negative priced) excess energy in some hours of the day to reduce the cost of producing the hydrogen. In this sense, hydrogen derived from renewable energy serves as a long duration storage option, where the fuel can be stored over days, weeks or months until needed and burned in a dispatchable plant without any carbon emissions.[13]

Pilot projects in Germany and Denmark, for example, are currently testing using excess wind generation to produce hydrogen through electrolysis[14] that can then be used as needed in a retrofitted natural gas generation plant. Various companies, including leading CT suppliers and startups, are working to further develop and commercialize both the turbines that can run on higher levels of hydrogen and the electrolysis facilities that would produce hydrogen using excess clean energy. We continue to monitor technology progress in the hydrogen space, to evaluate the

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[12] Goldmeer, Dr. Jeffrey. "Fuel Flexible Gas Turbines as Enablers for a Low or Reduced Carbon Energy Ecosystem." General Electric Company (May 2018). Available at: https://www.ge.com/content/dam/gepower/global/en_US/documents/fuel-flexibility/GEA33861%20-%20Fuel%20Flexible%20Gas%20Turbines%20as%20Enablers%20for%20a%20Low%20Carbon%20Energy%20Ecosystem.pdf

[13] *Id.*

[14] Fairley, Peter. "Europe Stores Electricity in Gas Pipes." Scientific American (April 2019). Available at: https://www.scientificamerican.com/article/europe-stores-electricity-in-gas-pipes/

potential for our gas generation assets to convert to hydrogen use in the future. We are also exploring ways to use electricity generated from our nuclear units to generate hydrogen through on-site electrolysis.

C. Emerging Nuclear Technologies

Nuclear power is one of the most reliable and lowest operating cost resources we have in our system. Our two nuclear plants provide nearly 30 percent of our electricity mix, carbon-free and at a cost (fuel and O&M) below $30/MWh. However, it is increasingly difficult to build new conventional nuclear units, in part due to their typical scale and associated high upfront costs.

Substantial industry research into several advanced nuclear technologies is ongoing. For example, in recent years there have been renewed efforts to develop advanced reactors that use sodium, gas or liquid metals in place of traditional cooling materials. Renewed research is also ongoing into applications wherein the nuclear fuel itself can be dissolved into molten salt, in order to operate at lower pressures than traditional pressurized water reactors. Using molten salt in this way is intended to improve safety considerations. Some advanced reactor designs are intended to reduce spent fuel volumes, by either enabling longer durations between refueling events or instituting closed fuel cycles that reprocess and reuse spent fuel within the reactor. Reducing spent fuel volumes can both reduce fuel costs and mitigate spent fuel storage challenges. Some designs also incorporate passive safety designs through natural convection cooling.

Other developers are researching potential application of light water reactor technology to small modular reactors (SMR). SMRs would be intended to be more flexible, able to serve smaller scale needs, and allow reduced backup infrastructure, as compared to existing nuclear units. This general concept is already used in military applications and for marine vessels that need to go long periods between refueling. SMRs are typically less than 300 MW in size and factory fabricated in modular units. The modular design is intended to enable streamlined production, shipping, and installation processes, in order to help manage costs. Further, the units are intended to go longer in between refueling outages than conventional plants, and allow refueling of one unit as the others continue to operate.[15] As an emerging technology, however, it is not yet clear whether SMR costs will be competitive with other sources of energy.

[15] *See* "Benefits." NuScale Power. Available at: https://www.nuscalepower.com/benefits

Several companies are currently working through NRC licensing processes for emerging nuclear technology, with the goal of attaining design approval for their advanced and small modular reactors by the mid-2020s, in order to complete pilot plants in the late 2020s.

D. Energy Storage Advancements

Large scale battery energy storage is increasing its presence on the grid, being used to integrate renewables, defer grid investments, and more. In fact, the Company has had a sodium-sulfur battery operating on the NSP System since 2009, in order to gain valuable technology experience.[16] Many batteries installed today use lithium-ion (li-ion) chemistries, benefitting from economies of scale gained in consumer electronics and, to some extent, electric vehicle manufacturing. Grid-scale li-ion batteries typically store energy for relatively short durations, providing a few hours of capacity or energy services.[17] While these shorter duration batteries hold great promise to mitigate demand peaks or short periods of intermittency now, in the long term with higher renewable penetration, the grid will need a combination of short and longer duration storage capabilities to effectively match variable renewable output to customer load. Further, costs for short and longer duration storage will need to decline further for energy storage to be deployed at scale.

To this end, there are several emerging storage applications that either use different chemical and physical properties, with the goal of mitigating cost and/or duration challenges. A few examples of emerging energy storage technologies we follow include:

- **Solid state li-ion batteries**: Current li-ion batteries, while continuing to become more cost effective for stationary storage applications, use a liquid electrolyte that has room to improve in terms of energy density. Development is underway that would replace the liquid electrolyte with solid materials, that offer higher energy densities and reduce potential for leakage and flammability. Solid state batteries hold promise to reduce the cost of energy storage, because increasing energy density allows more energy to be stored for discharge when needed. They also hold promise in increasing the number of times the battery can cycle before requiring material replacement.[18] These batteries are not yet

[16] The Luverne MinnWind Storage Project is a 1 MW, 7MW-h sodium sulfur (NaS) battery paired with an 11 MW wind facility in western Minnesota.
[17] As noted above, our modeling included a 4-hour duration generic battery energy storage option, which we believe is in line with most commercialized grid-scale lithium ion batteries installed currently.
[18] Tohoku University. "Highest energy density all-solid-state batteries now possible." ScienceDaily. (March

commercially available, but there is substantial interest in continuing development. Large industrials – such as Samsung, Hyundai, and Solvay – and venture funds such as Breakthrough Energy have invested in startups developing the technology.[19]

- **Flow batteries**: Flow batteries are a category of technology that includes several types of chemistry compositions. While not a new technology in general, application to stationary power system remains relatively nascent. In general, flow batteries are a cross between a conventional battery and a fuel cell, where a liquid electrolyte cycles through a core, and ion transfers between the cathode and anode generates electricity. As such, flow batteries tend to have favorable life cycles and may provide longer duration storage than li-ion designs; as the electrolytes are separate from the cell itself, the tanks can be scaled up without also scaling up the cell. However, round trip efficiency can be lower than in lithium-ion batteries, and this application has not been proven to serve substantially longer durations than lithium-ion.[20] [21] San Diego Gas & Electric, a utility in California, has recently installed a flow battery to its grid for a four year pilot project, where it will evaluate battery economics, renewable integration, and wholesale market services potential.[22]
- **Electrothermal energy storage**: Thermal storage for renewables has been implemented in limited use cases. There are, for example, existing large scale solar thermal facilities in the desert southwest that use large tanks of molten to store energy in the form of heat, across several hours or even days, until needed. This concept has not traditionally been applied to solar PV or wind facilities; however, a company called Malta is working to develop Carnot batteries (i.e. pumped thermal storage) that could be deployed either at greenfield or brownfield locations. Their concept converts the electricity from a solar PV or wind facility into thermal energy through a heat pump. Heat can be stored in molten salt while cold is stored in a chilled liquid. To discharge the energy, transfer fluid is run through both the hot and cold storage tanks, creating steam that can be used to convert the energy back into electricity. This

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2019). Available at https://www.sciencedaily.com/releases/2019/03/190322105701.htm

[19] Wesoff, Eric, "Industry Giants Samsung and Hyundai Invest in Solid-State Batteries." Greentech Media (September 2018). Available at: https://www.greentechmedia.com/articles/read/industry-giants-samsung-and-hyundai-invest-in-solid-state-batteries

[20] Dagget, Jamie. "Can Flow Batteries compete with Li-ion?" DNV GL (January 2019). Available at: https://blogs.dnvgl.com/energy/can-flow-batteries-compete-with-li-ion

[21] "Flow Batteries." Energy Storage Association. Available at: http://energystorage.org/energy-storage/storage-technology-comparisons/flow-batteries

[22] "California ISO Adds Flow Battery to the Grid." T&D World (May 2019). Available at: https://www.tdworld.com/energy-storage/california-iso-adds-flow-battery-grid

system is intended to provide longer duration storage, with a longer facility life and at lower capital cost than a typical battery storage facility.[23] In Germany, Malta and other partners are working to develop a pilot project on a brownfield coal site, in order to repurpose the steam turbine to generate electricity from the stored renewable energy.[24]

- **Subsurface pumped hydro storage**: Pumped hydro storage has been the primary method of long duration storage on the grid for many years, including the Company's own Cabin Creek pumped hydro facility in the Colorado service area. As noted above, however, we have not included it in our generic resource modeling due to dependence on specific geologic structures and related challenges in estimating generic costs. There are, however, companies working to provide scalable pumped hydro solutions that can be built in areas without the typical geologic structures. For example, a company called Quidnet is proposing to use conventional reservoir technology and typical oil and gas well practices to create subterranean compressed hydro storage facilities. To store energy, water would be pumped down into an underground well and held under pressure in the rock formation. When energy is needed, the pressure would be released and the water would flow through a conventional hydro turbine to generate electricity. This system is intended to be closed loop, to conserve water. The necessary underground rock structures are also more ubiquitous, and the plants can be more flexible in scale than conventional pumped hydro storage.[25]

[23] "Projects: Malta." Google X. Available at: https://x.company/projects/malta/
[24] Deign, Jason. "Germany Looks to Put Thermal Storage Into Coal Plants." Greentech Media (March 2019). Available at: https://www.greentechmedia.com/articles/read/germany-thermal-storage-into-coal-plants
[25] "Solution." Quidnet Energy. Available at: http://www.quidnetenergy.com/

APPENDIX F7 – MINNESOTA ENERGY STORAGE SYSTEMS ASSESSMENT

I. INTRODUCTION

In the 2019 legislative session in Minnesota, there was legislation passed as a part of the jobs, economic development, energy, and commerce omnibus bill amending Minnesota Statutes 2018, section 216B.2422 to require utilities to include an assessment of energy storage systems in their resource plan filing. The full text of the legislation is included below:

> Subd. 7.**Energy storage systems assessment.**(a) Each public utility required to file a resource plan under subdivision 2 must include in the filing an assessment of energy storage systems that analyzes how the deployment of energy storage systems contributes to:
> (1) meeting identified generation and capacity needs; and
> (2) evaluating ancillary services.
> (b) The assessment must employ appropriate modeling methods to enable the analysis required in paragraph (a).
> **EFFECTIVE DATE.** This section is effective the day following final enactment.

In this Appendix, we include background on Xcel Energy's growing experience with energy storage technologies, a narrative on the values that storage can provide to the system, some of the shortcomings of current storage technologies, and how we analyzed energy storage as a part of this Resource Plan.

Xcel Energy's long-term carbon strategy depends on the deployment of advanced clean technologies. We expect grid-scale energy storage to play an important role in our long-term plans. While we do not anticipate significant reliance on battery storage resources in this plan for the Upper Midwest in the near term, we are piloting storage technology across our system to test the capabilities, and will look for opportunities for more aggressive deployment of these resources in the future as we have generation capacity needs.

As discussed in more detail below, grid-scale storage can help integrate increasing levels of renewable resources. Storage can also provide other system benefits, including more reliable grid operations, voltage support, and frequency control. Utilities are already taking advantage of many different values of grid-scale storage. In fact, utilities are the leading developers of storage technology in the nation. As grid owners and operators, utilities are uniquely situated to maximize the potential benefits of storage. As detailed further in this Appendix, Xcel Energy has a number of advanced storage projects already deployed on our system and a growing interest in using storage in the future.

At the same time, we recognize that storage today has limitations. We discuss here three significant challenges for storage: First, storage cannot today solve the problem of the wide seasonal variation in renewable energy generation, which is the chief factor preventing the creation of fully renewable electricity system. Second, while storage can initially help integrate renewables by moving energy from the time it is produced to when it is needed, the value of each additional increment of storage capacity declines as more is added to the system. Finally, although storage can provide multiple services to the grid – power quality and grid support, for example – the value of all of these services are not all additive (or "stackable"). As a general rule, these services are not all available at the same time. Despite these limitations, we are bullish on the potential of storage as a part of our electricity system.

II. XCEL ENERGY'S ENERGY STORAGE EXPERIENCE

Electricity storage devices include a variety of technologies that store electrical energy directly (e.g. capacitors) or, more typically, after converting to some other form of potential or kinetic energy. For example, pumped hydro storage facilities use electrical energy to pump water to a higher elevation and store that water as gravitational potential energy; flywheels use electrical energy to rotate a mass to high velocities and thus store energy as kinetic energy; compressed air projects store energy in a geologic formation as pressurized potential energy; and batteries use electrical energy to drive chemical reactions and then store that energy as chemical potential energy. As no energy conversion process occurs without inefficiencies or losses, any energy storage system will discharge a lesser amount of energy than used to charge the device. If deployed properly, energy storage can help enable a smarter, stronger, cleaner and more reliable grid.

Xcel Energy has long been a leader in deploying energy storage. We have operated pumped hydro energy storage on our system for decades and have adapted its operation to meet our evolving system. Today, we are implementing pilots and other programs exploring new storage technologies that will play a role in our energy future.

A. Cabin Creek Pumped Storage

Historically, pumped storage hydro has been the dominant source of energy storage – even today, nearly 92 percent of operational storage in the US is pumped storage. Our largest energy storage asset is the 324 MW Cabin Creek pumped hydroelectric storage facility in Colorado. The Cabin Creek facility was built in 1967. Like all pumped storage facilities, it has an upper and a lower reservoir. When economic, we pump water from the lower to the upper reservoir. When the system has additional

energy needs, we allow the water to "spill" out of the upper reservoir to the lower through a hydro turbine to generate electricity. Originally, the facility was used to transfer excess energy from off-peak hours to on-peak hours, but today it is also used for renewable energy integration. We spill water to meet customer demand when the wind stops blowing and pump water to the upper reservoir during times when the wind energy generated on our system exceeds customer demands.

B. Luverne MinnWind Storage Project

The Luverne wind-to-battery project in Minnesota was one of the first battery storage pilot projects the Company pursued and the first U.S.-based pairing of wind energy and a storage battery. The pilot was intended to test the various ways batteries could be used to provide wind integration and regulation services supporting the energy grid. The 1 MW, 7 MWh sodium sulfur battery paired with an 11 MW wind project has been in-service since 2009, and was recently updated by the manufacturer with new grounding technology and cells, extending the life of the battery and allowing us to test new battery applications. It was funded in part by a $1 million grant from Minnesota's Renewable Development Fund.[1]

C. SolarTAC

We are the original founding member, host utility and a development partner at the Solar Technology Acceleration Center (SolarTAC), an outdoor solar testing facility located in Aurora, Colorado.[2] Together, the solar industry and utilities work at SolarTAC to test, validate and demonstrate advanced solar technologies under actual field conditions. We worked with our SolarTAC partners to test two different battery storage projects.

- A community energy storage project at SolarTAC is testing a more cost-effective way to improve the integration of solar power in areas with high solar production. Working with the Electric Power Research Institute (EPRI), we are testing a 25-kilowatt battery integrated with four small photovoltaic installations that simulate a neighborhood with multiple rooftop solar power systems.
- Through our Solar2Battery project, we installed a 1.5 MW battery to evaluate how energy storage can help in operating the electricity grid with energy from large-scale solar facilities.

[1] Xcel Energy Wind-to-Battery Project: https://www.xcelenergy.com/staticfiles/xe/Corporate/Environment/wind-to-battery%20fact%20sheet.pdf
[2] Solar Technology Acceleration Center: http://www.solartac.org/

These projects have increased our knowledge of how batteries respond to intermittent solar generation, how battery chemistries perform over time, and how energy storage systems can create value for our system.

D. Innovative Clean Technologies Program

The Colorado Public Utilities Commission has approved an Innovative Clean Technologies (ICT) program to test emerging technologies that are designed to lower carbon emissions associated with electricity service. We currently have two battery storage demonstration projects operating under the ICT program:

- Stapleton Community Energy Storage Project: As demand for solar energy at our customers' homes and businesses increases, we are examining how battery storage can help integrate higher concentrations of customer solar energy on our system. Through a project in Denver's Stapleton neighborhood, Xcel Energy installed six customer batteries and six larger grid batteries to test rooftop solar integration and grid support capabilities.[3]
- Panasonic Battery Demonstration Project: Through a public-private partnership, Xcel Energy, Panasonic and Denver International Airport are collaborating to test a battery storage system that can both serve as a microgrid to provide backup power to Panasonic's Denver headquarters and support Xcel Energy's grid at other times. As part of the project, Xcel Energy owns a 1.3 MW solar carport installation and a 1 MW/2MWh lithium ion battery. Panasonic also owns a 0.20 MW solar array located atop its building, which is also tied into the system.[4]

E. Fort McCoy Solar plus Battery Microgrid Partnership Project

We are partnering with Fort McCoy, a U.S. Army installation in Wisconsin, to develop a solar-plus-storage microgrid demonstration project to provide a secure source of power to certain critical facilities on the Army Base. The project will combine onsite solar photovoltaic generation with energy storage to provide additional resilience to support identified facilities through a microgrid in an extended outage, likely in combination with existing backup generation.

[3] Community Storage Project in Stapleton Neighborhood: https://www.xcelenergy.com/energy_portfolio/innovation/stapleton
[4] Panasonic Battery Demonstration Project: https://www.xcelenergy.com/staticfiles/xe-responsive/Energy%20Portfolio/CO-Panasonic-Fact-Sheet.pdf

Through this project, the Company will gain a solar resource to supply energy to its customers, as well as experience with operating and maintaining a solar-plus-battery microgrid and optimizing the use of these resources. We will also gain experience valuable to understanding the performance of these systems, applicability and implementation of new MISO rules for battery storage participating in MISO markets, as well as knowledge and insight that will enhance our ability to understand, plan for and accommodate future battery storage applications. We anticipate this project will be operational in 2021.

These pilot projects have provided operational experience for future, widespread deployment of batteries on our system. From these projects, we have gained detailed information on the value, costs and benefits of battery installations. The projects demonstrate the need for better interoperability between the devices and systems. They will inform future system architecture, including cybersecurity and interconnection issues associated with battery operation. In addition, we currently have nearly 300 residential batteries installed across our states and are working with customers and the storage industry to provide battery interconnection guidelines and support. The legislation passed in Minnesota in 2019 also allows for cost recovery of energy storage system pilot projects.

F. Colorado Energy Plan

The Colorado Energy Plan (CEP) is the next step in our efforts to transform our energy system for our Colorado affiliate. It includes the retirement of two existing coal units and the construction of 1,100 MWs of new wind and 700 MWs of new solar. As part of the all-source bids associated with the CEP, we received 133 total energy storage bids from 97 separate projects. Taking advantage of the tax credit incentives, several of the project developers were able to present us with competitive pricing for batteries paired with solar. From these bids, we selected two separate battery-plus-solar projects totaling over 600 MWs of universal scale solar paired with 275 MWs of battery storage, which was then the largest utility-proposed acquisitions of battery storage in the U.S. The Colorado Public Utilities Commission approved CEP in August 2018, and with this approval we are moving forward to implementation.

III. ENERGY STORAGE VALUES

Energy storage can be deployed in all parts of the energy grid, and can help to enable a smarter, stronger, cleaner, and more reliable energy grid for our customers. There are multiple opportunities for energy storage to add value to our system. We focus

here on four key areas: renewable integration, grid support, deferred investment, and power quality.

A. Renewable Energy Integration

As Xcel Energy continues to add significant amounts of renewable energy generation to our system, energy storage can support integrating those renewables into the energy grid. Renewable energy is available when the wind blows or the sun shines, and customer energy demand is often not synchronized with its availability. Storage can help shift renewable energy to time periods when it is needed, reducing the need for investment in peaking plants and support facilities. This is especially true for short-term deviations – a few minutes to a few hours – between customer demand and renewable generation.

B. Grid Support

As the owners and operators of the grid, utilities are first and foremost responsible for the safety, reliability, and optimal operation of our system for our customers. A reliable electric system requires attention to the physics of electricity transmission and distribution. It is not enough to match generation and power supply; we also must make sure that the power can be delivered to customers. Energy storage can help with grid reliability and resilience by providing:

- voltage support at critical places on the electric system where low voltage prevents the transmission of power;
- ancillary services such as:
    - frequency regulation – ensuring that the appropriate frequency of the alternating current on the system is maintained
    - spinning reserves – available resources to increase power output to meet fast changes in demand
    - operating reserves – resources to make up the difference between production and demand when production is low
- energy arbitrage, purchasing and storing electricity during off-peak times, and then utilizing that stored power during periods when electricity prices are the highest;
- readily available reserves, reducing the need for additional investments in "quick start" generation and transmission assets that maintain the system in the event of a disruption; and

- Black start capability, or the ability to restart the entire electric system in the event the whole system goes down.

Utilities are well-positioned to maximize the value of these storage capabilities to ensure system planning and visibility with the primary objective of enhancing reliability and optimizing performance in a cost-effective manner. We can facilitate the deployment of energy storage on our system when and where it is most needed.

C. Deferred Investment

Storage has the potential to take the place of traditional grid investments across our system, including investments in peaking generation, transmission and distribution upgrades, and reliability investments to maintain grid support. Its ability to do so depends on whether the proposed storage resource is (1) capable of providing the same benefits as the asset it replaces; (2) cheaper than the more traditional alternative; and (3) has some level of visibility and control by the grid operator. As storage technologies continue to improve and prices come down, there are greater opportunities for storage to take the place of existing technologies, especially in areas where the unique circumstances of the system make traditional technologies more expensive.

We are actively exploring additional deferral opportunities for our system where storage may provide a solution. This requires new tools and processes to analyze the appropriate location and size of the potential storage solution, as well as a cost-benefit analysis of those solutions as compared to traditional grid investments. Properly positioned storage can defer or reduce the need for incremental transmission and distribution investments, while poorly-sited storage may require additional investments in new capacity or distribution upgrades.

D. Power quality

Some of our customers seek power quality above and beyond what is provided by our standard electric service. Batteries can improve power quality by helping avoid the momentary outages that interfere with the operation of sensitive electronic equipment. Projects like our Panasonic pilot have demonstrated the value of customer-utility partnerships in addressing these issues by placing a utility-owned battery close to, or at, a customer site to provide premium power quality service, while also allowing the utility to leverage the battery for grid services.

We are optimistic about these and other benefits of grid-scale storage. Key to capturing the full spectrum of these benefits is the recognition that storage is first and

foremost a grid asset. As more and more energy storage is deployed on our system and across the country, it is important that the rules governing ownership and operation of energy storage assets are clear and aimed at maximizing the grid benefits of storage while encouraging its affordable, reliable and safe deployment. Utilities are uniquely situated to understand the grid and its needs and should play an important role both in owning and operating grid-scale storage.

IV. CHALLENGES OF CURRENT ENERGY STORAGE TECHNOLOGY

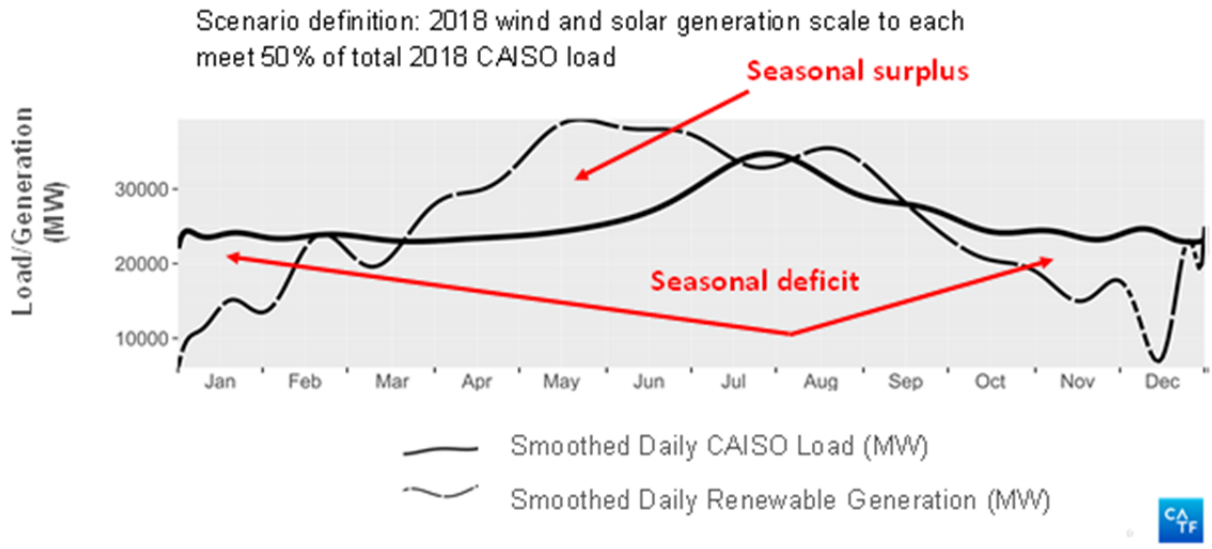
Energy storage offers opportunities to enhance our operations, help us integrate renewable energy, and play an important role in achieving our clean energy vision. At the same time, storage is not a silver bullet that would solve all electricity system challenges. While we see storage as a growing part of our energy system, it must be part of a diverse clean energy portfolio. Storage has inherent limitations that policy makers and utilities must keep in mind as we invest in the energy system of the future.

A. Seasonal Renewable Variation

Xcel Energy has been a long-time leader in renewable energy, and has done nation-leading work to integrate growing levels of renewables across our system. Wind and solar have been a key part of our strategy for more than a decade, and we plan to continue to add renewable energy as long as we can do so cost effectively and reliably.

As discussed above, storage has growing value to help integrate renewable energy on the electric system. Seasonal variation in renewable generation is the primary reason that the cost of renewable energy grows so substantially as renewable penetration increases. The Clean Air Task Force (CATF) chart below shows that, during the periods when renewable output is very high, the California energy system would generate substantial additional renewable energy. This additional renewable energy would have to charge a massive amount of storage capacity to ensure that load is served when renewable output is relatively low.

**Figure 1: Clean Air Task Force –
Smoothed Daily Load and Renewable Energy Generation, Mixed Renewable Scenario**



In fact, CATF estimates that 9.6 million MW-hours of energy storage would be required to achieve 80 percent renewables in California—compared to the roughly 150,000 MW-hours of storage in California now. To reach 100 percent renewables, CATF has concluded that California would need 36 million MW-hours of storage. The cost of storage to achieve 100 percent renewable electricity in California would be astronomical – an estimated $3.6 trillion in capital costs to store all the surplus renewable generation, even assuming a 60 percent drop from today's storage costs.

We believe similar challenges would exist on our system. Based on E3's analysis of our carbon reduction scenarios for our Upper Midwest System, excluding new gas resources more than doubles the costs of reducing CO_2 emissions 85% by 2030 and 95% by 2045 compared to reaching the same goal with only renewable energy and storage additions.[5]

We remain committed to providing our customers with a carbon-free electric system, and we will add renewable energy to that system as long as it makes sense. We expect that storage will play an important role in a future clean energy system. However, given the huge challenge of seasonal variation in renewable generation, it is not realistic to expect that storage will make a 100 percent renewable energy system possible. Storage alone cannot provide our customers with the reliable and affordable

[5] Energy and Environmental Economics analysis of Low Carbon Scenarios on Xcel Energy's Upper Midwest System (E3 System Study), Appendix P2.

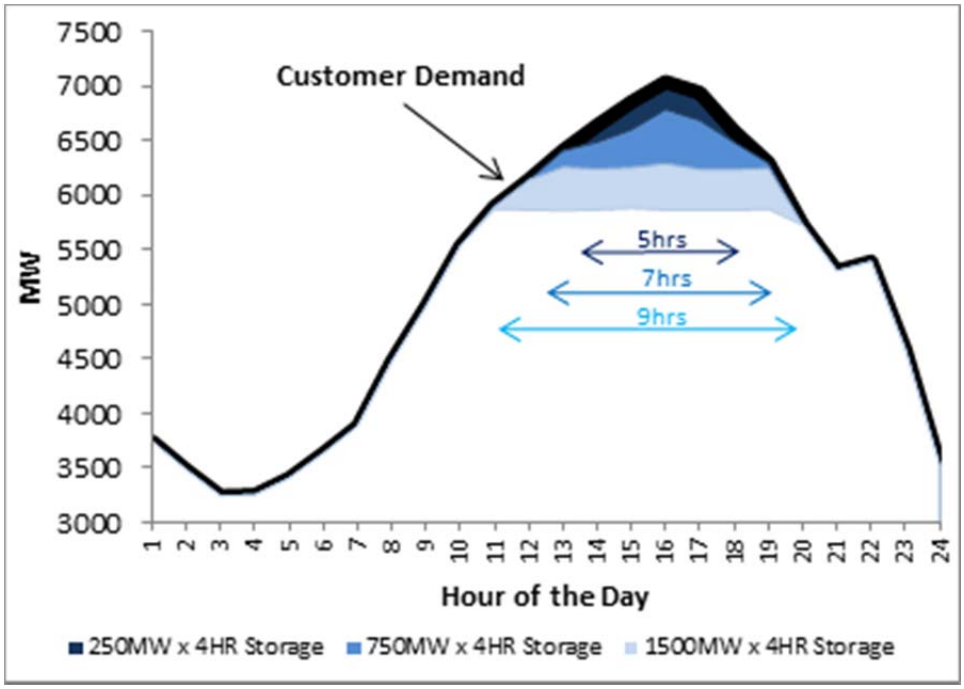
energy that they need. A broader suite of new dispatchable zero carbon technologies will be key to achieving our long-term carbon goals.

B. Declining Marginal Capacity Value

Storage can help meet peak energy demand by shifting some excess renewable energy to periods when it is needed, but this value declines dramatically as more storage is added to the system. As its name implies, a system peak is like the top of a mountain or a pyramid. It represents a short period of time during each day when energy usage is at its highest. Energy storage can shave off and lower the top of the peak, but it also widens it. As a result, larger, more expensive storage systems are required to further reduce the system energy needs.

The following chart illustrates this problem. The black line represents a single illustrative day of energy demand for one of our operating companies. Suppose that a 250 MW battery with four hours of storage capability is added to the system. It will shave off the top of the peak for a five hour period and shift the curve so that it takes advantage of parts of the day where excess renewables may be generated. The result is a lower, wider peak – more like a plateau. The next tranche of peak reductions requires substantially more storage to achieve the same effect – in this example, 750 MW of four hour batteries that are able to discharge over an approximately 7-hour period. The next tranche of demand reduction will require an even more substantial investment in storage i.e. a 1500 MW battery operating for almost 9 hours.

Figure 2: Battery Storage for Peak Demand Reduction



This chart illustrates that more batteries with longer duration are required at each step to reduce the peak. This problem is further compounded during periods of low renewable production, when excess generation may not be available to re-charge batteries to be available for the next peak.[6] At some point, it is not technically or economically feasible to continue to use storage to shift energy from off-peak to on-peak periods.

C. Stacking Storage Values

As referenced above, storage provides multiple values, each of which can enhance the operation and efficiency of the grid. Adding multiple values together – "stacking" – can make the storage resource more valuable as a whole. For example, a storage resource that provides voltage support and renewable integration will be more valuable than a storage resource that provides only one of these benefits. As the cost of storage continues to decline, stacking these benefits together increases the probability that a utility would choose to add a battery or other storage resource to its system.

[6] See E3 System Study, Figure 4-4, Appendix P2.

At the same time, in determining the value of a storage resource, its multiple potential benefits should not be added if one value precludes another. A battery may simultaneously provide voltage support and frequency regulation, but it cannot, for example, simultaneously integrate renewables and provide black start capability. In the latter case, the battery must be available to restart the system, and it may not be available to do so if it has been discharged to integrate renewables. Thus, the value of storage must be determined based on a utilities need for the potential value streams storage provides, and the ability and efficiency of storage to meet those needs.

V. ENERGY STORAGE ANALYSIS IN THE RESOURCE PLAN

We are considering storage opportunities in our resource planning processes in a number of our states. As mentioned above, our Colorado system already has 324 MW of pumped storage and we will be adding another 275 MW of storage embedded in solar by 2022. In this Resource Plan analysis we included a four hour generic battery storage resource in the modeling as an option to meet energy and capacity needs. The characteristics and cost assumptions for the storage resource can be found in the Strategist Assumptions in Appendix F2. In our modeling, the generic storage was allowed to compete with other resources to meet energy and capacity needs per the statutory requirement. If we have future needs, our model will select storage when it is a cost-effective resource. We continue to consider new tools and processes to analyze the appropriate location and size of storage solutions including the evaluation of potential values storage assets might provide to the system.

The Strategist model includes a spinning reserve requirement of 137 MW based on a 12 month rolling average of spinning reserves carried by the NSP System within MISO. Strategist does not account for other ancillary services and the associated value storage or any other resource may provide. Costs related to integrating renewables are included in Strategist by adding an integration cost to wind and solar.

Included as Appendix P2 is E3's Low Carbon Scenario analysis which used E3's RESOLVE model to evaluate deep decarbonization scenarios on our Upper Midwest System. The RESOLVE model utilizes a chronological hourly dispatch in contrast to the load duration curve methodology utilized by Strategist. In addition, RESOLVE includes the following operating reserve requirements which must be met by each resource portfolio:

1. Load following reserves requirements are set at 3% of load;
2. Frequency regulation reserve requirements are 27 MW; and
3. Spin reserve requirements are set at 1% of load.

The conclusions of E3's Low Carbon Scenario analysis generally support our preferred plan as a least cost way to achieve deep reductions in CO_2 emissions. Regarding storage, E3's analysis found the storage additions were not cost-effective on our system in the near-term, but were selected later in the planning period.

We will continue to evaluate storage in future resource plans, and will acquire new modeling tools that are better able to analyze high renewable scenarios. We expect storage to be part of our resource portfolio as costs continue to decline and we add more renewables to our system. Like other resources, much of the value of storage is in its ability to provide capacity and energy (arbitrage) and therefore it is primarily those needs will help drive storage additions in the future. Given our excess capacity position thru the mid-2020s, storage is unlikely to be cost-effective in the near term. However, the Company will continue to explore near term storage opportunities that could provide value to our system. In addition, storage resource will be considered to help meet firm, dispatchable capacity needs that have been identified in our Preferred Plan in the 2030s.

The Potential for Load Flexibility in Xcel Energy's Northern States Power Service Territory

PREPARED FOR

Xcel Energy

PREPARED BY

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June 2019

THE Brattle GROUP

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Executive Summary

Highlights:

- This study estimates the amount of cost-effective demand response available in Xcel Energy's Northern States Power (NSP) service territory, including an assessment of emerging "load flexibility" programs that can capture advanced sources of value such as geo-targeted distribution investment deferral and grid balancing services.
- Through 2023, NSP's cost-effective DR opportunities are constrained by limitations of its existing metering technology, access to low-cost peaking capacity, a limited need for distribution capacity deferral and grid balancing services, and relatively high costs of emerging DR technologies.
- In later years of the study horizon, and under conditions that are more favorable to the economics of DR, cost-effective DR potential increases significantly, exceeding the PUC's 400 MW DR procurement requirement.
- New, emerging load flexibility programs account for around 30% of the 2030 incremental DR potential estimates in this study.

Background

The purpose of this study is to estimate the potential capability of all cost-effective demand response (DR) that could be deployed in Xcel Energy's Northern States Power (NSP) service territory through 2030.[1] The study addresses the Minnesota PUC's requirement that NSP "acquire no less than 400 MW of additional demand response by 2023" and "provide a full and thorough cost-effectiveness study that takes into account the technical and economic achievability of 1,000 MW of additional demand response, or approximately 20% of Xcel's system peak in total by 2025."

The scope of this study extends significantly beyond those of prior studies. Specifically, we account for opportunities enabled by the rapid emergence of consumer-oriented energy technologies. Advanced metering infrastructure (AMI), smart appliances, electric vehicles, behavioral tools, and automated load control for large buildings are just a few of the technologies driving a resurgence of interest in the value that can be created through new DR programs. These technologies enable DR to evolve from providing conventional peak shaving services to providing around-the-clock

[1] Throughout this study, we simply refer to Xcel Energy as "NSP" when describing matters relevant to its NSP service territory.

"load flexibility" in which electricity consumption is managed in real-to address economic and system reliability conditions.

This study also takes a detailed approach to assessing the cost-effectiveness of each DR option. While emerging DR programs introduce the potential to capture new value streams, they are also dependent on technologies that in some cases have not yet experienced meaningful cost declines. Further, opportunities to create value through DR vary significantly from one system to the next. A detailed assessment of the costs and benefits of each available DR option is necessary to identify the DR portfolio that is the right "fit" for a given utility system.

The Brattle Group's Load*Flex* model is used to assess NSP's emerging DR opportunities. The Load*Flex* modeling framework builds upon the standard approach to quantifying DR potential that has been used in prior studies around the U.S. and internationally, but incorporates a number of differentiating features which allow for a more robust evaluation of load flexibility programs:

- **Economically optimized enrollment:** Assumed participation in DR programs is tailored to the incentive payment levels that are cost-effective for the DR program, thus providing a more complete estimate of total cost-effective potential than prior methodologies.
- **Utility-calibrated load impacts:** Load impacts are calibrated to the characteristics of NSP's customer base. This includes accounting for the market saturation of various end-use appliances, customer segmentation based on size, and NSP's estimates of the capability of its existing DR programs.
- **Sophisticated DR program dispatch:** DR program dispatch is optimized subject to detailed accounting for the operational constraints of the program, including tariff-related program limitations and an hourly representation of load control capability for each program.
- **Realistic accounting for "value stacking":** DR program operations are simulated to maximize total benefits across multiple value streams, while recognizing the operational constraints of the program and accounting for necessary tradeoffs when pursuing multiple value streams.
- **Industry-validated program costs:** DR program costs are based on a detailed review of NSP's current DR offerings, a review of experience and studies in other jurisdictions, and conversations with vendors.

Findings

Base Case

NSP currently has one of the largest DR portfolios in the country, with 850 MW of load curtailment capability (equivalent to roughly 10% of NSP's system peak). The portfolio primarily consists of an interruptible tariff program for medium and large C&I customers, and a residential air-conditioning direct load control (DLC) program. The DLC program is transitioning from utilizing a conventional compressor switch technology to instead leveraging newer smart thermostats.

There is an opportunity to tap into latent interest in the current NSP programs and grow participation in those existing programs through new marketing efforts and refinements to program design. According to our analysis, doing so could provide 293 MW of incremental cost-effective potential by 2023. The majority of this growth could come from increased enrollment in a redesigned interruptible tariff program for the medium and large C&I segments, and from the transition to a residential air-conditioning DLC program that more heavily utilizes smart thermostat technology.

NSP's DR portfolio could also be expanded to include new programs that are not currently offered by the company. Our analysis considered eight new programs, including time-of-use (TOU) rates, critical peak pricing (CPP), home and workplace EV charging load control, timer-based water heating load control and a more advanced "smart" water heating program, behavioral DR, ice-based thermal storage, and automated DR for lighting and HVAC of commercial and industrial customers. Some of these programs could provide ancillary services and geo-targeted distribution deferral benefits, in addition to the conventional DR value streams.

Based on current expectations about the future characteristics of the NSP market, smart water heating is the only new program that we find to be cost-effective in 2023 among the emerging options described above, providing an additional 13 MW of incremental cost-effective potential. Through 2023, NSP's cost-effective DR opportunities are constrained by limitations of its existing metering technology, access to low-cost peaking capacity, a limited need for distribution capacity deferral and frequency regulation, and relatively high costs of emerging DR technologies.

This expanded portfolio, which reflects all cost-effective DR options available to NSP across a broad range of potential use cases, would fall short of the PUC's 2023 procurement requirement. In 2023, the current portfolio plus the incremental cost-effective DR identified in this study would equate to 1,156 MW of total peak reduction capability, 154 MW short of the procurement requirement.[2]

In 2025, the potential in the expanded portfolio increases. This increase is driven primarily by the ability to begin offering time-varying rates once smart meters are fully deployed in 2024. However, it is likely that several years will be needed for smart metering-based programs to ramp up to full participation, so the incremental potential associated with these programs is still somewhat constrained in 2025. The current portfolio plus the incremental DR in the expanded portfolio equate to 1,243 MW of cost-effective DR potential in 2025.

By 2030, NSP's cost-effective DR potential will increase further. This increase is driven primarily by the maturation of smart metering-based DR programs. Other factors contributing to the increase in cost-effective potential include a continued transition to air-conditioning load control through smart thermostats, an expansion of the smart water heating program through ongoing

[2] NSP has interpreted the PUC's Order to require 400 MW of capacity-equivalent DR, which equates to 391 MW of generator-level load reduction when accounting for the reserve requirement, and 362 MW of meter-level load reduction when additionally accounting for line losses.

voluntary replacements of expiring conventional electric water heaters, and overall growth in NSP's customer base. By 2030, we estimate that NSP's current portfolio plus the incremental cost-effective DR would amount to 468 MW. New, emerging DR programs account for 33% of the incremental potential. Achieving this potential would require not only growth in existing programs, but the design and implementation of several new DR program as well.

High Sensitivity Case

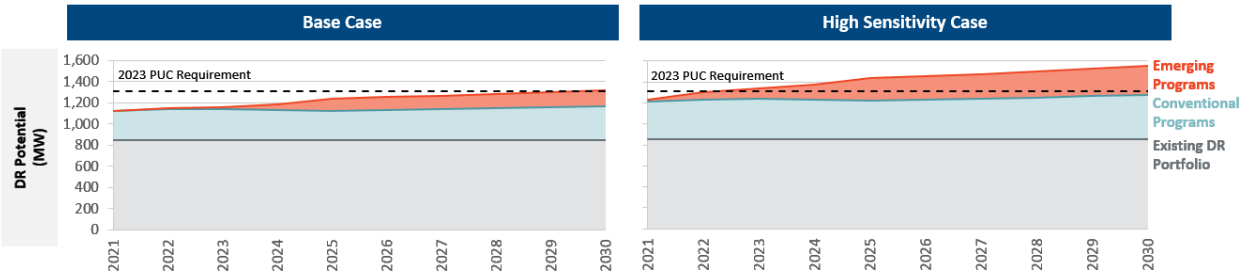
NSP's market may evolve to create more economically favorable conditions for DR than currently expected. For instance, growth in market adoption of intermittent renewable generation could contribute to energy price volatility and an increased need for high-value grid balancing services. Further, the costs of emerging DR technologies may decline significantly, or the cost of competing resources (e.g., peaking capacity) may be higher than expected. To understand how these alternative conditions would impact DR potential, we analyzed a sensitivity case. The High Sensitivity Case illustrates the potential for DR under an alternative set of market conditions that are more favorable to DR program economics. The case is not a forecast of what is likely to happen in the future in NSP's service territory, particularly in the near-term years of the study horizon.

Under the illustrative assumptions of the High Sensitivity Case there is significantly more cost-effective incremental potential. In 2023 there is a total of 484 MW of incremental cost effective potential, which would satisfy the PUC's procurement requirement. By 2030, the total portfolio of DR programs, including the existing programs, could reach 705 MW.

The mix of cost-effective programs in the High Sensitivity case is essentially the same as in the Base Case. However, larger program benefits justify higher incentive payments, which leads to higher participation and overall potential in these programs. Auto-DR for C&I customers also presents an opportunity to increase load flexibility in the High Sensitivity Case, though the potential in this program is subject to uncertainty in technology cost and customer adoption.

Under both the Base Case and the High Sensitivity Case assumptions, avoided generation capacity costs are the primary benefit of the DR portfolio. In the High Sensitivity Case, additional price volatility due a greater assumed mix of renewable generation in the regional supply portfolio leads to an increase in the share of total that is attributable to avoided energy costs. The total value of frequency regulation provided by DR also increases modestly relative to the Base Case, as a greater need for this service is assumed for renewable generation integration purposes. Figure ES-1 summarizes the DR potential estimates and benefits of the DR portfolio under Base Case and High Sensitivity Case assumptions.

Figure ES-1: NSP's DR Potential and Annual Portfolio Benefits



2030 Avoided Cost ($M/yr)

	Energy	Generation Capacity	System Average T&D Deferral	Geotargeted Distribution Deferral	Frequency Regulation	Total
Conventional Programs	$1.7	$15.5	$0.9	$0.0	$0.0	$18.1
Emerging Programs	$5.7	$7.4	$0.4	$0.0	$1.2	$14.7
Total	$7.4	$22.9	$1.3	$0.0	$1.2	$32.8

	Energy	Generation Capacity	System Average T&D Deferral	Geotargeted Distribution Deferral	Frequency Regulation	Total
Conventional Programs	$3.1	$26.8	$1.1	$0.0	$0.0	$31.0
Emerging Programs	$19.6	$19.5	$0.8	$0.7	$4.6	$45.2
Total	$22.7	$46.3	$1.9	$0.7	$4.6	$76.2

Notes: Benefits shown in 2023 dollars. Estimates include benefits from NSP's existing 850 MW portfolio.

An expanded portfolio of DR programs will have operational flexibility beyond the capabilities of conventional existing programs. For instance, load flexibility programs could be dispatched to reduce the system peak, but also to address local peaks on the distribution system which may occur during later hours of the day. Off-peak load building through electric water heating could help to mitigate wind curtailments and take advantage of negative energy prices. The provision of frequency regulation from electric water heaters could further contribute to renewables integration value.

Specific recommendations for acting on the findings of this study including the following:

- Aggressively pursue the transition to smart thermostats as well as recruitment of medium C&I customers into the Interruptible program.
- Pilot and deploy a smart water heating program. As a complementary activity, evaluate the impacts of switching from gas to electric heating, accounting for the grid reliability benefits associated with this flexible source of load.
- Prior to the smart metering rollout, build the foundation for a robust offering of time-varying rates, including identifying rate options that could be offered on an opt-out basis.
- Develop measurement & verification (M&V) 2.0 protocols to ensure that program impacts are dependable and can be integrated meaningfully into resource planning efforts.
- Design programs with peak period flexibility, to be able to respond to changes such as a shifts in the net peak due to solar PV adoption, or a shift in the planning emphasis from a focus on the MISO peak to a focus on more local peaks, for instance.

I. Introduction

Purpose

The purpose of this study is to estimate the potential capability of all cost-effective demand response (DR) that could be deployed in Xcel Energy's Northern States Power (NSP) service territory.[3] Xcel Energy commissioned this study to satisfy the requirements of the Minnesota Public Utilities Commission (PUC) Order in Docket No. E-002/RP-15-21. That Order, established in January 2017, required NSP to "acquire no less than 400 MW of additional demand response by 2023" and to "provide a full and thorough cost-effectiveness study that takes into account the technical and economic achievability of 1,000 MW of additional demand response, or approximately 20% of Xcel's system peak in total by 2025."

Background

The Brattle Group conducted an assessment of NSP's DR potential in 2014.[4] That study specifically addressed opportunities to reduce NSP's system peak demand. As such, the assessment had a primary focus on "conventional" DR programs that are utilized infrequently to mitigate system reliability concerns. The study also included price-based DR options that would be enabled by the eventual deployment of smart meters.

The scope of this 2018 study extends significantly beyond that of the 2014 study. Specifically, we account for opportunities enabled by the rapid emergence of consumer-oriented energy technologies. Advanced metering infrastructure (AMI), smart appliances, electric vehicles, behavioral tools, and automated load control for large buildings are just a few of the technologies driving a resurgence of interest in the value that can be created through new DR programs. These technologies enable DR to evolve from providing conventional peak shaving services to providing around-the-clock "load flexibility" in which electricity consumption is managed in real-to address economic and system reliability conditions. The Brattle Group's Load*Flex* model is used to assess these emerging opportunities.

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[3] Throughout this study, we simply refer to Xcel Energy as "NSP" when describing matters relevant to its NSP service territory.

[4] Ryan Hledik, Ahmad Faruqui, and David Lineweber, "Demand Response Market Potential in Xcel Energy's Northern States Power Service Territory," prepared for Xcel Energy, April 2014.

This 2018 study also extends beyond the scope of the 2014 study by evaluating the cost-effectiveness of each DR option.[5] While emerging DR programs introduce the potential to capture new value streams, they are also dependent on technologies that in some cases have not yet experienced meaningful cost declines. Further, opportunities to create value through DR vary significantly from one system to the next. A utility with significant market penetration of solar PV may find the most value in advanced load shifting capabilities that address evening generation ramping issues on a daily basis, whereas a system with a near-term need for peaking capacity may find more value in the types of conventional DR programs that reduce the system peak during only a limited number of hours per year. A detailed assessment of the costs and benefits of each available DR option is necessary to identify the DR portfolio that is the right "fit" for a given utility system.

This report summarizes the key findings of The Brattle Group's assessment of NSP's DR market potential. Additional detail on methodology and results is provided in the appendices.

NSP's Existing DR Portfolio

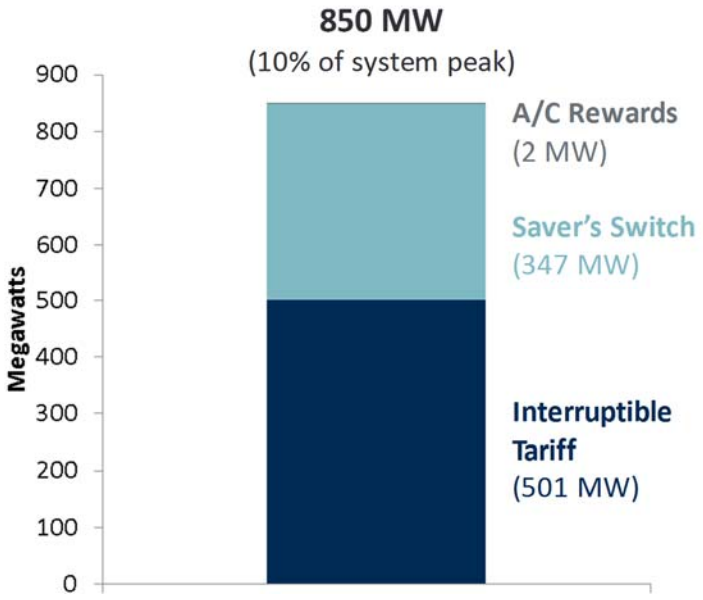
The capability of NSP's existing DR portfolio is substantial. It is the eighth largest portfolio among all US investor-owned utilities when DR capability is expressed as a percentage of peak demand. The portfolio is the largest in MISO in terms of total megawatt capability, and second when expressed as a percentage of peak demand.

As of 2017, Xcel Energy had 850 MW of DR capability across its NSP service territory, accounting for roughly 10 percent of system peak demand. This capability comes primarily from two programs. The largest is an "interruptible tariff" program, which provides commercial and industrial (C&I) customers with energy bill savings in return for a commitment to curtail electricity demand to pre-established levels when called upon by the utility. Roughly 11 percent of the peak-coincident demand of medium and large C&I customers is enrolled in this program.

The second program is NSP's Saver's Switch program. Saver's Switch is a conventional residential load control program, in which the compressor of a central air-conditioning unit or the heating element of an electric resistance water heater is temporarily cycled off to reduce electricity demand during DR events. Saver's Switch is one of the largest such programs in the country. Roughly 52 percent of all eligible residential customers (i.e., those with central air-conditioning) are enrolled in the program, accounting for around 29% of all of NSP's residential customers. Saver's Switch is gradually being transitioned to a program based on newer smart thermostat technology, called "A/C Rewards." A/C Rewards contributes an additional 2 MW to NSP's existing DR capability, though this is expected to grow significantly in coming years. A summary of NSP's DR portfolio is provided in Figure 1.

[5] The 2014 study developed a "supply curve" of DR options available to NSP as inputs to its integrated resource plan (IRP), but did not explicitly evaluate the extent to which those options would be less costly than serving electricity demand through the development of new generation resources.

Figure 1: NSP 2017 DR Capability



Sources: NSP 2017 DR program data and 2017 NSP system peak demand (8,546 MW)

Important Considerations

The focus of this study is on quantifying the amount of cost-effective DR capability that can be achieved above and beyond NSP's current 850 MW DR portfolio. We estimate the incremental DR potential that can be achieved through an expansion of existing program offerings, the introduction of new programs, and consideration of a broad range of potential system benefits that are available through DR. Specifically, this study is structured to quantify all DR potential that satisfies the following three conditions:

1. **Incremental:** All quantified DR potential is incremental to NSP's existing 850 MW DR portfolio.[6]

2. **Cost-effective:** The present value of avoided resource costs (i.e., benefits) must outweigh program costs, equipment costs, and incentives.

3. **Achievable:** Program enrollment rates are based on primary market research in NSP's service territory and supplemented with information about utility experience in other jurisdictions.

[6] For the purposes of this analysis, all incremental potential estimates assume NSP's portfolio of existing programs continues to be offered as currently designed in future years, and that the 850 MW impact persists throughout the forecast horizon. Existing DR participants are excluded from the estimates of incremental potential.

The findings of this study should be interpreted as a quantitative screen of the DR opportunities available to NSP. Further development of individual programs, and testing of the programs through pilots, will provide additional insight regarding the potential benefits and costs that such programs may offer to NSP and its customers when deployed on a full scale basis.

II. Methodology

This study analyzes three ways to increase the capability of NSP's existing DR portfolio. First, we assess the potential to increase enrollment in existing programs. Increased enrollment could be achieved through targeted program marketing efforts, for example. Second, the menu of DR programs offered to customers could be expanded to include new, non-conventional options. These non-conventional options include emerging "load flexibility" programs which go beyond peak shaving to provide around-the-clock decreases and increases in system load. Third, consistent with the introduction of more flexible DR programs, we consider a broadened list of potential benefits in the cost-effectiveness screening process, such as ancillary services and geographically-targeted deferral of distribution capacity upgrades.

Conventional DR Programs

Our analysis considers conventional DR programs that have been offered by utilities for many years, including in some cases by NSP.

- **Direct load control (DLC):** Participant's central air-conditioner is remotely cycled using a switch on the compressor. The modeled program is based on NSP's Savers Switch program.

- **Smart thermostats:** An alternative to conventional DLC, smart thermostats allow the temperature setpoint to be remotely controlled to reduce A/C usage during peak times. The modeled program is based on NSP's A/C Rewards program, which provides customers with options to use their own thermostat, self-install a thermostat purchased from NSP's online store, or use a NSP-installed thermostat. Smart thermostat programs are based on newer technology than the other "conventional" DR programs in this list, but included here as the program is already offered by NSP.

- **Interruptible rates:** Participants agree to reduce demand to a pre-specified level and receive an incentive payment in the form of a discounted rate.

- **Demand bidding:** Participants submit hourly curtailment schedules on a daily basis and, if the bids are accepted, must curtail the bid load amount to receive the bid incentive payment or may be subject to a non-compliance penalty. While a conventional option, demand bidding is not currently offered by NSP.

Non-conventional DR Programs

Pricing programs are one type of non-conventional DR option. We consider two specific time-varying rate options which generally span the range of impacts that can be achieved through pricing programs: A static time-of-use rate and a dynamic critical peak pricing rate.

- **Time-of-use (TOU) rate:** Currently being piloted by NSP for residential customers and offered on a full-scale basis to C&I customers. Static price signal with higher price during peak hours (assumed 5-hour period aligned with system peak) on non-holiday weekdays. Modeled as being offered on an opt-in and an opt-out (default) basis. The study also includes an optional TOU rate for EV charging.

- **Critical peak pricing (CPP) rate:** Provides customers with a discounted rate during most hours of the year, and a much higher rate (typically between 50 cents/kWh and $1/kWh) during peak hours on 10 to 15 days per year. CPP rates are modeled as being offered on both an opt-in and an opt-out (default) basis.

The second category of non-conventional DR programs relies on a variety of advanced behavioral and technological tools for managing customer electricity demand.

- **Behavioral DR:** Customers are informed of the need for load reductions during peak times without being provided an accompanying financial incentive. Customers are typically informed of the need for load reductions on a day-ahead basis and events are called somewhat sparingly throughout the year. Behavioral DR programs have been piloted by several utilities, including Consumers Energy, Green Mountain Power, the City of Glendale, Baltimore Gas & Electric, and four Minnesota cooperatives.

- **EV managed charging:** Using communications-enabled smart chargers allows the utility to shift charging load of individual EVs plugged-in from on-peak to off-peak hours. Customers who do not opt-out of an event receive a financial incentive. The managed EV charging program was modeled on three recent pilots: PG&E (with BMW), United Energy (Australia), and SMUD. Allows curtailment of charging load for up to three hours per day, fifteen days per year. Impacts were modeled for both home charging and workplace charging programs.

- **Timed water heating:** The heating element of electric resistance water heaters can be set to heat water during off-peak hours of the day. The thermal storage capabilities of the water tank provide sufficient hot water during peak hours without needing to activate the heating element.

- **Smart water heating:** Offers improved flexibility and functionality in the control of the heating element in the water heater. The thermostat can be modulated across a range of temperatures. Multiple load control strategies are possible, such as peak shaving, energy

price arbitrage through day/night thermal storage, or the provision of ancillary services such as frequency regulation. Modeled for electric resistance water heaters, as these represent the vast majority of electric water heaters and are currently the most attractive candidates for a range of advanced load control strategies.

- **Ice-based thermal storage:** Commercial customers shift peak cooling demand to off-peak hours using ice-based storage systems. The thermal storage unit acts as a battery for the customer's A/C unit, charging at night (freezing water) and discharging (allowing ice to thaw to provide cooling) during the day.

- **C&I Auto-DR:** Auto-DR technology automates the control of various C&I end-uses. Features of the technology allow for deep curtailment during peak events, moderate load shifting on a daily basis, and load increases and decreases to provide ancillary services. Modeled end-uses include HVAC and lighting (both luminaire and zonal lighting options).

DR Benefits

This study accounts for value streams that are commonly included in assessments of DR potential:

- **Avoided generation capacity costs:** The need for new peaking capacity can be reduced by lowering system peak demand. Important considerations when estimating the equivalence of DR and a peaking generation unit are discussed later in this section of the report.

- **Reduced peak energy costs:** Reducing load during high priced hours leads to a reduction in energy costs. Our analysis estimates net avoided energy costs, accounting for costs associated with the increase in energy consumption during lower cost hours due to "load building." The energy benefit accounts for avoided average line losses. Our analysis likely includes a conservative estimate of this value, as peak line losses are greater than off-peak line losses. Our analysis does not include the effect of any potential change in energy market prices that may result from changes in load patterns (sometimes referred to as the "demand response induced price effect," or DRIPE). It is simply a calculation of reduced resource costs.

- **System-wide deferral of transmission and distribution (T&D) capacity costs.** System-wide reductions in peak demand can, on average, contribute to the reduced need for peak-driven upgrades in T&D capacity. We account for this potential value using methods that were established in a recent Minnesota PUC proceeding.[7]

This study also accounts for value streams that can be captured through more advanced DR programs:

[7] Minnesota PUC Docket No. E999/CIP-16-541.

- **Geo-targeted distribution capacity investment deferral:** DR participants may be recruited in locations on the distribution system where load reductions would defer the need for capacity upgrades. NSP's 5-year distribution plan was used to identify candidate deferral projects, and qualifying DR programs were evaluated based on their ability to contribute to the deferral.[8]

- **Ancillary services:** The load of some end-uses can be increased or decreased in real time to mitigate system imbalances. The ability of qualifying DR programs to provide frequency regulation was modeled, as this is the highest-value ancillary service (albeit with limited system need).

- **Load building / valley filling:** Load can be shifted to off-peak hours to reduce wind curtailments or take advantage of low or negatively priced hours. DR was dispatched against hourly energy price series to capture the economic incentive that energy prices provide for this service.

Figure 2 summarizes the ways in which this assessment of DR potential extends the scope of prior studies in Minnesota and other jurisdictions. In the figure, "X" indicates the value streams that each DR program is assumed to provide.

Figure 2: Options for Expanding the Existing DR Portfolio

1 Increase enrollment in the conventional portfolio

2 Extend DR value streams

3 Include non-traditional DR options

	Generation capacity avoidance	Reduced peak energy costs	System peak related T&D deferral	Targeted distribution capacity deferral	Valley filling/ Load building	Ancillary services
Direct load control (DLC)	X	X	X			
Interruptible tariff	X	X	X			
Demand bidding	X	X	X		X	
Smart thermostat	X	X	X			
Time-of-use (TOU) rates	X	X	X			
Dynamic pricing	X	X	X			
Behavioral DR	X	X	X			
EV managed charging	X	X	X	X	X	
Smart water heating	X	X	X		X	X
Timed water heating	X	X	X		X	
Ice-based thermal storage	X	X	X	X	X	
C&I Auto-DR	X	X	X	X	X	X

Notes: "X" indicates the value streams that each DR option is assumed to be able to provide.

[8] The distribution plan was in-development at the time of our analysis. Distribution data was provided to Brattle in March 2018.

Defining DR Potential

We use the Utility Cost Test (UCT), also known as the Program Administrator Cost Test (PACT), to determine the cost-effectiveness of the incremental DR portfolio. The UCT determines whether a given DR program will increase or decrease the utility's revenue requirement. This is the same perspective that utilities take when deciding whether or not to invest in a supply-side resource (e.g., a combustion turbine) through the IRP process.[9] Since the purpose of this DR potential study is to determine the amount of DR that should be included in the IRP, the UCT was determined to be the appropriate perspective. Major categories of benefits and costs included in the UCT are summarized Table 1.

Table 1: Categories of Benefits and Costs included in the Utility Cost Test

Benefits	Costs
Avoided generation capacity	Incentive payments
Avoided peak energy costs	Utility equipment & installation
Avoided transmission capacity	Administration/overhead
Avoided distribution capacity	Marketing/promotion
Ancillary services	

Throughout this study, we quantify DR potential in two different ways:

Technical Potential: Represents achievable potential without consideration for cost-effectiveness. In other words, this is a measure of DR capability that could be achieved from anticipated enrollment associated with a moderate participation incentive payment, regardless of whether or not the incentive payment and other program costs exceed the program benefits. As it is used here, the term "technical potential" differs from its use in energy efficiency studies. Technical potential in energy efficiency studies assumes 100% participation, whereas we assume an achievable level of participation in this assessment of DR potential.

Cost-effective Potential: Represents the portion of technical potential that can be obtained at cost-effective incentive payment levels. For each program, the assumed participation incentive payment level is set such that the benefit-cost ratio is equal to 1.0. Participation rates are estimated to align with this incentive payment level. When non-incentive costs (e.g., equipment and installation costs) are found to outweigh the benefits alone, the benefit-cost ratio is less than 1.0 and there is no opportunity to offer a cost-effective participation incentive payment. In that case, the program is considered to have no cost-effective potential.

[9] According to the National Action Plan for Energy Efficiency: "The UCT is the appropriate cost test from a utility resource planning perspective, which typically aims to minimize a utility's lifecycle revenue requirements."

The Load*Flex* Model

The Brattle Group's Load*Flex* model was used to estimate DR potential in this study. The Load*Flex* modeling framework builds upon the standard approach to quantifying DR potential that has been used in prior studies around the U.S. and internationally, but incorporates a number of differentiating features which allow for a more robust evaluation of DR programs:

- **Economically optimized enrollment:** Assumed participation in DR programs is tailored to the incentive payment levels that are cost-effective for the DR program. If only a modest incentive payment can be justified in order to maintain a benefit-cost ratio of 1.0, then the participation rate is calibrated to be lower than if a more lucrative incentive payment were offered. Prior approaches to quantifying DR potential ignore this relationship between incentive payment level and participation, which tends to under-state the potential (and, in some cases, incorrectly concludes that a DR program would not pass the cost-effectiveness screen).

- **Utility-calibrated load impacts:** Load impacts are calibrated to the characteristics of NSP's customer base. In the residential sector, this includes accounting for the market saturation of various end-use appliances (e.g., central air-conditioning, electric water heating). In the commercial and industrial (C&I) sector, this includes accounting for customer segmentation based on size (i.e., the customer's maximum demand) and industry (e.g., hospital, university). Load curtailment capability is further calibrated to NSP's experience with DR programs where available (e.g., impacts from existing DLC programs or dynamic pricing pilots).

- **Sophisticated DR program dispatch:** DR program dispatch is optimized subject to detailed accounting for the operational constraints of the program. In addition to tariff-related program limitations (e.g., how often the program can be called, hours of the day when it can be called), Load*Flex* includes an hourly profile of load interruption capability for each program. For instance, for an EV home charging load control program, the model accounts for home charging patterns, which would provide greater average load reduction opportunities during evening hours (when EV owners have returned home from work) than in the middle of the day.

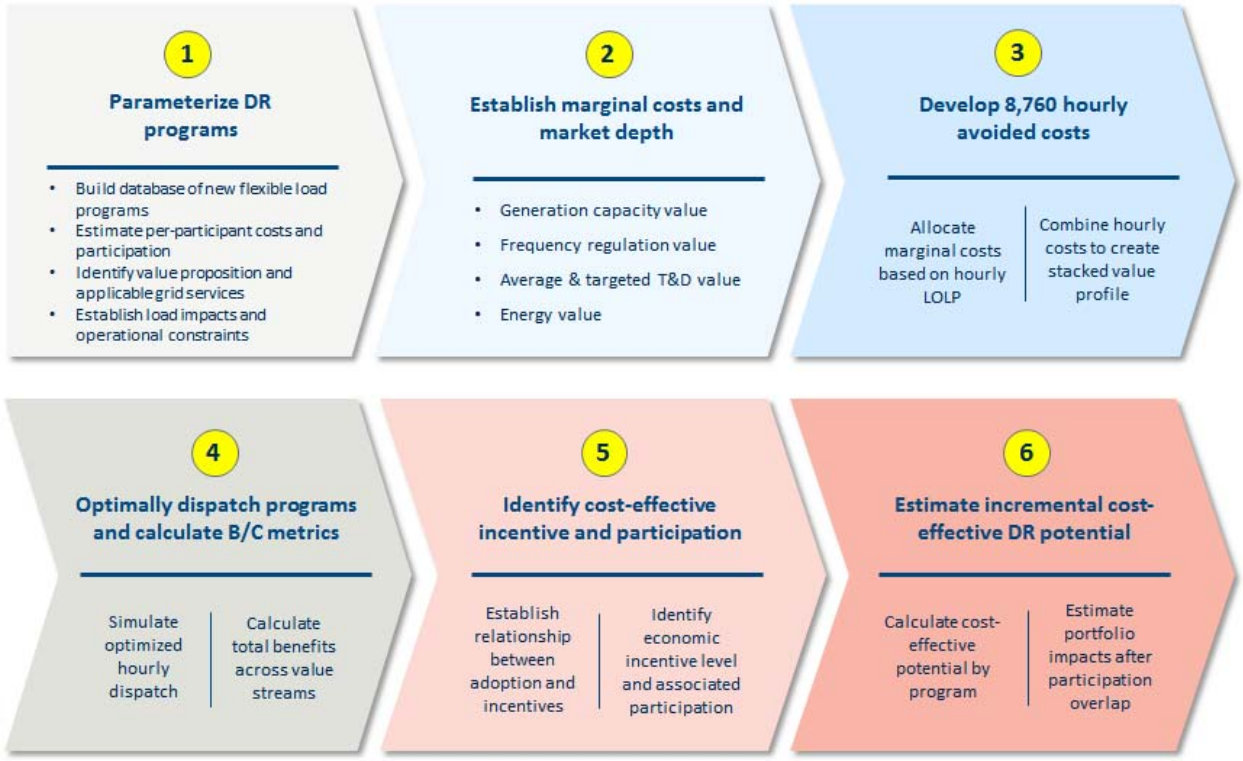
- **Realistic accounting for "value stacking":** DR programs have the potential to simultaneously provide multiple benefits. For instance, a DR program that is dispatched to reduce the system peak and therefore avoid generation capacity costs could also be dispatched to address local transmission or distribution system constraints. However, tradeoffs must be made in pursuing these value streams – curtailing load during certain hours of the day may prohibit that same load from being curtailed again later in the day for a different purpose. Load*Flex* accounts for these tradeoffs in its DR dispatch algorithm. DR program operations are simulated to maximize total benefits across multiple value streams, while recognizing the operational constraints of the program. Prior studies of load flexibility value have often

assigned multiple benefits to DR programs without accounting for these tradeoffs, thus double-counting benefits.

- **Industry-validated program costs:** DR program costs are based on a detailed review of NSP's current DR offerings. For new programs, costs are based on a review of experience and studies in other jurisdictions and conversations with vendors. Program costs are differentiated by type (e.g., equipment/installation, administrative) and structure (e.g., one-time investment, ongoing annual fee, per-kilowatt fee) to facilitate integration into utility resource planning models.

The Load*Flex* modeling framework is organized around six steps, as summarized in Figure 3. Appendix A provides detail on the methodology behind each of these steps.

Figure 3: The Load*Flex* Modeling Framework



Modeling Scenarios

The value that DR will provide depends on the underlying conditions of the utility system in which it is deployed. Generation capacity costs, the anticipated need for new transmission and distribution (T&D) assets, and energy price volatility are a few of the factors that will determine DR value and potential. To account for uncertainty in NSP's future system conditions, we considered two modeling scenarios: A "Base Case" and a "High Sensitivity Case."

The **Base Case** most closely aligns with NSP's expectations for future conditions on its system, as defined in its IRP. The Base Case represents a continuation of recent market trends, combined with information about known or planned developments during the planning horizon.

The **High Sensitivity Case** was developed to illustrate how the value of DR can change under alternative future market conditions. The High Sensitivity Case is defined by assumptions about the future state of the NSP system and MISO market that are more favorable to DR program economics. The High Sensitivity Case is not intended to be the most likely future state of the NSP system. Relative to the Base Case, the High Sensitivity Case consists of a higher assumed generation capacity cost, more volatile energy prices due to greater market penetration of renewable generation, a significant reduction in emerging DR technology costs, and an increase in the need for frequency regulation.

Defining features of the two cases are summarized in Table 2. Appendix A includes more detail on assumptions and data sources behind the two cases.

Table 2: Defining Features of Base Case and High Sensitivity Case

	Base Case	High Sensitivity Case
Generation capacity (Net CONE)	$64/kW-yr (2018 NSP IRP)	$93/kW-yr (2018 EIA Annual Energy Outlook)
Hourly energy price	Based on MISO MTEP "Continued Fleet Change" case (15% wind+solar by 2032)	Based on MISO MTEP "Accelerated Fleet Change" case (30% wind+solar by 2032)
Frequency regulation	Price varies, 25 MW average need by 2030	Price same as Base Case, 50 MW average need by 2030
System average T&D deferral	Transmission: $3.6/kW-yr, Distribution: $9.5/kW-yr (2017 NSP Avoided T&D Study)	Same as Base Case
Geo-targeted T&D deferral	Value varies by distribution project, 90 MW eligible for deferral by 2030	Same as Base Case
DR technology cost	10% reduction from current levels by 2030 (in real terms)	30% reduction from current levels by 2030 (in real terms)

Notes: Unless otherwise specified, values shown are for year 2030 and in nominal dollars.

Modeling results are summarized for the years 2023 and 2030. 2023 is the year by which NSP must procure additional DR capability according to the Minnesota PUC's Order in Docket No. E-002/RP-15-21. The 2030 snapshot captures the potential for significant future changes in system conditions and their implications for DR value, and is consistent with the longer-term perspective of NSP's IRP study horizon. A summary of annual results, including intermediate years, is provided in Appendix D.

Data

To develop participation, cost, and load impact assumptions for this study, we relied on a broad range of resources. Where applicable, we relied directly upon information from NSP's experience with DR programs in its service territory. We also utilized the results of primary market research that was conducted directly with customers in NSP's service territory in order to better understand their preferences for various DR program options. Where NSP-specific information was unavailable, we reviewed national data on DR programs, DR potential studies from other jurisdictions, and DR program impact evaluations. A complete list of resources is provided in the References section and described further in Appendix A.

In an assessment of emerging DR opportunities, it is important to recognize that data availability varies significantly by DR program type. Conventional DR programs, such as air-conditioning load control, have decades of experience as full-scale deployments around the US and internationally. By contrast, emerging DR programs like EV charging load control have only recently begun to be explored, largely through pilot projects. Figure 4 summarizes data availability for each of the DR program types analyzed in this study.

Figure 4: Data Availability by DR Program Type

	Participation	Costs	Peak Impacts	Advanced Impacts
Residential				
Air-conditioning DLC	●	●	●	N/A
Smart thermostat	●	●	●	N/A
TOU rate	●	●	◑	N/A
CPP rate	●	●	◑	N/A
Behavioral DR	◑	◑	◑	N/A
Smart water heating	◔	◔	◑	◔
Timed water heating	◔	◔	◑	◔
EV managed charging (home)	○	○	◔	N/A
EV charging TOU (home)	○	○	◔	N/A
C&I				
Interruptible tariff	●	●	●	N/A
Demand bidding	●	●	●	N/A
TOU rate	●	●	◑	N/A
CPP rate	●	●	◑	N/A
Ice-based thermal storage	◔	◔	◔	◔
EV workplace charging	○	○	◔	N/A
Automated DR	○	◔	◔	○

Notes:

● NSP-specific data, including market research, pilot programs, and full-scale deployments

◑ Signficant program experience in other jurisdictions

◔ Some pilot or demonstration project experience in other jurisdictions

○ Speculative, estimated from theoretical studies and calibrated to NSP conditions

"Advanced impacts" refers to load flexibilty capability beyond conventional peak period reductions (e.g., frequency regulation)

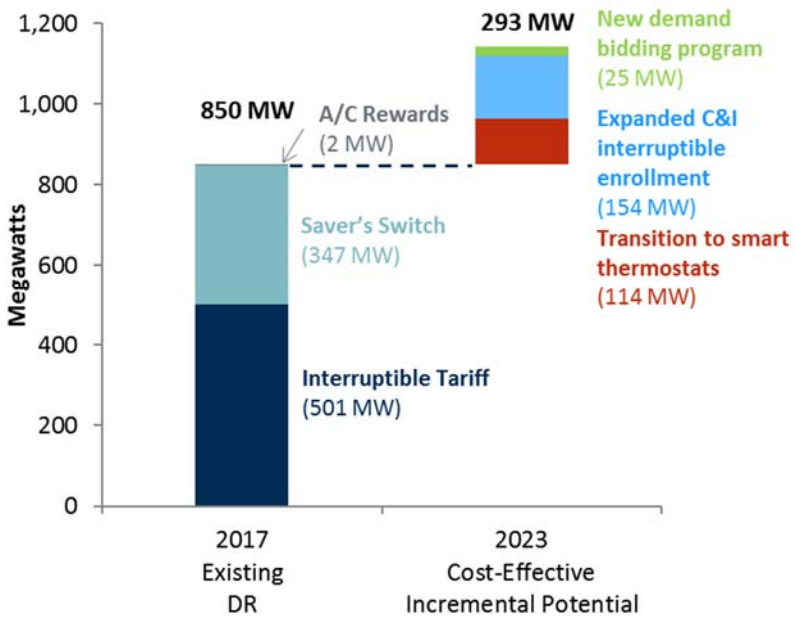
III. Conventional DR Potential in 2023

As an initial step in the assessment of NSP's cost-effective DR potential, we analyzed the potential if NSP were to deploy a portfolio of conventional DR programs. As defined for this study, conventional programs include interruptible tariffs, air-conditioning DLC, smart thermostats, and demand bidding. These program types are currently offered by NSP, with the exception of demand bidding. Therefore, the assessment of conventional programs is largely an assessment of the potential to grow the current DR portfolio through options such as new marketing initiatives or targeted marketing toward specific customer segments. We initially focus on the year 2023, as that is the year by which the Minnesota PUC has required NSP to procure additional DR capability.[10]

Figure 5 summarizes the cost-effective potential in a conventional DR portfolio in 2023. There is 293 MW of cost-effective incremental potential. Drivers of this potential include the expanded enrollment in NSP's interruptible tariff program, greater per-participant impacts that will be achieved as NSP continues to transition from a switch-based air-conditioning DLC program to a smart thermostat-based program, overall growth in NSP's customer base between 2017 and 2023, and a modest amount of potential in a new demand bidding program.

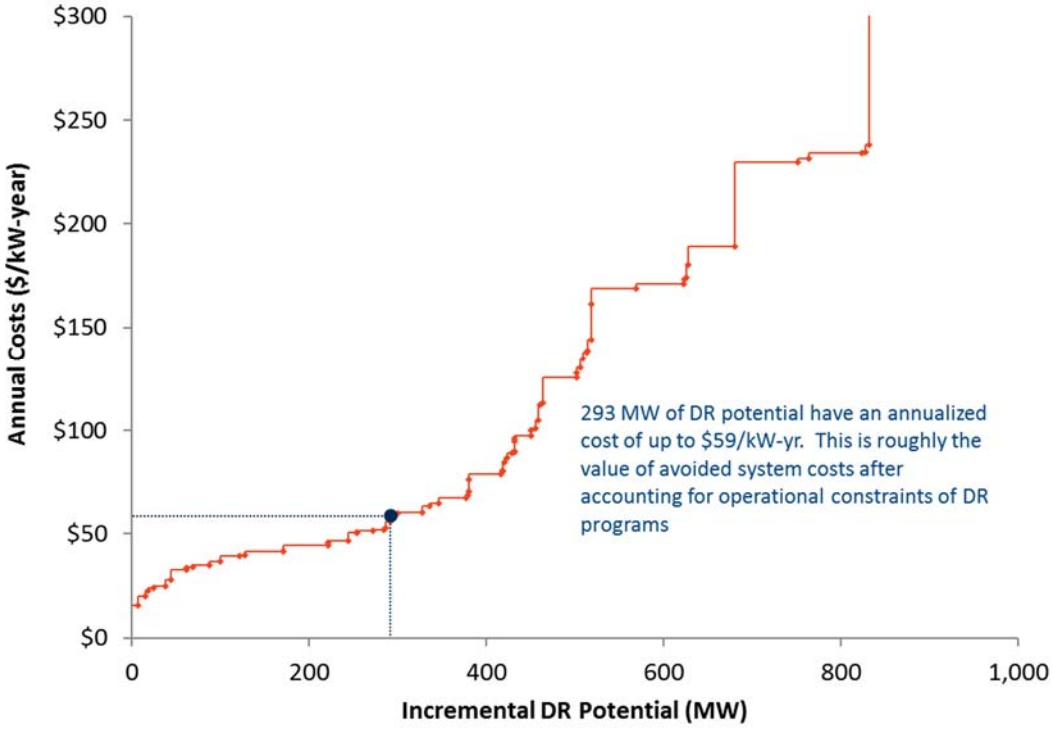
[10] NSP has interpreted the PUC's Order to require 400 MW of capacity-equivalent DR, which equates to 391 MW of generator-level load reduction when accounting for the reserve requirement, and 362 MW of meter-level load reduction when also accounting for line losses.

Figure 5: Total DR Potential in 2023 (Conventional Portfolio)



The incremental potential in conventional DR programs can be expressed as a "supply curve." Figure 6 illustrates the costs associated with achieving increasing levels of DR capability. The upward slope of the curve illustrates how DR capability (i.e., enrollment) increases as incentive payments increase. The curve also captures the different costs and potential associated with each conventional DR program and applicable customer segment. Cost-effective DR capability is identified with the blue dotted line. There is roughly 293 MW of incremental DR potential available at a cost of less than $59/kW-year. That cost equates to the value of avoided system costs after accounting for the operational constraints of DR programs.

Figure 6: NSP's Incremental DR Supply Curve in 2023 (Conventional Portfolio)



Note: Supply curve shows conventional DR potential without accounting for cost-effectiveness. Potential estimates if the DR options were offered simultaneously as part of a portfolio at each price point (i.e. accounts for overlap). Program costs presented in nominal terms.

As discussed previously in this report, the Minnesota PUC has established a DR procurement requirement of 400 MW by 2023. It is important to clarify whether this 400 MW is a capacity-equivalent value, a generator-level value, or a meter-level value. Specifically, 1 MW of load reduction at the meter (or customer premise) avoids more than 1 MW at the generator level due to line losses between the generator and the customer. Further, 1 MW of load reduction at the generator level provides more than 1 MW of full capacity-equivalent value, as the load reduction would also avoid the additional capacity associated with NSP's obligation to meet the planning reserve requirement. Based on NSP's calculations, which account for line losses and the reserve requirement, 1 MW of load reduction at the meter level equates to 1.08 MW of load reduction at the generator level and 1.11 MW of capacity-equivalent value.

NSP has interpreted the PUC's Order to require 400 MW of capacity-equivalent DR. This equates to 391 MW of generator-level load reduction when accounting for the reserve requirement, and 362 MW of meter-level load reduction when also accounting for line losses. These values are summarized in Table 3. Throughout this report, DR values are reported at the generator level. Thus, for consistency, we refer to the procurement requirement as a 391 MW generator-level value unless otherwise specified.

Table 3: NSP's 2023 DR Procurement Requirement

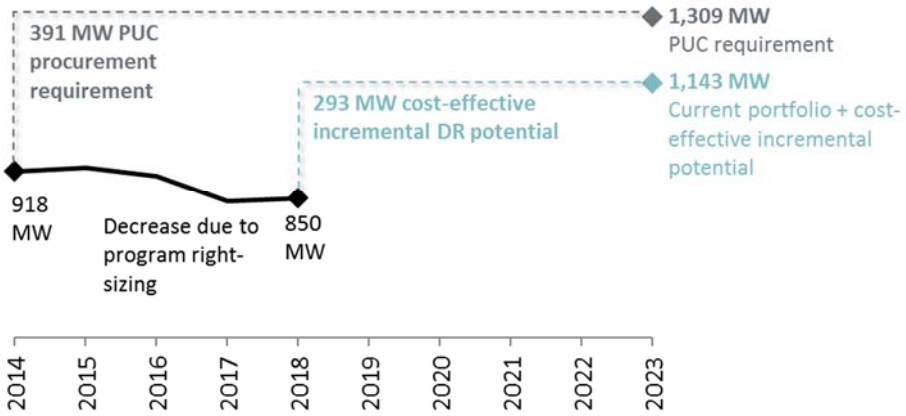
	Requirement (MW)	Notes
Meter level	361.7	Premise-level
Generator level	390.7	Grossed up for 8% line losses
Capacity equivalent	400.0	Grossed up for line losses and reserve requirement

Source: Calculations provided by NSP.

Our interpretation of the PUC's Order is that the required DR procurement is incremental to NSP's DR capability as it existed in 2014.[11] NSP had 918 MW of DR capability in 2014, leading to a total DR capability requirement of 1,309 MW in 2023. NSP's DR capability decreased between 2014 and 2017 largely due to an effort to ensure that enrolled load would be available for curtailment when called upon, thus leading to an incremental DR requirement that is larger than 391 MW (at the generator level).[12]

Combined with current capability of 850 MW, the incremental cost-effective DR potential in 2023 would result in a total portfolio of 1,143 MW. This estimate of cost-effective potential is 166 MW short of the PUC's DR procurement requirement. Figure 7 illustrates the gap between NSP's conventional DR potential and the DR procurement requirement.

Figure 7: NSP DR Capability (Conventional Portfolio)



Note: Chart is scaled such that vertical axis does not start at zero. 391 MW procurement requirement is expressed at the generator level and is equivalent to 400 MW of DR capacity.

[11] 2014 is the year of NSP's prior DR potential study, which was used to inform the Minnesota PUC's establishment of the DR procurement requirement.

[12] For instance, some customers did not realize that they were participating in the program and dropped out when notified, or otherwise elected to reduce their enrolled load level.

IV. Expanded DR Potential in 2023

Given the shortfall of the conventional DR portfolio relative to the 2023 procurement target, it is relevant to consider if an expanded portfolio of DR options could mitigate the shortfall. We analyzed eight additional emerging DR programs that could be offered to up to four different customer segments (if applicable). As described in Section II, these emerging DR options include both price based programs (e.g., TOU and CPP rate designs) and technology-based programs (e.g., Auto-DR and smart water heating).

Base Case

Among the individual measures with the most *technical potential* in 2023 are HVAC Auto-DR for Medium C&I customers and thermal storage for commercial customers. Each of these programs has technical potential in excess of 100 MW.

Pricing programs and lighting Auto-DR for C&I customers, timed water heating programs, and behavioral DR compose the next tier of opportunities, with technical potential in each ranging between 50 and 100 MW. These programs generally have the potential to reach significant levels of enrollment or, alternatively, to provide deep load reductions among a smaller share of customers.

The Small C&I segment accounts for many of the DR programs with the lowest technical potential, as there is a relatively small share of load in this segment and these customers have historically demonstrated a lower willingness to participate in DR programs.

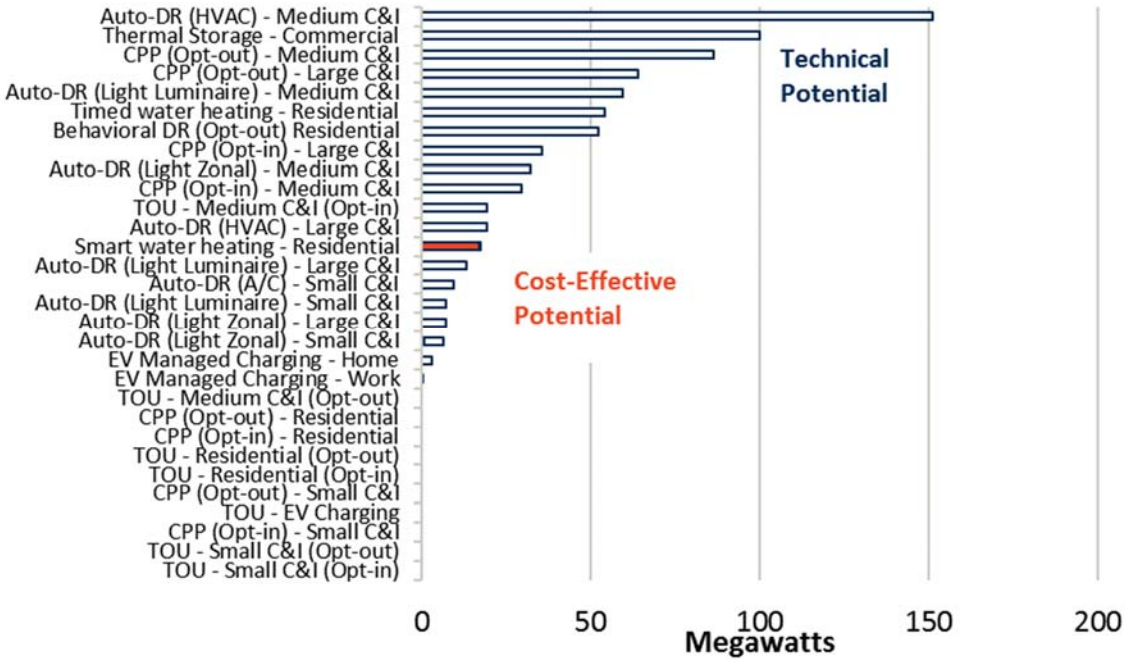
EV charging load control programs also have very modest technical potential in 2023. This is driven in part by a limited projection of EV adoption over the next five years. It is also driven by a lack of coincidence between peak charging load and the timing of the system peak.

Pricing programs (i.e., TOU, CPP) cannot be offered on a full scale basis in 2023 to residential and small C&I customers, as AMI will not yet be fully deployed. Therefore, pricing programs have not been included in the potential estimates for 2023. Rollout of the programs is assumed to begin in 2024, upon NSP's projected completion of the AMI rollout.

Programs with significant *technical potential* do not necessarily have significant *cost-effective potential*. After accounting for cost-effectiveness under Base Case market conditions as well as technical constraints, the potential in DR programs is limited in 2023. Individually, only smart water heating and a modest amount of automated load control for C&I customers pass the cost-effectiveness screen. These programs pass the cost-effectiveness screen largely because they are capable of providing an expanded array of value streams, such as frequency regulation and geo-targeted T&D deferral.

Figure 8 summarizes the technical and cost-effective potential in each of the new DR program options. Potential is first shown for DR programs as if they were each offered in isolation.

Figure 8: New DR Program Potential in 2023 (Base Case)

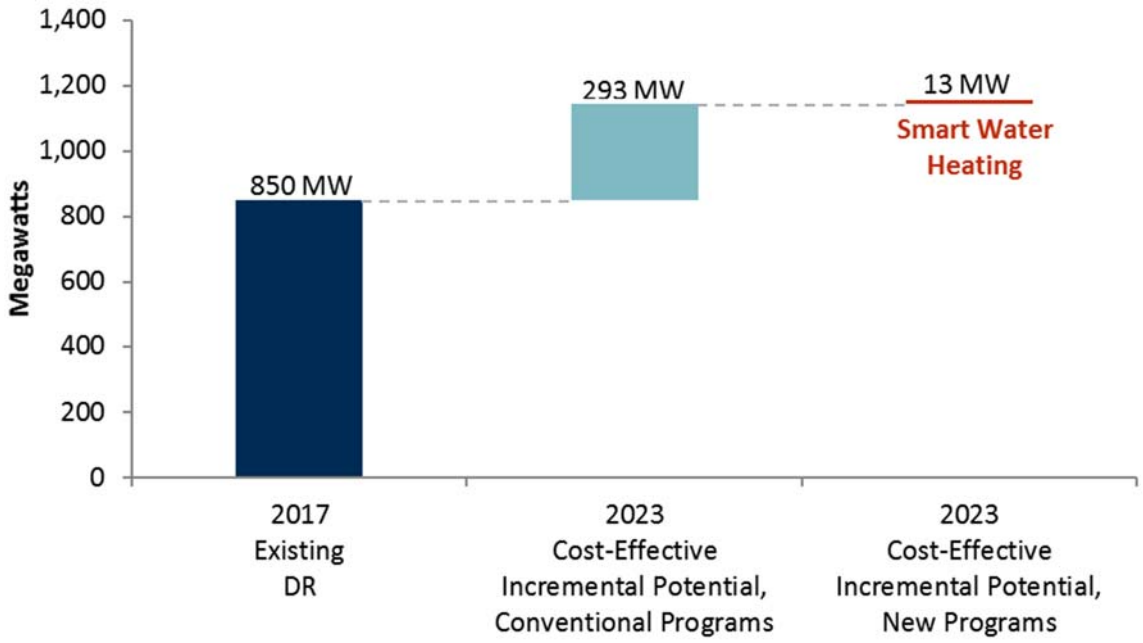


Note: Results reflect NSP system-wide DR potential. Impacts assume each program is offered in isolation; they are not additive. All potential is incremental to NSP's existing portfolio.

The program-level DR impacts shown above cannot be added together to arrive at the potential capability of a DR portfolio. Adjustments must be made to account for double-counting of impacts when customers are enrolled in more than one program, and for limits on the need for certain value streams such as frequency regulation. Thus, combining the cost-effective programs into a portfolio can result in lower total potential DR capability than if the individual impacts shown above were simply summed.

In the 2023 scenario described above, the smart water heating program alone could satisfy NSP's need for frequency regulation. With that value stream no longer available to the Auto-DR program, the Auto-DR program fails the cost-effectiveness screen. **With the addition of the smart water heating program, NSP's cost-effective DR portfolio would increase by 13 MW. Achievement of all cost-effective DR potential would amount to total system-wide DR capability of 1,156 MW, but would still fall short of the PUC's procurement target by 154 MW.** The expanded capability in 2023 is illustrated in Figure 9.

Figure 9: Total DR Potential in 2023 (Expanded Portfolio)



Near-term Limitations on DR Value

The value of DR is very dependent on the characteristics of the system in which it is deployed. Several factors limit NSP's cost-effective DR in 2023, relative to other jurisdictions.

- **Low capacity prices:** NSP has access to low-cost peaking capacity, primarily due to the presence of brownfield sites that significantly reduce development costs. For instance, the all-in cost of a new combustion turbine in NSP's IRP is $63/kW-year, which is 23 percent lower than the cost of a CT assumed by the U.S. Energy Information Administration (EIA) in its Annual Energy Outlook (AEO). Similarly, a recent study approved by the Minnesota PUC determined that the average value of T&D capacity deferral achieved through reductions in customer consumption is approximately $11/kW-year in NSP's service territory.[13] This value, which was determined through a detailed bottom-up engineering assessment, is significantly lower than that of T&D deferral benefits observed in other studies, which can commonly reach values of $30/kW-year.[14] The value of T&D deferral is dependent on characteristics of the utility system and drivers of the investment need, and therefore varies significantly across utilities.

[13] Xcel Energy, "Minnesota Transmission and Distribution Avoided Cost Study," submitted to the Minnesota Department of Commerce, Division of Energy Resources (Department), July 31, 2017

[14] Ryan Hledik and Ahmad Faruqui, "Valuing Demand Response: International Best Practices, Case Studies, and Applications," prepared for EnerNOC, January 2015.

- **Metering technology limitations:** NSP has not yet deployed AMI, with an estimated forecast that system-wide AMI installation will be completed in 2024. AMI-based DR programs, such as time-varying rates and behavioral DR, cannot be offered to customers until deployment is complete. This effectively excludes the possibility of introducing any AMI-based programs in the year 2023.

- **High DR technology costs:** Some emerging DR programs depend on new technologies that have not yet experienced the cost declines that could be achieved at scale. While these technology costs could decrease over time, those reductions are not achieved in the early years of the study horizon.

- **Limited need for additional DR value streams:** While certain DR value streams potentially can be very valuable, these value streams can also be limited in need. For instance, our analysis of NSP's five-year distribution plan identified only 38 MW of projects that were potential candidates for geo-targeted capacity investment deferral. Those projects accounted for roughly 10 percent of the total value of NSP's plan. To qualify, projects need to satisfy criteria such as being driven by growth in demand and being of a certain size.[15] Similarly, while frequency regulation is often a highly-valued ancillary service and can be provided by certain types of DR, the need for frequency regulation across most markets is significantly less than one percent of system peak demand. This limits the amount of that value stream that can be provided by DR.

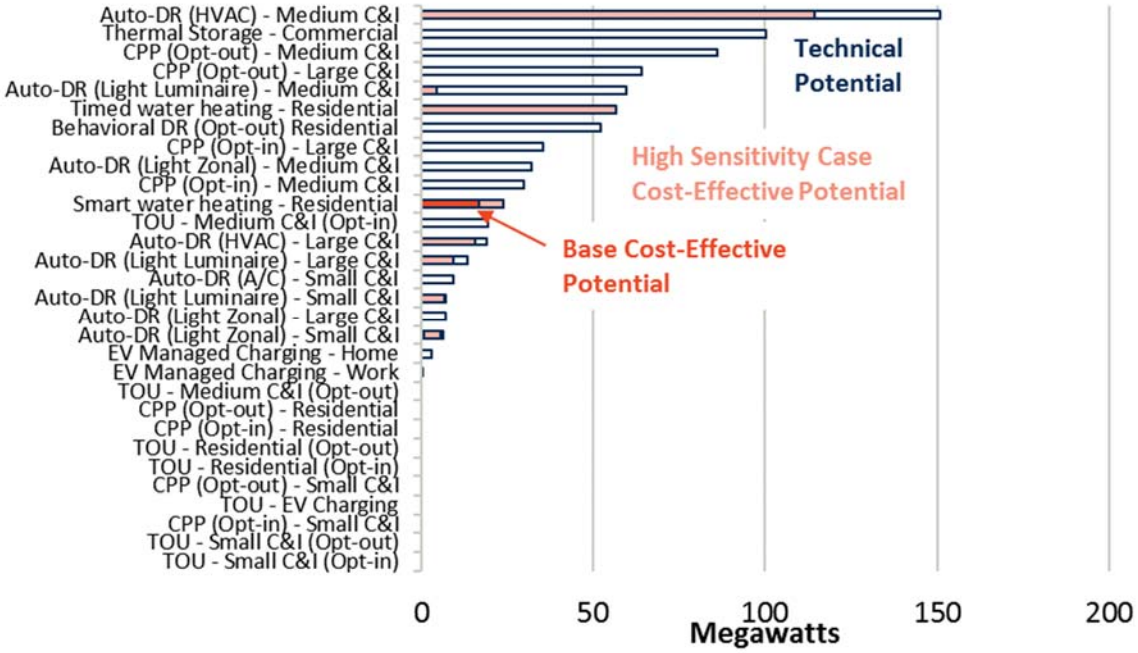
High Sensitivity Case

The High Sensitivity Case illustrates the potential for DR under an alternative set of market conditions that are more favorable to DR program economics. As discussed earlier in this report, assumptions behind the High Sensitivity Case are not a forecast of what is likely to happen in the future in NSP's service territory, particularly in the near-term years of the study horizon.

Under the illustrative High Sensitivity Case assumptions, cost-effective DR potential increases significantly. Several programs that were not previously passing the cost-effectiveness screen, such as medium C&I HVAC-based Auto DR, residential timed water heating, and a small amount of lighting-based Auto-DR do pass the screen under the more favorable assumptions in this case. Figure 10 summarizes the increase in cost-effective potential at the individual program level.

[15] Details of the geo-targeted T&D deferral analysis are included in Appendix A.

Figure 10: New DR Program Potential in 2023 (High Sensitivity Case)



Note: Results reflect NSP system-wide DR potential. Impacts assume each program is offered in isolation; they are not additive. All potential is incremental to NSP's existing portfolio.

A DR portfolio constructed from cost-effective programs in the High Sensitivity Case would produce total incremental DR potential of 484 MW in 2023. Under the illustrative assumptions in this case, the cost-effective incremental portfolio would consist of 393 MW of conventional DR programs, and 91 MW of new DR programs. The portfolio of new DR programs includes residential smart water heating [16] (24 MW) and C&I HVAC-based Auto-DR (67 MW). Achievement of all cost-effective DR potential under the High Sensitivity Case would amount to total system-wide DR capability of 1,334 MW.

[16] Smart water heating has lower cost-effective potential in 2023 than timed water heating. However, the smart water heating program provides more value and more significant per-participant impacts as participation ramps up in the later years of the study horizon, so it is the water heating program that was included in the portfolio.

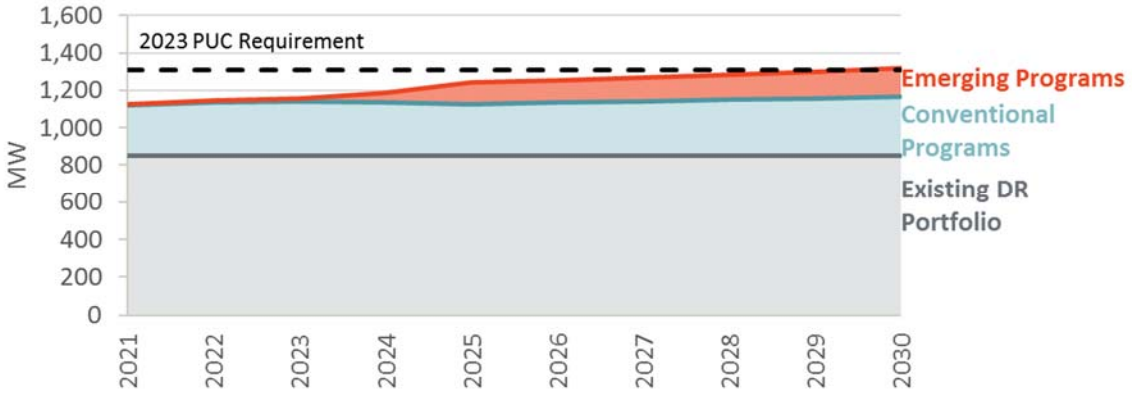
V. Expanded DR Potential in 2030

Base Case

Opportunities to expand cost-effective DR portfolio will grow beyond 2023. Most significantly, time-varying rates (such as TOU and CPP rates) can be offered to customers following completion of the AMI rollout in 2024. Additionally, the customer base is projected to grow over the study horizon, expanding the population of customers eligible to participation in DR programs. Growth in the market penetration of renewable generation will likely lead to more volatility in energy costs, further creating opportunities for DR to provide value. Additionally, current participants in the Savers Switch program are expected to transition to the smart thermostat-based A/C Reward program over time. Smart thermostats provide a greater per-participant demand reduction than the technology in the Savers Switch program, therefore further increasing DR potential.

Figure 11 summarizes growth in DR potential under Base Case assumptions for the portfolio of cost-effective DR programs. The majority of the post-2023 growth comes from the introduction of time-varying pricing programs.

Figure 11: Cost-Effective DR Potential, Base Case



Under Base Case conditions, benefits of the DR program are primarily driven by avoided generation capacity costs. Avoided generation capacity costs account for $51 million of the $66 million (77 percent) in total annual benefits from the DR programs in the year 2030. This is because the relatively low avoided costs in the Base Case scenario tend to favor conventional DR programs which are primarily constrained to reducing the system peak, but have lower costs as a result of this somewhat limited functionality. Table 4 summarizes the annual benefits, by category, of the incremental cost-effective DR portfolio in 2030 for the Base Case.

Table 4: Annual Avoided Costs from 2030 DR Portfolio, Base Case ($ million/year)

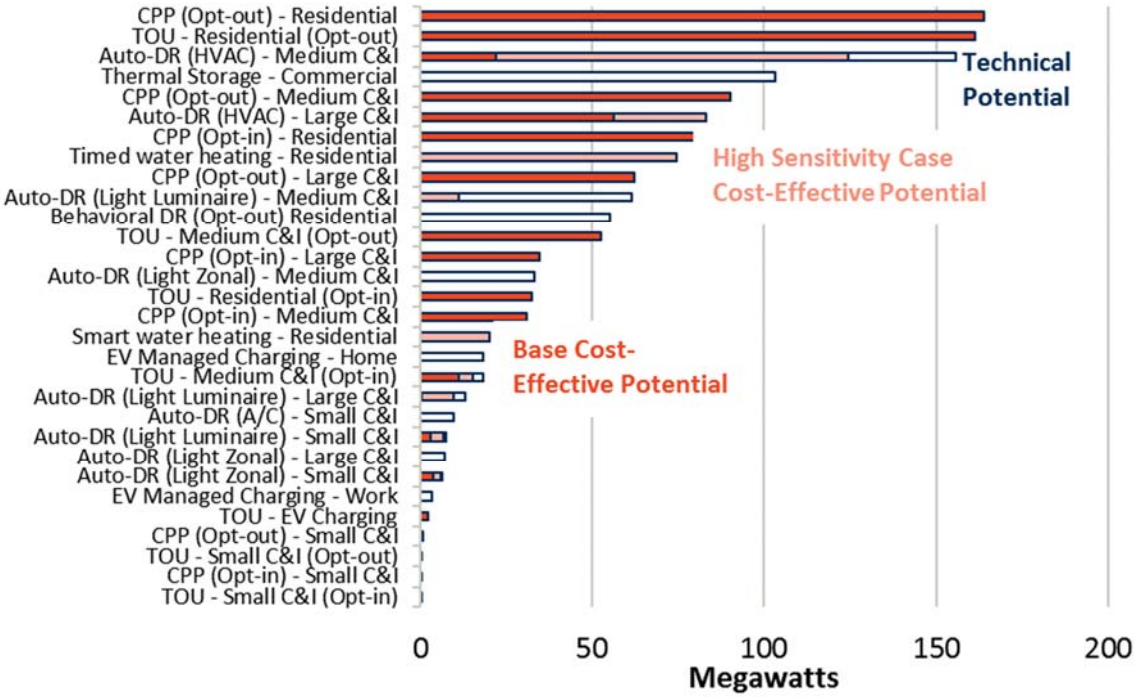
	Energy	Generation Capacity	System Average T&D Deferral	Geotargeted Distribution Deferral	Frequency Regulation	Total
Conventional Programs	$5.0	$43.6	$2.8	$0.0	$0.0	$51.4
Emerging Programs	$5.7	$7.4	$0.4	$0.0	$1.2	$14.7
Total	$10.7	$50.9	$3.2	$0.0	$1.2	$66.1

Notes: Benefits shown in 2023 dollars. Estimates include benefits from NSP's existing 850 MW portfolio.

High Sensitivity Case

Drivers of growth over time under the illustrative High Sensitivity Case conditions are similar to growth drivers under Base Case conditions, with AMI-enabled time-varying rates accounting for the majority of new opportunities after 2023. Figure 12 summarizes the 2030 incremental measure-level potential for both the Base Case and the High Sensitivity Case.

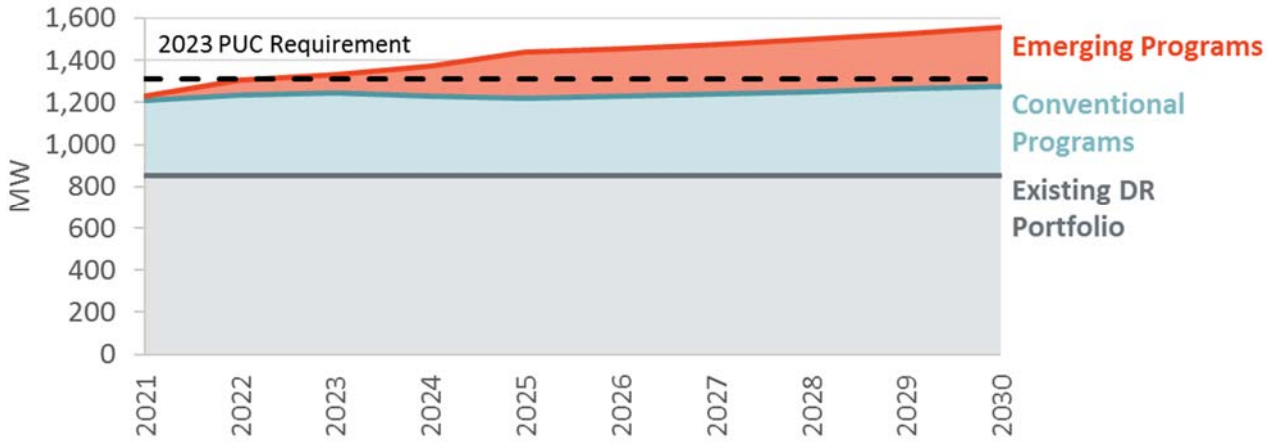
Figure 12: New DR Program Potential in 2030



Note: Results reflect NSP system-wide DR potential. Impacts assume each program is offered in isolation; they are not additive. All potential is incremental to NSP's existing portfolio.

The capability of the cost-effective DR portfolio for the High Sensitivity Case is summarized in Figure 13.

Figure 13: Cost-Effective DR Potential, High Sensitivity Case



Over the longer-term, new policies could potentially drive down DR costs and therefore increase cost-effective potential. One initiative that has garnered some attention is the development of a technology standard known as "CTA-2045." CTA-2045 is a communications interface which would allow various control technologies to connect to appliances through a standard port or socket. While widespread adoption of this standard is not considered to be imminent, it could potentially have positive implications for DR adoption in the longer term. See the Sidebar at the end of this section for further discussion of the outlook for CTA-2045.

The benefits of DR under the High Sensitivity Case assumptions continue to be driven primarily by avoided generation capacity costs. However, additional price volatility due a greater assumed mix of renewable generation in the regional supply portfolio leads to an increase in the share of total that is attributable to avoided energy costs. The total value of frequency regulation provided by DR also increases modestly relative to the Base Case, as a greater need for this service is assumed for renewable generation integration purposes. Table 5 summarizes the annual benefits, by category, of the incremental cost-effective DR portfolio in 2030 for the High Sensitivity Case.

Table 5: Annual Avoided Costs from 2030 DR Portfolio, High Sensitivity Case ($ million/year)

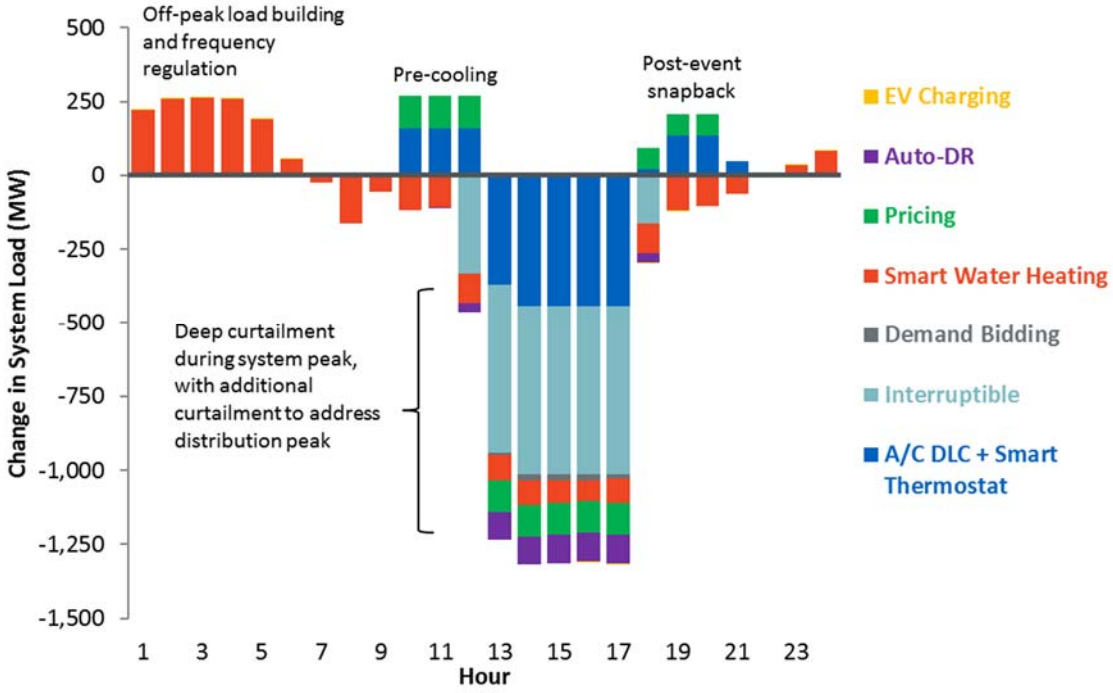
	Energy	Generation Capacity	System Average T&D Deferral	Geotargeted Distribution Deferral	Frequency Regulation	Total
Conventional Programs	$8.6	$69.7	$3.3	$0.0	$0.0	$81.5
Emerging Programs	$19.6	$19.5	$0.8	$0.7	$4.6	$45.2
Total	$28.2	$89.2	$4.0	$0.7	$4.6	$126.8

Notes: Benefits shown in 2023 dollars. Estimates include benefits from NSP's existing 850 MW portfolio.

DR Portfolio Operation

The addition of emerging programs to NSP's DR portfolio will improve operational flexibility across NSP's system. Figure 14 illustrates how the cost-effective DR portfolio from the High Sensitivity Case could operate on an hourly basis during the days of the year with the highest system peak demand. The profile shown maximizes avoided costs relative to the system cost assumptions used in this study.

Figure 14: Average Load Impacts of the 2030 Cost-Effective DR Portfolio on Top 10 Load Days (High Sensitivity Case)



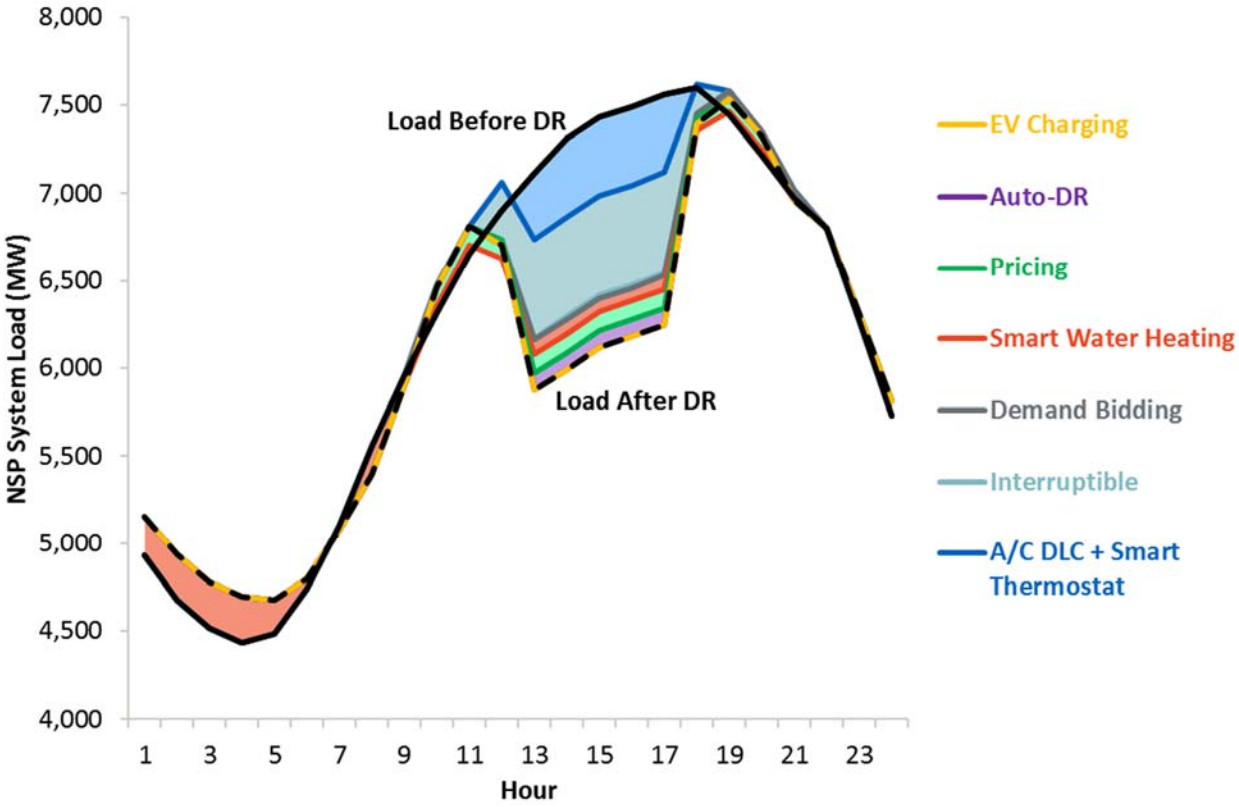
Note: Shown for cost-effective programs identified in 2030, accounting for portfolio overlap.

A deep curtailment of load during system peak hours is utilized to capture significant generation and T&D capacity deferral benefits. These also tend to be hours when energy costs are highest, leading to additional energy value. The duration of the peak load curtailment spans a fairly broad period of time – seven hours – in order to account for the lack of coincidence of the system and local peak demand that drive capacity needs. Load curtailment can be staggered across DR programs – and across participants in a given DR program – in order to achieve this duration of demand reduction.

Load increases are observed immediately before and after the peak load reduction. This is driven mostly by the need to maintain and restore building temperatures to desired levels around DR events. The smart water heating program builds load during nighttime hours, shifting heating load to the lowest cost hours and potentially reducing the curtailment of renewable generation.

Figure 15 illustrates how NSP's system load shape changes as a result of the impacts shown in Figure 14 above. The figure shows a steep reduction in load during hours of the MISO system peak, while NSP's later peak is only modestly reduced. This is primarily due to NSP's planning needs being driven by MISO coincident peak demand. If the MISO peak shifts later in the day due to solar PV adoption, or if NSP transitions to an increased focus on its own peak demand in planning activities, then the dispatch of the DR programs would need to be modified accordingly. In particular, it may become necessary to stagger the utilization of DR programs across a broader window of hours in order to "flatten" peak demand across the hours of the day.

Figure 15: Average Impacts of the 2030 Cost-Effective DR Portfolio on NSP System Load (High Sensitivity Case)



Note: Shown for cost-effective programs identified in 2030, accounting for portfolio overlap.

Sidebar: The Outlook for CTA-2045

CTA-2045 is a standard which specifies a low-cost communications "socket" that would be embedded in electric appliances and other consumer products. If consumers wished to make an appliance capable of participating in a demand response program, they could simply plug a communications receiver into the socket, thus allowing the appliance to be controlled by themselves or a third party. CTA-2045 has the potential to establish a low-cost option for two-way communications capability in appliances, thus reducing the cost and hassle of consumer enrollment in DR programs that would otherwise require on-site installation of more costly equipment.

Development of CTA-2045 began in 2011, through work by the Consumer Technology Association (CTA) and the Electric Power Research Institute (EPRI). Refinements to the standard are ongoing. To assess the outlook for CTA-2045 and its potential implications for future DR efforts, we conducted phone and email interviews with subject matter experts from utilities, appliance manufacturers, and DR software platforms.

There is a shared view that CTA-2045 is facing a chicken-and-egg problem. Manufacturers have been hesitant to incorporate the standard into their products, because there is a cost associated with doing so and they have not yet observed demand in the market for the communications functionality. At the same time, a barrier preventing increased adoption of DR technologies could be some of the costs and installation challenges that CTA-2045 would ultimately address.

Products with CTA-2045 functionality have not yet been deployed at scale, and where available are sold at a price premium that is significantly higher than the unit costs that could ultimately be achieved at scale. The relative lack of enthusiasm among manufacturers for rolling out CTA-2045 compliant products has led to a slow pace of development of the standard itself. Progress is being made incrementally, though technical issues still remain to be resolved.

Looking forward, some in the industry feel that the mandating CTA-2045 through a new state appliance standard could be the catalyst that is needed for adoption to become broadly widespread. Aggressive support for CTA-2045 by large utilities is also considered to be the type of activity that would facilitate adoption.

If compliance with CTA-2045 ultimately were to accelerate through activities like those described above, electric water heaters are poised to become the first such commercial application, as they have been the most common test case for proving the technical concept and are an attractive source of load flexibility. Particularly in the context of water heaters, CTA-2045 would help to overcome the challenge of enrolling customers in a DR program during the very narrow window of time during which their existing water heater expires and must be replaced. Other controllable end-uses, such as thermostats or even electric vehicle chargers could be candidates for the standard, though these technologies sometimes already come pre-equipped with communications capabilities.

VI. Conclusions and Recommendations

NSP's sizeable existing DR portfolio has the potential to be expanded by tapping into latent demand for existing programs and also by rolling out a new portfolio of emerging DR programs. Specific recommendations for acting on the findings of this study including the following:

Aggressively pursue the transition to smart thermostats as well as recruitment of medium C&I customers into a redesigned Interruptible program. NSP's relatively low avoided costs mean that lower cost, established DR programs are the most economically attractive options in the near term. Smart thermostats and a modernized Medium C&I interruptible program present the largest incremental opportunity and the least amount of uncertainty/risk.

Pilot and deploy a smart water heating program. There is significant experience with advanced water heating load control in the Upper Midwest, and the technology is rapidly advancing. The thermal storage capabilities of water heaters provide a high degree of load flexibility that can be adapted to a range of system needs.

As a complementary activity to the development of a smart water heating program, also evaluate the economics and environmental impacts of switching from gas to electric heating, factoring in the grid reliability benefits associated with this flexible source of load. Doing so would require revisiting existing state policies that prohibit utility-incentivized fuel switching.

Build the foundation for a robust offering of time-varying rates. As a first step, prepare a strategy for rolling out innovative rates soon after AMI is deployed. This should include exploring rate offerings that could be deployed to customers on a default (opt-out) basis, as default rate offerings maximize the overall economic benefit for the program.

Develop measurement & verification (M&V) 2.0 protocols to ensure that the impacts of the program are dependable and can be integrated meaningfully into resource planning efforts. Included in this initiative could be the development of a data collection plan to enhance the quality of future market potential studies. Further, detailed customer segmentation and geographically granular load data at the distribution system level will provide an improved base from which to develop a cost-effective DR strategy.

Design programs with peak period flexibility. From a planning standpoint, the timing of the peak period could change for a variety of reasons (e.g., DR flattens the peak, solar PV shifts the net peak, or the planning emphasis shifts from a focus on the MISO peak to a focus on more local peaks). DR programs will need to be designed with the flexibility to adjust the timing of curtailments in response to these changes.

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Appendix A: Load*Flex* Modeling Methodology and Assumptions

The Load*Flex* Model

The Brattle Group's Load*Flex* model was developed to quantify the potential impacts, costs, and benefits of demand response (DR) programs. The Load*Flex* modeling approach offers the flexibility to accurately estimate the broader range of benefits that are being offered by emerging "DR 2.0" programs which not only reduce system peak demand, but also provide around-the-clock load management opportunities.

The Load*Flex* modeling framework builds upon the standard approach to quantifying DR potential that has been used in prior studies around the U.S. and internationally, but incorporates a number of differentiating features which allow for a more robust evaluation of DR programs:

- **Economically optimized enrollment:** Assumed participation in DR programs is tailored to the incentive payment levels that are cost-effective for the DR program. If only a modest incentive payment can be justified in order to maintain a benefit-cost ratio of 1.0, then the participation rate is calibrated to be lower than if a more lucrative incentive payment were offered. Prior approaches to quantifying DR potential ignore this relationship between incentive payment level and participation, which tends to under-state the potential (and, in some cases, incorrectly concludes that a DR program would not pass the cost-effectiveness screen).

- **Utility-calibrated load impacts:** Load impacts are calibrated to the characteristics of the utility's customer base. In the residential sector, this includes accounting for the market saturation of various end-use appliances (e.g., central air-conditioning, electric water heating). In the commercial and industrial (C&I) sector, this includes accounting for customer segmentation based on size (i.e., the customer's maximum demand) and industry (e.g., hospital, university). Load curtailment capability is further calibrated to the utility's experience with DR programs (e.g., impacts from existing DLC programs or dynamic pricing pilots).

- **Sophisticated DR program dispatch:** DR program dispatch is optimized subject to detailed accounting for the operational constraints of the program. In addition to tariff-related program limitations (e.g., how often the program can be called, hours of the day when it can be called), Load*Flex* includes an hourly profile of load interruption capability for each program. For instance, for an EV home charging load control program, the model accounts for home charging patterns, which would provide greater average load reduction

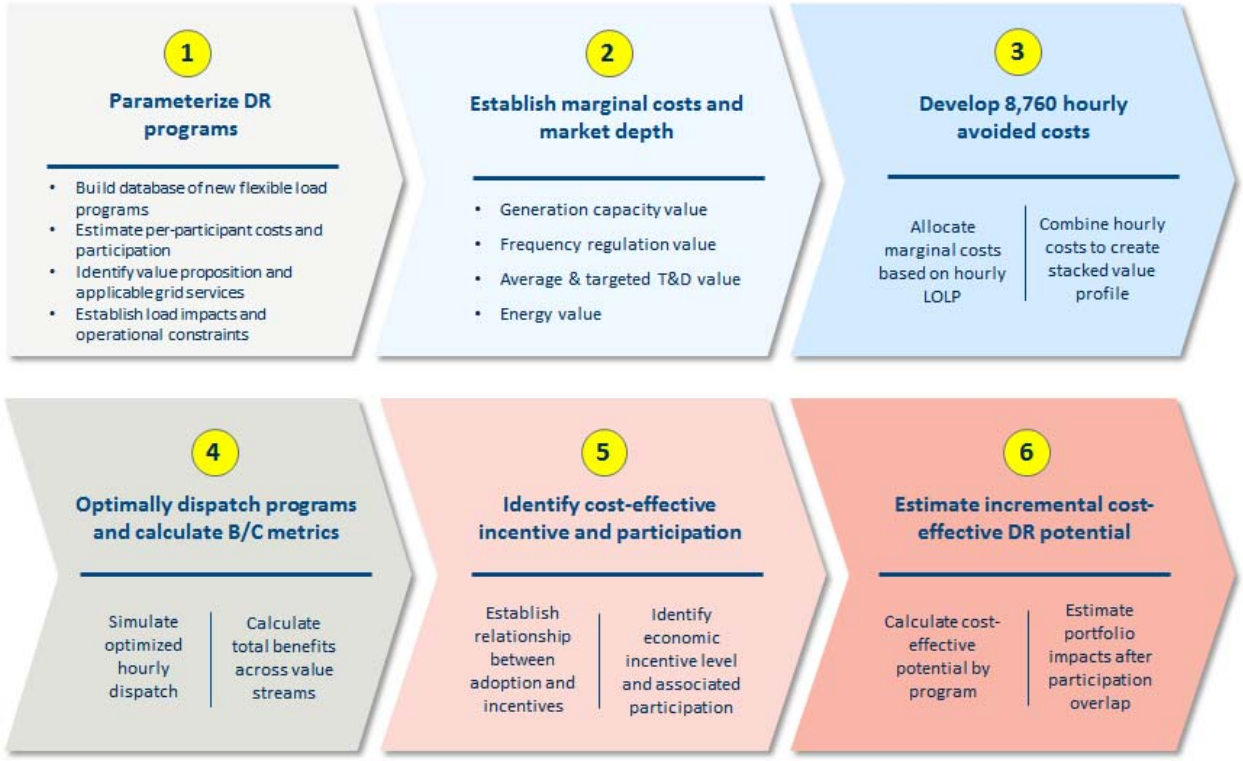
opportunities during evening hours (when EV owners have returned home from work) than in the middle of the day.

- **Realistic accounting for "value stacking":** DR programs have the potential to simultaneously provide multiple benefits. For instance, a DR program that is dispatched to reduce the system peak and therefore avoid generation capacity costs could also be dispatched to address local distribution system constraints. However, tradeoffs must be made in pursuing these value streams – curtailing load during certain hours of the day may prohibit that same load from being curtailed again later in the day for a different purpose. Load*Flex* accounts for these tradeoffs in its DR dispatch algorithm. DR program operations are simulated to maximize total benefits across multiple value streams, while recognizing the operational constraints of the program. Prior studies have often assigned multiple benefits to DR programs without accounting for these tradeoffs, thus double-counting benefits.

- **Industry-validated program costs:** DR program costs are based on a detailed review of the utility's current DR offerings. For new programs, costs are based on a review of experience and studies in other jurisdictions and conversations with vendors. Program costs are differentiated by type (e.g., equipment/installation, administrative) and structure (e.g., one-time investment, ongoing annual fee, per-kilowatt fee) to facilitate integration into utility resource planning models.

The Load*Flex* methodology is organized around six steps, as summarized in Figure 16. The remainder of this appendix describes each of the six steps in further detail, documenting methodology, assumptions, and data sources.

Figure 16: The Load*Flex* Modeling Framework



Step 1: Parameterize the DR programs

Each DR program is represented according to two broad categories of characteristics: Performance characteristics and cost characteristics.

Program Performance Characteristics

The performance characteristics of each DR program are represented in detail in Load*Flex* to accurately estimate the ability of the DR programs to provide system value. The following are key aspects of each program's performance capability.

Load impact profiles

Each DR program is represented with 24-hour average daily profiles of load reduction and load increase capability. These 24-hour impact profiles are differentiated by season (summer, winter, shoulder) and day type (weekday, weekend). For instance, air-conditioning load curtailment capability is highest during daytime hours in the summer, lower during nighttime summer hours, and non-existent during all hours in the winter.

Whenever possible, load impacts are derived directly from NSP's experience with its existing DR programs and pilots. NSP's experience directly informed the impact estimates for direct load control, smart thermostat, and interruptible rates programs. For emerging non-pricing DR

programs, impacts are based on a review of experience and studies in other jurisdictions and tailored to NSP's customer mix and climate. Methods used to develop impact profile estimates for emerging non-pricing DR programs include the following:

- *C&I Auto-DR:* The potential for C&I customers to provide around-the-clock load flexibility was primarily derived from data supporting a 2017 statewide assessment of DR potential in California[17], a 2013 LBNL study of DR capability[18], and electricity load patterns representative of C&I buildings in Minneapolis developed by the Department of Energy.[19] Customer segment-specific estimates from these studies were combined to produce a composite load impact profile for the NSP service territory based on assumptions about NSP's mix of C&I customers. Impacts were scaled as necessary for consistency with NSP's prior experience with C&I DR programs.

- *Water heating load control:* Assumptions for the water heating load control programs – both grid interactive water heating and static timed water heating - are derived from a 2016 study on the value of various water heating load control strategies.[20] The program definition assumes that only customers with existing electric resistance water heaters will be eligible for participating in the water heating programs.

- *Behavioral DR:* Impacts are derived from a review of the findings of behavioral DR pilot studies conducted around the US, including for Baltimore Gas & Electric, Consumers Energy, Green Mountain Power, Glendale Water and Power, Portland Gas Electric, and Pacific Gas and Electric. Most behavioral DR pilot studies have been conducted by Oracle (OPower) and have generally found that programs with a limited number of short curtailment events (4-10 events for 3-5 afternoon/evening hours) can achieve 2% to 3% load reduction across enrolled customers.[21] Based on these findings, we assumed that a

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17 Peter Alstone et al., Lawrence Berkeley National Laboratory, "Final Report on Phase 2 Results: 2025 California Demand Response Potential Study." March 2017.

18 Daniel J. Olsen, Nance Matson, Michael D. Sohn, Cody Rose, Junqiao Dudley, Sasank Goli, and Sila Kiliccote (Lawrence Berkeley National Laboratory), Marissa Hummon, David Palchak, Paul Denholm, and Jennie Jorgenson (National Renewable Energy Laboratory), and Ookie Ma (U.S. Department of Energy), "Grid Integration of Aggregated Demand Response, Part 1: Load Availability Profiles and Constraints for the Western Interconnection," LBNL-6417E, 2013.

19 See U.S. Department of Energy Commercial Reference Buildings at: https://www.energy.gov/eere/buildings/commercial-reference-buildings

20 Ryan Hledik, Judy Chang, and Roger Lueken. "The Hidden Battery: Opportunities in Electric Water Heating." January 2016. Posted at: http://www.electric.coop/wp-content/uploads/2016/07/The-Hidden-Battery-01-25-2016.pdf

21 For example, see Jonathan Cook et al., "Behavioral Demand Response Study – Load Impact Evaluation Report", January 11, 2016, prepared for Pacific Gas & Electric Company, available at: http://www.oracle.com/us/industries/utilities/behavioral-demand-response-3628982.pdf, and OPower,

behavioral DR program called 10 times per year between 3 pm and 6 pm would achieve a 2.5% load reduction.

- *EV managed charging:* Estimates of load curtailment capability are based on projections of aggregate EV charging load shapes provided by Xcel Energy. The ability to curtail this charging load is based on a review of recent utility EV charging DR pilots, including managed charging programs at several California utilities (PG&E, SDG&E, SCE, and SMUD) and United Energy in Australia.[22]

- *Ice-based thermal energy storage:* Estimates of load curtailment capability are estimated based on charging and discharging (freezing and cooling) information from Ice Bear[23] and adapted to mirror building use patterns in Minnesota based on load profiles from the U.S. Department of Energy.[24]

For impacts from pricing programs, we relied on Brattle's database of time-varying pricing offerings. The database includes the results of more than 300 experimental and non-experimental pricing treatments across over 60 pilot programs.[25] It includes published results from Xcel Energy's various pricing pilots during this time period. The results of the pilots in the database are used to establish a relationship between the peak-to-off-peak price ratio of the rates and the average load reduction per participant, in order to simulate price response associated with any given rate design. This relationship between load reduction and price ratio is illustrated in Figure 17.

"Transform Every Customer into a Demand Response Resource: How Utilities Can Unlock the Full Potential of Residential Demand Response", 2014, available at: https://go.oracle.com/LP=42838?elqCampaignId=74613.

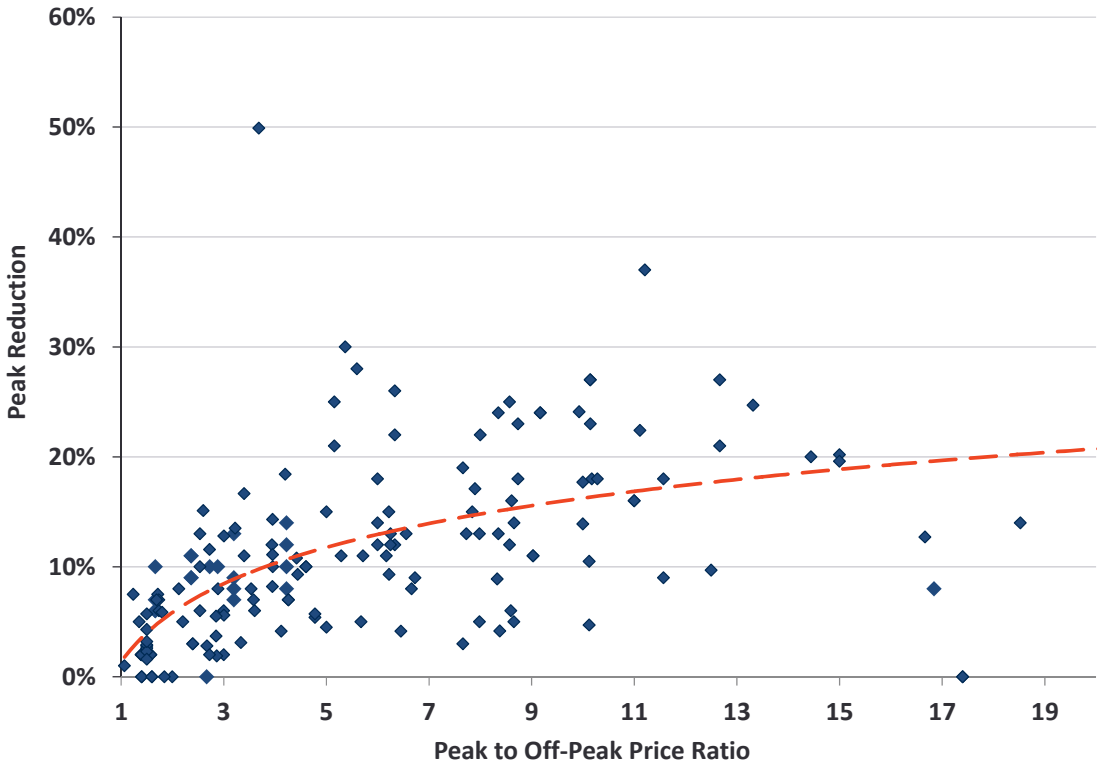
22 Pilot programs reviewed include BMW and PG&E's i Charge Forward Pilot, SCE's Workplace Charging Pilot, SMUD's EV Innovators Pilot, SDG&E's Power Your Drive Pilot, and United Energy's EV smart grid demonstration project.

23 Ice Energy, "Ice Bear 20 Case Study," November 2016. Available: https://www.ice-energy.com/wp-content/uploads/2016/12/SantaYnez_CaseStudy_Nov2016.pdf

24 See U.S. Department of Energy Commercial Reference Buildings at: https://www.energy.gov/eere/buildings/commercial-reference-buildings

25 Ahmad Faruqui, Sanem Sergici, and Cody Warner, "Arcturus 2.0: A Meta-Analysis of Time-Varying Rates for Electricity," *The Electricity Journal*, 2017.

Figure 17: Relationship between Price Ratio and Price Response in Residential Pricing Pilots



Results shown only for price ratios less than 20-to-1 and for treatments that did not include automating technology such as smart thermostats.

Daily relationship between load reduction and load increase

Some DR programs will require a load increase to offset or partially offset the load that is reduced during a curtailment event. In Load*Flex*, each program definition includes a parameter that represents the percent of curtailed load that must be offset by increased load on the same day, including the timing of when the load increase must occur. For instance, in a water heating load control program, any reduction in water heating load is assumed to be offset by an equal increase in water heating load on the same day in order to meet the customer's water heating needs. Alternatively, a reduction in air-conditioning load may only be offset partially by an increase in consumption, but it would immediately follow the curtailment.

Where data is available, these load building assumptions are based on the same data sources described above. Otherwise, these impacts are derived from assumptions that were developed for FERC's 2009 *A National Assessment of Demand Response Potential*.

Tariff-related operational constraints

Most DR programs will have administrator-defined limits on the operation of the program. This includes the maximum number of hours per day that the program can be curtailed, whether or not those curtailment hours must be contiguous, and the maximum number of days per year with

allowed curtailment. Assumed operational constraints are based on Xcel Energy's program definitions and a review of common limitations from programs offered in other jurisdictions.

Ancillary services availability

If a DR program has the advanced control and communications technology necessary to provide ancillary services, Load*Flex* accounts for the capacity that is available to provide fast-response load increases or decreases in response to real-time fluctuations in supply and demand. In this study, smart water heating and Auto-DR are assumed to be able to offer ancillary services. Specifically, we model frequency regulation as it is the most valuable ancillary services product. Capability is based on the same data sources described above.

Table 6 summarizes the performance characteristics for each DR program in this study. In the table, "load shifting capability" identifies whether or not a program is capable of shifting energy usage from peak periods to off-peak periods on a daily basis.

Table 6: DR Program Performance Characteristics

Segment	Program	Peak-coincident curtailment capability (kW/participant)	Hours of Curtailment (hours)	Average regulation up provided (kW/participant)	Average regulation down provided (kW/participant)	Load shifting capability?
Residential	A/C DLC - SFH	0.62	75	0.00	0.00	No
Residential	Behavioral DR (Opt-out)	0.06	40	0.00	0.00	No
Residential	CPP (Opt-in)	0.34	75	0.00	0.00	No
Residential	CPP (Opt-out)	0.17	75	0.00	0.00	No
Residential	EV Managed Charging - Home	0.46	45	0.00	0.00	Yes
Residential	EV Managed Charging - Work	0.09	45	0.00	0.00	Yes
Residential	Smart thermostat - MDU	0.86	75	0.00	0.00	No
Residential	Smart thermostat - SFH	1.15	75	0.00	0.00	No
Residential	Smart water heating	0.46	4,745	0.37	0.38	Yes
Residential	Timed water heating	0.43	1,825	0.00	0.00	Yes
Residential	TOU - EV Charging (Opt-in)	0.05	1,460	0.00	0.00	Yes
Residential	TOU (Opt-in)	0.17	1,284	0.00	0.00	No
Residential	TOU (Opt-out)	0.08	1,284	0.00	0.00	No
Small C&I	A/C DLC	1.93	75	0.00	0.00	No
Small C&I	Auto-DR (A/C)	1.37	200	0.37	0.49	Yes
Small C&I	Auto-DR (Light Luminaire)	1.07	300	0.52	0.57	Yes
Small C&I	Auto-DR (Light Zonal)	0.92	300	0.44	0.49	Yes
Small C&I	CPP (Opt-in)	0.02	75	0.00	0.00	No
Small C&I	CPP (Opt-out)	0.01	75	0.00	0.00	No
Small C&I	Demand Bidding	0.02	200	0.00	0.00	No
Small C&I	Interruptible	1.98	90	0.00	0.00	No
Small C&I	TOU (Opt-in)	0.01	1,281	0.00	0.00	No
Small C&I	TOU (Opt-out)	0.00	1,281	0.00	0.00	No
Medium C&I	A/C DLC	3.92	75	0.00	0.00	No
Medium C&I	Auto-DR (HVAC)	46.17	430	14.61	14.09	Yes
Medium C&I	Auto-DR (Light Luminaire)	18.22	300	8.62	8.83	Yes
Medium C&I	Auto-DR (Light Zonal)	9.81	300	5.47	5.78	Yes
Medium C&I	CPP (Opt-in)	4.83	75	0.00	0.00	No
Medium C&I	CPP (Opt-out)	2.42	75	0.00	0.00	No
Medium C&I	Demand Bidding	4.43	200	0.00	0.00	No
Medium C&I	Interruptible	27.45	90	0.00	0.00	No
Medium C&I	Thermal Storage	50.97	644	0.00	0.00	Yes
Medium C&I	TOU (Opt-in)	2.31	1,281	0.00	0.00	No
Medium C&I	TOU (Opt-out)	1.39	1,281	0.00	0.00	No
Large C&I	Auto-DR (HVAC)	592.09	430	151.57	207.60	Yes
Large C&I	Auto-DR (Light Luminaire)	416.95	120	191.67	200.74	Yes
Large C&I	Auto-DR (Light Zonal)	224.51	120	103.21	108.09	Yes
Large C&I	CPP (Opt-in)	283.92	75	0.00	0.00	No
Large C&I	CPP (Opt-out)	141.67	75	0.00	0.00	No
Large C&I	Demand Bidding	260.28	200	0.00	0.00	No
Large C&I	Interruptible	483.62	90	0.00	0.00	No

Notes:
Program impacts shown reflect impacts for new participants. Impacts shown assume each program is offered independently.

Program Cost Characteristics

The costs of each program include startup costs, marketing and customer recruitment, the utility's share of equipment and installation costs, program administration and overhead, churn costs (i.e., the annual cost of replacing participants that leave the program), and participation incentives.[26]

[26] The Utility Cost Test (UCT) is the cost-effectiveness screen used in this study, which calls for including incentive payments as a cost.

Cost assumptions are based on NSP's current program costs, where applicable. Otherwise, costs are based on a review of experience and studies in other jurisdictions and conversations with vendors, and are tailored for consistency with NSP's current program costs. Notable assumptions in developing the cost estimates include the following:

- Water heating technology costs include the cost of the load control and communications equipment and the *incremental* cost of replacing the existing water heater (50-gallon average) with a larger water heater (80-gallon) when the existing water heater expires. The full cost of a new water heater is not assigned to the program.

- Similarly, EV charging load control equipment costs include the incremental cost of load control and communications technology, but not the full cost of a charging unit.

- The cost of AMI is not counted against any of the DR programs, as it is treated as a sunk cost that is likely to be justified by a broad range of benefits that the new digital infrastructure will provides to customers and to NSP. However, a rough estimate of the cost of IT and billing system upgrades specifically associated with offering time-varying pricing programs are included in the costs for those programs.

- The cost of advanced lighting control systems is not counted against DR programs as these control systems are typically installed for non-energy benefits.

Table 7 summarizes Base Case cost assumptions for 2023 and Table 8 summarizes High Sensitivity Case cost assumptions for 2030. The 2030 assumptions reflect an assumed 25% reduction in the cost (in real terms) of emerging technologies. Costs in both tables are shown in nominal dollars. As discussed later in this appendix, the "base" incentive levels are derived from commonly observed payments both by NSP and in other jurisdictions. They do not reflect the cost-effective incentive payment levels that are ultimately established through the modeling.

Table 7: 2023 Base Case Program Cost Assumptions

		One-Time Costs			Recurring Costs			
Segment	Program	Fixed Cost ($)	Variable Equipment Cost ($/participant)	Other Initial Costs ($/participant)	Fixed Admin & Other ($/year)	Variable Admin & Other ($/participant-year)	Base Annual Incentive Level ($/participant-year)	Economic Life (years)
Residential	A/C DLC - SFH	$0	$172	$92	$0	$13	$59	15
Residential	Behavioral DR (Opt-out)	$0	$0	$0	$0	$4	$0	15
Residential	CPP (Opt-in)	$223,208	$0	$80	$83,703	$2	$0	15
Residential	CPP (Opt-out)	$223,208	$0	$40	$83,703	$2	$0	15
Residential	EV Managed Charging - Home	$0	$229	$0	$0	$17	$45	15
Residential	EV Managed Charging - Work	$0	$229	$0	$0	$17	$45	15
Residential	Smart thermostat - MDU	$0	$126	$92	$0	$11	$28	10
Residential	Smart thermostat - SFH	$0	$126	$92	$0	$11	$28	10
Residential	Smart water heating	$0	$686	$34	$0	$0	$28	10
Residential	Timed water heating	$0	$458	$34	$0	$0	$11	10
Residential	TOU - EV Charging (Opt-in)	$0	$0	$0	$83,703	$0	$0	15
Residential	TOU (Opt-in)	$223,208	$0	$57	$83,703	$1	$0	15
Residential	TOU (Opt-out)	$223,208	$0	$29	$83,703	$0	$0	15
Small C&I	A/C DLC	$0	$172	$92	$0	$13	$237	15
Small C&I	Auto-DR (A/C)	$0	$0	$2,218	$0	$22	$112	15
Small C&I	Auto-DR (Light Luminaire)	$0	$0	$1,328	$0	$22	$112	15
Small C&I	Auto-DR (Light Zonal)	$0	$0	$1,001	$0	$22	$112	15
Small C&I	CPP (Opt-in)	$74,403	$0	$80	$27,901	$0	$0	15
Small C&I	CPP (Opt-out)	$74,403	$0	$40	$27,901	$0	$0	15
Small C&I	Demand Bidding	$0	$0	$0	$691,944	$0	$1	15
Small C&I	Interruptible	$0	$0	$0	$280,126	$0	$259	15
Small C&I	TOU (Opt-in)	$74,403	$0	$57	$20,926	$0	$0	15
Small C&I	TOU (Opt-out)	$74,403	$0	$29	$20,926	$0	$0	15
Medium C&I	A/C DLC	$0	$343	$92	$0	$13	$481	15
Medium C&I	Auto-DR (HVAC)	$0	$0	$26,820	$0	$22	$9,444	12
Medium C&I	Auto-DR (Light Luminaire)	$0	$0	$33,220	$0	$22	$4,351	15
Medium C&I	Auto-DR (Light Zonal)	$0	$0	$24,719	$0	$22	$4,351	15
Medium C&I	CPP (Opt-in)	$74,403	$0	$1,144	$27,901	$22	$0	15
Medium C&I	CPP (Opt-out)	$74,403	$0	$572	$27,901	$22	$0	15
Medium C&I	Demand Bidding	$0	$0	$0	$280,126	$0	$249	15
Medium C&I	Interruptible	$0	$0	$0	$280,126	$0	$5,627	15
Medium C&I	Thermal Storage	$0	$120,114	$34	$0	$382	$0	20
Medium C&I	TOU (Opt-in)	$74,403	$0	$1,144	$20,926	$22	$0	15
Medium C&I	TOU (Opt-out)	$74,403	$0	$572	$20,926	$22	$0	15
Large C&I	Auto-DR (HVAC)	$0	$0	$306,980	$0	$22	$108,307	12
Large C&I	Auto-DR (Light Luminaire)	$0	$0	$495,047	$0	$22	$86,691	15
Large C&I	Auto-DR (Light Zonal)	$0	$0	$367,510	$0	$22	$86,691	15
Large C&I	CPP (Opt-in)	$74,403	$0	$1,144	$27,901	$22	$0	15
Large C&I	CPP (Opt-out)	$74,403	$0	$572	$27,901	$22	$0	15
Large C&I	Demand Bidding	$0	$0	$0	$315,839	$0	$14,651	15
Large C&I	Interruptible	$0	$0	$0	$315,839	$0	$90,997	15

Notes:

All costs shown in nominal dollars. Variable equipment cost and other initial costs include 2.5% churn cost adder. Analysis assumes a 6.44% discount rate for annualizing one-time costs.

Table 8: 2030 High Sensitivity Case Program Cost Assumptions

		One-Time Costs			Recurring Costs			
Segment	Program	Fixed Cost ($)	Variable Equipment Cost ($/participant)	Other Initial Costs ($/participant)	Fixed Admin & Other ($/year)	Variable Admin & Other ($/participant-year)	Base Annual Incentive Level ($/part.-yr)	Economic Life (years)
Residential	A/C DLC - SFH	$0	$140	$75	$0	$16	$69	15
Residential	Behavioral DR (Opt-out)	$0	$0	$0	$0	$5	$0	15
Residential	CPP (Opt-in)	$182,204	$0	$65	$97,609	$2	$0	15
Residential	CPP (Opt-out)	$182,204	$0	$33	$97,609	$2	$0	15
Residential	EV Managed Charging - Home	$0	$187	$0	$0	$20	$52	15
Residential	EV Managed Charging - Work	$0	$187	$0	$0	$20	$52	15
Residential	Smart thermostat - MDU	$0	$103	$75	$0	$13	$33	10
Residential	Smart thermostat - SFH	$0	$103	$75	$0	$13	$33	10
Residential	Smart water heating	$0	$560	$28	$0	$0	$33	10
Residential	Timed water heating	$0	$374	$28	$0	$0	$13	10
Residential	TOU - EV Charging (Opt-in)	$0	$0	$0	$97,609	$0	$0	15
Residential	TOU (Opt-in)	$182,204	$0	$47	$97,609	$1	$0	15
Residential	TOU (Opt-out)	$182,204	$0	$23	$97,609	$1	$0	15
Small C&I	A/C DLC	$0	$140	$75	$0	$16	$277	15
Small C&I	Auto-DR (A/C)	$0	$0	$1,810	$0	$26	$130	15
Small C&I	Auto-DR (Light Luminaire)	$0	$0	$1,084	$0	$26	$130	15
Small C&I	Auto-DR (Light Zonal)	$0	$0	$817	$0	$26	$130	15
Small C&I	CPP (Opt-in)	$60,735	$0	$65	$32,536	$0	$0	15
Small C&I	CPP (Opt-out)	$60,735	$0	$33	$32,536	$0	$0	15
Small C&I	Demand Bidding	$0	$0	$0	$806,905	$0	$1	15
Small C&I	Interruptible	$0	$0	$0	$326,666	$0	$302	15
Small C&I	TOU (Opt-in)	$60,735	$0	$47	$24,402	$0	$0	15
Small C&I	TOU (Opt-out)	$60,735	$0	$23	$24,402	$0	$0	15
Medium C&I	A/C DLC	$0	$280	$75	$0	$16	$561	15
Medium C&I	Auto-DR (HVAC)	$0	$0	$21,893	$0	$26	$11,013	12
Medium C&I	Auto-DR (Light Luminaire)	$0	$0	$27,117	$0	$26	$5,074	15
Medium C&I	Auto-DR (Light Zonal)	$0	$0	$20,178	$0	$26	$5,074	15
Medium C&I	CPP (Opt-in)	$60,735	$0	$934	$32,536	$26	$0	15
Medium C&I	CPP (Opt-out)	$60,735	$0	$467	$32,536	$26	$0	15
Medium C&I	Demand Bidding	$0	$0	$0	$326,666	$0	$291	15
Medium C&I	Interruptible	$0	$0	$0	$326,666	$0	$6,562	15
Medium C&I	Thermal Storage	$0	$98,049	$28	$0	$445	$0	20
Medium C&I	TOU (Opt-in)	$60,735	$0	$934	$24,402	$26	$0	15
Medium C&I	TOU (Opt-out)	$60,735	$0	$467	$24,402	$26	$0	15
Large C&I	Auto-DR (HVAC)	$0	$0	$250,588	$0	$26	$126,301	12
Large C&I	Auto-DR (Light Luminaire)	$0	$0	$404,107	$0	$26	$101,093	15
Large C&I	Auto-DR (Light Zonal)	$0	$0	$299,998	$0	$26	$101,093	15
Large C&I	CPP (Opt-in)	$60,735	$0	$934	$32,536	$26	$0	15
Large C&I	CPP (Opt-out)	$60,735	$0	$467	$32,536	$26	$0	15
Large C&I	Demand Bidding	$0	$0	$0	$368,313	$0	$17,085	15
Large C&I	Interruptible	$0	$0	$0	$368,313	$0	$106,116	15

Notes:
2030 one-time costs assumed to be 30% lower than 2023 one-time costs (in real terms), reflecting assumed declines in technology costs. All costs shown in nominal dollars. Variable equipment cost and other initial costs include 2.5% churn cost adder. Analysis assumes a 6.44% discount rate for annualizing one-time costs.

Step 2: Establish system marginal costs and quantity of system need

Load*Flex* was used to quantify a broad range of value streams that could be provided by DR. These include avoided generation capacity costs, avoided system-wide T&D costs, additional avoided distribution costs from geo-targeted deployment of the DR programs, frequency regulation, and net avoided marginal energy costs.

The system costs that could be avoided through DR deployment are estimated based on market data that is specific to NSP's service territory. Assumptions used in developing each marginal (i.e., avoidable) cost estimate are described in more detail below, for both the Base Case and the High Sensitivity Case.

Avoided generation capacity costs

DR programs are most appropriately recognized as substitutes for new combustion turbine (CT) capacity. CTs are "peaking" units with relatively low up-front installation costs and high variable costs. As a result, they typically only run up to a few hundred hours of the year, when electricity demand is very high and/or there are system reliability concerns. Similarly, use of DR programs in the U.S. is typically limited to less than 100 hours per year. This constraint is either written into the DR program tariff or is otherwise a practical consideration to avoid customer fatigue and program drop-outs.

In contrast, new intermediate or baseload capacity (e.g., gas-fired combined cycle) has a higher capital cost and lower variable cost than a CT, and therefore could run for thousands of hours per year. The DR programs considered in this study cannot feasibly avoid the need for new intermediate or baseload capacity, because they cannot be called during a sufficient number of hours of the year. Energy efficiency is a more comparable demand-side alternative to these resource types since it is a permanent load reduction that applies to a much broader range of hours.

In the Base Case, the installed cost of new CT capacity is based on data provided directly by NSP and consistent with the assumptions in NSP's 2019 IRP for a brownfield CT. The total cost amounts to $60.60/kW-year; this is sometimes referred to the gross cost of new entry (CONE). The gross CONE value is adjusted downward to account for the energy and ancillary services value that would otherwise be provided by that unit. Based on simulated unit profit data provided by NSP, we have estimated the annual energy and ancillary services value to be roughly $5.50/kW-year. The resulting net CONE value is $55.20/kW-year. This calculation is described further in Table 9 below.

This same approach is used to establish the capacity cost for the High Sensitivity Case. Rather than using the CT cost from NSP's IRP, we relied on the U.S. Energy Information Administration's (EIA's) estimate of the installed cost of an Advanced CT from the 2018 Annual Energy Outlook. For the Midwest Reliability Organization West region, this amounts to a gross CONE of $76.80/kW-year. Reducing this value by the same energy and ancillary services value described above leads to a net CONE of $71.40/kW-year.

Table 9: Combustion Turbine Cost of New Entry Calculation

Variable		NSP 2019 IRP Brownfield CT	NSP 2019 IRP Greenfield CT	AEO 2018 Advanced CT
Overnight Capital Cost ($/kW)	[1]	$467	$617	$698
Effective Charge Rate (%)	[2]	10%	10%	10%
Levelized Capital Cost ($/kW-yr)	[3]=[1]x[2]	$46.7	$61.7	$69.8
Annual Fixed Costs ($/kW-yr)	[4]	$13.9	$13.9	$7.0
Gross Cost of New Entry ($/kW-yr)	[5]=[3]+[4]	$60.6	$75.6	$76.8
E&AS Margins ($/kW-yr)	[6]	$5.5	$5.5	$5.5
Net Cost of New Entry ($/kW-yr)	[7]=[5]-[6]	$55.2	$70.2	$71.4

Notes: All costs shown in 2018 dollars. Assumes that overnight capital costs are recovered at 10% effective charge rate. AEO 2018 advanced CT costs shown for the Midwest Reliability Organization West region. Capacity costs are held constant in real terms throughout the period of study.

DR produces a reduction in consumption at the customer's premise (i.e. at the meter). Due energy losses on transmission and distribution lines as electricity is delivered from power plants to customer premises, a reduction in one kilowatt of demand at the meter avoids more than one kilowatt of generation capacity. In other words, assuming line losses of 8% percent, a power plant must generate 1.08 kW in order to deliver 1 kW to an individual premise.[27] When estimating the avoided capacity cost of DR, the avoided cost is grossed up to account for this factor. For this study, Xcel Energy provided load data at the generator level, thus already accounting for line loss gross-up.

Similarly, NSP incorporates a planning reserve margin of 2.4% percent into its capacity investment decisions.[28] This effectively means NSP will plan to have enough capacity available to meet its projected peak demand plus 2.4% percent of that value. In this sense, a reduction of one kilowatt at the meter level reduces the need for 1.024 kW of capacity. Including the 2.4% reserve margin adjustment increases the net CONE value described above from $55.2 and $71.4/kW-year to $56.5 and $73.1/kW-year, for the Base and High Sensitivity Cases respectively. This is the generation capacity value that could be provided by DR if it were to operate exactly like a CT.

Avoided transmission capacity costs

Reductions in system peak demand may also reduce the need for transmission upgrades. A portion of transmission investment is driven by the need to have enough capacity available to move electricity to where it is needed during peak times while maintaining a sufficient level of

[27] 8% represents an average line loss across NSP territories and customer segments. Actual line losses range from 2 to 10%.

[28] NSP's planning reserve margin target is 7.8% of load during the MISO peak, which translates into a margin of 2.4% during its own system peak.

reliability. Other transmission investments will not be peak related, but rather are intended to extend the grid to remotely located sources of generation, or to address constraints during mid- or off-peak periods. Based on the findings of NSP's 2017 T&D Avoided Cost Study for energy efficiency programs, we have assumed an avoidable transmission cost of $3.10/kW-year in 2023, rising to $3.60/kW-year in 2030.[29]

Avoided system-wide distribution capacity costs

Similar to transmission value, there may be long-term distribution capacity investment avoidance value associated with reductions in peak demand across the NSP system. For programs that do not provide the higher-value distribution benefits from geo-targeted deployment, as described below, we have assumed that peak demand reductions can produce avoided distribution costs of $8.10/kW-year in 2023, rising to $9.50/kW-year in 2030, based on NSP's 2017 T&D Avoided Cost Study.

Geo-targeted distribution capacity costs

DR participants may be recruited in locations on the distribution system where load reductions would defer the need for local capacity upgrades. This local deployment of the DR program can be targeted at specifically locations where distribution upgrades are expected to be costly.

DR cannot serve as a substitute for distribution upgrades in all cases, such as adding new circuit breakers, telemetry upgrades, or adding distribution lines to connect new customers. However, in many cases, system upgrades are needed to meet anticipated gradual load growth in a local area. At times, system planners must over-size distribution investments relative to the immediate needs to meet local load to allow for future load growth or utilize equipment (such as transformers) that only comes in certain standard sizes. To the extent that DR can be used to reduce local peak loads, the loading on the distribution system is reduced, which means otherwise necessary distribution upgrades may be deferred. Such deferrals are especially valuable if load growth is relatively slow and predictable such that the upgraded system would not be fully utilized for many years.

To quantify geo-targeted distribution capacity deferral value in Load*Flex*, we began with a list of all distribution capacity projects in NSP's five-year plan. Brattle worked with NSP staff to reduce this list to a subset of projects that are likely candidates for deferral through DR. Four criteria were applied to identify the list of candidate deferral projects:

1. The need for the distribution project must be driven by load growth. DR could not be used to avoid the need to simply replace aging equipment, for example.

[29] Xcel Energy, Minnesota Power, Otter Tail Power Company, Mendota Group & Environmental Economics, "Minnesota Transmission and Distribution Avoided Cost Study," July 31, 2017.

2. The project must have a meaningful overall cost on a per-kilowatt basis. In our analysis, we required that the cost of the project equate to a value of at least $100,000 per megawatt of reduced demand in order to be considered.[30] This is the equivalent of roughly $7/kW-year on an annualized basis. Projects below this cost threshold were excluded from the geo-targeted deferral analysis.

3. There must be sufficient local customer load in order for the upgrade to be deferrable through the use of DR. For instance, if a 20 MW load reduction would be needed to avoid a specific distribution upgrade, and there was only 25 MW of total load at that location in the system, then DR would not be a useful candidate because it is unlikely that DR could consistently and reliably produce an 80% load reduction. In establishing this criterion, projects with more than 6 MVA of "load at risk"[31] were excluded, as 6 MVA represents about half of the load on a typical feeder.

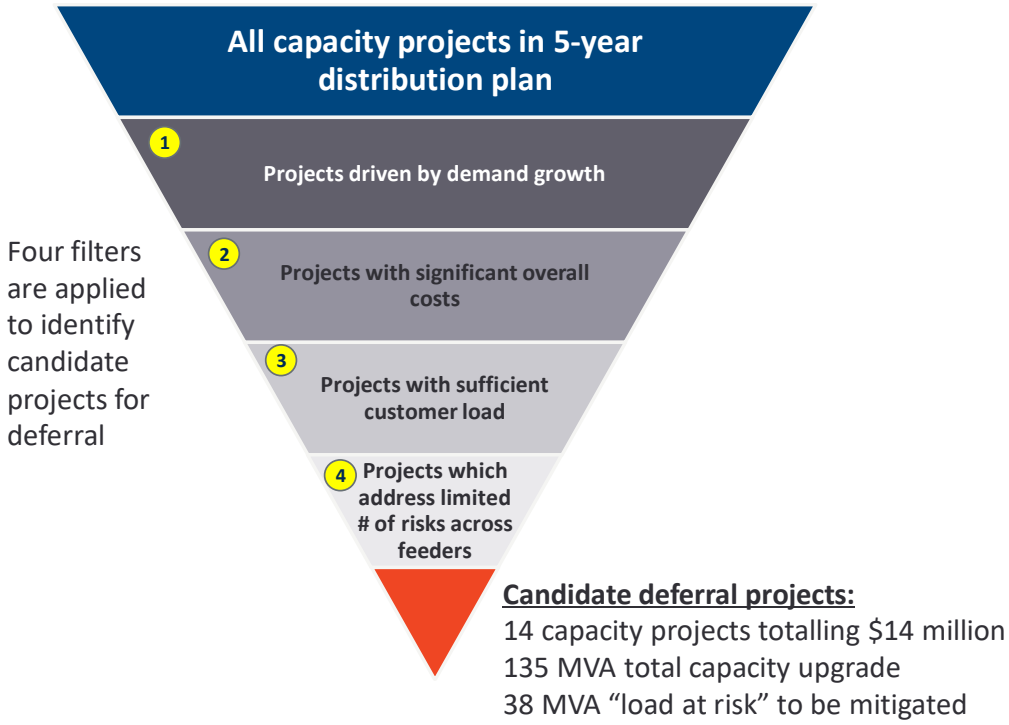
4. The project should not be needed to simultaneously address many risks across feeders. In some cases, distribution upgrades are needed to mitigate a number of different contingencies. There are significant operational challenges associated with using DR in a similar manner. Projects were screened out based on the number and severity of risks that they were intended to address.

After applying the above criteria, up to roughly 10% of the cost of NSP's 5-year plan remained as potentially deferrable through the use of DR. We have assumed linear growth in NSP's distribution capacity needs, meaning the geo-targeted distribution deferral opportunity increases by this amount every five years over the forecast horizon. Figure 17 summarizes the process for identifying geo-targeted distribution deferral opportunities.

[30] For simplicity, we assumed 1 MVA = 1 MW.

[31] "Load at risk" effectively represents the load reduction that would need to be achieved to defer the capacity upgrade.

Figure 18: Identification of Candidates for Geo-targeted Distribution Investment Deferral



Avoided energy costs

Load can be shifted from hours with higher energy costs to hours with lower energy costs, thus producing net energy cost savings across the system.[32] Hourly energy costs in this study are based on the 2018 MISO Transmission Expansion Plan (MTEP18) modeled day-ahead prices for the NSP hub. These modeled prices were used to capture evolving future system conditions that would not be reflected in historical prices. MTEP18 presents four "futures" that represent broadly different long-term views of MISO energy system, enabling the evaluation of the avoided energy value of DR under different market conditions.

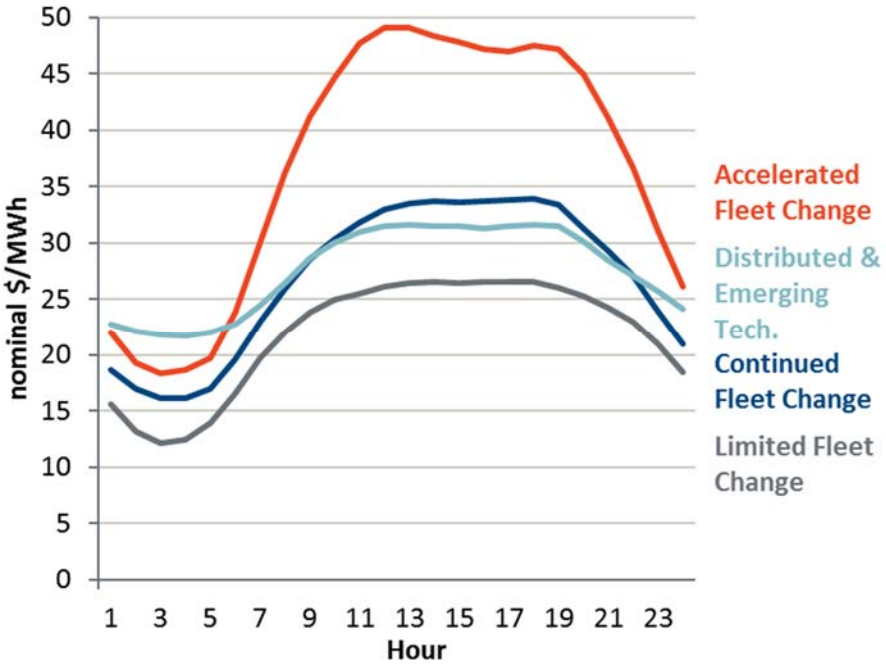
For the Base Case, we relied on prices from MTEP18's Continued Fleet Change (CFC) future. This future assumes a continuation of trends in the MISO market from the past decade: persistent low gas prices, limited demand growth, continued economic coal retirements, and gradual growth in renewables above state requirements.[33] Figure 19 below shows that 2022 energy prices under the

[32] Energy savings refer to reduced fuel and O&M costs. In this study, we do not model the impact that DR would have on MISO wholesale energy prices. This is sometimes referred to as the demand response induced price effect (DRIPE). It represents a benefit to consumers and an offsetting cost to producers, with no net change in costs across the system as a whole.

[33] See MISO, "MTEP 18 Futures – Summary of definitions, uncertainty variables, resource forecasts, siting process and siting results." for additional details on MTEP18 scenarios.

CFC future lie somewhere in the middle of the four MTEP scenarios (energy prices in other years follow the same relative pattern across scenarios).

Figure 19: Average Energy Price by Hour of Day in 2022 MTEP Scenarios for NSP Hub



For the High Sensitivity Case, we relied on prices from the Accelerated Fleet Change (AFC) future. The AFC case has twice the amount of renewable generation capacity additions as the CFC future. However, increased load growth, accelerated coal retirements, and higher gas prices lead to overall higher energy prices, particularly in daytime hours. For our analysis years (2023, 2025 and 2030), we relied on prices from the nearest MTEP modeling year (2022, 2027, and 2032, respectively) and adjusted them accordingly for inflation (assumed to be 2.2% per year).

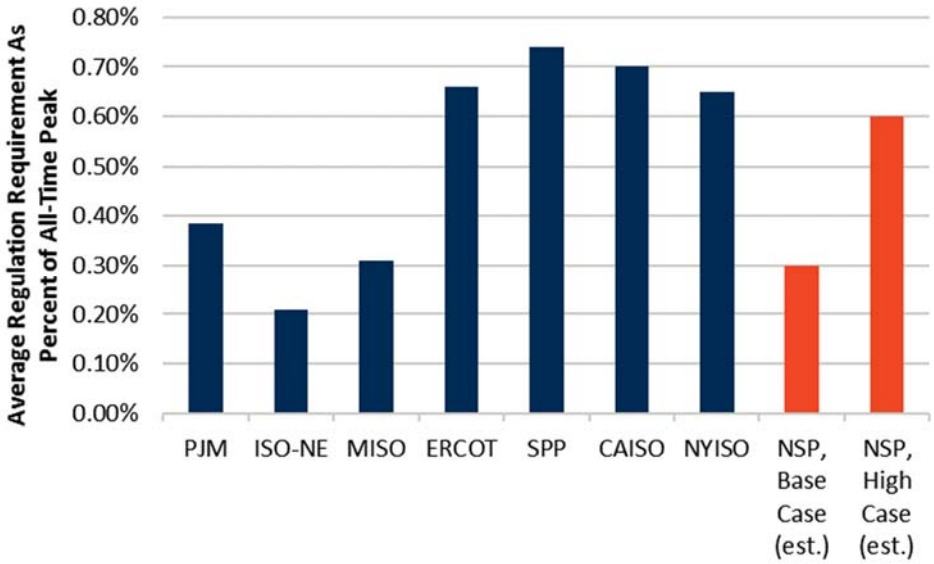
Ancillary services

The load of some end-uses can be increased or decreased in real time to mitigate system imbalances. The ability of qualifying DR programs to provide frequency regulation was modeled, as this is the highest-value ancillary service.

Frequency regulation is a high value resource with a very limited need. Across most markets, the need for frequency regulation capacity is less than 1% of the system peak. We assume that the frequency regulation needs in the NSP system across all analysis years are 25 MW (0.3% of annual peak) in the Base Case, and 50 MW in the High Sensitivity Case (0.6% of annual peak).[34] Figure 20 summarizes frequency regulation needs across various U.S. markets, demonstrating that the quantities of frequency regulation assumed in this study are consistent with experience elsewhere.

[34] Calculated assuming an annual peak of 8,335 MW after line losses.

Figure 20: Frequency Regulation Requirements Across Wholesale Markets



Sources and Notes: Values for wholesale markets extracted from PJM, "RTO/ISO Regulation Market Comparison", April 13, 2016. Orange bars for NSP assume that NSP's all-time peak is 8,335 MW at the customer level, based on three years of provided peak load data and assumed 8% line losses. Frequency regulation values for all markets are average levels as of 2016.

Because regulation prices were not available from the 2018 MTEP, we utilized 2017 hourly generation regulation prices for the MISO system adjusted for inflation.

Table 10 summarizes the potential value of each DR benefit. Values shown are the maximum achievable value. Operational constraints of the DR resources (e.g., limits on number of load curtailments per year) often result in realized benefits estimates that are lower than the values shown.

Table 10: Summary of Avoided Costs/Value Streams in 2023

Value Stream	Quantity of Need		Avoided Cost		Description
	Base Case	High Case	Base Case	High Case	
Avoided Generation Capacity	Unconstrained	Unconstrained	$63.0/kW-year	$81.5/kW-year	Base: Xcel's Brownfield CT costs minus estimated CT energy revenues from 2018 IRP, plus 2.4% reserve margin gross-up.
Avoided Transmission Capacity	Unconstrained	Unconstrained	$3.1/kW-year	$3.1/kW-year	72% of avoided transmission & distribution costs estimated under the discrete valuation approach in Xcel's 2017 T&D Avoided Cost Study.
Avoided Distribution Capacity	Unconstrained	Unconstrained	$8.0/kW-year	$8.0/kW-year	28% of avoided transmission & distribution costs estimated under the discrete valuation approach in Xcel's 2017 T&D Avoided Cost Study.
Geo-targeted Distribution Capacity	38 MW	38 MW	$25.8/kW-year	$25.8/kW-year	Total value of 14 projects identified as eligible for distribution capacity deferral by demand response.
Frequency Regulation	25 MW	50 MW	Avg: $12.4/MWh	Avg: $12.4/MWh	2017 MISO regulation prices. Assumes that NSP's share of regulation need is 25 MW in 2023 and 50 MW in 2030.
Avoided Energy	Unconstrained	Unconstrained	Avg: $27.5/MWh	Avg: $27.5/MWh	Hourly MISO MTEP18 modeled energy prices for NSP HUB. 2023 used prices from the CFC 2022 scenario, and 2030 used prices from the AFC 2032 scenario.
Top 10% Average			$50.5/MWh	$71.3/MWh	
Bottom 10% Average			$8.1/MWh	$8.6/MWh	

Notes: All values shown in nominal dollars. 2030 avoided costs are similar, rising at inflation.

Step 3: Develop 8,760 hourly profile of marginal costs

Each of the annual avoided cost estimates established in Step 2 is converted into a chronological profile of hourly costs for all 8,760 hours of the year. In each hour, these estimates are added together across all value streams to establish the total "stacked" value that is obtainable through a reduction in load in that hour (or, conversely, the total cost associated with an increase in load in that hour).

Capacity costs are allocated to hours of the year proportional to the likelihood that those hours will drive the need for new capacity. In other words, the greater the risk of a capacity shortage in a given hour, the larger the share the marginal capacity cost that is allocated to that hour.

Capacity costs are allocated across the top 100 load hours of the year. The allocation is roughly proportional to each hour's share of total load in the hours. This means more capacity value is allocated to the top load hour than the 100th load hour.

Different allocators are used to allocate generation, transmission, and distribution capacity costs. Generation and transmission capacity costs are allocated based on 2017 hourly MISO system gross load.[35] Distribution capacity costs are allocated based on hourly feeder load data provided by NSP. Both generic distribution capacity deferral and geo-targeted distribution capacity deferral value

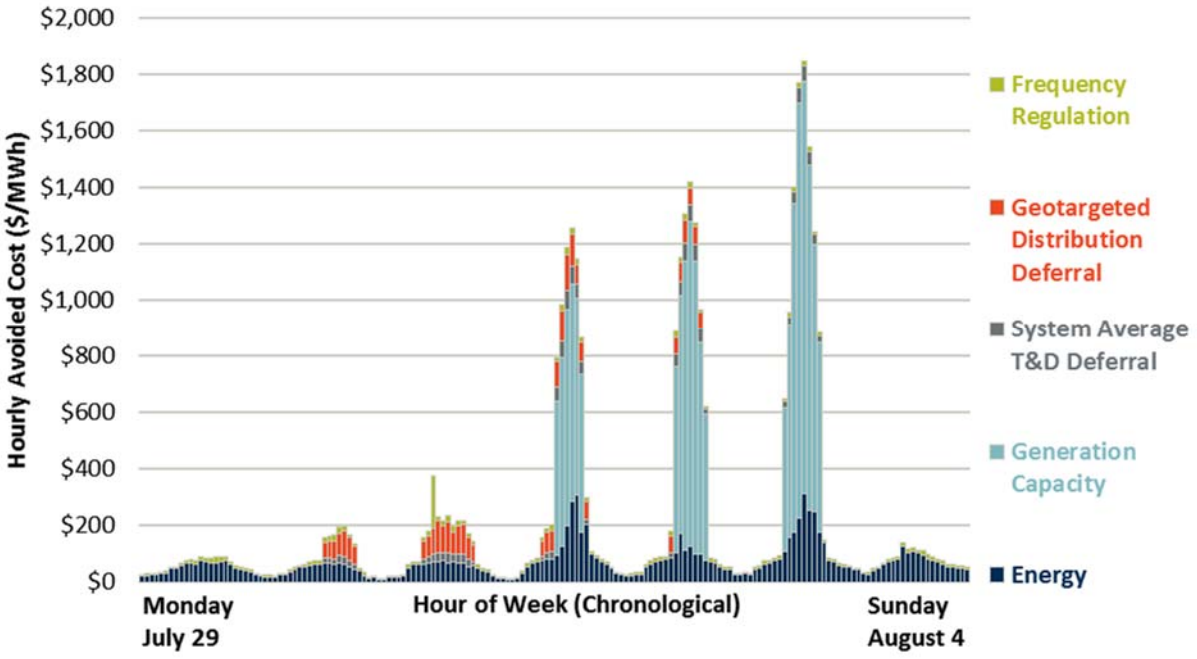
[35] Capacity value was allocated proportional to MISO gross load because NSP is required to use its MISO-coincident peak for resource adequacy planning decisions.

are allocated over a larger number of peak hours (roughly 330 hours, rather than 100 hours), representing that a single distribution project will address multiple feeders with load profiles that are only partially coincident.

A conceptually similar approach to quantifying capacity value is used in the California Energy Commission's time-dependent valuation (TDV) methodology for quantifying the value of energy efficiency, and also in the CPUC's demand response cost-effectiveness evaluation protocols. This hourly allocation-based approach effectively derates the value of distributed resources relative to the avoided cost of new peaking capacity by accounting for constraints that may exist on the operator's ability to predict and respond to resource adequacy needs. These constraints could result in DR utilization patterns that reflect a willingness to bypass some generation capacity value in order to provide distribution deferral value, for instance. The approach is effectively a theoretical construct intended to quantify long-term capacity value, rather than reflecting the way resource adequacy payments would be monetized by a DR operator in a wholesale market.

Figure 21 illustrates the "stacked" marginal costs associated with each value stream for a single week in the study period. The figure shows that certain hours present a significantly larger opportunity to reduce costs through load reduction – namely, those hours to which capacity costs are allocated.

Figure 21: Chronological Allocation of Marginal Costs (Illustration for Week of July 29)



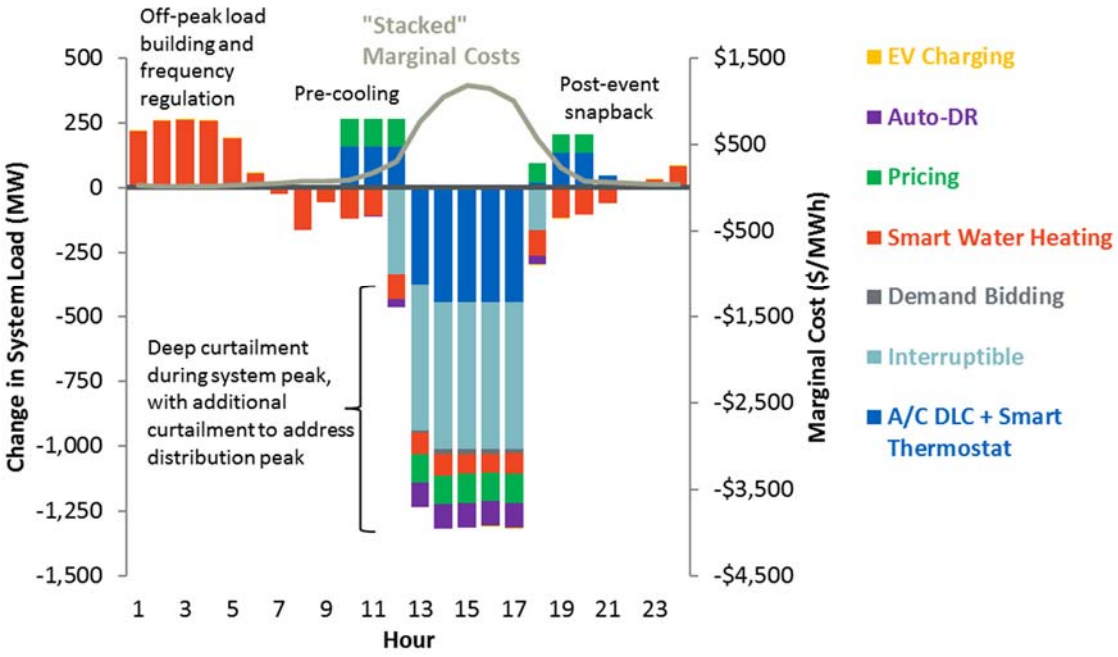
Notes: Marginal costs reflect avoided costs from the 2030 High Sensitivity Case.

Step 4: Optimally dispatch programs and calculate benefit-cost metrics

As discussed above, using DR to pursue one value stream may require forgoing opportunities to pursue other "competing" sources of value. While the value streams quantified in this study can be estimated individually, those estimates are not purely additive. A DR operator must choose how to operate the program in order to maximize its value. Accurately estimating the total value of DR programs requires accounting for tradeoffs across the value streams.

Load*Flex* employs an algorithm that "co-optimizes" the dispatch of a DR program across the hourly marginal cost series from Step 3, subject to the operational constraints defined in Step 1, such that overall system value produced by the program is maximized. In other words, the programs are operated to reduce load during hours when the total cost is highest and build load during hours when the total cost is lowest, without violating any of the established conditions around their use. Figure 22 illustrates how the dispatch of the High Sensitivity Case portfolio in this study compares to the hourly cost profile on those same days.

Figure 22: Illustrative Program Operations Relative to "Stacked" Marginal Costs



Through an iterative process, Load*Flex* determines when the need for a given value stream has been fully satisfied by DR in each hour, and excludes that value stream from that hour for incremental additions of DR. This ensures that DR is not over-supplying certain resources and being incorrectly credited for services that do not provide additional value to the system.

Step 5: Identify cost-effective incentive and participation levels

A unique feature of Load*Flex* is the ability to identify participation levels that are consistent with the incentive payments that are economically justified for each DR program. This ensures that each program's economic potential estimate is based on an incentive payment level that produces a benefit-cost ratio of 1.0. Without this functionality, the analysis would under-represent the potential for a given DR program, or could even exclude it from the analysis entirely based on inaccurate assumptions about uneconomic incentive payments levels.

As a starting point, participation estimates for each DR program are established to represent the maximum enrollment that is likely to be achieved when offered in NSP's service territory at a "typical" incentive payment level. The estimates are tailored to NSP's customer base using data on current program enrollment, as well as survey-based market research conducted directly with NSP's customers.[36] For DR programs not included in the market research study, we developed participation assumptions based on experience with similar programs in other jurisdictions and applied judgement to make the participation rates consistent with available evidence that is specific to NSP's customer base.

Table 11 summarizes these "base" participation rates for conventional DR programs. In all cases, participation is expressed as a percent of the eligible customer base. For instance, the population of customers eligible for the smart thermostat program is limited to those customers with central air-conditioning.

The 2017 values represent current participation levels. Values in future years reflect participation rates if the programs were offered as part of an expanded DR portfolio. This accounts for the fact that a single customer could not simultaneously participate in two different programs.

Residential air-conditioning load control participation assumptions reflect a transition from compressor switch-based direct load control program to a smart thermostat-based program. These programs are currently marketed by NSP as "Savers Switch" and "AC Rewards", respectively. Based on the aforementioned primary market research conducted in NSP's service territory, we estimate that a 66% participation rate among eligible customers is achievable at the medium incentive level for these programs collectively. In 2017, participation in air-conditioning load control programs reached 52% of eligible residential customers, mostly through the Savers Switch program. In the future, NSP will increase its marketing emphasis on the AC Rewards program as its primary air-conditioning load control program. Therefore, we assume that achievable incremental participation in residential air-conditioning load control transitions from an equal split between AC Rewards and Savers Switch in 2018 to a 75/25 split in favor of AC Rewards by

[36] Ahmad Faruqui, Ryan Hledik, and David Lineweber, "Demand Response Market Potential in Xcel Energy's Northern States Power Service Territory," April 2014.

2023. Additionally, NSP will focus on transitioning customers from Savers Switch to AC Rewards as compressor switches reach the end of their useful life. Based on information about the age of deployed switches and conversations with NSP, we assume that the number of switches replaced by smart thermostats grows from around 6,600/year in 2018 to 10,000/year in 2023 and onwards.

It is important to note that the participation rates shown are consistent with a participation incentive payment level that is representative of common offerings across the U.S. Participation rates are shown for all programs at these incentive levels, regardless of whether or not the programs are cost-effective at those incentive levels.[37] Later in this section of the appendix, we describe adjustments that are made to these "base" incentive levels to reflect enrollment that could be achieved at cost-effective incentive levels.

Table 11: Participation Assumptions for Conventional DR Programs

Participation as a percentage of eligible customers

Segment	Program	2017	2023	2030
Residential	A/C DLC - SFH	52%	50%	39%
Residential	Smart thermostat - SFH	0%	16%	24%
Residential	Smart thermostat - MDU	0%	35%	32%
Small C&I	A/C DLC	0%	30%	30%
Small C&I	Interruptible	0%	14%	12%
Small C&I	Demand Bidding	0%	2%	1%
Medium C&I	A/C DLC	73%	64%	64%
Medium C&I	Interruptible	3%	13%	11%
Medium C&I	Demand Bidding	0%	6%	5%
Large C&I	Interruptible	12%	44%	43%
Large C&I	Demand Bidding	0%	5%	4%

Notes:
Participation rates shown for programs at the portfolio level (i.e. accounts for program overlap). Lower participation rates for some programs in 2030 relative to 2023 result from customers switching to an opt-in CPP rate (for which participation estimates are shown separately). High Medium C&I participation in A/C DLC is relative to a small portion of the customer segment that is eligible for enrollment.

Table 12 illustrates the potential participation rates for each new DR program analyzed in the study. As noted above, these enrollment rates are consistent with "base" incentive payment levels and do not reflect enrollment associated with cost-effective payment levels. **Here, participation in each program is shown as if the program were offered in isolation.** In other words, it is the achievable participation level in the absence of other programs being offered. In our assessment of expanded DR portfolios that include multiple new DR programs, restrictions on participation in multiple programs are accounted for and the participation rates are derated accordingly.

[37] This is the basis for our estimate of "technical potential".

Table 12: Participation Assumptions for New DR Programs

Participation as a percentage of eligible customers

Segment	Program	2017	2023	2030
Residential	Behavioral DR (Opt-out)	0%	80%	80%
Residential	CPP (Opt-in)	0%	0%	20%
Residential	CPP (Opt-out)	0%	0%	80%
Residential	EV Managed Charging - Home	0%	20%	20%
Residential	EV Managed Charging - Work	0%	20%	20%
Residential	Smart water heating	0%	15%	50%
Residential	Timed water heating	0%	50%	50%
Residential	TOU - EV Charging (Opt-in)	0%	0%	20%
Residential	TOU (Opt-in)	1%	0%	16%
Residential	TOU (Opt-out)	0%	0%	80%
Small C&I	Auto-DR (A/C)	0%	5%	5%
Small C&I	Auto-DR (Light Luminaire)	0%	5%	5%
Small C&I	Auto-DR (Light Zonal)	0%	5%	5%
Small C&I	CPP (Opt-in)	0%	0%	20%
Small C&I	CPP (Opt-out)	0%	0%	80%
Small C&I	TOU (Opt-in)	3%	0%	10%
Small C&I	TOU (Opt-out)	0%	0%	80%
Medium C&I	Auto-DR (HVAC)	0%	5%	5%
Medium C&I	Auto-DR (Light Luminaire)	0%	5%	5%
Medium C&I	Auto-DR (Light Zonal)	0%	5%	5%
Medium C&I	CPP (Opt-in)	0%	14%	14%
Medium C&I	CPP (Opt-out)	0%	79%	79%
Medium C&I	Thermal Storage	0%	3%	3%
Medium C&I	TOU (Opt-in)	21%	19%	19%
Medium C&I	TOU (Opt-out)	0%	0%	80%
Large C&I	Auto-DR (HVAC)	0%	5%	5%
Large C&I	Auto-DR (Light Luminaire)	0%	5%	5%
Large C&I	Auto-DR (Light Zonal)	0%	5%	5%
Large C&I	CPP (Opt-in)	0%	22%	22%
Large C&I	CPP (Opt-out)	0%	81%	81%
Large C&I	TOU (Opt-in)	100%	100%	100%

Notes:
Participation rates shown for programs when offered independently (i.e. rates do not account for program overlap).

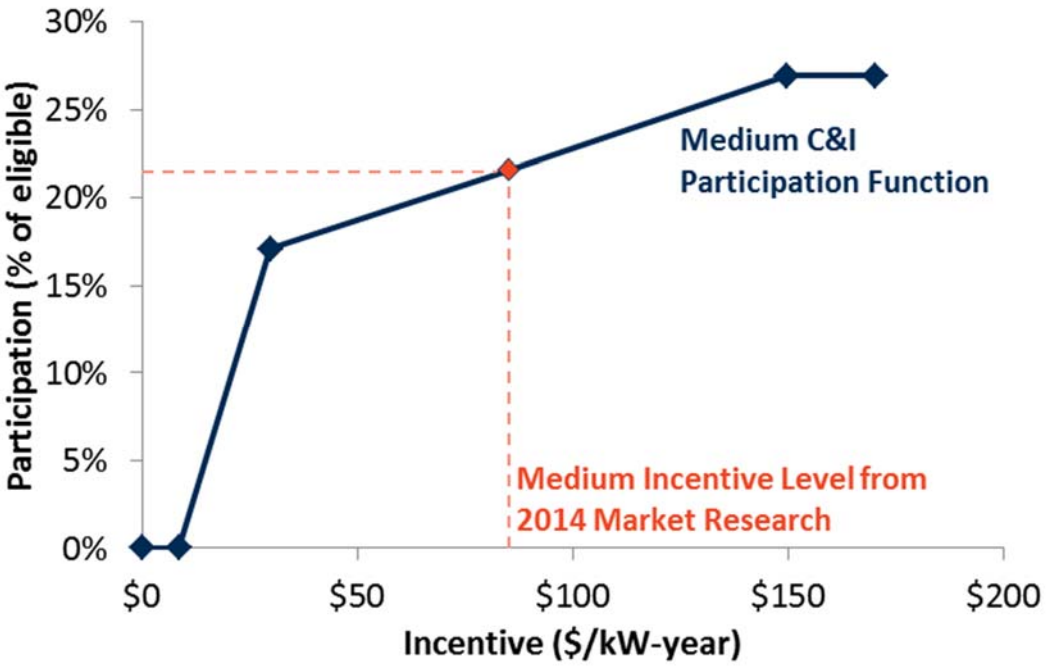
As discussed above, the cost-effectiveness screening process in many DR potential studies often treats programs as an all-or-nothing proposition. In other words, the studies commonly assume a base incentive level and then simply evaluate the cost-effectiveness of the programs relative to that incentive level. However, in reality, the incentives can be decreased or increased to accommodate lower or higher thresholds for cost effectiveness. For instance, in a region with lower avoided cost, a lower incentive payment could be offered, and vice versa. Program participation will vary according to these changes in the incentive payment level.

In Load*Flex* model, participation is expressed as a function of the assumed incentive level. The incentive level that produces a benefit-cost ratio of 1.0 is quantified, thus defining the maximum

potential cost-effective participation for the program.[38] The DR adoption function for each program is derived from the results of the aforementioned 2014 market research study, which tested customer willingness to participate in DR programs at various incentive levels.

An illustration of the participation function for the Medium C&I Interruptible program is provided in Figure 23. The figure expresses participation in the program (vertical axis) as a function of the customer incentive payment level (horizontal axis). At an incentive level of around $85/kW-yr, slightly more than 20% of eligible customers would participate in the program. If the economics of the program could only justify an incentive payment less than this (e.g., due to low avoided capacity costs), participation would decrease according to the blue line in the chart, and vice versa. Below an incentive payment level of around $25/kW-yr, customer willingness to enroll in the program quickly drops off.

Figure 23: Medium C&I Interruptible Tariff Adoption Function



Step 6: Estimate cost-effective DR potential

After the cost-effective potential of each individual DR program is estimated, the programs are combined into a portfolio. Constructing the portfolio is not as simple as adding up the potential estimates of each individual program. In some cases, two programs may be targeting the same end-use (e.g., timed water heating and smart water heating), so their impacts are not additive.

[38] In some cases, the non-incentive costs (e.g., equipment costs) outweigh the benefits, in which case the program does not pass the cost-effectiveness screen.

In instances where two cost-effective programs target the exact same end-use, we have assumed that the portfolio would only include the program that produces the larger impact by the end of the study horizon. In the water heating example, this means that the smart water heating program was included and the timed water heating program was not.

In other cases, two "competing" programs would likely be offered simultaneously to customers as mutually exclusive options. For instance, it is possible that C&I customers would only be allowed to enroll in either an interruptible tariff program or a CPP rate. Simultaneous enrollment in both could result in customer being compensated twice for the same load reduction – once through the incentive payment in the interruptible tariff, and a second time through avoiding the higher peak price of the CPP rate. In these cases, we relied on the results of the aforementioned 2014 market research study, which used surveys to determine relative customer preferences for these options when offered simultaneously. Participation rates were reduced in the portfolio to account for this overlap.

In cases where two programs would be offered simultaneously to the same customer segment, but would target entirely different end-uses (e.g., a smart thermostat program and an EV charging load control program), no adjustments to the participation rates were deemed necessary.

Appendix B: NSP's Proposed Portfolio

At a stakeholder meeting on August 8, 2018, NSP presented a draft portfolio of proposed DR programs. The DR portfolio that NSP is considering consists of the programs and deployment years summarized in Table 13.

Table 13: NSP's Draft Portfolio of DR Programs

Program	First Year of Rollout
Saver's Switch	Existing
A/C Rewards	Existing
EV home charging control	2020
Med/large C&I Auto-DR	2021
Med/large C&I interruptible tariff (program expansion)	2021
Med/large C&I Opt-in CPP	2022
Residential smart water heating	2023
Residential behavioral DR	2023
Residential opt-out TOU	2024

The potential for this portfolio was quantified under the Base and High Sensitivity cases for years 2023 and 2030. Results are summarized in Table 14. In the table, the values in the row labeled "All Proposed Programs" indicate the incremental technical potential in each of the programs that have been proposed by NSP. The values in the row "Cost-Effective Proposed programs" indicate the amount of incremental DR in the proposed programs that can be achieved at cost-effective incentive payment levels. In both cases, DR potential is shown at the portfolio level, accounting for overlap in participation when multiple programs are offered simultaneously.

Table 14: Incremental Potential in NSP's Draft Portfolio of DR Programs (MW)

	Base Case		High Sensitivity Case	
	2023	2030	2023	2030
All Proposed Programs	642	907	658	927
Cost-Effective Proposed Programs	262	461	411	677

Note: Values shown are incremental to the existing 850 MW portfolio.

Appendix C: Base Case with Alternative Capacity Costs

For its 2019 IRP, NSP has developed cost assumptions for new CT capacity at brownfield and greenfield sites. Our Base Case assumptions rely on brownfield CT costs as the avoided generation cost estimate, as this is the lowest cost option available to NSP for future peaking generation development. To test the sensitivity of our findings to that assumption, we modeled an alternative case in which the avoided capacity cost in the Base Case is based on a greenfield CT rather than a brownfield CT.[39] Other Base Case assumptions remained unchanged.

The greenfield CT capacity cost is higher than the brownfield CT cost, which increases the benefits of DR programs due to higher avoided generation costs. Relative to the Base Case, the cost-effective incremental potential in the DR portfolio increases by 73 MW in 2023 and by 119 MW in 2030. Nearly all of this increase in potential is attributable to a further expansion of participation in programs that were already cost-effective in the Base Case. The additional potential is mostly in the smart thermostat program, increases from 112 MW to 148 MW in 2023 and from 169 MW to 220 MW in 2030. Other programs that were economic in the Base Case (residential smart water heating, additional C&I interruptible, and demand bidding) also have small increases in cost-effective potential.

The only program that was initially uneconomic under Base assumptions but becomes economic under the greenfield CT capacity cost assumption is HVAC-based Auto-DR: 3 MW of Large C&I Auto-DR becomes cost-effective in 2023, growing to 6 MW in 2030 (in addition to 32 MW of Medium C&I Auto-DR). Together, these programs account for 4% of additional potential in 2023, but over 30% of additional potential in 2030.

Table 15 compares the portfolio-level incremental DR potential for the Base Case with brownfield CT costs to the alternative case with greenfield CT costs. Annual program-level potential estimates are provided in Appendix D.

[39] Table 9 of this report summarizes the greenfield, brownfield and AEO 2018 CT costs used in this analysis.

Table 15: Incremental Cost-Effective Potential in Portfolio of DR Programs with Alternative CT Costs (MW)

	2023	2030
Base Case (Brownfield CT Cost)	306	468
Alternative Case (Greenfield CT Cost)	378	587
Difference (Alternative - Base)	73	119

Note: Values shown are incremental to the existing 850 MW portfolio.

Appendix D: Annual Results Summary

Base Case, All Programs

Technical Potential (MW, at generator-level)

Segment	Program	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	A/C DLC - SFH	0	0	0	0	0	0	0	0	0	0
Residential	Behavioral DR (Opt-out)	52	52	52	53	53	54	54	54	55	55
Residential	CPP (Opt-in)	0	0	0	15	62	65	69	73	76	80
Residential	CPP (Opt-out)	0	0	0	157	157	159	160	161	163	164
Residential	EV Managed Charging - Home	1	2	3	5	7	9	12	14	16	18
Residential	EV Managed Charging - Work	0	0	1	1	1	2	2	3	3	3
Residential	Smart thermostat - MDU	3	13	16	16	16	16	16	16	17	17
Residential	Smart thermostat - SFH	161	161	161	175	190	204	219	233	248	262
Residential	Smart water heating	6	11	17	23	29	30	34	40	49	60
Residential	Timed water heating	11	43	54	55	55	55	55	56	56	56
Residential	TOU (Opt-in)	0	0	0	6	23	25	26	28	29	31
Residential	TOU (Opt-out)	0	0	0	155	155	156	157	159	160	161
Residential	TOU - EV Charging (Opt-in)	0	0	0	0	1	1	1	2	2	2
Small C&I	A/C DLC	44	44	44	44	44	44	45	45	45	45
Small C&I	Auto-DR (A/C)	2	8	9	9	9	10	10	10	10	10
Small C&I	Auto-DR (Light Luminaire)	1	6	7	7	7	7	7	7	8	8
Small C&I	Auto-DR (Light Zonal)	1	5	6	6	6	6	6	6	6	6
Small C&I	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-out)	0	0	0	1	1	1	1	1	1	1
Small C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Small C&I	Interruptible	65	65	65	65	66	66	66	67	67	67
Small C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	TOU (Opt-out)	0	0	0	0	0	1	1	1	1	1
Medium C&I	A/C DLC	3	3	3	4	4	4	5	5	5	6
Medium C&I	Auto-DR (HVAC)	30	121	151	152	152	153	154	154	155	156
Medium C&I	Auto-DR (Light Luminaire)	12	48	60	60	60	60	61	61	61	62
Medium C&I	Auto-DR (Light Zonal)	6	26	32	32	32	33	33	33	33	33
Medium C&I	CPP (Opt-in)	6	24	30	30	30	30	30	31	31	31
Medium C&I	CPP (Opt-out)	86	86	86	87	87	88	89	89	90	90
Medium C&I	Demand Bidding	4	16	20	20	20	20	20	20	20	20
Medium C&I	Interruptible	310	310	310	313	316	318	321	324	326	329
Medium C&I	Thermal Storage	20	80	100	101	101	101	102	102	103	103
Medium C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-out)	0	0	0	51	51	51	51	52	52	52
Large C&I	Auto-DR (HVAC)	4	15	19	19	19	19	19	19	19	18
Large C&I	Auto-DR (Light Luminaire)	3	11	13	13	13	13	13	13	13	13
Large C&I	Auto-DR (Light Zonal)	1	6	7	7	7	7	7	7	7	7
Large C&I	CPP (Opt-in)	7	28	36	35	35	35	35	35	35	35
Large C&I	CPP (Opt-out)	64	64	64	64	64	63	63	63	63	62
Large C&I	Demand Bidding	2	6	8	8	8	8	8	8	8	8
Large C&I	Interruptible	85	85	85	84	83	82	81	80	79	78

Notes:
Figure shows incremental load reduction available when DR programs are offered in isolation.
Measure-level results do not account for cost-effectiveness or overlap when offered simultaneously as part of a portfolio.
No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

Base Case, All Programs

Cost-Effective Potential (MW, at generator-level)

Segment	Program	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	A/C DLC - SFH	0	0	0	0	0	0	0	0	0	0
Residential	Behavioral DR (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	CPP (Opt-in)	0	0	0	11	44	46	49	52	54	57
Residential	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Home	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Work	0	0	0	0	0	0	0	0	0	0
Residential	Smart thermostat - MDU	0	1	1	4	6	6	6	6	7	7
Residential	Smart thermostat - SFH	112	112	112	122	131	139	146	154	162	169
Residential	Smart water heating	4	9	13	17	22	23	25	29	35	42
Residential	Timed water heating	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	TOU - EV Charging (Opt-in)	0	0	0	0	0	0	1	1	2	2
Small C&I	A/C DLC	19	19	19	21	22	22	22	22	22	22
Small C&I	Auto-DR (A/C)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Small C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Small C&I	Interruptible	32	32	32	31	30	30	30	30	30	30
Small C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	A/C DLC	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (HVAC)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Medium C&I	CPP (Opt-in)	0	0	0	10	19	19	19	20	20	20
Medium C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Demand Bidding	4	14	18	16	15	15	15	15	15	15
Medium C&I	Interruptible	45	45	45	31	16	17	18	19	20	22
Medium C&I	Thermal Storage	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (HVAC)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Large C&I	CPP (Opt-in)	0	0	0	16	32	32	32	32	32	31
Large C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Demand Bidding	1	6	7	6	5	5	5	5	5	5
Large C&I	Interruptible	58	58	58	55	51	51	50	49	48	47
Portfolio-Level Total		**276**	**296**	**306**	**338**	**393**	**405**	**418**	**433**	**450**	**468**

Notes:
Incremental load reduction available when DR programs are offered simultaneously as part of portfolio, accounting for overlap between programs.
No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

Alternative Base Case with Greenfield CT Costs, All Programs

Technical Potential (MW, at generator-level)

Segment	Program	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	A/C DLC - SFH	0	0	0	0	0	0	0	0	0	0
Residential	Behavioral DR (Opt-out)	52	52	52	53	53	54	54	54	55	55
Residential	CPP (Opt-in)	0	0	0	15	62	65	69	73	76	80
Residential	CPP (Opt-out)	0	0	0	157	157	159	160	161	163	164
Residential	EV Managed Charging - Home	1	2	3	5	7	9	12	14	16	18
Residential	EV Managed Charging - Work	0	0	1	1	1	2	2	3	3	3
Residential	Smart thermostat - MDU	3	13	16	16	16	16	16	16	17	17
Residential	Smart thermostat - SFH	180	180	180	204	227	245	262	280	298	315
Residential	Smart water heating	6	13	19	26	33	34	38	44	53	65
Residential	Timed water heating	11	43	54	55	55	55	55	56	56	56
Residential	TOU (Opt-in)	0	0	0	6	23	25	26	28	29	31
Residential	TOU (Opt-out)	0	0	0	155	155	156	157	159	160	161
Residential	TOU - EV Charging (Opt-in)	0	0	0	0	1	1	1	2	2	2
Small C&I	A/C DLC	44	44	44	44	44	44	45	45	45	45
Small C&I	Auto-DR (A/C)	2	8	9	9	9	10	10	10	10	10
Small C&I	Auto-DR (Light Luminaire)	1	6	7	7	7	7	7	7	8	8
Small C&I	Auto-DR (Light Zonal)	1	5	6	6	6	6	6	6	6	6
Small C&I	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-out)	0	0	0	1	1	1	1	1	1	1
Small C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Small C&I	Interruptible	65	65	65	65	66	66	66	67	67	67
Small C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	TOU (Opt-out)	0	0	0	0	0	1	1	1	1	1
Medium C&I	A/C DLC	3	3	3	4	4	4	5	5	5	6
Medium C&I	Auto-DR (HVAC)	30	121	151	152	152	153	154	154	155	156
Medium C&I	Auto-DR (Light Luminaire)	12	48	60	60	60	60	61	61	61	62
Medium C&I	Auto-DR (Light Zonal)	6	26	32	32	32	33	33	33	33	33
Medium C&I	CPP (Opt-in)	6	24	30	30	30	30	30	31	31	31
Medium C&I	CPP (Opt-out)	86	86	86	87	87	88	89	89	90	90
Medium C&I	Demand Bidding	4	16	20	21	21	21	21	22	22	22
Medium C&I	Interruptible	310	310	310	313	316	318	321	324	326	329
Medium C&I	Thermal Storage	20	80	100	101	101	101	102	102	103	103
Medium C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-out)	0	0	0	51	51	51	51	52	52	52
Large C&I	Auto-DR (HVAC)	4	15	19	19	19	19	19	19	19	19
Large C&I	Auto-DR (Light Luminaire)	3	11	13	13	13	13	13	13	13	13
Large C&I	Auto-DR (Light Zonal)	1	6	7	7	7	7	7	7	7	7
Large C&I	CPP (Opt-in)	7	28	36	35	35	35	35	35	35	35
Large C&I	CPP (Opt-out)	64	64	64	64	64	63	63	63	63	62
Large C&I	Demand Bidding	2	6	8	8	8	8	8	8	8	8
Large C&I	Interruptible	85	85	85	84	83	82	81	80	79	78

Notes:
Figure shows incremental load reduction available when DR programs are offered in isolation.
Measure-level results do not account for cost-effectiveness or overlap when offered simultaneously as part of a portfolio.
No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

Alternative Base Case with Greenfield CT Costs, All Programs

Cost-Effective Potential (MW, at generator-level)

Segment	Program	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	A/C DLC - SFH	0	0	0	0	0	0	0	0	0	0
Residential	Behavioral DR (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	CPP (Opt-in)	0	0	0	11	44	46	49	52	54	57
Residential	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Home	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Work	0	0	0	0	0	0	0	0	0	0
Residential	Smart thermostat - MDU	2	10	12	12	12	12	12	12	13	13
Residential	Smart thermostat - SFH	148	148	148	159	170	180	190	200	210	220
Residential	Smart water heating	5	10	15	21	26	27	30	35	42	51
Residential	Timed water heating	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	TOU - EV Charging (Opt-in)	0	0	0	0	0	0	1	1	2	2
Small C&I	A/C DLC	31	31	31	31	32	32	32	32	32	32
Small C&I	Auto-DR (A/C)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Small C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Small C&I	Interruptible	34	34	34	32	31	31	31	31	31	31
Small C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	A/C DLC	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (HVAC)	0	0	0	9	18	20	23	26	29	32
Medium C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Medium C&I	CPP (Opt-in)	0	0	0	10	19	19	19	20	20	20
Medium C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Demand Bidding	4	16	19	18	16	16	16	16	16	16
Medium C&I	Interruptible	47	47	47	32	17	18	19	20	21	23
Medium C&I	Thermal Storage	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (HVAC)	1	2	3	4	5	5	5	5	6	6
Large C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Large C&I	CPP (Opt-in)	0	0	0	16	32	32	32	32	32	31
Large C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Demand Bidding	2	6	8	6	5	5	5	5	5	5
Large C&I	Interruptible	61	61	61	58	54	53	52	51	50	49
Portfolio-Level Total		**335**	**365**	**378**	**418**	**480**	**498**	**517**	**538**	**562**	**587**

Notes:

Incremental load reduction available when DR programs are offered simultaneously as part of portfolio, accounting for overlap between programs.
No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

High Sensitivity Case, All Programs

Technical Potential (MW, at generator-level)

Segment	Program	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	A/C DLC - SFH	0	0	0	0	0	0	0	0	0	0
Residential	Behavioral DR (Opt-out)	52	52	52	53	53	54	54	54	55	55
Residential	CPP (Opt-in)	0	0	0	15	62	65	69	73	76	80
Residential	CPP (Opt-out)	0	0	0	157	157	159	160	161	163	164
Residential	EV Managed Charging - Home	1	2	3	5	7	9	12	14	16	18
Residential	EV Managed Charging - Work	0	0	1	1	1	2	2	3	3	3
Residential	Smart thermostat - MDU	3	13	16	17	17	17	17	17	17	17
Residential	Smart thermostat - SFH	213	213	213	238	263	283	302	321	341	360
Residential	Smart water heating	8	16	24	32	40	42	47	56	68	83
Residential	Timed water heating	11	45	57	66	76	76	75	75	75	74
Residential	TOU (Opt-in)	0	0	0	6	23	25	26	28	29	31
Residential	TOU (Opt-out)	0	0	0	155	155	156	157	159	160	161
Residential	TOU - EV Charging (Opt-in)	0	0	0	0	1	1	1	2	2	2
Small C&I	A/C DLC	44	44	44	44	44	44	45	45	45	45
Small C&I	Auto-DR (A/C)	2	8	9	9	9	10	10	10	10	10
Small C&I	Auto-DR (Light Luminaire)	1	6	7	7	7	7	7	7	8	8
Small C&I	Auto-DR (Light Zonal)	1	5	6	6	6	6	6	6	6	6
Small C&I	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-out)	0	0	0	1	1	1	1	1	1	1
Small C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Small C&I	Interruptible	65	65	65	65	66	66	66	67	67	67
Small C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	TOU (Opt-out)	0	0	0	0	0	1	1	1	1	1
Medium C&I	A/C DLC	3	3	3	4	4	4	5	5	5	6
Medium C&I	Auto-DR (HVAC)	30	121	151	152	152	153	154	154	155	156
Medium C&I	Auto-DR (Light Luminaire)	12	48	60	60	60	60	61	61	61	62
Medium C&I	Auto-DR (Light Zonal)	6	26	32	32	32	33	33	33	33	33
Medium C&I	CPP (Opt-in)	6	24	30	30	30	30	30	31	31	31
Medium C&I	CPP (Opt-out)	86	86	86	87	87	88	89	89	90	90
Medium C&I	Demand Bidding	4	17	21	21	22	22	22	22	22	22
Medium C&I	Interruptible	310	310	310	313	316	318	321	324	326	329
Medium C&I	Thermal Storage	20	80	100	101	101	101	102	102	103	103
Medium C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-out)	0	0	0	51	51	51	51	52	52	52
Large C&I	Auto-DR (HVAC)	4	15	19	19	19	19	19	19	19	18
Large C&I	Auto-DR (Light Luminaire)	3	11	13	13	13	13	13	13	13	13
Large C&I	Auto-DR (Light Zonal)	1	6	7	7	7	7	7	7	7	7
Large C&I	CPP (Opt-in)	7	28	36	35	35	35	35	35	35	35
Large C&I	CPP (Opt-out)	64	64	64	64	64	63	63	63	63	62
Large C&I	Demand Bidding	2	6	8	8	8	8	8	8	8	8
Large C&I	Interruptible	85	85	85	84	83	82	81	80	79	78

Notes:
Figure shows incremental load reduction available when DR programs are offered in isolation.
Measure-level results do not account for cost-effectiveness or overlap when offered simultaneously as part of a portfolio.
No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

High Sensitivity Case, All Programs

Cost-Effective Potential (MW, at generator-level)

Segment	Program	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	A/C DLC - SFH	0	0	0	0	0	0	0	0	0	0
Residential	Behavioral DR (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	CPP (Opt-in)	0	0	0	11	44	46	49	52	54	57
Residential	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Home	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Work	0	0	0	0	0	0	0	0	0	0
Residential	Smart thermostat - MDU	3	12	15	15	15	15	15	15	15	15
Residential	Smart thermostat - SFH	176	176	176	186	197	208	219	230	241	252
Residential	Smart water heating	8	16	24	32	40	42	47	56	68	83
Residential	Timed water heating	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	TOU - EV Charging (Opt-in)	0	0	0	0	0	0	1	1	2	2
Small C&I	A/C DLC	32	32	32	32	32	32	32	33	33	33
Small C&I	Auto-DR (A/C)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Small C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Small C&I	Interruptible	34	34	34	32	31	31	31	31	31	31
Small C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	A/C DLC	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (HVAC)	11	45	56	64	72	72	73	74	75	76
Medium C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Medium C&I	CPP (Opt-in)	0	0	0	10	19	19	19	20	20	20
Medium C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Demand Bidding	4	16	20	18	16	16	16	16	16	16
Medium C&I	Interruptible	47	47	47	32	17	18	19	20	22	23
Medium C&I	Thermal Storage	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (HVAC)	2	8	10	11	12	12	11	11	11	11
Large C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Large C&I	CPP (Opt-in)	0	0	0	16	32	32	32	32	32	31
Large C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Demand Bidding	2	6	8	7	5	5	5	5	5	5
Large C&I	Interruptible	62	62	62	58	55	54	53	52	51	50
Portfolio-Level Total		**380**	**454**	**484**	**524**	**586**	**603**	**623**	**647**	**674**	**705**

Notes:
Incremental load reduction available when DR programs are offered simultaneously as part of portfolio, accounting for overlap between programs.
No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

Base Case, NSP Proposed Portfolio

Technical Potential (MW, at generator-level)

Segment	Program	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	A/C DLC - SFH	0	0	0	0	0	0	0	0	0	0
Residential	Behavioral DR (Opt-out)	0	0	52	53	53	54	54	54	55	55
Residential	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Residential	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Home	2	3	3	5	7	9	12	14	16	18
Residential	EV Managed Charging - Work	0	0	0	0	0	0	0	0	0	0
Residential	Smart thermostat - MDU	0	0	0	0	0	0	0	0	0	0
Residential	Smart thermostat - SFH	161	161	161	175	190	204	219	233	248	262
Residential	Smart water heating	0	0	8	15	22	23	26	31	39	48
Residential	Timed water heating	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-out)	0	0	0	155	155	156	157	159	160	161
Residential	TOU - EV Charging (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	A/C DLC	44	44	44	44	44	44	45	45	45	45
Small C&I	Auto-DR (A/C)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Small C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Small C&I	Interruptible	53	53	53	53	54	54	54	54	54	55
Small C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	TOU (Opt-out)	0	0	0	0	0	1	1	1	1	1
Medium C&I	A/C DLC	3	3	3	4	4	4	5	5	5	6
Medium C&I	Auto-DR (HVAC)	30	121	151	152	152	153	154	154	155	156
Medium C&I	Auto-DR (Light Luminaire)	12	48	60	60	60	60	61	61	61	62
Medium C&I	Auto-DR (Light Zonal)	6	26	32	32	32	33	33	33	33	33
Medium C&I	CPP (Opt-in)	0	6	24	30	30	30	30	31	31	31
Medium C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Medium C&I	Interruptible	310	310	310	313	316	318	321	324	326	329
Medium C&I	Thermal Storage	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (HVAC)	4	15	19	19	19	19	19	19	19	18
Large C&I	Auto-DR (Light Luminaire)	3	11	13	13	13	13	13	13	13	13
Large C&I	Auto-DR (Light Zonal)	1	6	7	7	7	7	7	7	7	7
Large C&I	CPP (Opt-in)	0	7	28	35	35	35	35	35	35	35
Large C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Large C&I	Interruptible	85	85	85	84	83	82	81	80	79	78

Notes:
Figure shows incremental load reduction available when DR programs are offered in isolation.
Measure-level results do not account for cost-effectiveness or overlap when offered simultaneously as part of a portfolio.
No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

Base Case, NSP Proposed Portfolio

Cost-Effective Potential (MW, at generator-level)

Segment	Program	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	A/C DLC - SFH	0	0	0	0	0	0	0	0	0	0
Residential	Behavioral DR (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Residential	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Home	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Work	0	0	0	0	0	0	0	0	0	0
Residential	Smart thermostat - MDU	0	0	0	0	0	0	0	0	0	0
Residential	Smart thermostat - SFH	112	112	112	122	131	139	146	154	162	169
Residential	Smart water heating	0	0	8	13	18	19	21	25	30	36
Residential	Timed water heating	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-out)	0	0	0	95	95	96	96	97	98	99
Residential	TOU - EV Charging (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	A/C DLC	21	21	21	22	23	23	23	23	22	22
Small C&I	Auto-DR (A/C)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Small C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Small C&I	Interruptible	14	14	14	14	15	15	15	15	15	15
Small C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	A/C DLC	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (HVAC)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Medium C&I	CPP (Opt-in)	0	4	15	19	19	19	19	20	20	20
Medium C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Medium C&I	Interruptible	13	13	13	15	16	17	18	19	20	22
Medium C&I	Thermal Storage	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (HVAC)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Large C&I	CPP (Opt-in)	0	6	26	32	32	32	32	32	32	31
Large C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Large C&I	Interruptible	52	52	52	52	51	51	50	49	48	47
Portfolio-Level Total		**213**	**223**	**262**	**384**	**400**	**410**	**420**	**433**	**446**	**461**

Notes:
Incremental load reduction available when DR programs are offered simultaneously as part of portfolio, accounting for overlap between programs.
No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

High Sensitivity Case, NSP Proposed Portfolio

Technical Potential (MW, at generator-level)

Segment	Program	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	A/C DLC - SFH	0	0	0	0	0	0	0	0	0	0
Residential	Behavioral DR (Opt-out)	0	0	52	53	53	54	54	54	55	55
Residential	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Residential	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Home	2	3	3	5	7	9	12	14	16	18
Residential	EV Managed Charging - Work	0	0	0	0	0	0	0	0	0	0
Residential	Smart thermostat - MDU	0	0	0	0	0	0	0	0	0	0
Residential	Smart thermostat - SFH	213	213	213	238	263	283	302	321	341	360
Residential	Smart water heating	0	0	8	16	24	26	31	39	51	66
Residential	Timed water heating	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-out)	0	0	0	155	155	156	157	159	160	161
Residential	TOU - EV Charging (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	A/C DLC	44	44	44	44	44	44	45	45	45	45
Small C&I	Auto-DR (A/C)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Small C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Small C&I	Interruptible	53	53	53	53	54	54	54	54	54	55
Small C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	TOU (Opt-out)	0	0	0	0	0	1	1	1	1	1
Medium C&I	A/C DLC	3	3	3	4	4	4	5	5	5	6
Medium C&I	Auto-DR (HVAC)	30	121	151	152	152	153	154	154	155	156
Medium C&I	Auto-DR (Light Luminaire)	12	48	60	60	60	60	61	61	61	62
Medium C&I	Auto-DR (Light Zonal)	6	26	32	32	32	33	33	33	33	33
Medium C&I	CPP (Opt-in)	0	6	24	30	30	30	30	31	31	31
Medium C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Medium C&I	Interruptible	310	310	310	313	316	318	321	324	326	329
Medium C&I	Thermal Storage	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (HVAC)	4	15	19	19	19	19	19	19	19	18
Large C&I	Auto-DR (Light Luminaire)	3	11	13	13	13	13	13	13	13	13
Large C&I	Auto-DR (Light Zonal)	1	6	7	7	7	7	7	7	7	7
Large C&I	CPP (Opt-in)	0	7	28	35	35	35	35	35	35	35
Large C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Large C&I	Interruptible	85	85	85	84	83	82	81	80	79	78

Notes:
Figure shows incremental load reduction available when DR programs are offered in isolation.
Measure-level results do not account for cost-effectiveness or overlap when offered simultaneously as part of a portfolio.
No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

High Sensitivity Case, NSP Proposed Portfolio

Cost-Effective Potential (MW, at generator-level)

Segment	Program	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	A/C DLC - SFH	0	0	0	0	0	0	0	0	0	0
Residential	Behavioral DR (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Residential	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Home	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Work	0	0	0	0	0	0	0	0	0	0
Residential	Smart thermostat - MDU	0	0	0	0	0	0	0	0	0	0
Residential	Smart thermostat - SFH	176	176	176	186	197	208	219	230	241	252
Residential	Smart water heating	0	0	8	16	24	26	31	39	51	66
Residential	Timed water heating	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-out)	0	0	0	95	95	96	96	97	98	99
Residential	TOU - EV Charging (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	A/C DLC	36	36	36	34	33	33	34	34	34	34
Small C&I	Auto-DR (A/C)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Small C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Small C&I	Interruptible	15	15	15	15	15	15	15	15	15	15
Small C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	A/C DLC	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (HVAC)	11	45	56	64	72	72	73	74	75	76
Medium C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Medium C&I	CPP (Opt-in)	0	4	15	19	19	19	19	20	20	20
Medium C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Medium C&I	Interruptible	14	14	14	15	17	18	19	20	22	23
Medium C&I	Thermal Storage	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (HVAC)	2	8	10	11	12	12	11	11	11	11
Large C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Large C&I	CPP (Opt-in)	0	6	26	32	32	32	32	32	32	31
Large C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Large C&I	Interruptible	56	56	56	55	55	54	53	52	51	50
Portfolio-Level Total		**309**	**359**	**411**	**543**	**570**	**585**	**603**	**624**	**649**	**677**

Notes:

Incremental load reduction available when DR programs are offered simultaneously as part of portfolio, accounting for overlap between programs.

No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

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The Cost-Effectiveness of Demand Response in NSP's Service Territory

PRESENTED TO

Northern States Power (NSP)

PRESENTED BY

Ryan Hledik
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December 2017

THE Brattle GROUP

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Introduction

In 2014, Brattle conducted a bottom-up assessment of demand response (DR) potential in Minnesota, but did not evaluate DR cost-effectiveness

- The study identified around 400 MW of traditional DR "technical potential" in the sense that it did not account for the cost-effectiveness of the DR measures
- These estimates of DR potential were not estimates of economic potential; they were inputs to the resource planning modeling process

Subsequently, a range of views on cost-effective DR potential emerged in Minnesota

- NSP has estimated between 71 and 130 MW of incremental economic potential
- The PUC has established a requirement of 400 MW of additional DR capability by 2023 and consideration of 1,000 MW of new DR by 2025

The purpose of this presentation is to revisit the 2014 Potential Study and provide Brattle's assessment of the amount of cost-effective DR available from that study

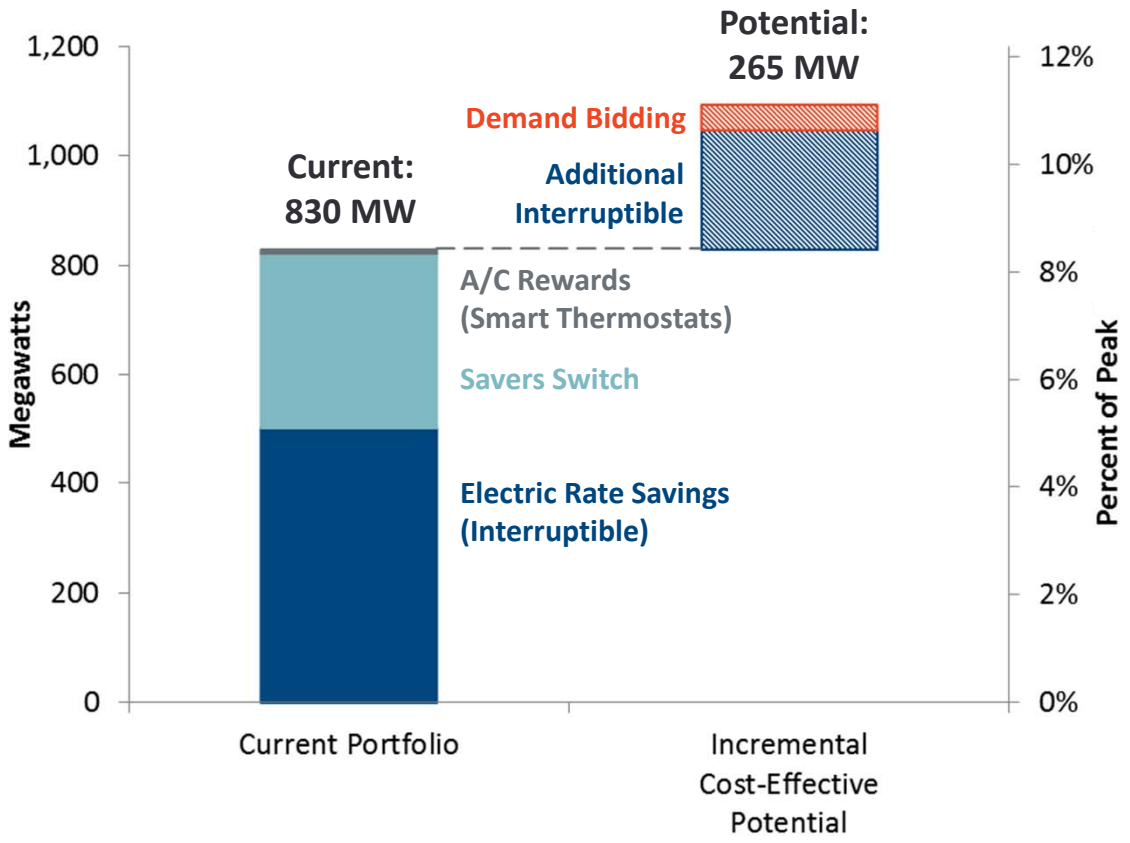
Note: 71 MW economic potential estimate identified by Staff in an October 2016 briefing paper, based on review of NSP IRP modeling data. 130 MW based on preliminary cost-effectiveness analysis conducted by NSP in 2015 (prior further detailed IRP modeling), as filed in Appendix N to the Resource Plan.

Key Findings

Comments

- NSP's current DR portfolio is one of the largest in the U.S.
- The market for traditional cost-effective DR in MN may be approaching saturation
- We identified 260 MW of incremental cost-effective DR potential among the options considered in the 2014 Study
- This estimate is subject to uncertainty; through probabilistic simulation, we estimate that there is a 75% chance the potential is under 300 MW
- There may be additional value in around-the-clock load flexibility (not quantified in this study)

Existing DR Capability and Cost-Effective Potential



Notes: Potential shown for 2023. Projected 2023 peak load of 9,848 MW was used as basis for estimating % of peak impact. All impacts shown at the generator-level (grossed up for losses). A/C Rewards was launched as a pilot program in August 2017.

Key findings (cont'd)

In spite of the limited amount of traditional incremental cost-effective DR identified in this study, there may be more value in alternative forms of demand flexibility

Emerging opportunities for "demand flexibility" include

- Renewables integration: Providing a suite of DR programs that mimic energy, capacity, and a range of ancillary services in response to rapidly changing system conditions
- Distribution benefits: Geographically-targeted programs designed to defer the need for expensive upgrades in capacity-constrained locations on the system

Accordingly, the definition of demand response should be expanded and assessed in the next IRP

- Emerging DR programs include thermal storage (e.g., grid-integrated water heaters), bring-your-own-thermostat programs, behavioral DR, electric vehicle charging control, and AMI-enabled time-varying pricing
- The definition could also be expanded to include options such as distributed battery storage, combined heat-and-power (CHP), and some types of energy efficiency

Organization of the presentation

1. **A national perspective on NSP's DR portfolio**
2. **Best practices for quantifying DR cost-effectiveness**
3. **Our assessment of NSP's cost-effective DR potential**
4. **Moving forward with DR in Minnesota—initial thoughts**

A National Perspective on NSP's DR portfolio

We benchmarked NSP's DR portfolio against other utilities in the U.S.

For context, it is helpful to first understand how NSP's portfolio compares to those of other utilities

The benchmarking analysis relied largely on DR program data from two sources: the FERC and the EIA

- From 2006 to 2012, FERC conducted a bi-annual survey of utility DR programs, including significant detail on program type, enrollment, capability, etc.
- The EIA annually collects basic aggregate data on DR enrollment and capability by major customer class; the most recent data is from 2015
- While the FERC data is older, it appears to contain fewer reporting errors and is therefore the primary data source we relied on in our analysis
- We do not anticipate that changes in utility DR programs since 2012 would materially change the broad findings of the benchmarking analysis

See Appendix A for additional detail on benchmarking analysis

NSP currently has 830 MW of DR capability

Comments

Savers Switch:

Air-conditioning direct load control (DLC) program, mostly targeting residential and small C&I customers

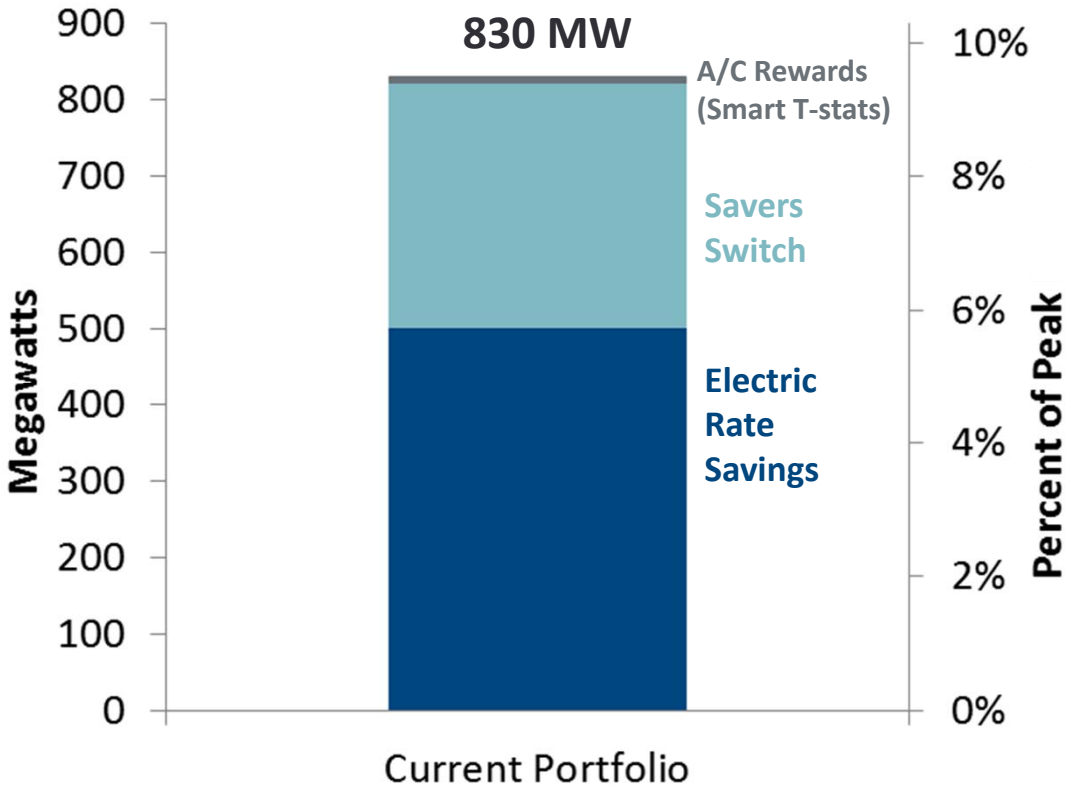
A/C Rewards:

Direct load control for customer-owned smart thermostats (residential)

Electric Rate Savings:

Interruptible tariff, targeting medium to large C&I customers

NSP DR Capability (2017)



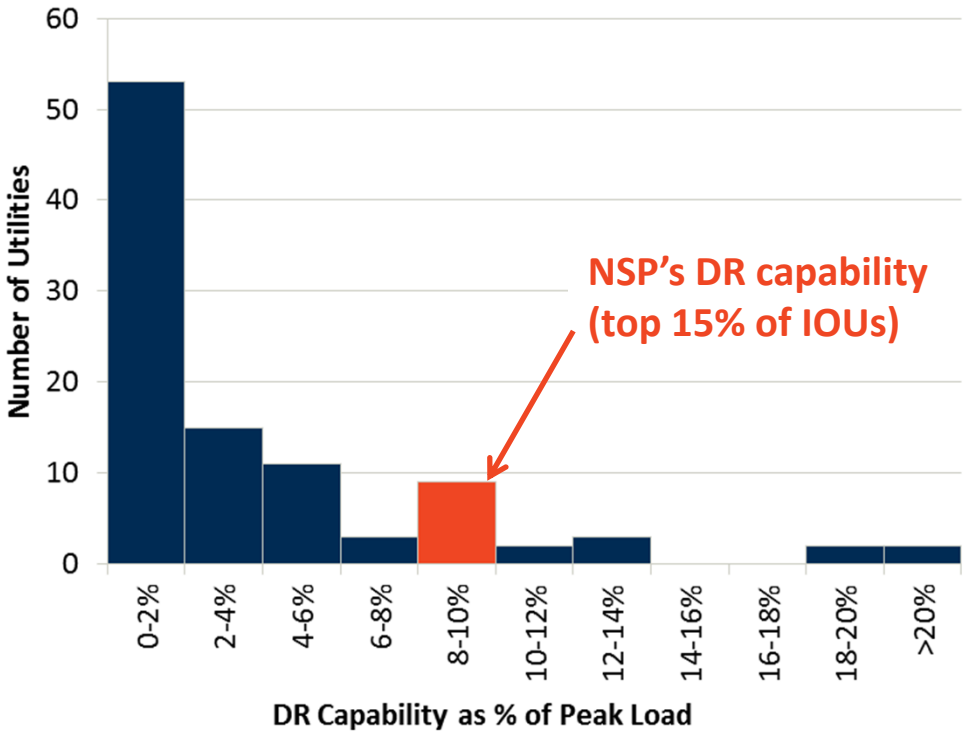
Notes: Percent of peak impact shown relative to actual 2016 peak load of 8,774 MW. All impacts shown at the generator-level (grossed up for losses). A/C Rewards was launched as a pilot program in August 2017. See appendix for further description of programs.

NSP's DR capability is in the top 15% of U.S. IOUs

Comments

- NSP's residential A/C load control program is the **2nd** most highly subscribed DR program in the country
- Around half of all eligible households are participating in NSP's Saver's Switch program
- In terms of absolute megawatts, NSP's portfolio is the **8th** largest program in the country; as a % of peak demand, it is ranked **11th**

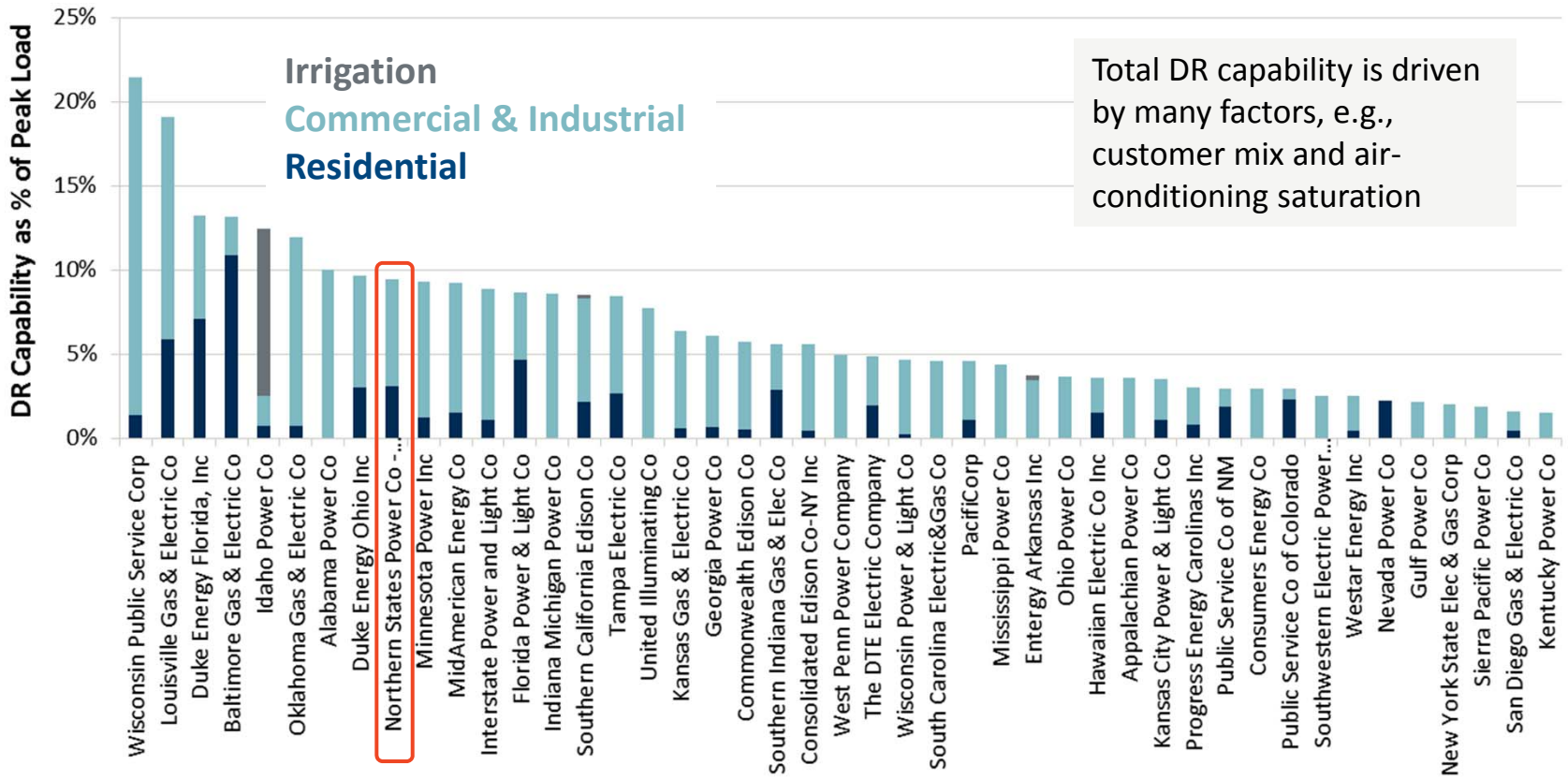
Distribution of DR Capability Among All U.S. IOUs



Sources and Notes: FERC, *2012 Assessment of Demand Response and Advanced Metering* and EIA 861 peak load data. Sample of 100 U.S. IOUs. Excludes IOUs that did not participate in the FERC survey, and excludes peak reduction capability from time-of-use programs because these loads are not controllable. NSP's capability calculated as current portfolio divided by 2016 peak load.

NSP ranks near the top of the largest IOU DR portfolios in terms of % of peak load

DR Capability of 45 IOUs with Largest Programs (as % of Peak Demand)



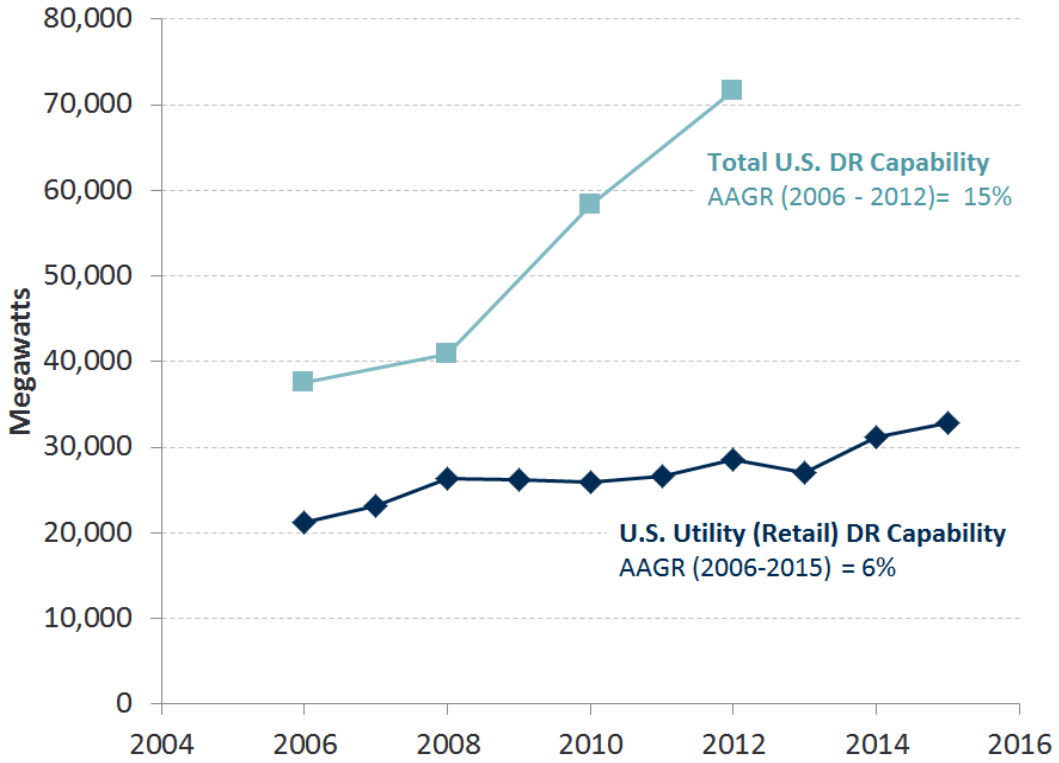
Sources and Notes: FERC, *2012 Assessment of Demand Response and Advanced Metering* and EIA 861 peak load data. Sample of 100 U.S. IOUs. Excludes IOUs that did not participate in the FERC survey, and excludes peak reduction capability from time-of-use programs because these loads are not controllable. NSP's capability calculated as current portfolio divided by 2016 peak load.

National DR growth has been driven by ISO/RTO programs – much more than by utility programs

Comments

- There is sometimes a misperception that utility DR programs were the primary drivers of DR growth over the past decade
- While U.S. DR capability grew at an annual rate of **15%** between 2006 and 2012, most of this growth was driven by programs operated by ISOs and RTOs
- PJM accounted for roughly half of the total ISO/RTO growth, in part due to significant efforts to integrate DR into its capacity market, which offered significant payments for demand reductions
- Utility DR programs only grew at an annual rate of **6%** during that time

Distribution of DR Capability Among all U.S. IOUs



Sources and Notes: Total U.S. DR Capability reflects data reported in 2006–2012 FERC surveys, which include DR capability provided by aggregators , power marketers, and state and federal energy authorities. U.S. Utility (Retail) DR Capability reflects data reported in 2006–2015 EIA-861 data.

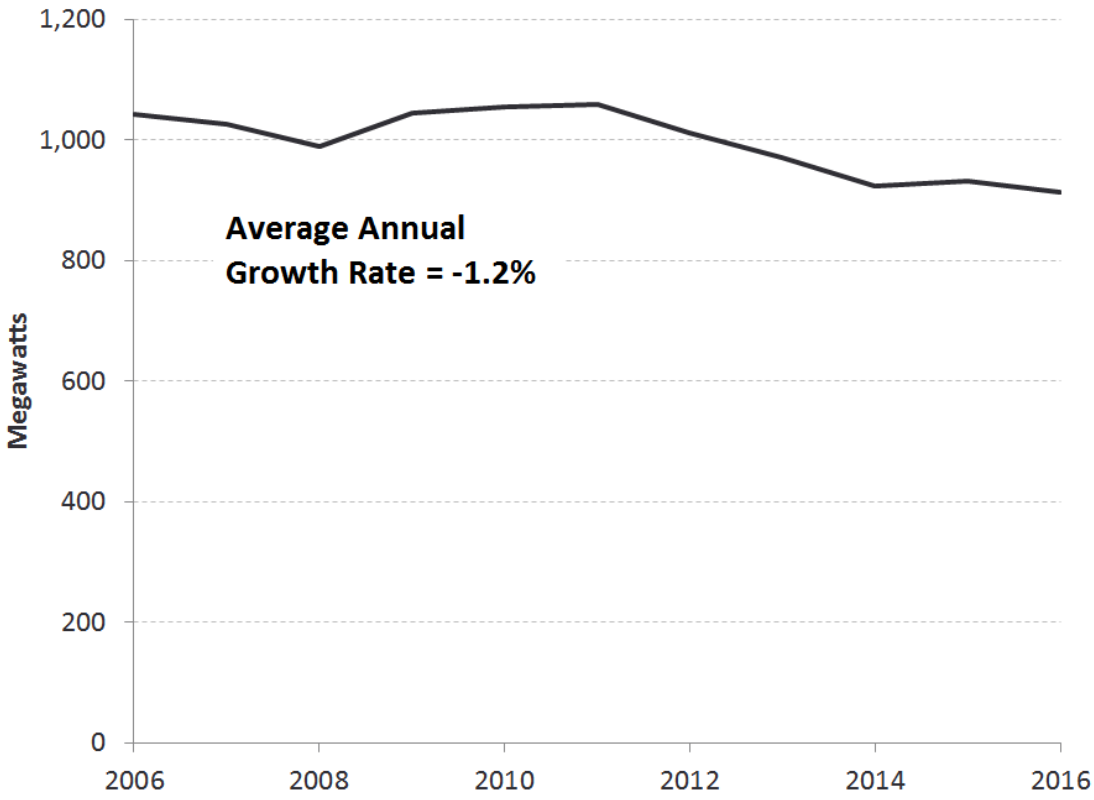
Relative to modest national growth in utility DR over the past decade, NSP's DR capability has dipped

Comments

A few explanations:

- EPA constraints on the use of backup generation as DR, imposed in 2013
- Increased utilization of the interruptible tariff program in 2016, leading to some drop-outs
- Allowing DR participants to lower their contractually committed load reduction level in anticipation of more frequent program use
- Possibly approaching market saturation due to high enrollment rates (relative to other U.S. utilities)

Historical NSP DR Capability



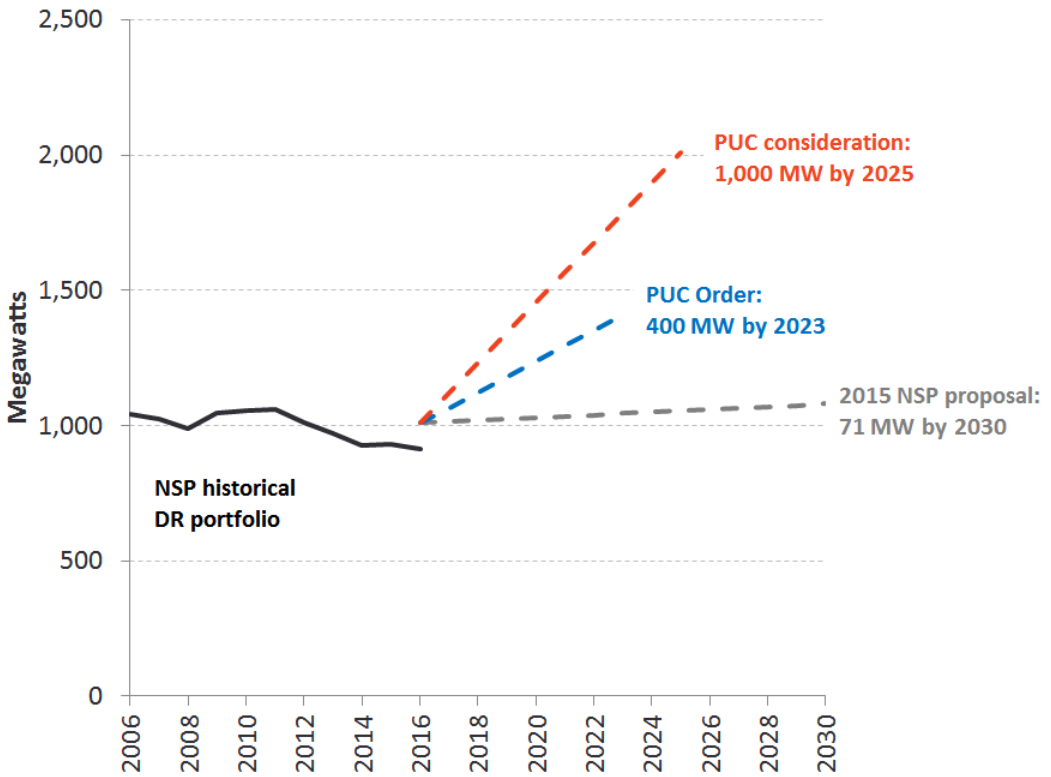
Sources and Notes: Data provided by NSP. Values shown are for entire NSP service territory.

To what extent can NSP's DR portfolio cost-effectively grow beyond recent levels?

Comments

- NSP proposed to reverse the recent historical decline with 71 MW of DR growth
- The PUC has ordered NSP to pursue 400 MW of additional DR
- The PUC's interest in 1,000 MW of new DR would significantly exceed historical observed growth rates among U.S. utilities
- **In the remainder of this presentation, we explore where NSP's cost-effective DR potential falls on this spectrum**

DR Proposals Relative to Historical Growth



Sources and Notes: Data provided by NSP. Projections of growth were established by the PUC and NSP relative to the size of the 2014 DR portfolio; therefore, they do not align with 2016 reported values.

Best Practices for Quantifying the Cost-Effectiveness of DR

There are two established options for determining the cost-effectiveness of DR

1. Incorporate DR options into the resource planning model

- Dynamically accounts for the advantages and disadvantages of DR relative to supply-side options
- However, it is difficult to implement comprehensively due to modeling and computational limitations

2. Conduct a detailed cost-effectiveness screening

- Performed outside of the IRP model
- Commonly used in regulatory proceedings to evaluate DR and EE cost-effectiveness (i.e., the Total Resource Cost test)
- Has the advantage of transparency, while still relying on the same cost and operational assumptions used in the IRP model
- Allows for a broader range of sensitivity cases around uncertain variables

We rely on the screening-based approach

The value of DR is assessed based on its ability to avoid the need for new peaking generation

The DR programs analyzed in the 2014 Potential Study are most appropriately considered substitutes for new combustion turbine (CT) capacity

CTs are "peaking" units with relatively high variable costs; as a result, they typically only run up to **a few hundred hours of the year**, when electricity demand is very high and/or there are system reliability concerns

Similarly, use of DR programs in the U.S. is typically limited to **<100 hours per year** – this constraint is either written into the tariff or is otherwise a practical consideration to avoid customer fatigue and program drop-outs

In contrast, new intermediate or baseload capacity (e.g., gas-fired combined cycle) has a higher capital cost and lower variable cost than a CT, and therefore will run **thousands of hours per year**

The DR programs considered in the 2014 Potential Study cannot feasibly avoid the need for new intermediate or baseload capacity, because they cannot be called during a sufficient number of hours of the year; energy efficiency is a more comparable demand-side alternative to these resource types since it is a permanent load reduction that applies to a much broader range of hours

Note: For more data on the number of interruptions per year in a typical U.S. DR program, see SEPA, "2017 Utility Demand Response Market Snapshot," October 2017.

Comparing traditional DR to a new CT

Even though traditional DR is most comparable to a CT, there are operational differences between these resources that must be taken into account

	Demand Response	New Combustion Turbine
Total hours of availability	Roughly 100 hrs/yr	Roughly 8,200 hrs/yr (accounting for planned and unexpected maintenance)
Seasonal availability	A/C: Summer only; Other programs: year-round	Year-round
Daily window of availability	A/C: roughly 2 to 7 pm; Other programs: business hours	Any hour of day
Other considerations	Must try to limit consecutive interruptions	None
Variable cost	$0/MWh	$40/MWh
Fixed cost	$30-250/kW-yr	$50-70/kW-yr

CTs can run any hour of the year (subject to outages), whereas the timing of DR use is constrained

DR costs are largely fixed incentive payments and/or up-front investment in technology; there is not usually a cost to call a DR event

DR fixed costs include incentives, equipment, marketing & administration. CT fixed cost based on values reported in NSP's IRP. CT variable cost assumes $3/MMBtu delivered gas price, and CT heat rate of 9.75 MMBtu/MWh and VOM of $10/MWh, consistent with an 'advanced CT' in EIA's *Updated Capital Cost Estimates for Utility Scale Generating Plants* (2013).

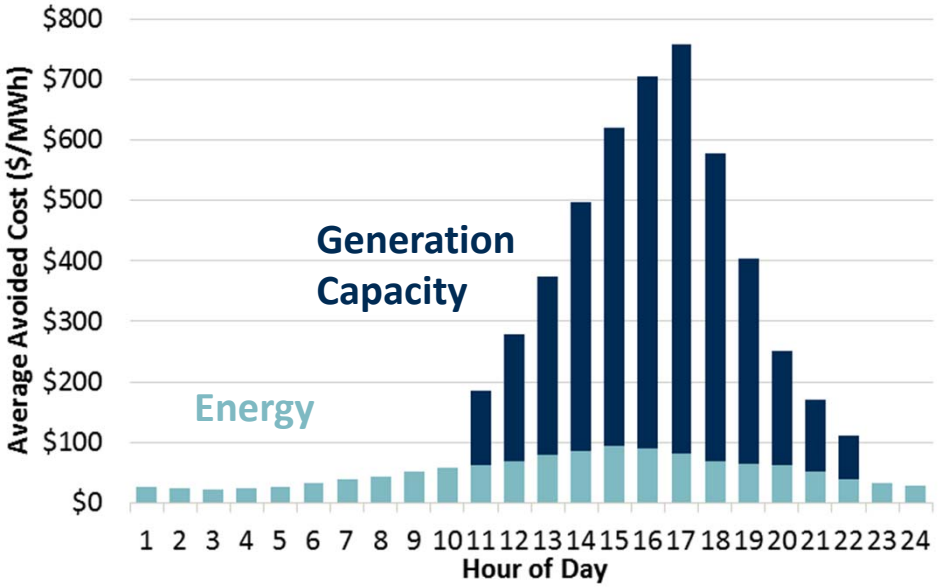
In addition to operational differences, considerations such as the dependability of the resource may also factor into the decision. See Appendix B for additional discussion of DR operational constraints

We account for the operational constraints of DR in our cost-effectiveness analysis

Comments

- Capacity costs are allocated to hours of the year proportional to the risk of capacity shortages in those hours
- In the base scenario, capacity costs are allocated to the top 100 system load hours of the year (this assumption is tested through sensitivity analysis)
- The allocation is roughly proportional to each load hour's share of total load in the hours (i.e., more capacity cost is allocated to the top load hour than the 100th)
- A similar approach has been used in California's DR cost-effectiveness protocols, and in the state's time-dependent valuation (TDV) metric for quantifying the value of energy efficiency
- The hourly allocation of capacity costs is added to 2013 hourly MISO energy market prices for NSP's service territory

Allocation of Marginal Costs: 2023 Average over Days With Capacity Value



Notes: On days without peak capacity constraints, there is no allocation of capacity value. Avoided costs shown for 2023 in nominal dollars. 2013 energy prices escalated to 2023 dollars assuming 2.2% inflation.

Avoided T&D capacity costs are also included in the analysis

Avoided T&D capacity costs are only sometimes included in assessments of DR cost-effectiveness

- Depends on DR program objectives and the physical characteristics of the utility system
- Requires higher frequency of interruptions due to lack of coincidence between transmission and distribution system peaks

Nationally, T&D investment needs are increasingly being driven by factors other than peak demand growth, limiting the T&D value of peak demand reductions. Factors commonly driving T&D investment include

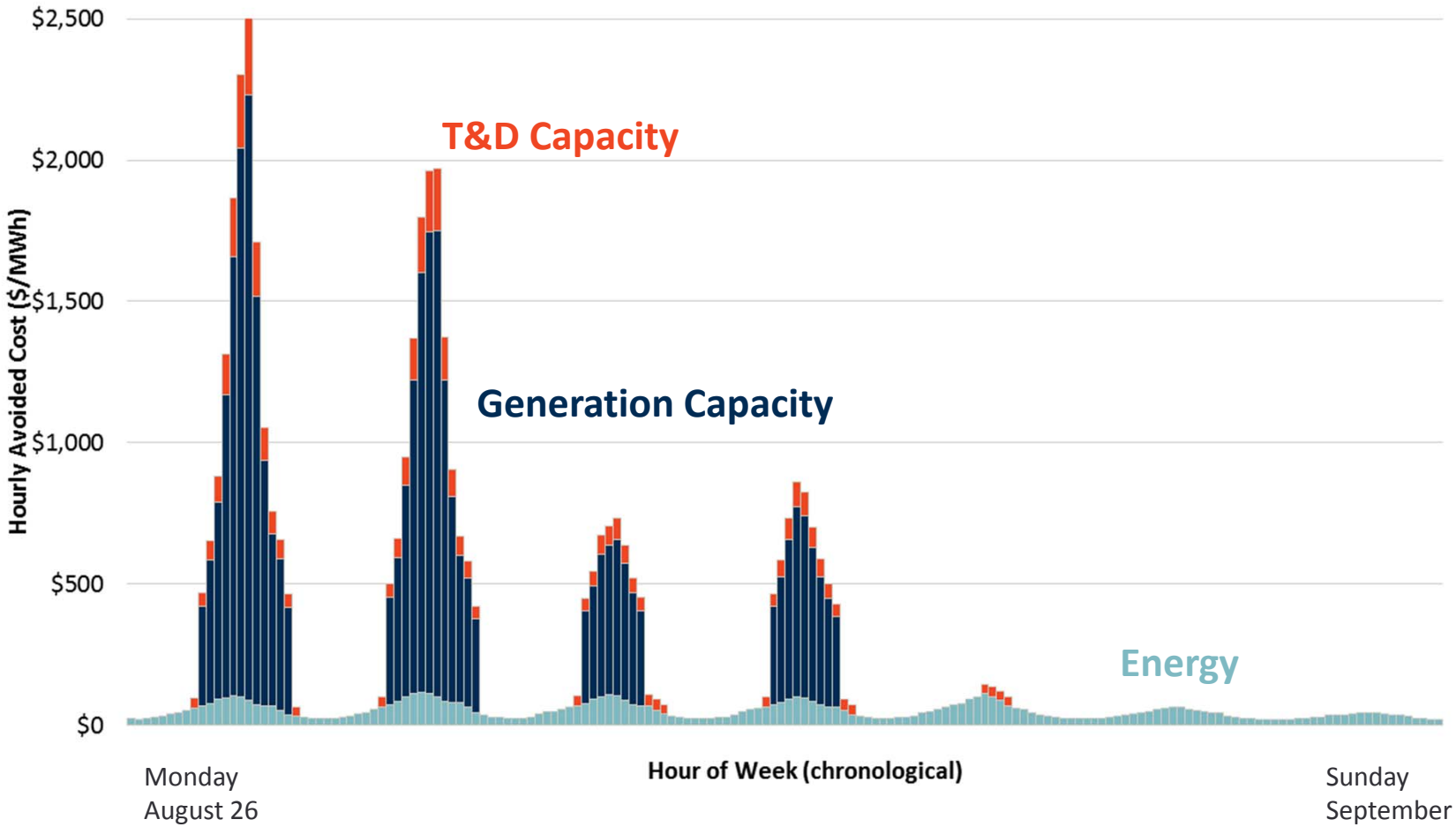
- Replacement of aging equipment
- General reliability improvements that are unrelated to peak demand
- Expansion to accommodate renewable generation

In Minnesota, there is no established approach to the treatment of T&D costs in DR cost-effectiveness analysis

- Docket No. E999/CIP-16-541 established a marginal (i.e., avoidable) T&D capacity cost of approximately $11/kW-year for NSP's energy efficiency programs
- We have adopted this as the base case marginal T&D capacity cost for DR
- In our analysis, the $11/kW-year is allocated across hours of the year in a manner similar to generation capacity, but spread over twice as many hours to account for the lack of coincidence between the overall system peak and the T&D peaks

DR is "dispatched" against the resulting hourly generation cost profile (energy + capacity + T&D)

Chronological Allocation of Marginal Costs (Illustration for Week of August 26)



Our methodology allows for robust representation of uncertainty in key variables

We first assess cost-effectiveness through "deterministic analysis"

- This is the standard industry approach
- The approach produces a point-estimate of cost-effective DR potential
- It is based on "most likely" (i.e., Base Case) values for each key variable
- However, it does not account for uncertainty in the key assumptions

We then assess cost-effectiveness through "probabilistic analysis"

- This is also known as "Monte Carlo analysis"
- It accounts for the range of uncertainty in the key variables
- A probability distribution is assigned to each uncertain variable
- Each probability distribution has an associated minimum, maximum, and most likely value based on historical data, experience from other jurisdictions, and/or our expert judgment
- A value is randomly drawn from each distribution and cost-effectiveness is estimated using those randomly selected values
- This process is repeated 2,000 times to establish a distribution of possible outcomes around the amount of cost-effective DR potential

Other key assumptions in the analysis

Avoided generation capacity cost

- $57/kW-year: This is the 2023 CT cost from NSP's IRP ($69/kW-year) adjusted downward to account for energy profit margins that the unit would earn ($12/kW-yr)
- Lower-bound of probabilistic analysis = $8/kW-yr, based on recent MISO capacity prices
- Upper-bound = $79/kW-year, based on MISO Net Cost of New Entry assumptions for CTs

Avoided T&D cost

- Base = $11/kW-yr, from 2017 EE Avoided T&D Cost Study (Discrete Method)
- Lower-bound = $0
- Upper-bound = $42/kW-year, the 2023 value from Xcel's 2016 filing for the 2017-19 Conservation Improvement Program filing (Docket No. 16-115)
- Note: The upper-bound reflects a value observed in some other jurisdictions. T&D costs are highly system-specific, therefore it does not directly reflect NSP's costs. The value is simply included to establish an upper-bound on the range of costs that may generally be avoided through system-wide reductions in demand through DR programs.

Avoided energy costs

- Based on 2013 MISO hourly day-ahead LMPs for Minnesota hub

DR program operational constraints

- Air-conditioning DLC: 15 interruptions per summer, 2 pm to 7 pm
- Other programs: 80-100 hours of interruption, minimum 1 hour duration per interruption (note: assumed interruptions are significantly more frequent than current operation of the programs)

Relevant programs

- The analysis is limited to non-pricing programs (DLC, interruptible tariffs, demand bidding)
- These are the programs that were included in the "DR supply curves" created in the 2014 study

Our Assessment of NSP's Cost-Effective DR Potential

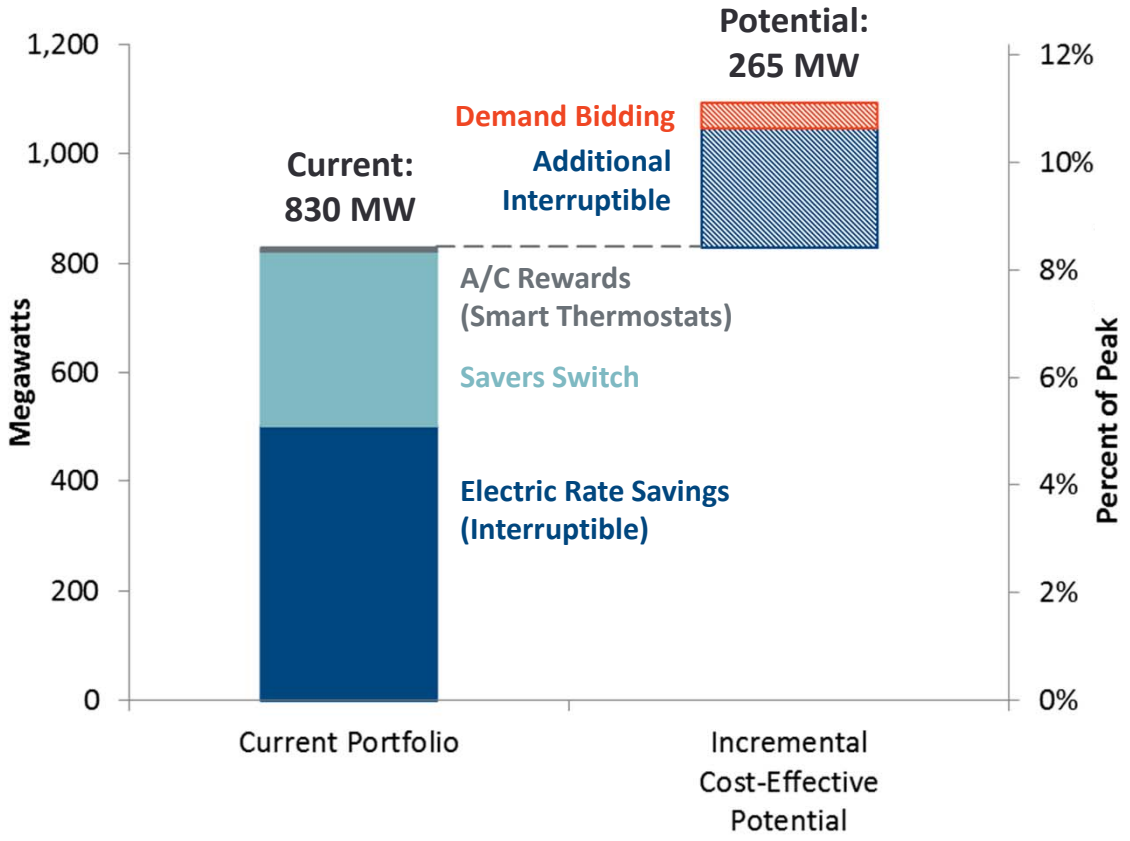
Results of Deterministic Analysis

In the Base Case, we estimate 265 MW of cost-effective potential for new DR programs

Comments

- Incremental potential resides primarily in an expansion of the interruptible tariff offering for medium C&I customers
- There is modest incremental potential in the introduction of a new demand bidding program, though given the small size of the potential it is worth considering if those resources would be better spent on other new initiatives
- Incremental growth in conventional air-conditioning DLC programs is not found to be cost-effective
- Note: We have only assessed the DR potential that is incremental to existing programs; we have not analysed the cost-effectiveness of existing programs

Existing DR Capability and Cost-Effective Potential



Notes: Potential shown for 2023. Projected 2023 peak load of 9,848 MW was used as basis for estimating % of peak impact. All impacts shown at the generator-level (grossed up for losses). A/C Rewards was launched as a pilot program in August 2017.

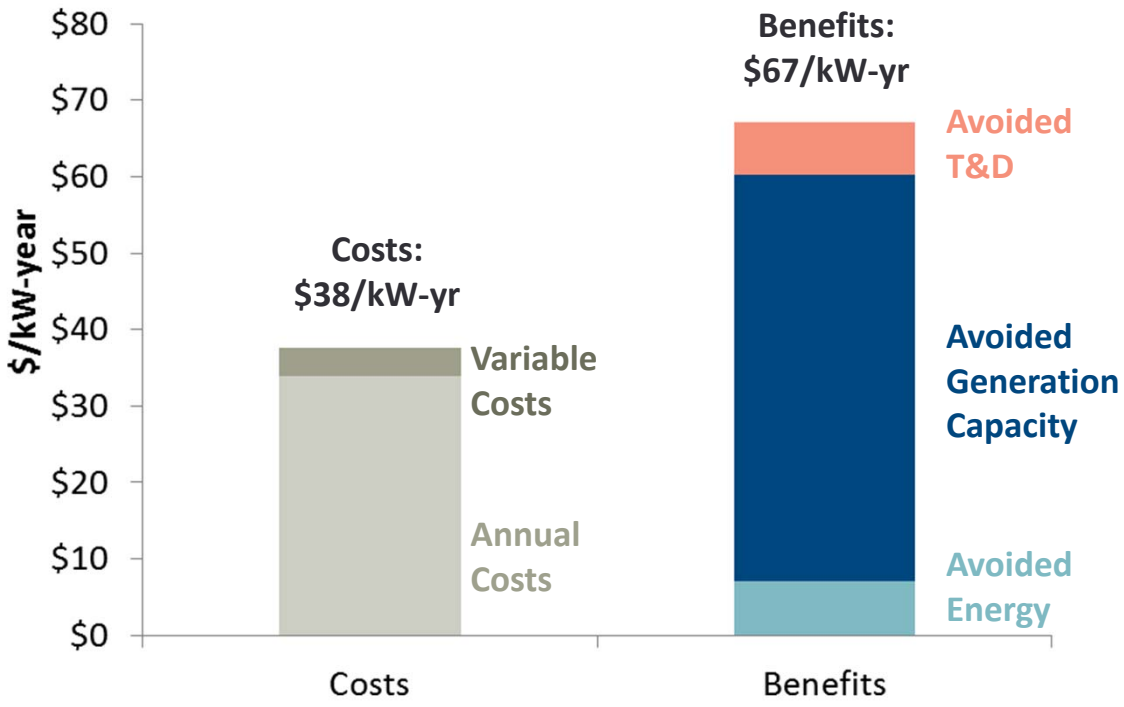
Results of Deterministic Analysis

The benefits of DR are largely avoided generation capacity costs

Comments

- The benefit-cost ratio of the portfolio of incremental cost-effective DR programs is 1.8-to-1
- Avoided generation capacity costs account for 80% of the total benefits
- The vast majority of costs are annual costs associated with participation incentive payments, program administration, and marketing/recruitment

Total Costs and Benefits of all Identified Cost-Effective Incremental DR Potential



Note: Benefits and costs are shown only for those individual DR measures with a benefit-cost ratio greater than 1.0.

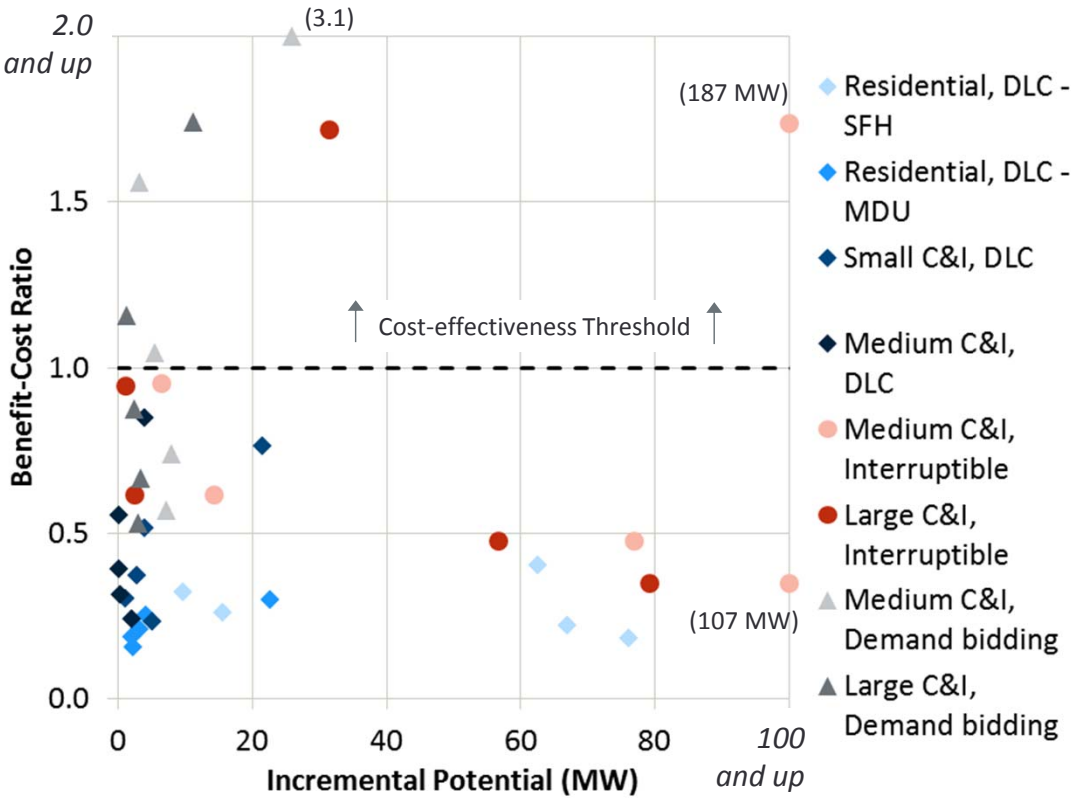
Results of Deterministic Analysis

Only a few of the analyzed programs are cost-effective

Comments

- In the chart at right, each data point represents a single incentive payment level associated with one DR program for one customer class (a range of incentive payment levels were analyzed in the 2014 Potential Study)
- Under Base Case assumptions, the most cost-effective program is Medium C&I Demand Bidding at the lowest incentive payment threshold, though the MW potential associated with this program is small
- Expanded Interruptible Tariffs have significantly more incremental cost-effective potential, particularly for Medium C&I customers, with benefit-cost ratios around 1.5

B-C Ratio and Incremental Potential of Each DR Program



Note: Each data point represents a single incentive payment level for one DR program and one customer class.

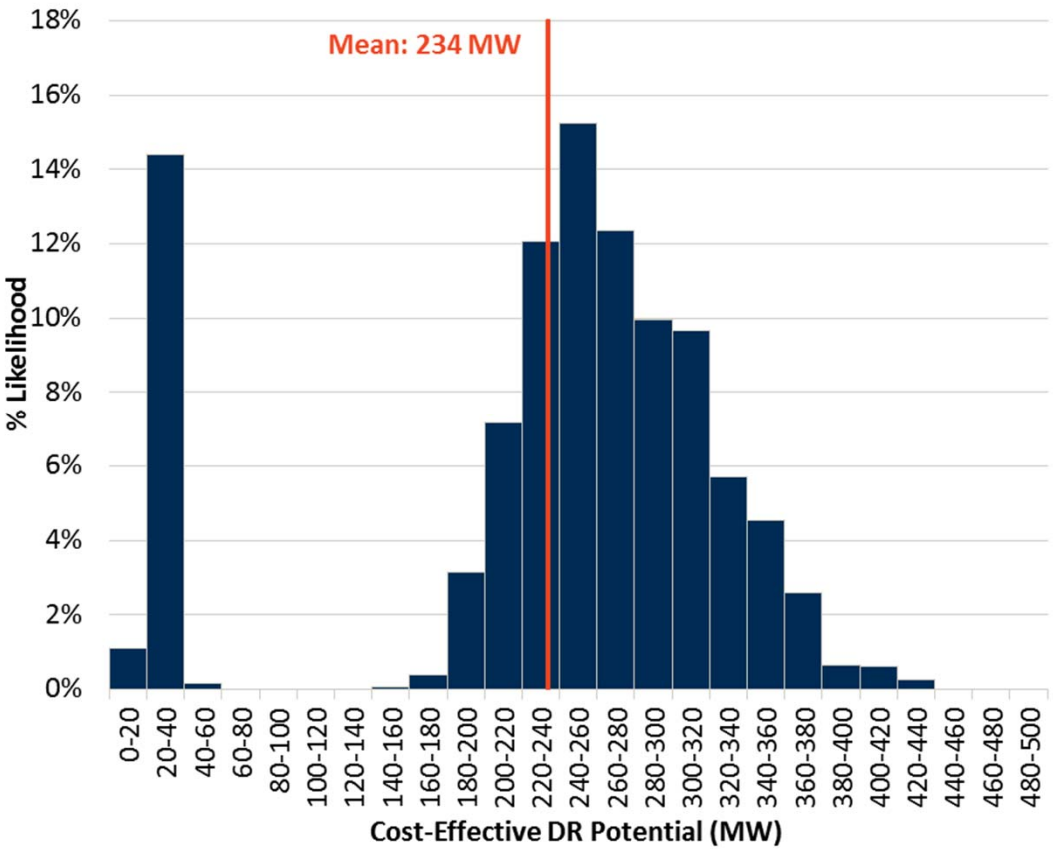
Results of Probabilistic Analysis

Accounting for uncertainty in avoided cost estimates produces consistent findings

Comments

- There is a 75% chance that cost-effective DR potential is less than 300 MW
- Whether the potential is less than 50 MW or in excess of 160 MW depends largely on whether or not the Medium C&I Interruptible Tariff program is cost-effective
- It is highly unlikely that the cost-effective potential in the programs analyzed in the 2014 Potential Study exceeds 350 MW

DR Potential Probability Distribution



Note: See Appendix B for details about the assumed range of each uncertain variable in the analysis.

Summary of findings

- NSP has already established a large portfolio of mature DR programs, which means that there are limited opportunities for incremental cost-effective growth in traditional DR
- NSP's incremental cost-effective DR potential is most likely between 200 and 300 MW
- The ability to efficiently enroll medium-sized C&I customers in an expanded Interruptible Tariff program is a key factor determining the amount of DR that is cost-effective
- This cost-effective potential of the programs analyzed in the 2014 Potential Study is less than the 400 MW to 1,000 MW target established by the PUC
- Further, there are likely to be operational challenges in achieving system peak demand reductions that are significantly beyond the capabilities of the current portfolio (i.e., an infeasible number of DR events to be called)
- Rather than pursuing a significant amount of traditional, peak demand-focused DR, there may be greater opportunities in alternative "flexible load" programs

Moving Forward with DR in Minnesota – Initial Thoughts

The cost-effectiveness findings in this presentation are not the end of the story

In spite of the limited amount of traditional incremental cost-effective DR identified in this study, there may be more value in alternative forms of demand flexibility

Renewables integration presents one such opportunity

- Minnesota has a goal of integrating 40%+ renewables
- This will require more than simple peak load reductions – it will require availability during non-peak hours, fast response times, and the ability to ramp quickly
- DR and other behind-the-meter options have the potential to provide these services

Avoided distribution costs are another emerging opportunity for DR

- There is growing interest in the use of demand-side resources to address very location-specific constraints on the distribution system
- If adequate enrollment can be achieved, it may be possible to defer the need for upgrades in locations where capacity constraints are a near-term concern
- This concept is largely in the trial phase and requires a novel approach to DR deployment and evaluation; however it is worth consideration in future DR studies

NSP's next DR potential study will include an expanded definition of DR

Which "demand flexibility" options are of interest to stakeholders?

An expanded definition of demand flexibility could possibly include:

- Distributed battery storage
- Thermal storage (incl. grid-integrated water heaters)
- EV charging control
- Some types of energy efficiency
- Bring-your-own-thermostat (BYOT) programs
- Behavioral DR
- AMI-enabled dynamic pricing

Appendix A:
Details of DR Benchmarking Analysis

Description of National DR Data

We analyzed two national DR datasets: FERC's surveys of utilities in its *Assessment of DR and Advanced Metering* Staff Reports (2006–2012) and EIA-861 Demand Response data files (2006–2015)

- In 2006–2012, FERC surveyed utilities every two years on their individual DR programs to inform its annual *Staff Report*
- The EIA has conducted the survey for many years , but annually and on aggregate DR portfolios
- Both datasets survey IOUs, munis, coops, and other load-serving entities. Shared data fields include annual capability and actual peak reduction from DR, number of customers enrolled, maximum demand from DR customers, and program costs
- To analyze DR capability as % of peak load, we also compiled peak load data reported in the EIA-861 data files

Description of National DR Data (cont.)

The FERC and EIA datasets provide information on DR penetration across utilities nationwide, but there are limitations:

- In our experience, these types of national datasets can have some reporting errors and inconsistencies
- We found the FERC survey data to more accurately represent utility DR capabilities (including NSP's) so we chose to benchmark using the latest FERC survey data available (2012)
- The % of peak metric is based on a single year of reported actual peak load
  - To the extent utilities do not adjust DR MW estimates with load, resulting % may appear high in a low load year, and low in a high load year

Peer Group Selection Criteria

We selected a subset of similarly situated utilities to compare NSP's DR portfolio to those of its peer group

MISO peer group represents large IOUs in nearby states

- Neighboring states in the Upper Midwest (MN, WI, IA, MI)
- Investor-owned utilities
- Peak demand greater than 1,000 MW

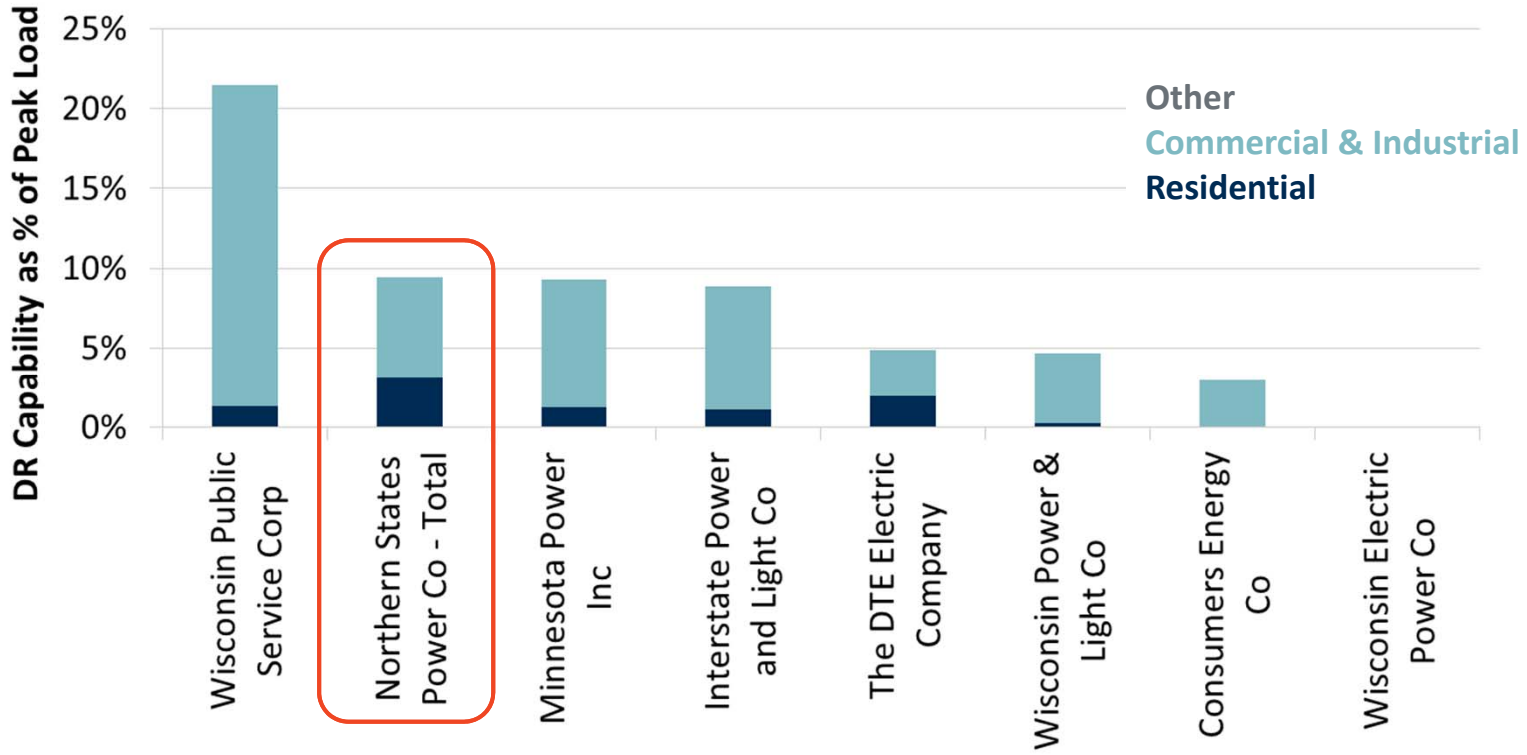
Other RTO peer group represents large IOUs with comparable peak load and serving major cities

- RTOs with capacity market (NYISO, PJM, ISO-NE)
- Investor-owned utilities serving major cities
- Peak demand greater than 5,000 MW

NSP Compared to MISO Peer Group

NSP ranks highly among MISO IOUs in total and residential DR capability.

- NSP has the most "nameplate" DR capability (830 MW) of all MISO IOUs, and ~300 MW beyond that of the next closest IOU (DTE: 550 MW, WPSC: 500 MW).
- WPSC has a larger portfolio as a % of peak demand, though lower enrollment as a % of its total customer base due to a portfolio predominantly composed of C&I

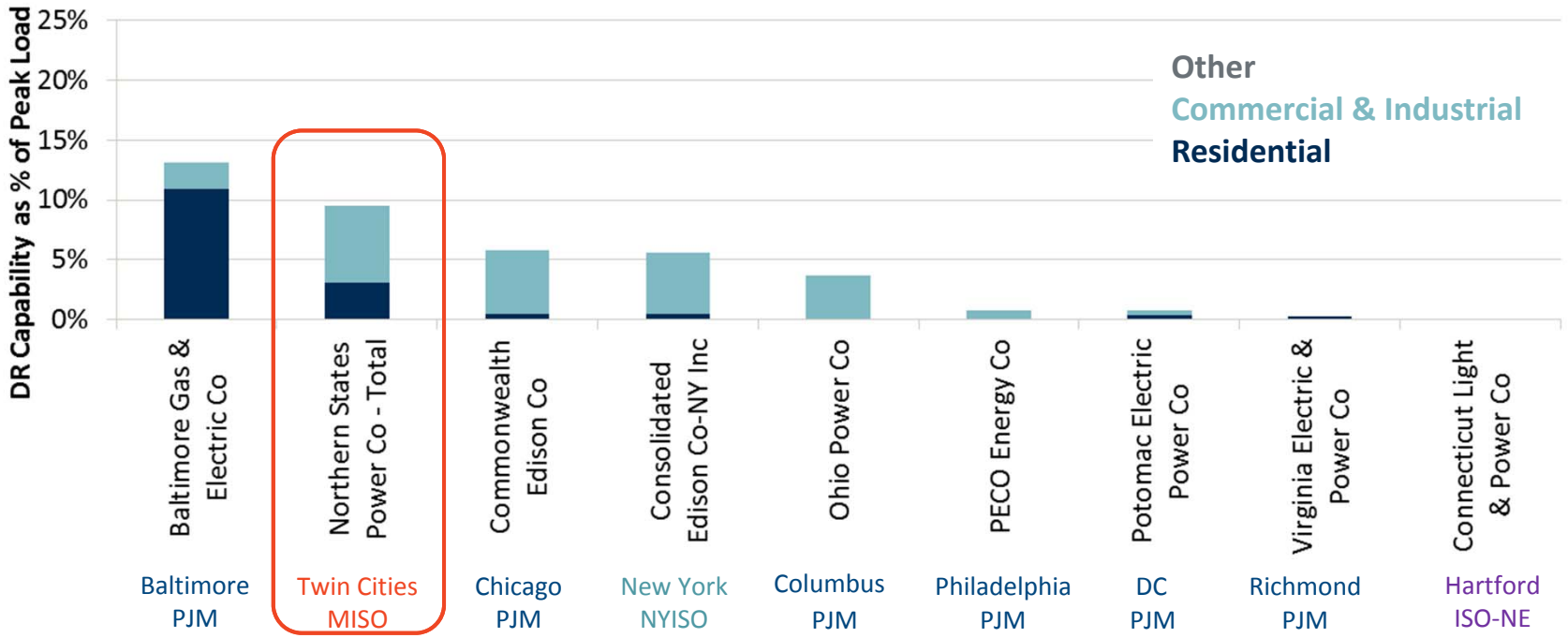


Sources and Notes: FERC, *2012 Assessment of Demand Response and Advanced Metering* and EIA 861 peak load data. Excludes peak reduction capability from time-of-use programs because these loads are not controllable. NSP's capability calculated as current portfolio divided by 2016 peak load.

NSP Compared to Other RTO Peer Group

NSP compares favorably to large IOUs in markets with more lucrative DR products (PJM and NYISO)

- BG&E (920 MW) and ComEd (1,360 MW) are the only other IOUs in peer group with comparable total MW DR capability. Outside of peer group, NSP ranks **8th** nationally in total DR capability, and **11th** nationally in DR capability as share of peak.



Sources and Notes: FERC, *2012 Assessment of Demand Response and Advanced Metering* and EIA 861 peak load data. Excludes peak reduction capability from time-of-use programs because these loads are not controllable. Share in residential DR does not control for differences in overall load composition. For example, BG&E total energy sales were 75% residential compared to NSP energy sales which were only 29% residential. NSP's capability calculated as current portfolio divided by 2016 peak load.

NSP's existing DR portfolio ranks highly against those of other large IOUs

NSP DR Capability Compared to IOU Peer Group

2012 FERC Survey

	RTO	State	Peak Load (MW)	DR Peak Reduction Capability: Total DR (MW)	Res. (MW)	C&I (MW)	**Total DR (% of peak)**	Share of DR MW: Res. (%)	C&I (%)	Customers Enrolled in DR: Res. (customers)	Total (customers)
Northern States Power Co - Total	MISO	MN	8,774	830	270	560	**9%**	33%	67%	446,808	467,161
Wisconsin Public Service Corp	MISO	WI	2,347	504	32	473	**21%**	6%	94%	25,375	25,861
Minnesota Power Inc	MISO	MN	1,633	152	20	132	**9%**	13%	87%	7,217	7,761
Interstate Power and Light Co	MISO	IA	3,130	279	34	245	**9%**	12%	88%	48,928	49,115
The DTE Electric Company	MISO	MI	11,182	547	219	328	**5%**	40%	60%	281,031	281,689
Wisconsin Power & Light Co	MISO	WI	2,851	134	7	127	**5%**	5%	95%	10,700	10,800
Consumers Energy Co	MISO	MI	8,387	246	0	246	**3%**	0%	100%	0	30
Wisconsin Electric Power Co	MISO	WI	6,294	0	0	0	**0%**	-	-	0	152
Baltimore Gas & Electric Co	PJM	MD	7,002	919	763	157	**13%**	83%	17%	405,944	411,064
Commonwealth Edison Co	PJM	IL	23,601	1,357	116	1,241	**6%**	9%	91%	83,537	87,312
Consolidated Edison Co-NY Inc	NYISO	NY	5,492	305	23	282	**6%**	8%	92%	22,395	32,202
Ohio Power Co	PJM	OH	9,670	351	0	351	**4%**	0%	100%	0	8
PECO Energy Co	PJM	PA	8,549	64	0	64	**1%**	0%	100%	0	118
Potomac Electric Power Co	PJM	DC	6,674	50	25	25	**1%**	50%	50%	25,000	72,769
Virginia Electric & Power Co	PJM	VA	16,787	50	50	0	**0%**	100%	0%	28,000	28,013
Connecticut Light & Power Co	ISONE	CT	5,280	5	0	5	**0%**	0%	100%	0	12
All MISO IOUs in Survey Data (12 IOUs)			55,231	2,978	718	2,260	**5%**	24%	76%	880,849	908,232
All U.S. IOUs in Survey Data (100 IOUs)			456,353	19,942	5,289	14,273	**4%**	27%	72%	4,653,575	4,838,625
All Utilities in Survey Data (387 Utilities)			563,074	27,383	7,015	19,346	**5%**	26%	71%	5,801,247	6,025,979

Sources and Notes: FERC, *2012 Assessment of Demand Response and Advanced Metering* and EIA 861 peak load data. Excludes utilities that did not participate in the FERC survey, and excludes peak reduction capability from time-of-use programs because these loads are not controllable. Res. and C&I DR do not add up to Total DR for All U.S. IOUs and All Utilities because Other DR is excluded from table. NSP's capability calculated as current portfolio divided by 2016 peak load.

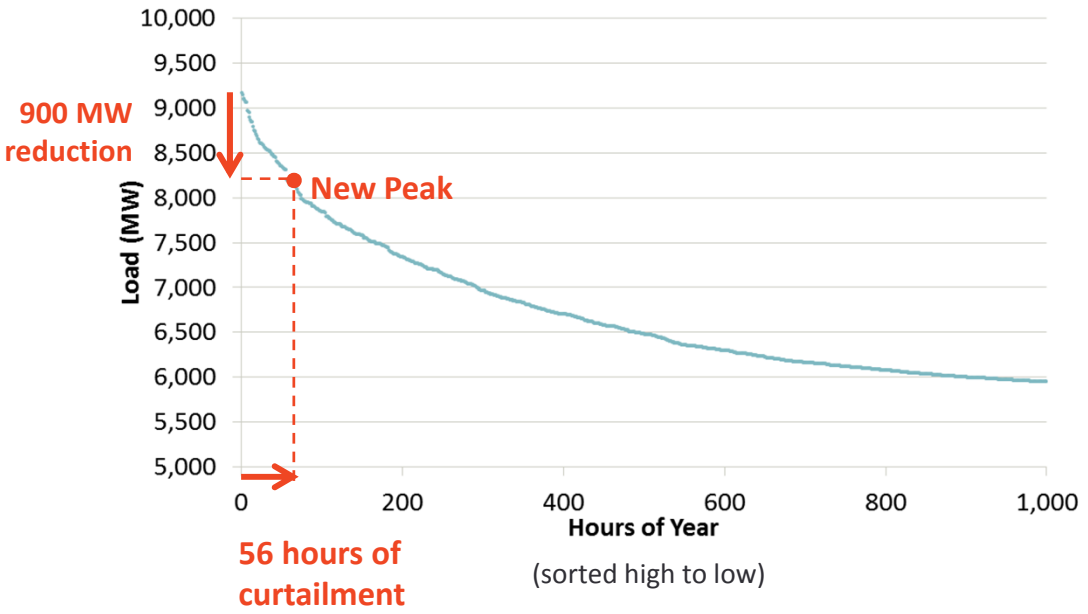
Appendix B: Additional Considerations in Assessing DR Potential

The operational constraints of DR programs have implications for the ability to reduce peak demand

Comments

- Reducing system peak demand by 900 MW (roughly the size of NSP's current DR portfolio) requires load reductions in the top **56** hours of the year
- Otherwise, one of these top **56** hours will set the new peak at a level that exceeds the target
- In 2013, those top **56** hours occurred on **8** different days of the year

NSP's 2013 Load Duration Curve



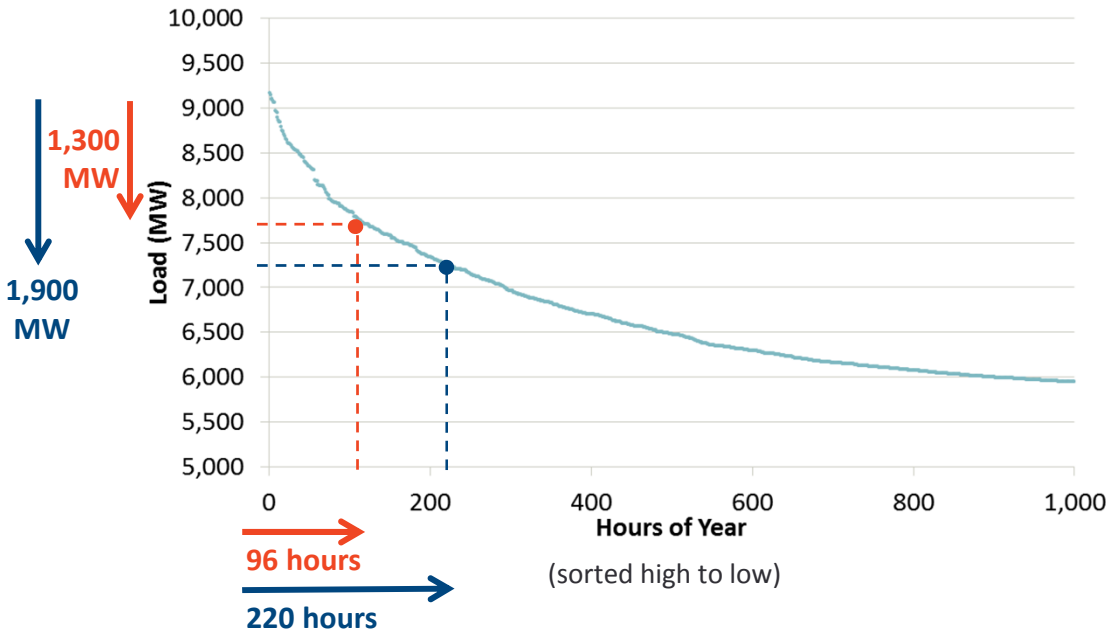
Sources and Notes: 2013 system load for NSP service territory, provided by Xcel. 2013 was chosen as the year for this example, because it was the year with the highest peak demand in the past several years.

Achieving larger load reductions requires that DR be dispatched during more hours of the year

Comments

- A **1,300 MW** reduction (the PUC's target for NSP's DR capability) would require that DR be dispatched during at least **96** hours of the year
- In 2013, those hours spanned **13** days of the year, **12** different hours of the day, and **5** days of the week
- DR events would need to be called on **5** consecutive days in this scenario
- Achieving a **1,900 MW** peak reduction would require that DR be utilized during **27** different days of the year
- The number and frequency of necessary interruptions is significantly higher in other recent years, when peak load was less concentrated in the top hours

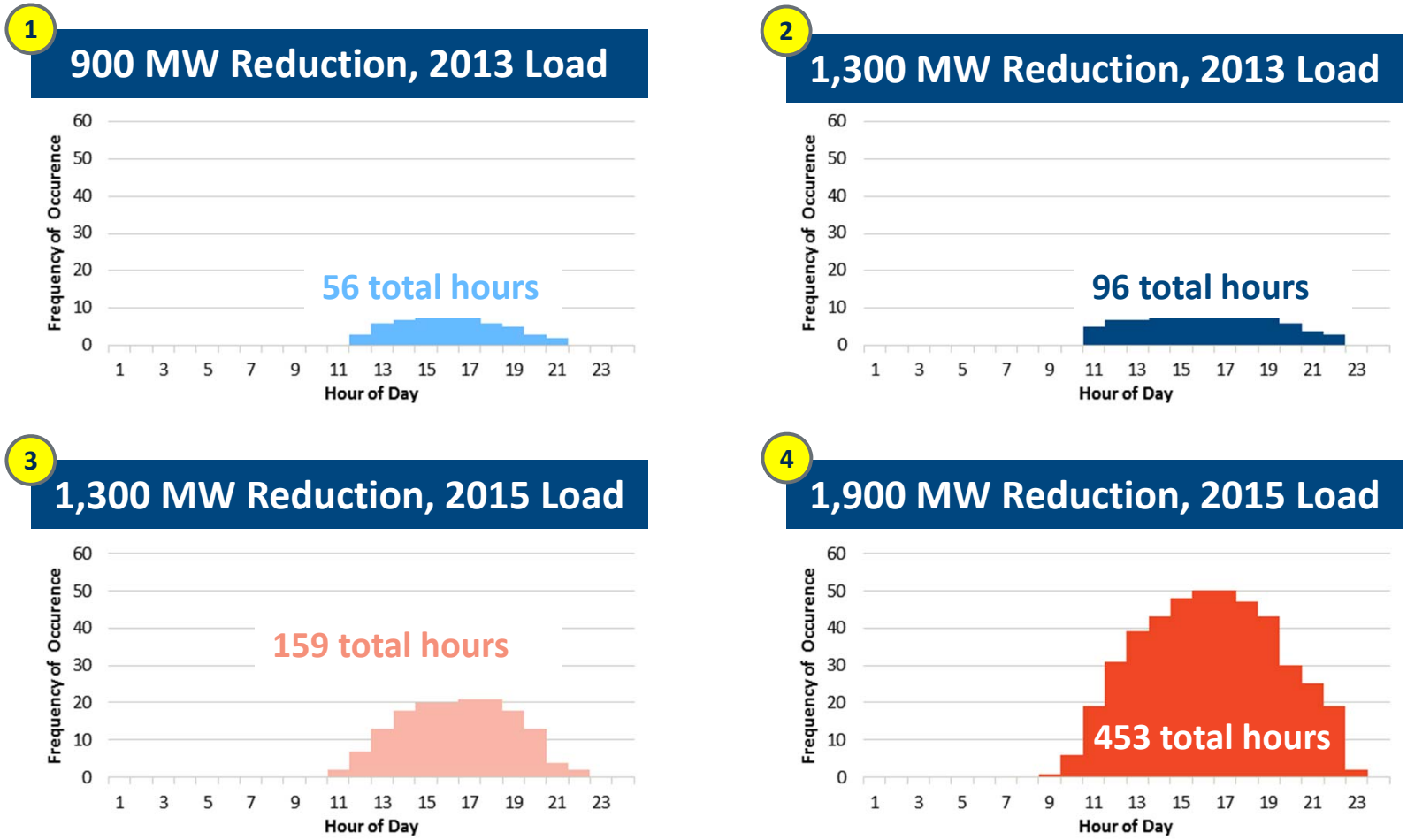
NSP's 2013 Load Duration Curve



Sources and Notes: 2013 system load for NSP service territory, provided by Xcel. 2013 was chosen as the year for this example, because it was the year with the highest peak demand in the past several years. Results will vary depending on the year being analyzed.

Achieving very large peak demand reductions will likely exceed the capabilities of traditional DR

Hours of Day When DR Would Need to be Utilized



Note: The charts illustrate the distribution of hours when a DR event would need to be called in order to achieve the specified load reduction for the specified year's load shape.

Appendix C:
Cost-Effectiveness Analysis Assumptions

Additional assumptions

Hours of generation capacity value allocation

- Base case = Top 100 load hours
- Min (probabilistic analysis) = Top 25 hours
- Max (probabilistic analysis) = Top 250 hours

Load year

- 2013, selected because it represents the highest peak demand in recent historical data (2012 through 2015) and also has the peakiest load shape, contributing to a slightly higher value of DR than other years

Planning reserve margin

- For the purposes of estimating avoided generation capacity costs, impacts are grossed up by the planning reserve margin
- This accounts for a reduced planning need
- NSP's planning reserve margin for its own system peak is 2.41% due to non-coincidence with the MISO peak

Line losses

- Impacts in the 2014 Potential Study were reported at the generator level; no gross-up was needed to account for line losses

Energy margin

- According to NSP modeling, the net energy margins (sum of marginal energy price minus the unit's variable costs over all operational hours) for a new CT in the study years is roughly between $6 and $18/kW-year
- We assume $12/kW-year, the middle of this range

Participation

- Base case impacts were based on the supply curve values produced for the 2014 Potential Study
- In an appendix to that study, we conducted a sensitivity case for each DR program's participation assumption, based on participation rates used in the 2009 FERC Assessment of DR Potential (which were based on the 75th percentile of national DR enrollment rates)
- For all but one program, the sensitivity case participation rates were lower than those used in the 2014 study
- For the probabilistic assessment in cost-effectiveness analysis, we used the absolute value of the difference between the FERC values and the 2014 Potential Study values to create upper- and lower-bound participation rates.
- The upper- and lower-bounds range anywhere from +/-5% of the Base participation rate, to +/-82%, depending on the program analyzed

Additional methodological notes

The scope of this study was only to assess the cost-effectiveness of the DR programs analyzed the 2014 Potential Study

We did not analyze time-varying pricing programs, since NSP has not deployed AMI

We have only assessed the DR potential that is incremental to existing programs; we have not analyzed the cost-effectiveness of NSP's existing DR portfolio

Our analysis is conducted from the standpoint of DR costs and benefits in 2023, the year by which the PUC has required NSP to add 400 MW of DR (and the year before the projected need for new peaking capacity, per the IRP)

Appendix D:
Additional Background

NSP's DR programs

Savers Switch:

- Central air-conditioning DLC
- Compressor switch with 15- to 20-minute cycling
- Additional option to enroll water heater
- Residential and business customers
- Residential incentive = 15% savings on energy charges (June – Sept)
- Business incentive = $5/ton of A/C (June – Sept)
- 321 MW of peak demand reduction capability (2016)

A/C Rewards:

- DLC for customer-owned smart thermostats
- Temporary modification of thermostat set point
- Residential
- Incentive = $25/yr, plus up to $125 rebate toward purchase of select smart thermostats or $75 payment for registering an installed smart thermostat
- 8 MW of peak demand reduction capability (2016)

Electric Rate Savings:

- Interruptible tariff, customer must reduce load to pre-specified level
- Medium and large C&I customers
- Minimum 50 kW demand reduction for eligibility
- Control periods can occur any time of year
- Incentive = $5.86 to $8.44 per kW of controllable load (June-Sept), $1.75 to $4.33 per kW (Oct-May)
- 501 MW of peak demand reduction capability (2016)

The 2014 DR Potential Study

The purpose of the study was to:

- Quantify the potential peak demand reduction that could be achieved through an expanded portfolio of demand response (DR) options in NSP's service territory, without cost considerations
- Identify future DR opportunities for NSP

We considered 22 different programmatic DR options and segmented the market into four customer classes

- 9 of the options were existing programs and 13 were possible new options
- 10 were considered "traditional" DR options and 12 were AMI-enabled options

We also estimated program costs which, when combined with the peak reduction estimates, produced a "supply curve" of traditional DR resources that could be used as input to NSP's integrated resource planning (IRP) process

Note: Our DR potential estimates did not account for the cost-effectiveness of the DR measures

The 2014 Potential Study (cont'd)

The following DR options were analyzed

Currently offered options

- **Direct load control (DLC):** Participant's central air-conditioner is remotely cycled using a switch
- **Interruptible rates:** Participants agree to reduce demand to a pre-specified level and receive an incentive payment in the form of a discounted rate
- **Time-of-use (TOU) rates:** NSP currently offers TOU rates, which are replaced in our analysis by re-designed rates (see discussion below)

Possible new options

- **Demand bidding:** Participants submit hourly curtailment schedules on a daily basis and, if the bids are accepted, must curtail the bid load amount to receive the bid incentive payment or may be subject to a non-compliance penalty
- **Critical peak pricing (CPP) rates:** Provides customers with a discounted rate during most hours of the year, and a much higher rate (typically between 50 cents/kWh and $1.00/kWh) during peak hours on up to 10 or 15 days per summer; can be offered with "enabling technology" which automates load reductions in response to the higher priced hours
- **Redesigned time-of-use (TOU) rates:** Existing TOU rates were redesigned to be more manageable and targeted, with a shorter peak period and a revised peak-to-off-peak price ratio

Xcel Energy Demand Response Offerings

2017-2019 Stakeholder Engagement Process Summary Report

MN PUC Docket No. E-002/RP-19-368

May 2019

Co-convened by the Great Plains Institute and Center for Energy and Environment

About this Report

AUTHOR

Trevor Drake, Great Plains Institute

ATTRIBUTION OF COMMENTS

This document provides a synthesis of remarks by stakeholders at seven meetings between December 2017 and January 2019. The notes do not indicate consensus among the group, but rather are meant to capture the collective discussion and key points raised by participants. No view should be attributed to any specific individual or organization.

The stakeholder engagement process and this resulting summary are intended to support, but not replace, important discussions within the formal regulatory process. Comments summarized as part of this report represent a perspective at a specific point in time and are not intended to limit the ability of any party to take any position in future regulatory proceedings.

ACKNOWLEDGEMENTS

GPI and CEE would like to thank Xcel Energy for the opportunity to serve as third-party facilitators for this stakeholder engagement process. We would also like to thank the stakeholders and speakers who attended and thoughtfully participated in the seven meetings that were convened as part of this process.

ABOUT THE CO-CONVENERS

Great Plains Institute: A nonpartisan, nonprofit, Great Plains Institute is transforming the energy system to benefit the economy and environment. For the last 20 years, the institute has worked on energy solutions that strengthen our communities, grow the economy, and improve lives while reducing emissions. More information is available at www.betterenergy.org

Center for Energy and Environment: The Center for Energy and Environment is a clean energy nonprofit with special expertise in energy efficiency that stretches back nearly 40 years. CEE provides a range of practical and cost-effective energy solutions for homes, businesses, and communities to strengthen the economy while improving the environment. More information is available at www.mncee.org

QUESTIONS ABOUT THIS REPORT

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I. Introduction

BACKGROUND ON DEMAND RESPONSE

Across the United States, profound changes are affecting the way that electric systems are being planned and operated. These changes include a shift away from power generation from large power plants towards greater deployment of variable, distributed electricity generation from wind and solar, increasing demand for electrified transportation and buildings, a desire for more consumer choice, and pressure to reduce carbon emissions and environmental impacts. Utilities, their regulators, and energy system stakeholders across the nation are grappling with how to address these changes and pressures while attending to the need to operate electric systems safely, reliably, and affordably.

Demand response encompasses a broad set of technologies and approaches that are used to modify customers' demand for electricity to provide system-level services. Demand response programs have the capabilities to help respond to many, if not all, of the profound changes and pressures affecting the electric system today. While demand response has historically been used to incentivize customers to curtail their demand for electricity during emergency events, it can also be used for other purposes, including enhancing overall reliability, reducing operations costs by deferring or avoiding infrastructure investments, shaping loads to accommodate variable electricity generation resources like wind and solar, providing choice to customers in how much they pay for electricity based on when they use it, and providing ancillary services such as frequency regulation.

Electric utilities across Minnesota already operate several demand response programs, ranging from interruptible tariffs that provide commercial and industrial customers a lower electricity rate in return for the ability to curtail demand during emergency events, to electrified home water heaters and air-conditioners that can be controlled by utilities to manage aggregated residential electricity loads across many customers at once.

DEMAND RESPONSE REQUIREMENT FOR XCEL ENERGY IN MINNESOTA

In its January 11, 2017 Order approving Xcel Energy's 2016-2030 Resource Plan, the Minnesota Public Utilities Commission required the electric utility to include in its next resource plan the procurement of 400 megawatts of additional demand response resources by 2023 and to evaluate the cost-effectiveness of 1,000 MW of additional demand response by 2025. In December 2017, Xcel Energy hired the Great Plains Institute (GPI) and Center for Energy and Environment (CEE) to convene stakeholder meetings to solicit input on the development of its demand response offerings towards achieving compliance with the Commission's order. Xcel Energy also hired The Brattle Group to conduct an updated demand response potential study including cost-effectiveness analysis, which became available near the end of the stakeholder engagement process.

This report summarizes key points of discussion and feedback received throughout the stakeholder engagement process, which took place across seven meetings from December 2017 to January 2019.

II. Process Overview

ORIGINAL PROCESS GOALS

Beginning in December 2017, Xcel Energy initially established the following goals to help guide the stakeholder engagement process that would be co-convened by GPI and CEE:

- Create a base understanding of demand response efforts in Minnesota compared to other areas of the nation.
- Discuss the scope of demand response efforts in Minnesota.
- Provide an opportunity to share ideas amongst stakeholders regarding demand response efforts within and outside Xcel Energy's service territory.
- Brainstorm new and updated program ideas for Xcel Energy's portfolio.
- Examine opportunities and challenges to new demand response technologies and any policy changes needed for success.

PROCESS REVISIONS

The above set of goals provided a helpful and broad starting point for stakeholder discussions. However, after the first two meetings, it became clear that it would be most valuable to focus stakeholder discussions specifically on the new or expanded demand response offerings that Xcel Energy could deploy to achieve compliance with the Commission's order. Therefore, after the second meeting, GPI, CEE, and Xcel Energy worked together to restructure the process around the following revised set of goals:

1. Identify a set of consensus-based design characteristics for any new or expanded demand response program or portfolio or programs.
2. Understand and discuss the results of The Brattle Group's demand response potential study in the context of the proposed design characteristics.
3. Apply the design characteristics to the list of Xcel Energy's potential new and expanded demand response programs and identify which programs comport with the agreed-upon design characteristics.
4. Review and offer feedback to the demand response programs that Xcel Energy is developing to comply with the commission's order, considering both the design principles and the results of the potential study.

This report details the group's progress in working to achieve these goals. Importantly, Xcel Energy stated to the group that their next Resource Plan will assume the additional demand response as required in the Commission's order, but that not all programs that will be deployed to achieve compliance would be fully developed by the time that the 2020-2034 Resource Plan is filed. Therefore, while the group did develop design characteristics—in the form of the Design Principles and Filing Objectives listed in this report—and discussed them with regard to Xcel Energy's proposed DR offerings, many of those offerings were still in development at the time of these meetings and could not be fully evaluated. Therefore, the Design Principles and Filing Objectives can be especially useful to provide ongoing guidance as those offerings are developed and proposed for approval.

TIMELINE AND MEETING TOPICS

Between December 2017 and January 2019, GPI and CEE convened a total of seven meetings, each covering the topics listed below. Meetings were held in-person in various locations in Minneapolis and St. Paul. Most meetings also allowed remote attendance when possible.

Meeting 1: Introduction to Demand Response

- Presentations:
  - Demand response 101 (Xcel Energy, The Brattle Group)
  - Regional transmission organizations and demand response (MISO)
  - Current utility demand response programs in Minnesota (Xcel Energy, Great River Energy)
- Discussion:
  - New demand response technologies and opportunities

Meeting 2: Demand response technologies and programs

- Presentations:
  - Current utility demand response programs in Minnesota (Otter Tail Power)
  - What XcelEnergy is currently exploring for new DR technologies and programs
- Discussions:
  - Q&A with MISO staff
  - Panel on DR technologies and programs, including enabling technologies, examples from other utility markets, and DR aggregators

Meeting 3: Demand response values, benefits, and challenges (April 2018)

- Presentation:
  - Demand response values and benefits (Xcel Energy)
- Discussions:
  - Stakeholder panel on demand response benefits and challenges (MN Department of Commerce, Citizens Utility Board, Fresh Energy)
  - What are stakeholders' objectives for Xcel Energy's additional DR offerings?

Meeting 4: Demand response cost-effectiveness; stakeholder guidance (May 2018)

- Presentation:
  - Evaluating demand response cost-effectiveness in resource planning (Xcel Energy)
- Discussion:

- What are stakeholders' design principles for Xcel Energy's additional DR offerings? (continued from Meeting 3)

Meeting 5: Demand response potential; distribution geo-targeting (August 2018)

- Presentations:
  - Demand response potential study preliminary results (The Brattle Group)
  - Demand response geo-targeting on the distribution system (Center for Energy and Environment)
- Discussion:
  - Exploring the preliminary results of the most recent demand response potential study

Meeting 6: Xcel Energy's draft demand response portfolio (August 2018)

- Presentation:
  - Draft portfolio of additional demand response offerings (Xcel Energy)
- Discussion:
  - Stakeholder feedback on Xcel Energy's draft portfolio

Meeting 7: Xcel Energy's proposed demand response programs (January 2019)

- Presentation:
  - Demand response potential study final results (The Brattle Group)
  - Proposed list of new and expanded demand response offerings (Xcel Energy)
  - Recommendations from Advanced Energy Management Alliance and Xcel Large Industrials to enable Xcel to achieve the Commission's mandate for incremental demand response in its service territory.
- Discussion:
  - Q&A on the final demand response potential study
  - Stakeholder feedback on Xcel Energy's new and expanded demand response offerings

PARTICIPATING ORGANIZATIONS

Meetings in this process were open to the public and noticed in MN PUC Docket No. E-002/RP-15-21. GPI also sent email invitations to a distribution list of parties that had expressed interest in Xcel Energy's demand response programs.

Meetings drew an average attendance of 30-40 individuals per meeting. GPI, CEE, and Xcel Energy would like to thank the following organizations for their participation in one or more (and in many cases, all) of the seven meetings. As noted above, comments summarized in this

document represent the collective insights of stakeholders who attended these meetings and should not be attributed to any specific organization or individual.

- MISO
- Advanced Energy Management Alliance
- Center for Energy and Environment
- Citizens Utility Board of Minnesota
- Fresh Energy
- Great River Energy
- Landis+Gyr
- LLS Resources, LLC
- Minnesota Department of Commerce
- Minnesota Municipal Utilities Association
- Minnesota Pollution Control Agency
- Minnesota Power
- Minnesota Public Utilities Commission
- MN Attorney General's Office
- MN Department of Commerce
- MN Pollution Control Agency
- NRG Curtailment Solutions, Inc.
- Otter Tail Power Company
- Rakon Energy LLC
- Stoel Rives, on behalf of the Xcel Large Industrials
- Strategen Consulting
- The Brattle Group
- The Mendota Group, LLC

MEETING MATERIALS

All meeting materials from this process, including agendas, slide decks, resources, documents developed for the group, and meeting notes are available online at https://trello.com/b/vgrVwhQ3/xcel-energy-demand-response-workgroup.

III. Design Principles and Filing Objectives

Demand response is a complex and wide-ranging topic. Demand response programs can be designed to offer services at the distribution and wholesale market level, engage every type of customer, and relate to or overlap with other program offerings including energy efficiency and time-varying rates. Given this complexity and the fact that Xcel Energy's demand response programs were still in development at the time these stakeholder convenings took place, GPI and CEE asked stakeholders to collaborate in developing a set of consensus-based principles that could provide guidance to any new or expanded demand response offering, allowing flexibility on behalf of Xcel Energy to design programs in consideration of the parameters set by stakeholders.

Stakeholders participating in this process developed two lists—Design Principles and Filing Objectives. The Design Principles provide guidance for designing demand response programs or portfolios of programs. The Filing Objectives describe what information stakeholders would like to see when new demand response offerings are presented for consideration to the appropriate regulatory body (the Minnesota Public Utilities Commission and/or the Minnesota Department of Commerce). These two lists are interrelated and therefore intended to be taken as a package. In other words, while all stakeholders may not have supported each of these objectives or principles on their own, they found the full set acceptable.

Importantly, these are meant to be general guidelines and not absolute requirements. Just because an offering arguably complies with these does not guarantee that stakeholders will

approve of it. These simply offer a starting point for developing demand response offerings that have a higher likelihood of earning stakeholder approval in the regulatory process.

DESIGN PRINCIPLES

What would stakeholders like to see from a demand response portfolio of any size from Xcel Energy in Minnesota?

1. **Compensate demand response appropriately given the specific benefits it provides.**

   Incentives and penalties should be informed by the underlying benefits and value streams that the program is intended to achieve. It's up to the utility to find the right incentive levels that will both elicit customer action and enable the desired benefits at a lower cost than other resource options.

2. **Ensure pricing and expectations are clear, concise, and transparent for customers.**

   The utility should make efforts to ensure that customers participating in DR programs understand the program rules.

3. **Provide flexibility and options for customers.**

   Demand response programs are ultimately made possible as a result of cooperation from customers. Therefore, it's important that the utility provides offerings that allow flexibility and options for customers with different needs, while also delivering the desired system benefits.

FILING OBJECTIVES:

What would need to be true to earn stakeholder support when new or expanded demand response offerings are filed with the Commission?

1. **Be clear about the outcomes that demand response offerings are designed to achieve, and how those should be measured down the road.**

   Outcomes addressed should include cost-effectiveness, customer engagement as participation, system reliability and flexibility, carbon reduction, resource integration, and avoidance of building new assets.

2. **Fully evaluate demand response program costs and benefits.**

   Costs and benefits should be evaluated from the perspective of multiple key actors affected by demand response programs, including the utility, DR participants, ratepayers who are not DR participants, and society at-large (e.g., including public policy related impacts such as greenhouse gas emissions). This evaluation should include consideration of alternatives to achieving the same benefits (e.g., if DR is being used to

address a system need, how do DR costs and benefits compare to those of whatever alternative might be used to meet that system need?).

Demand response programs can deliver several benefits, including the following: reducing peak loads; shifting loads from high-cost times to low-cost ones; shifting loads from periods with high greenhouse gas emissions to periods with lower emissions; beneficially adding new loads with attention to costs and emissions; reducing energy and capacity costs; and reducing the costs of necessary ancillary services including frequency regulation, spinning reserves, and supplement reserves. DR programs can achieve higher levels of cost effectiveness by ensuring that programs are enabling as many benefits as possible.

The costs and benefits being evaluated may depend on the particular regulatory pathway through which a new demand response program is proposed (e.g., programs being proposed as CIP offerings may be evaluated differently than those being proposed through a miscellaneous filing).

At least one stakeholder felt that the MISO capacity auction does not provide an accurate price signal for determining the cost-effectiveness of DR offerings and that the MISO-calculated CONE (cost of new entry) should be used as a proxy. Xcel Energy staff responded that DR offerings would need to compete with the company's individual CONE, which is being updated for the upcoming IRP and is expected to be lower than the MISO value due to the availability of many brownfield sites (as opposed to more expense greenfield sites) for new CT's.[1]

3. **Address reliability and resilience of demand response offerings, as relevant.**

   Demand response proposals should include evidence to show how the proposed offerings will reliably deliver the intended benefits. This evidence could include physical testing, the deployment of incentives and penalties that can arguably elicit a response from customers, and audits to confirm that a program is reliably delivering its intended benefits when called upon. In cases of entirely new offerings where showing evidence of costs and benefits may not be possible, pilot projects could be deployed to develop the needed evidence.

4. **Delineate between dispatchable and non-dispatchable demand response.**

   The group discussed the difference between "dispatchable" and "non-dispatchable" DR, but did not come to consensus on exact definitions for those terms. In general, this objectives asks Xcel Energy to differentiate between something like a time-of-use rate, which could be considered a DR offering but is arguably not dispatchable (i.e., it can't be called upon to reduce load in an emergency event), and something like critical peak pricing, which is arguably dispatchable to reduce load when needed. Some stakeholders questioned the extent to which non-dispatchable offerings qualify as demand response.

[1] Meeting 4 Notes, pages 3-4, available online at https://trello.com/c/aNqgmBv4/4-meeting-4-dr-design-principles-objectives-and-cost-effectiveness-5-1-2018

In addition, some stakeholders asked that Xcel Energy clarify which demand response offerings, and how much of those offerings, are accredited in MISO.

5. **Show transparency towards meeting the objectives listed above.**

   For all of the filing objectives above, Xcel Energy is more likely to earn support from stakeholders by showing or explaining its efforts to meet these objectives as transparently as possible.

6. **Consideration of the AEMA/XLI Recommendations**

   The Advanced Energy Management Alliance (AEMA), which represents the interests of demand response service providers, including aggregators and the end-use consumers who ultimately provide demand response resources, was one of the organizations that provided dedicated stakeholder participation to this process. AEMA partnered with Xcel Large Industrials (XLI), a group of Xcel's largest industrial customers who are represented in regulatory matters by the law firm Stoel Rives LLP, to develop a set of recommendations for what they would like to see reflected in Xcel Energy's DR offerings based on discussions during this process.

   GPI and CEE, at the request of AEMA and XLI and with consent from Xcel Energy, distributed a document listing those recommendations in advance of the seventh meeting. Facilitators also allowed AEMA and XLI to present their recommendations to the group at that meeting.[2]

   Most of the best practices that AEMA and XLI recommended were in alignment with the group's previously developed Design Principles and Filing Objectives, though their recommendations offered much more specific detail. The one best practice area that differed most notably from the group's Design Principles and Filing Objectives was in regard to the utility's use of third-party DR service providers.[3] AEMA and XLI argue in their written proposal that demand response aggregators can offer services that benefit both customers and the utility, ultimately making DR programs more effective. [4]

   The appropriate use of third parties to support Xcel Energy's demand response efforts was a theme that arose in several discussions throughout the stakeholder engagement process. and may be worth considering when new or expanded demand response offerings are proposed for approval.

[2] The recommendations document and associated slide deck from AEMA and XLI are available online at https://trello.com/c/qvtlayfB/23-meeting-7-wrap-up-1-22-2019

[3] AEMA proposals mirror the "Indiana Model" for consumer and aggregator participation in DR programs. Under the Indiana model, aggregators act as an intermediary between the utility and the customer, bringing the customer's load drop capabilities to the utility, and the utility will then, if appropriate, register the load drop capabilities with the ISO. Under this approach, there is no infringement on the state's prior decisions under FERC order 719

[4] Recommendations document at 3

IV. Demand Response Potential Study

BACKGROUND ON THE STUDY

To support both its own efforts to comply with the commission's requirement and stakeholder discussions under this process, Xcel Energy hired The Brattle Group to conduct a study of demand response potential in its Northern States Power (NSP) service territory.

The Brattle Group had conducted a previous study in 2014 that looked only at DR technical potential, which was the basis for the Commission's requirement. This more recent study looked beyond that technical potential, evaluating both cost-effective potential—in which demand response program costs, equipment costs, and incentives must outweigh avoided resource costs—and achievable potential, which estimated program enrollment rates based on local and national market research.

This new study sought to "estimate the potential capability of all cost-effective demand response (DR) that could be deployed in Xcel Energy's Northern States Power (NSP) service territory through 2030," including mid-point analyses at the year 2023, which was the deadline for procuring 400 MW of additional DR as required by the Commission, and the year 2025, which was the commission's deadline for evaluating the cost-effective achievability of 1,000 MW of additional DR.[5]

The study included two scenarios for evaluating DR deployment under different sets of assumptions – a Base Case and a High Sensitivity Case. The study states, "The Base Case most closely aligns with NSP's expectations for future conditions on its system, as defined in its IRP. The Base Case represents a continuation of recent market trends, combined with information about known or planned developments during the planning horizon."

By comparison, "The High Sensitivity Case was developed to illustrate how the value of DR can change under alternative future market conditions. The High Sensitivity Case is defined by assumptions about the future state of the NSP system and MISO market that are more favorable to DR program economics."[6] Importantly, the study notes that the High Sensitivity Case "is not a forecast of what is likely to happen in the future in NSP's service territory, particularly in the near-term years of the study horizon."[7]

[5] Ryan Hledik et al., *The Potential for Load Flexibility in Xcel Energy's Northern States Power Service Territory,* (The Brattle Group, January 2019), i, available online at https://trello.com/c/qvtlayfB/23-meeting-7-wrap-up-1-22-2019

[6] Ibid, iv

[7] Ibid, iv

INTERPRETING THE COMMISSION'S REQUIREMENT

Importantly, the study lists two clarifications around interpreting the commission's 400 MW requirement. The first is that there are three ways to measure demand response – at the capacity level, the generator level, and the meter level:

> 1 MW of load reduction at the meter (or customer premise) avoids more than 1 MW at the generator level due to line losses between the generator and the customer. Further, 1 MW of load reduction at the generator level provides more than 1 MW of full capacity-equivalent value, as the load reduction would also avoid the additional capacity associated with NSP's obligation to meet the planning reserve requirement. Based on NSP's calculations, which account for line losses and the reserve requirement, 1 MW of load reduction at the meter level equates to 1.08 MW of load reduction at the generator level and 1.11 MW of capacity-equivalent value.[8]

The report then states that while "NSP has interpreted the PUC's Order to require 400 MW of capacity-equivalent DR," the report itself assesses the commission's "procurement requirement as a 391 MW generator-level value unless otherwise specified."[9] To be consistent, this section of the stakeholder process summary uses demand response capability values that align to the report's 391 MW generator-level interpretation of the commission's 400 MW requirement.

The second clarification is that the requirement set by the commission was established based the 2014 potential study, when Xcel Energy had 918 MW of demand response capability. Much of this newer study looks at incremental DR potential from a lower 2018 baseline of 850 MW of DR capability. This reduction in the baseline is due to program right-sizing that took place after 2014, in which customers on interruptible tariffs were tested to check their ability to comply with the requirements of those tariffs and subsequently removed from the tariffs if warranted.[10]

The effect of this baseline change from 2014 to 2018 is that in order to meet the commission's requirement, Xcel Energy must procure an additional 459 MW of generator-level DR from the 2018 baseline, adding up to a total generator-level demand response capability of 1,309 MW by 2023.

RESULTS AND STAKEHOLDER DISCUSSION

With regard to the commission's 2023 requirement, the study concluded that under the Base Case assumptions Xcel Energy could cost-effectively deploy 306 MW of additional generator-level demand response by 2023 from a 2018 baseline, falling short of the Commission's 459 MW requirement (adjusted from the original 400 MW value as noted above). This was partly due

[8] Ibid, 17

[9] Ibid, 17

[10] Ibid, 18

to the assumption that advanced metering infrastructure (AMI) would not be fully deployed in 2023, an item that was of interest to stakeholders and is described in more detail below.

Beyond the 2023 deadline, the study found that, under the Base Case assumptions and with full AMI deployment in 2024, Xcel Energy could deploy "1,243 MW of cost-effective DR potential in 2025."[11] This quantity would be close to, but still short of, the incremental 459 MW (1,309 MW total potential) requirement for 2023. Looking out to 2030, the Base Case assumptions yielded 468 MW of incremental cost-effective DR, adding up to a total portfolio 1,318 MW.[12]

Staff from The Brattle Group presented preliminary results from the study at Meeting 5 and final results at Meeting 7. While the opportunity to discuss the study during meetings was clearly valuable to stakeholders, it seemed to facilitators that more time could have been useful to understand the study results in-depth. To support ongoing conversation and complement the information contained in the study, we have described below the topics that appeared to be of most interest to stakeholders during Meetings 5 and 7, including examples of specific issues or questions that were raised.

Avoided capacity costs

In order for demand response to be cost effective in the study, the sum of its program, equipment, and customer incentive costs would have to outweigh the cost of an avoided resource. Therefore, the assumed cost of an avoided resource was of particular interest to stakeholders because it serves as a threshold that demand response must pass to be considered cost effective.

As noted above under Filing Objective 2, Xcel Energy's cost of a new natural gas generation resource is significantly lower than national averages due to the availability of brownfield sites that reduce development costs for new turbines. This was a concern for some stakeholders. The study addresses this difference by looking at demand response potential under two different avoided capacity costs: Xcel Energy's assumed cost in its 2018 integrated resource plan of $64/kW-yr for the base case, and the U.S. Energy Information Administration's 2018 Annual Energy Outlook assumed cost of $93/kW-yr for the high sensitivity case.[13]

Cost-benefit analysis

In alignment with Filing Objective 2, many stakeholders wanted to better understand how the costs and benefits of demand response were analyzed in the study, in comparison to traditional forms of generation such as natural gas plants. In particular, some participants were interested in the assumptions around the operational constraints of

[11] Ibid, iii

[12] Ibid, iv

[13] Ibid, 13

demand response programs (e.g., the ability to actually elicit the required response from customers when needed, with attention to the necessary frequency and duration of that response).

Staff from The Brattle Group responded that they analyzed demand response costs and benefits by taking Xcel Energy's assumed cost of providing capacity through traditional generation (e.g., $63/kW-yr in the base case) and allocated that cost across the 100 hours of the year when electricity demand was most likely to be at its peak. This takes the annual avoided capacity cost and turns it into an hourly capacity cost that demand response must beat to be cost-effective in each of those hours. The Brattle Group's model then attempts to dispatch demand response in those hours instead of traditional generation, accounting for DR costs, operational constraints such as the inability to use air conditioning demand response programs in winter and additional values, such as deferral of transmission and distribution investments. Additional details of the cost benefit analysis are included in the study.

Incentive levels for existing program participants

One key clarification that arose through stakeholder discussion was that the study looked only at the costs to acquire *new* demand response program participants, either through entirely new programs or through the acquisition of new participants for existing programs. However, the study did not look at adjusting incentive levels or changing program designs for existing DR participants. Some stakeholders were concerned that so doing may have excluded potentially significant additional capacity of cost-effective DR and certainly excluded analysis of existing customer capacity beyond emergency-only interruptions. While any changes for existing program participants were outside the scope of this study, this issue may be worth considering as changes to existing demand response programs are proposed in the future.

Advanced metering infrastructure

Stakeholders were interested in how advanced metering infrastructure (AMI) was included in the potential study because it's a foundational technology that enables several demand response programs, including time-varying rates and critical peak pricing. With no residential advanced metering infrastructure currently deployed or planned other than for the residential time-of-use pilot that will commence in 2020, the study assumed that NSP would not achieve full AMI deployment until 2024. This was a factor in the study's finding that Xcel Energy could not cost-effectively achieve 459 MW of additional demand response by 2023 from a 2018 baseline.

Participants were also interested in assumptions around the costs of AMI. One of the challenges with addressing those costs is that AMI can be used to support many programs and services, demand response being only one of them, so it is difficult to assign a portion of the total investment in AMI to demand response programs alone. The Brattle Group staff explained that while AMI was assumed beginning in 2024, its costs were not included in the assessment of DR program costs.

The impact of this on the study is that programs that rely on AMI after 2024 may appear more cost effective than if a portion of the investment in AMI was included in their costs. Some stakeholders were interested in further discussing AMI investment costs, but

acknowledged that such a discussion might be better suited to a conversation outside of these demand response-specific meetings.

Transition from Saver's Switch to smart thermostats

In both Meeting 5 and Meeting 7, stakeholders were curious to know more about a shift that the study predicted between 2017 and 2023, in which current participants in the Saver's Switch program leave to become participants in smart thermostat programs. The Brattle Group staff explained that utility-controllable smart thermostats offer more sophisticated demand response controls over Saver's Switch, such as the ability to pre-cool spaces and coast through an event, rather than simply cycling A/C units during the event. Further, since the two programs control the same devices (i.e., A/C units), customers may not participate in both.

This transition between the two different technologies leads to a net increase of 114MW of demand response—roughly one third of the cost-effective demand response capacity that could be deployed before 2023.[14] The Brattle Group staff also noted that while these programs are offered to residential, commercial, and industrial customers, most of the increase is due to residential customers buying smart thermostats.

Full consideration of value streams, including ancillary services

Participants were interested in finding out whether and how DR value streams beyond avoided capacity were analyzed, including transmission and distribution deferral and ancillary services such as frequency regulation. Staff from The Brattle Group explained that up to 2023, most of the value attributed to demand response comes from deferred capacity investments. However, the study's High Sensitivity Case looks at the value of additional benefits from ancillary services towards 2030, including a doubling of the need for frequency regulation as well as additional need for transmission and distribution deferral. Staff from The Brattle Group clarified that frequency regulation is the only ancillary service that was modeled because it provides the greatest value to demand response.

Full consideration of newer demand response programs

The Brattle Group's study considered eight new demand response program options, but found that only smart water heating could cost-effectively be deployed before 2023.[15] Some stakeholders were interested in knowing more details about how these newer programs were considered. In particular, participants asked about behavioral demand response (in which customers receive non-monetary positive feedback for reducing their electricity usage in response to a notice) and heat pump space and water heating.

For behavioral demand response, which was not found to be cost effective under any of the cases modeled, The Brattle Group staff explained that they looked at studies and

[14] This value was initially presented as 105 MW in Meeting 5 (Brattle deck slide 11) and was later updated to 114 MW in the final version of the potential study.

[15] Hledik et al., Potential for Load Flexibility, 19-21

spoke with O-Power, a behavioral demand response service provider, to better understand the per-customer costs of running those programs. For heat pump space and water heating, the research team explained that they considered it, but didn't include it in the study for two reasons: first, that most of the benefits are efficiency rather than demand response; and second, that penetration of electric heat pumps is currently too low to warrant its inclusion, though that could change in the future. However, the study does include electric resistance water heaters, which currently have a more substantial market penetration.

V. Xcel Energy's Demand Response Offerings in Development

At the sixth stakeholder meeting in August 2018, Xcel Energy presented for feedback an initial list of demand response programs under development to meet the commission's requirement. This included eight residential DR programs, five programs for large commercial and industrial customers, and six programs for small/medium commercial and industrial customers.

INITIAL FEEDBACK

In response to the offerings presented at Meeting 6, stakeholders said that the list of programs seemed to strike a balance between traditional DR and forward-looking, innovative programs. They also said that Xcel Energy seemed to be looking at the right general buckets of opportunities. However, several stakeholders stated that they would need much more detail to be able to fully evaluate Xcel Energy's DR offerings. Below, we have summarized the general requests for more information that were raised during Meeting 6:

Contribution to Commission Requirement

The programs presented at Meeting 6 did not include estimated DR capabilities in terms of megawatts, so some stakeholders wanted to know how each program would contribute to the commission's requirement. As noted below, Xcel Energy provided initial estimates for these numbers in Meeting 7.

Cost-Effectiveness and Potential Study

Stakeholders desired to know more about the cost-effectiveness of each program being developed, and how that cost-effectiveness was derived, whether based on sensitivities in The Brattle Group's potential study or through another method. Some parties wanted additional information about how cost-effectiveness of DR programs would be represented in the forthcoming integrated resource plan. It was also noted that cost-effectiveness is determined differently depending on the regulatory process being used to seek program approval – another piece of information that stakeholders desired and is described further below.

Regulatory Process

Some stakeholders wanted more information about which regulatory process(es) would be used to seek approval for each DR program. Accordingly, parties were interested in cost-effectiveness tests (as notes above) depending on the regulatory vehicle being used as well as how measurement, verification, and reporting protocols would be executed.

Advanced Metering Infrastructure (AMI)

Stakeholders had several questions about advanced metering infrastructure in relation to new demand response offerings, including how AMI deployment would impact the timing and pricing of each offering and whether these offerings would be used to justify investment in AMI.

Alignment with Filing Objectives and Design Principles

Some stakeholders wanted more information about whether and how each program aligned with the group's Filing Objectives and Design Principles. In particular, some participants at Meeting 6 were concerned that the programs seemed fragmented, potentially limiting customer choice and compensation for flexibility. There was also a question raised about which programs are dispatchable (i.e., in the utility's control) versus those that affect load shape but cannot be actively controlled by the utility, such as time-varying rates.

Opportunities for Aggregators

Some parties wanted to know more about the role of aggregators in the various programs that were presented, including whether and how aggregators could participate.

Consolidating Offerings

Some participants recommended combining several of the different C&I demand response offerings into a single program to encourage broad participation and avoid competition between similar offerings.

REQUEST FOR A DETAILED TABLE OF OFFERINGS

At the conclusion of Meeting 6, there seemed to be general agreement among the group that a more detailed presentation of Xcel Energy's new DR programs under development would be helpful to aid with understanding and evaluating the offerings, both individually and as a total package. Several stakeholders suggested that Xcel Energy come back to the group with a table listing the various offerings, their alignment with the Filing Objectives and Design Principles, and responses to the pieces of information requested above.

In response, Xcel Energy staff offered to develop the table and provide as much information as they could, based on availability of that information and timing constraints. Xcel Energy staff presented the table for review at the seventh and final meeting in January 2019. Below, we have listed the specific items that stakeholders asked Xcel Energy to provide and a summary of

the information that was available in response. We have also included a summarized version of the table itself.[16] Since these items were of interest to stakeholders during these meetings, it's likely that they'll be of interest as program move through the regulatory approval process.

1. **Provide a name and short description of the offering**

   The table listed 20 individual demand response offerings under development, each with a short description.

2. **Provide a narrative explaining how it complies with the group's Filing Objectives and Design Principles.**

   The table included columns that respond to many of the Design Principles and Filing Objectives, though some of the information was not yet available.

3. **What is its contribution to meet the commission's requirement?**

   The table listed estimated DR capability values in megawatts for each program area based on the Brattle Group's potential study, adding up to a total of 271 MW. The values were representative of the incremental load available when DR programs are offered simultaneously as part of an overall portfolio, and therefore were provided by program type rather than for each specific program. Xcel Energy noted that these were initial placeholders and would fluctuate as programs are further developed.

4. **Is it expected to be cost effective?**

   There are two cost-effectiveness columns – one based on whether the program was deemed cost effective based on avoided capacity costs; the other is based on an additional a cost-benefit analysis that was not yet available.

5. **Is it dispatchable or non-dispatchable?**

   This was included for each offering.

6. **Does it utilize AMI (to help justify the cost of investing in AMI)?**

   This information was not yet available.

7. **Does it have energy efficiency benefits?**

   This was included for each offering.

8. **What evidence is there of customer interest in the program?**

   This information was not yet available.

9. **What regulatory process(es) will be used to seek approval, and are there specific conflicts or risks anticipated?**

   This information was available for some of the programs and unavailable for others.

10. **What role, if any, is there for demand response aggregators?**

[16] The full table is available online in both PDF and Microsoft Excel formats at https://trello.com/c/qvtlayfB/23-meeting-7-wrap-up-1-22-2019

In the table presented, one of the programs—interruptible offerings for medium and small C&I customers—was targeted for third-party aggregators.

Feedback in response to the table at Meeting 7 was limited and will need to be refined as individual offerings move through the regulatory process. Overall, stakeholders said that they thought Xcel Energy was taking a thoughtful approach to a variety of achievable programs, and that the portfolio seemed forward-thinking from the perspective of supporting resource integration in the future. Some participants inquired whether the programs could be combined into more streamlined customer offerings. Xcel Energy staff responded that streamlining would take place once the company's full demand response roadmap was complete.

Participants also had the following questions in response to the table. While these were not resolved in the meeting, they may be worth pursuing in the formal regulatory process for considering Xcel Energy's DR offerings:

- Would it make a difference to consider incremental demand response from *existing* participants, since The Brattle Group's report looked only at potential for new participants?
- What will the carbon reduction impacts be from these programs?
- How might activity at MISO affect these programs?

Table 1. Summarized Version of Xcel Energy's Demand Response Offerings in Development as of January 22, 2019

Program Type	Est. Potential (MW)	Segment	Product	Description	Est. Potential Achievement Date
Behavioral DR	-	Residential	"Hands-off" DR	Use messaging without technology to encourage DR event participation	2023
Commercial Building Controls	10	C&I, Medium	Commercial Building	Leverage EMS software to provide DR capacity & overall demand mgmt	2021
Critical Peak Pricing	41	C&I, Medium	Critical Peak Pricing (Opt-in)	Base periods are similar to TOU structure with lower energy/demand prices, but during "critical" periods customer pays higher pricing	2022
Electric Vehicles	<1	Residential	Electric Vehicle Smart Charging	MN residential smart charging pilot with L2 EVSE, proves out EE and peak load shifting, may include economic demand response	2020
			Electric Vehicles DR& Storage	Use EV's for DR and storage opportunities	2024
Interruptible Offerings	79	C&I, Medium, Small	Peak Partner Rewards	Customer receives incentives for nominated capacity and/or performance during DR events	2020
		C&I, Medium, Small	Third-Party Aggregation	Allow third-party aggregator to promote, recruit and enroll customers into DR program.	2021
		C&I, Medium	Interruptible Rates	Rate discount or credit for agreeing to reduce load during specified periods (updates to current program)	2022
Other (not included in Brattle Group potential study)	-	C&I	DERs for Ancillary Services	Use DERs to provide ancillary services	2021
		C&I	Leverage Microgrids	Leverage existing or planned microgrids for DR capacity	2022
		All	Geo-targeted Distribution	Identify stress points in distribution system & target affected customers with regular or enhanced DR offers	2019 - CEE
		TBD	Reverse DR Balance system	Load for excess renewable generation by incentivizing customers to use energy at these times	2023
		Residential	BTM Batteries/Storage	Deploy battery technology behind customer meters for DR and load capacity	2024
Smart Thermostats	112	Residential	Expand current smart thermostat program	Expand current ST offerings into other markets, existing programs, or gas DR	2021
			Home Energy Management (HEM)	Provide technology to customers that helps reduce energy usage, educates, and facilitates DR	2024
			Smart Thermostat Optimization	Deploy software to manage & optimize smart thermostat operations to improve energy savings, demand reductions, etc.	2020
Smart Water Heating	8	Residential	Water Heaters for DR	Leverage water heaters for DR capacity	2023
			Water Heaters DR using CEA-2045 connection/technology	Via a controlled demonstration, this project will provide economic justification and a plan for a market transformation	2023
Thermal Storage	-	C&I	Thermal Storage	Leverage things like refrigeration as storage devices to shift demand	2023
Updating Saver's Switch	21	Residential, Small C&I	Saver's Switch (2-way communicating)	Updating our current technology and expanding the program	2021

VI. Conclusion and Next Steps

In compliance with the Commission's requirement to procure an additional 400 MW of demand response, Xcel Energy is in the process of reviewing roughly 20 expanded and new DR program offerings in its NSP service territory.

Those offerings are based in part on a study that Xcel Energy hired The Brattle Group to conduct to identify the potential for cost-effective, incremental DR programs, which found that the company could meet some, but not all, of the Commission's required demand response capability cost-effectively by 2023. This finding was due to a series of factors, including low capacity prices, lack of advanced metering infrastructure to enable some programs, low development costs for new generation assets, and limited benefits from ancillary services and transmission and distribution deferral.

There are multiple next steps for Xcel Energy's demand response offerings for Minnesota. The portfolio as a whole will be considered in Xcel Energy's next Integrated Resource Plan filing, with an assumption of deploying enough DR to meet the Commission's requirement by 2023 for at least one of the plan options. The individual demand response programs that will be deployed to achieve that requirement are currently in development and will be brought forth for regulatory approval, though the exact details of regulatory consideration were not available at the time of these stakeholder meetings.

As those offerings are determined to move forward, the Design Principles and Filing Objectives that were collaboratively developed by stakeholders as part of this process offer a useful framework, both for providing ongoing guidance to the design of those offerings, and for evaluating them once they are finalized and submitted for regulatory consideration. To the extent that program offerings can be designed and filed in accordance with the stakeholder guidance captured in this report, they will have a higher likelihood of earning stakeholder support.

APPENDIX H – ENVIRONMENTAL REGULATIONS REVIEW

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I. GREENHOUSE GASES

A. Regulation of CO_2 from Existing Power Plants

1. Clean Power Plan

The U.S. Environmental Protection Agency (EPA) in October 2015 promulgated, under Section 111(d) of the Clean Air Act, a final rule *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, termed the "Clean Power Plan" (CPP).[1] At the time of our last Upper Midwest Resource Plan, the rule was final and some of our states were beginning to develop implementation plans. We discussed in that Plan how the expected CO_2 reductions under our Preferred Plan would position Xcel Energy for compliance with the CPP, under various assumptions about how our states might design their plans and allocate CO_2 allowances.

Several states and industry petitioners, led by West Virginia, filed suit at the D.C. Circuit Court to stay the CPP. The D.C. Circuit initially declined to stay the rule, but the U.S. Supreme Court stepped in and stayed implementation of the CPP in February 2016. In the interim, the D.C. Circuit Court has held the case in abeyance.

EPA estimated that at the national level, the CPP would have reduced electric sector CO_2 emissions by about 32% below 2005 levels by 2030. Xcel Energy has already exceeded this reduction, achieving approximately 34% below 2005 levels as of 2018 for our Upper Midwest system. Our Preferred Plan would take us beyond 80% below 2005 levels by 2030.

2. Affordable Clean Energy rule

EPA in October 2017 issued a proposed rule to repeal the CPP, based on its view that the CPP exceeds the EPA's statutory authority under the Clean Air Act.[2] EPA also published an Advanced Notice of Proposed Rulemaking seeking comment on whether to develop a replacement rule, and what form such a rule should take.[3] In August 2018, EPA then issued a proposed CPP replacement rule*, Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units*, termed the "Affordable Clean Energy" (ACE) rule.[4] The proposed rule applies to coal-fired steam electricity generating units in operation on or before January 8, 2014.

[1] 80 *Fed. Reg.* 64,662, October 23, 2015.
[2] 82 *Fed. Reg.* 48,035, October 16, 2017.
[3] 82 *Fed. Reg.* 61,507, December 28, 2017.
[4] 83 *Fed. Reg.* 44,746, August 31, 2018.

Whereas the CPP defined the Best System of Emission Reduction (BSER) to encompass CO_2 reductions achievable throughout the electricity system – including efficiency improvements at coal units themselves, switching from coal to gas, and renewable energy additions – the ACE proposal replaced this interpretation with a much narrower "inside the fence line" approach based only on heat rate improvements (HRI) implemented at the affected coal units. The proposal would require states to make unit-specific determinations of the achievable emissions reductions through HRI, expressed as an allowable emissions rate (lbs CO_2/MWh gross), and to evaluate eight "candidate technologies" for HRI: neural network/intelligent sootblowers, boiler feed pumps, air heater and duct leakage control, variable frequency drives, blade path upgrades for steam turbines, redesign/replace economizer, and improved operating and maintenance practices. EPA did not propose any BSER for existing natural gas-fired turbines, finding that available emissions reductions would be expensive or would likely provide only small reductions.

The proposed rule gives states limited flexibility in making these determinations. They may consider remaining useful life of a unit, which may result in the application of a less stringent standard of performance or later compliance date; may accept non-BSER measures, but only if implemented at the unit itself; and may allow averaging among units at a single power plant, but not across plants. States would not be allowed to average or trade across affected units, nor between affected units and non-affected sources such as wind or solar generation. As such, the proposed rule would not allow consideration of emission reductions achievable through measures such as renewable energy, energy efficiency, increasing natural gas generation, retiring or reducing operation of coal units.

3. Affordable Clean Energy Rule as Finalized

On June 19, 2019, EPA published a final ACE rule. Because of its release so near the filing of this Resource Plan, we are still reviewing the rule and, to the extent there are substantive differences between the proposed and final rule that impact our Preferred Plan, we offer to supplement the record. However, we include a preliminary review here.

The ACE rule finalizes EPA's repeal of the CPP, which EPA maintains exceeded EPA's statutory authority because EPA took an overly expansive view of section 111(d) and endeavored to reduce emissions by shifting the balance of coal, gas and renewable generation across the power grid rather than focusing only on measures

implemented at the affected coal units.[5]

As in the proposed rule, EPA defines the BSER as only including measures implemented at the affected coal-fired units. The rule does not allow state plans to set carbon reduction targets based on renewable energy development, shifting from coal to gas, or averaging or trading across units – strategies the CPP relied on to drive the bulk of its emission reductions – but rather maintains the list of eight approved HRI measures states may consider in establishing unit-specific performance standards. It grants states discretion to determine which of those projects to require at the affected units and, following the statutory text, allows states to take into account the remaining useful life of the source and other factors, including the cost reasonableness of requiring HRI on units with a limited remaining useful life.

The final rule allows states three years from the date that it is published in the Federal Register to finalize plans and submit their own implementing rules. Compliance is then required two years thereafter, although states have discretion to extend that compliance deadline based on specific factors at the regulated units. Based on this timeline, we believe compliance could be required around 2024, not including possible delays due to litigation of the final rule.

4. Relevance to Xcel Energy

Xcel Energy submitted comments on the proposed ACE rule, arguing the Clean Air Act allows EPA to provide states much greater flexibility to reduce CO_2 through a range of actions throughout the electric system, and that granting such flexibility would result in more cost-effective and greater CO_2 reductions. However EPA retained its narrow, "inside the fence line" approach.

Under the rule as finalized – and absent our plans for early retirement of all remaining Upper Midwest coal units under the last Resource Plan and the current Preferred Plan – we expect that HRI could be required on coal-fired units that continue to operate. However, section 111(d)(1) explicitly requires, and EPA emphasizes, that EPA must "permit the State in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies."[6] Further, the proposed rule specifies that consideration of remaining useful life would allow a state's plan to establish tailored compliance deadlines specific to each source; consider "changes in the operation of the units, among other factors the state believes

[5] EPA Fact Sheet, *Repeal of the Clean Power Plan*. June 19, 2019.
[6] ACE rule, 83 Fed. Reg. 44,749 (August 31, 2018).

are relevant";[7] consider "unreasonable cost of control resulting from plant age"; consider factors that "make application of a less stringent standard or final compliance time significantly more reasonable"; and consider "factors that influence decisions to invest in technologies to meet a potential performance standard [including] timing considerations like expected life of the source, payback period for investments, the timing of regulatory requirements, and other unit-specific criteria."[8]

The final rule also emphasizes this discretion:

> It will be up to the states to, either directly or indirectly, take cost into consideration in establishing unit-specific standards of performance. CAA section 111(d) explicitly allows the states to take into consideration, among other factors, the remaining useful life of the existing source in applying the standard of performance. For example, a state may find that an HRI technology is applicable for an affected coal-fired EGU but find that the costs are not reasonable when consideration is given to the timeframe for the planned retirement of the source (i.e., the source's remaining useful life).[9]

At this point, it is too early to predict exactly how Minnesota's ACE plan[10] will treat the units that the company is proposing to retire in our Preferred Plan. Minnesota's implementation of the ACE rule will depend on the outcome of inevitable litigation over the rule as well as the state plan development process, which will be in the hands of the Pollution Control Agency (PCA). Based on the factors set forth above, however, we believe that PCA could avoid requiring the installation of HRI on the company's coal units by incorporating the proposed unit retirement dates into the Minnesota ACE plan. Requiring HRI on units with only a few years of life remaining would necessitate a very short payback period, imposing accelerated depreciation of HRI investments and an unreasonable cost of control. We believe that, following the statutory language of Section 111(d)(1), EPA would be likely to approve such a plan. The company will continue to evaluate the implications of the ACE rule and work with PCA to harmonize the Minnesota ACE plan with the Preferred Plan in a manner that minimizes the cost of the ACE rule to customers.

B. Regulation of CO_2 from New, Modified and Reconstructed Power Plants

1. Standards of Performance for New, Modified and Reconstructed Stationary Sources

[7] 83 Fed. Reg. 44,763.
[8] 83 Fed. Reg. 44,766.
[9] EPA "Affordable Clean Energy" final rule, pre-publication version, at page 81. *Repeal of the Clean Power Plan; Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units; Revisions to Emission Guidelines Implementing Regulations*. June 19, 2019.
[10] We do not speak to ACE plans in the other Upper Midwest states served by Xcel Energy, since the Company has no coal units in North Dakota, South Dakota, Wisconsin or Michigan.

EPA in October 2015 promulgated, under Section 111(b) of the Clean Air Act, a final rule *Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units*.[11] The rule applies to newly constructed, modified, and reconstructed fossil fuel-fired utility boilers and IGCC units, and newly constructed and reconstructed stationary combustion turbines. The trigger for applicability is that construction of the new unit began, or the modification or reconstruction took place, after January 2014. EPA defined the BSER for new fossil fuel-fired utility boilers as highly efficient supercritical pulverized coal with partial post-combustion carbon capture and storage (CCS), with an equivalent performance standard of 1,400 lbs CO_2/MWh gross. The BSER for natural gas-fired stationary combustion turbines operated in a "baseload" configuration is defined as use of efficient natural gas combined cycle technology, with a corresponding performance standard of 1,000 lbs CO_2/MWh gross, while natural gas-fired units (generally simple cycles) operated in a "non-baseload" configuration are given a performance standard of 120 lbs CO_2/MMBtu. Modified and reconstructed units in each category are given their own BSER definitions and corresponding performance standards.[12]

Numerous parties challenged the 2015 rule in the U.S. Court of Appeals for the D.C. Circuit, with the cases consolidated under *North Dakota v. EPA*. At EPA's request, the D.C. Circuit has held the consolidated cases in abeyance since April 2017, pending the Agency's review of the 2015 rule and any resulting rulemaking.

2. Proposed 2018 Replacement Rule

EPA in December 2018 released a proposed rule revising the 2015 section 111(b) rule discussed above. This rule, titled *Review of Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units*,[13] revises the emissions standards for new, modified, and reconstructed fossil fuel-fired electric utility steam generating units. EPA proposes that BSER would not be partial CCS, based on EPA's updated assessment of capital costs of CCS, falling electricity demand, water availability, and limited geographic availability of sites suitable for sequestration. Instead, EPA proposes that BSER is the most efficient demonstrated steam cycle (e.g., supercritical steam conditions for large units, subcritical steam conditions for small units) in combination with best operating

[11] 80 *Fed. Reg.* 64,510, October 23, 2015.
[12] M.J. Bradley & Associates, August 14, 2015, *Summary of EPA's Final Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units*. Available at https://www.mjbradley.com/sites/default/files/MJB&A%20Summary%20of%20Final%20GHG%20NSPS_Aug14.pdf
[13] 83 *Fed. Reg.* 65,424, December 20, 2018.

practices. EPA proposes a corresponding set of emission standards, ranging from 1,900 lbs CO_2/MWh gross for units with heat input >2,000 MMBtu/hr, to 2,000 lbs CO_2/MWh gross for units with heat input <2,000 MMBtu/hr, to 2,200 lbs CO_2/MWh gross for various other types of units and for modified and reconstructed units.

EPA does not propose revisions to the 2015 rule for stationary combustion turbines. EPA does solicit comment on whether the rule should make allowances for circumstances in which simple-cycle stationary combustion turbines may be called upon to operate in excess of the "non-baseload" threshold in the 2015 rule, e.g. due to high utilization to balance solar and wind generation, and whether such turbines should be given a separate subcategory and standard of performance.

Finally, EPA proposes to retain its original "endangerment" finding as the basis for regulating CO_2 emissions from fossil fuel-fired EGUs, but takes comment on whether it is correct to interpret this finding as a finding made only once for each source category, or whether EPA must make a new endangerment finding each time it regulates an additional pollutant by an already-listed source category. EPA also solicits comment on whether there is a rational basis for declining to regulate CO_2 emissions from new coal-fired units in light of ongoing and projected reductions in power sector CO_2 emissions. The 111(b) revision remains a proposed rule as of this writing.

3. Relevance to Xcel Energy

Xcel Energy commented on the 2015 rule, indicating we did not agree CCS is an appropriate BSER because it was not adequately demonstrated and was not at the time deployed on any commercially operating power plant in the United States. Since that time CCS has been deployed on a small number of commercial units, but remains far from widespread. We believe CCS on *gas* units may become viable in the future, and is one of several potential carbon-free dispatchable technologies that could help achieve our 2050 aspiration of 100% carbon-free electricity. However, Xcel Energy does not have plans to build a new coal-fired power plant, with or without CCS, so the rule's requirements for new coal units have no impact on the Company.

We believe any new natural gas combined cycle unit we may construct would be able to meet the 2015 rule's performance standard of 1,000 lbs CO_2/MWh gross. It is possible that new simple-cycle stationary combustion turbines we build[14] could be called upon to operate in excess of the non-baseload thresholds in the 2015 rule, and

[14] Note that under the Preferred Plan, our modeling calls for no new gas combustion turbines until 2031, and even at that time, gas combustion turbines could be replaced by other resources that meet the same firm peaking need.

could struggle to achieve the 120 lbs CO_2/MMBtu performance standard applicable to such units. Since these units would likely operate this much only because they are supporting integration of higher amounts of renewables, we believe it may be appropriate for EPA to relax the non-baseload threshold or create a separate subcategory and standard of performance for such units. EPA's decision on simple-cycle aeroderivative turbines will become known when EPA finalizes the 111(b) rule.

C. Progress on the State of Minnesota's Greenhouse Gas Goals

The Next Generation Energy Act (NGEA) of 2007 states that:

> It is the goal of the state to reduce statewide greenhouse gas emissions across all sectors producing those emissions to a level at least 15 percent below 2005 levels by 2015, to a level at least 30 percent below 2005 levels by 2025, and to a level at least 80 percent below 2005 levels by 2050.[15]

These goals apply to all economic sectors; the NGEA does not provide goals specific to electricity or other sectors, or to individual companies. The Minnesota Pollution Control Agency (PCA) maintains the state's GHG inventory, publishes data,[16] and provides a biennial report to the Legislature on progress on the NGEA goals.[17]

1. Xcel Energy's CO_2 Inventory and Reporting Methods

Xcel Energy supports timely, transparent public reporting of CO_2 and other greenhouse gas emissions. Our comprehensive GHG reporting is based on The Climate Registry[18] and its *Electric Power Sector Protocol*, which aligns with the World Resources Institute and ISO 14000 series standards. Our company joined The Climate Registry as a founding member in 2007 to help establish a consistent and transparent standard for calculating, verifying and reporting greenhouse gases. Through The Climate Registry, we annually third-party verify, register and publicly disclose our greenhouse gas emissions. We have reported and verified emissions for 2005 through 2017, with verification of 2018 emissions pending. This reporting – which differs in a few respects from PCA's methodology for the state – takes the following approach:

- CO_2 emissions are reported from all owned power plants and purchased power across our Upper Midwest integrated system, serving five states. This is a broader boundary than PCA's method, which considers emissions from power plants within Minnesota and estimates emissions from power imported into

[15] Minn. Stat. §216H.02, subd. 1.
[16] See https://www.pca.state.mn.us/air/greenhouse-gas-emissions-data.
[17] See https://www.pca.state.mn.us/air/state-and-regional-initiatives.
[18] See https://www.theclimateregistry.org.

Minnesota.

- It includes CO_2 from owned fossil fuel-fired power plants, purchased power agreements (PPAs), and power purchased in the wholesale markets. The majority of these emissions (over 80 percent) are directly measured using Continuous Emissions Monitoring Systems (CEMS); a small portion (less than 10 percent) are from PPAs with counterparties whose emission rate is known because they report emissions to EPA, the Energy Information Administration or Federal Energy Regulatory Commission; a still smaller portion (less than 5 percent) are from counterparties who do not have a defined PPA with Xcel Energy and so are assigned a regional grid average emission rate.
- Reported emissions from power generation include CO_2 only, not methane and nitrous oxide. However, methane and nitrous oxide add less than ½ of one percent to our total CO_2-equivalent emissions, even after accounting for the greater global warming potentials of these gases.
- We report CO_2 from electricity provided to our customers. Xcel Energy sells a small portion of the electricity we generate and purchase as short-term sales into the wholesale market. CO_2 from these sales is excluded from our reporting, because the energy does not serve our customers, and it is likely that many companies purchasing the energy account for the emissions in their reporting, so including them in our reporting could result in double counting.

2. State Goal for 2015

PCA's statewide GHG inventory data now covers 2005 through 2016. Statewide GHG emissions declined about 5 percent from 2005 to 2015, missing the statewide goal of 15 percent. Statewide emissions declined more in 2016 – reaching 12 percent below 2005 by the end of that year – however performance varied by sector: electric sector emissions declined 29 percent, transportation emissions 8 percent, agriculture, forestry and land use emissions 12 percent, and waste emissions 6 percent, while emissions in the residential, commercial and industrial sectors all increased.[19]

Thus while the state overall and individual sectors have fallen short of the NGEA goals, the electric sector has approximately doubled the targeted reduction. According to PCA,

> Emissions from electricity used by Minnesotans are down by about 29% since 2005. This means the electricity generation sector has met the Act's 2015 goal, and has nearly

[19] See https://www.pca.state.mn.us/air/greenhouse-gas-emissions-data, as well as PCA's January 2019 report, *Greenhouse gas emissions in Minnesota: 1990-2016: Biennial report to the Legislature tracking the state's contribution to emissions contributing to climate change*, pages 5-6, available at https://www.pca.state.mn.us/sites/default/files/lraq-2sy19.pdf.

> reached the 2025 emissions reduction goal. Moreover, Minnesota's utilities have committed to additional coal plant closures that will further reduce GHG emissions from this sector in the future. Transportation is now the largest source of GHG emissions in Minnesota. This sector will require ongoing, focused effort to reduce emissions to the levels necessary to meet statutory goals.[20]

Xcel Energy's Upper Midwest CO_2 emissions have declined by even more. We provide below our emission reductions to date for three relevant years: 2015, for comparison to the NGEA goal for that year; 2016, for comparison to PCA's statewide data; and 2018, our latest emissions data available. Note that the 2018 data is not yet third-party verified.

Table 1: Xcel Energy Upper Midwest CO_2 Emission Reductions

Year	Total CO_2 from electricity serving customers (million short tons)	Reduction from 2005	Comparison
2015	21.1	25 percent	Exceeding state goal of 15 percent by 2015
2016	19.0	32 percent	More than double state goal for 2015 and exceeding state goal for 2025
2018	18.5	34 percent	More than double state goal for 2015 and exceeding state goal for 2025

3. State Goal for 2025

Under the Preferred Plan, Xcel Energy's Upper Midwest CO_2 emissions are on track for an approximately 60 percent reduction by 2025, doubling the NGEA statewide goal for that year. These reductions reflect our full 1,850 MW wind portfolio being online by that time, significant growth of solar, continued energy efficiency program achievements, continued operation of our carbon-free nuclear units, and retirement of one Sherco unit in 2023 (with the other two units at Sherco and the A.S. King unit retiring by 2030).

4. State goal for 2050

A true transformation has occurred in the electric sector since our last Resource Plan. In that plan, we discussed the state's 80 percent by 2050 goal qualitatively, but identified many technical and economic barriers to creating a Upper Midwest system that serves our customers' electricity needs affordably and reliably with only 20 percent of the CO_2 emissions of 2005. Today, only four years later, Xcel Energy has

[20] *Greenhouse gas emissions in Minnesota: 1990-2016*, page 2.

set a company-wide goal of an 80 percent reduction in CO_2 emissions *by 2030* – i.e. achieving the State's economy-wide goal, twenty years ahead of time. Moreover, we believe we can achieve this reduction cost-effectively, with our expected fleet transition and operational changes and with the renewable, carbon-free generation and energy storage technologies available today. Our 80 percent by 2030 goal is for all eight states Xcel Energy serves; under the Preferred Plan, our Upper Midwest system will achieve about an 84 percent reduction. And our aspiration for 2050 is 100 percent carbon-free electricity for our customers.

In announcing these goals, we stressed that they are not Resource Plans. Our Preferred Plan represents a concrete down payment on those Xcel Energy-wide goals – moving our Upper Midwest system beyond 80 percent reduction by 2030 and putting us on a trajectory to removing carbon from our customers' electricity entirely by 2050. We also made clear that our 2050 aspiration requires technologies not yet commercially available at the scale needed. This cannot be done with only wind, solar, and the short-duration battery storage technologies available today. It will likely require some amount of carbon-free dispatchable generation, longer-duration storage than is available today, more electrification, and more flexible demand. The technologies needed may include gas with carbon capture and storage, power to gas (renewable hydrogen), seasonal energy storage, advanced nuclear or small modular reactors, deep rock geothermal, and other technologies yet to be identified. Each of these options holds promise, but they will require further research, development, demonstration and deployment to become viable solutions at the cost and scale needed. Coupled with supportive federal and state policies, utility Resource Plans can send signals to the market around price, capabilities and timing for when these technologies will be needed.

In sum, we believe the state's goal of 80 percent reduction by 2050 is attainable and affordable within the electric sector, and that even 100 percent carbon-free electricity by 2050 is achievable with sufficient investment in new technology. That said, getting the last 20 percent of carbon out of the electric system is technically challenging and could face steeply increasing costs. This is especially the case if we limit the portfolio to two or three technologies – e.g., wind, solar and short-term storage – rather than creating a balanced portfolio of technologies for an affordable, reliable, and carbon-free system in 2050.

D. Recent Federal and State Legislation

No new state or federal legislation mandating a reduction in GHG emissions from Xcel Energy's system has passed as of filing this plan. However, some legislation has been proposed, which may indicate the potential shape of energy/climate policy in

coming years. We summarize here some of those proposals.

1. Green New Deal

In February 2019, Rep. Ocasio-Cortez (D-NY) and Sen. Markey (D-MA) introduced H. Res. 109 and S. Res. 59, formalizing one version of the "Green New Deal" (GND) concept of an aggressive mobilization to address climate change combined with nationwide job creation, modeled on the Depression-era programs of the Roosevelt Administration. The resolutions cite recent United Nations and U.S. Government reports on climate risks and propose that, in order to keep global temperature increase below 1.5 degrees Celsius, GHG emissions must be reduced 40-60 percent by 2030 from 2010 levels and reach net-zero global emissions by 2050. The resolutions point to the impacts of climate change in exacerbating systemic injustices and disproportionately impacting certain vulnerable communities, as well as the threat posed to national security, and call for ambitious progressive policies aimed at resolving social injustice as part of the transition.

The resolutions propose it is the duty of the Federal Government to create a GND that would achieve net-zero GHG emissions through a fair and just transition for all communities and workers; create millions of good, high-wage jobs and ensure prosperity and economic security for all; invest in infrastructure and industry to sustainably meet the challenges of the 21st century; secure for future generations clean air and water, climate and community resiliency, healthy food, access to nature, and a sustainable environment; and promote justice and equity by stopping current, preventing future, and repairing historic oppression of indigenous peoples, communities of color, migrant communities, deindustrialized communities, depopulated rural communities, the poor, low-income workers, women, the elderly, the unhoused, people with disabilities, and youth.[21]

To achieve these goals, the resolutions call for a ten-year national mobilization focusing on 1) building resiliency against the impacts of climate change, such as extreme weather; 2) repairing and upgrading infrastructure; 3) meeting 100% of the power demand through clean, renewable, and zero-emission energy sources; 4) building or upgrading energy efficient distributed and "smart" power grids; 5) upgrading all existing buildings for maximum resource efficiency (energy, water) and safety, including through electrification; 6) spurring growth in clean manufacturing; 7) working with farmers and ranchers on sustainable farming and decarbonization of the agricultural sector; 8) development of zero-emission vehicle infrastructure and manufacturing and more public transit/rail; 9) funding for communities with

[21] See https://www.congress.gov/bill/116th-congress/house-resolution/109/text.

pollution related health problems; 10) removing GHG from the atmosphere through proven low-tech solutions such as land preservation and afforestation; 11) restoring threatened and endangered ecosystems; 12) cleaning up hazardous waste sites; 13) eliminating sources of pollution; and 14) promoting international exchange of technologies and expertise on climate.[22]

Notably different from earlier GND proposals, the resolutions do not call for 100 percent renewable energy, but instead a transition to clean, zero-carbon energy, leaving open possibilities non-renewable but zero-carbon sources. They do not call for a carbon price, since at least some of the groups supporting the GND do not favor a carbon tax or cap-and-trade.

Since these GND resolutions are high-level statements of goals and principles for federal programs, rather than specific compliance mandates for electric utilities, we cannot directly evaluate this Resource Plan in relation to them. We note that this Resource Plan appears generally consistent with the resolutions in that it would:

- Reduce Xcel Energy's Upper Midwest emissions 80 percent by 2030, as compared to the GND goal of 50-60 percent;
- Put Xcel Energy on a path to 100 percent carbon-free electricity for our customers by 2050, more ambitious than the GND net-zero goal;
- Prioritize a fair and just transition by working to create new jobs and economic opportunities in the communities hosting retiring power plants, while also creating new employment in building and operating clean energy resources added to our system;
- Focus on reducing conventional pollution and expanding clean energy access for all;
- Improve the resiliency of our electric system and communities;
- Upgrade energy infrastructure and invest in a smarter energy grid, energy efficiency, and electrification of transportation and other end uses.

2. *Clean Energy Standard Act of 2019*

Senators Tina Smith (D-MN) and Ben Ray Luján (D-NM) in May 2019 introduced S. 1359, the *Clean Energy Standard Act of 2019*. This bill, which the authors describe as a path to net-zero emissions in the electric sector by midcentury, would establish a federal clean energy standard (CES) requiring retail electric suppliers to provide an

[22] https://www.congress.gov/bill/116th-congress/house-resolution/109/text.

increasing share each year of the electricity serving their customers from "clean energy" resources, defined to include renewables, qualified renewable biomass, hydroelectricity, nuclear, qualified waste-to-energy, qualified low carbon fuels, qualified combined heat and power, qualified energy storage, dispatchable low- and zero-emission technologies, and carbon capture, storage and utilization. The approach is modeled on state renewable energy standards, but broader since in addition to renewables it allows low- and zero-carbon resources to qualify.

The bill requires retail electricity suppliers with more than 60 percent clean energy today to increase their clean energy percentage (as a share of retail sales plus behind the meter generation) at 1.75 percent per year, while retail electricity suppliers with less than 60 percent today must increase at 2.75 percent per year. Retail electricity suppliers comply with the CES by adding clean energy resources to their fleet, purchasing federal clean energy credits from other retail electricity suppliers, or paying an alternate compliance payment initially set at 3 cents per kWh. Recognizing the need for 24/7 low- and zero-carbon technologies in addition to variable renewables, the bill provides innovation multipliers for dispatchable low-emission and dispatchable zero-emission technologies. It also establishes a new clean energy research, development, demonstration and deployment program within the US Department of Energy.

We believe the Company is well positioned to comply with the CES as introduced. Under our Preferred Plan, the Company would have greater than 60 percent qualifying clean energy from 2019 on, so be required to increase at the slower 1.75 percent per year rate; by 2023, the Company's clean energy percentage would exceed the 90 percent ceiling at which retail electricity suppliers are no longer required to increase until 2040. Due to planned renewable additions, maintenance of our nuclear units, and the proposed relicensing of Monticello, our modeling shows the Company in excess of its compliance obligation throughout the planning period of 2020 to 2034.

3. Walz/Flanagan Clean Energy Plan

In March 2019 Minnesota Gov. Walz and Lt. Gov. Flanagan proposed a "One Minnesota Path to Clean Energy," a set of three policy proposals designed to achieve 100 percent clean energy in the state's electricity sector by 2050. The three components are:

- *100 Percent Clean Energy by 2050*. This standard would require all electric utilities in Minnesota to use only carbon-free energy resources by 2050, while allowing each utility the flexibility to choose how and at what pace they meet the standard. The proposal includes provisions to assist workers and communities

affected by the transition, while prioritizing local jobs and prevailing wages for large new clean energy projects.

- *Clean Energy First*. This regulatory policy would require that, whenever a utility proposes to replace or add new power generation, it must prioritize energy efficiency and clean energy resources over fossil fuels. This policy would strengthen an existing renewable energy preference in Minnesota law, and it would allow for fossil fuel-based power only if needed to ensure reliable, affordable electricity.
- *Energy Optimization*. This proposal would raise Minnesota's Energy Efficiency Resource Standard for investor-owned electric utilities and expand the Conservation Improvement Program that helps Minnesota households and businesses save on their utility bills by using energy more efficiently. It would also encourage utilities to develop innovative new programs to help consumers and businesses switch to more efficient, cleaner energy. In addition, it would target more energy-saving assistance for low-income households."[23]

To carry out this proposal, the Administration worked with legislators to introduce HF1956, which included all three components above, and SF1456, which included only the Clean Energy First preference. The bills were incorporated into the respective House and Senate omnibus legislation. Ultimately, none of this package of bills passed the Minnesota Legislature in 2019, but they provide an indication of the potential direction of clean energy policy in Minnesota in the coming years. We believe the Preferred Plan positions the Company well to comply with these policies.

II. CONVENTIONAL POLLUTANTS

This section discusses requirements that may apply to emissions of pollutants that are regulated under four primary Clean Air Act (CAA) programs: National Ambient Air Quality Standards (NAAQS), a CAA program that addresses interstate transport of air pollution, CAA programs that address visibility impairment in national parks and wilderness areas, and a CAA program that addresses emissions of hazardous air pollutants. Each program is addressed in turn.

A. National Ambient Air Quality Standards

The CAA requires the EPA to set NAAQS to protect public health and the environment. NAAQS include both (1) primary standards to protect public health, including the health of sensitive populations, such as asthmatics, children and the

[23] See https://mn.gov/governor/news/?id=1055-374280.

elderly and (2) secondary standards to protect public welfare, including protection against damages to animals, crops and buildings. The EPA has established NAAQS for six pollutants: particulate matter (PM), nitrogen oxides (NO_x), sulfur dioxide (SO_2), ozone, carbon monoxide (CO), and lead (Pb). The NAAQS program has been in place since the early 1970s. The EPA is required to review the NAAQS every five years and revise them as appropriate to protect public health and welfare.

Once EPA adopts or revises a NAAQS, states have two years to monitor their air, analyze the data and submit to EPA their recommended classification of the state into Attainment areas (areas having monitored ambient air quality concentrations below the NAAQS), Nonattainment areas (areas having monitored ambient air quality concentrations above the NAAQS), and Unclassifiable areas. The EPA reviews the state's submittal and determines the final area designations a year later. When the EPA designates an area as Nonattainment, the state is given up to three years to develop a new State Implementation Plan (SIP) which identifies actions to be taken to bring the area back into Attainment. A SIP must include emission reduction requirements needed to demonstrate that air quality will attain the NAAQS in the timelines required by the CAA – usually within two to seven years after the SIP is submitted to the EPA for approval.

Recent revisions to all six NAAQS were finalized within the last few years to reflect the latest scientific information about the health effects of these air pollutants. Despite several NAAQS being significantly tightened, there are at present no Nonattainment areas in the state of Minnesota that might result in SIP emission reduction requirements being imposed on Xcel Energy's Upper Midwest power plants. The following table summarizes the current status of the NAAQS Attainment in Minnesota:

Table 2: Xcel Energy Upper Midwest System Status – NAAQS Attainment

Pollutant	Date Reviewed[24]	System Status[25]	Date Designated	Next Review[26]
PM	2012	Attainment	2015[27]	2020
O_3	2015	Attainment	2017[28]	2020
SO_2	2019	Attainment	2018[29]	2024
NO_x	2018	Attainment	2012[30]	2023
CO	2011	Attainment/Maintenance[31]		TBD[32]
Pb	2016	Attainment	2011[33]	2021

Our remaining coal plants are all equipped with scrubbers to control SO_2 emissions as well as air pollution control equipment to control PM emissions. All three Sherco units are equipped with NOx combustion controls that have significantly reduced NO_x emissions from the units. The King plant and our combined cycle gas plants are also equipped with Selective Catalytic Reduction (SCR) technology to control NO_x emissions.

With the planned retirement of Sherco Units 1 and 2, the only additional control equipment that could be required would be SCR technology to further reduce NO_x emissions from Sherco Unit 3. Depending on the date of required compliance, any need to install an SCR to address a NAAQS would either need to be completed by the attainment date or the unit would need to shut down by the attainment date. With the proposed 2030 retirement of Sherco 3, we believe unit retirement may be acceptable in lieu of SCR. Additionally, a full analysis may render the controls not cost-effective

[24] This column reflects the last time each NAAQS was reviewed. Note that in the case of the most recent reviews of the NAAQS for SO_2, NOx, CO and Pb, EPA did not change the level of the NAAQS, so there was no need to initiate a new designation and planning process for those standards.
[25] This column reflects the designation of areas for locations where Xcel Energy's Upper Midwest coal or natural gas plants are located.
[26] This column reflects the date of EPA's announced plans to review a NAAQS, application of the five year CAA deadline for NAAQS reviews, or "TBD" if the five year deadline has passed and there is no announced plan to complete the next NAAQS review.
[27] *See* 80 Fed. Reg. 2206, 2247-48 (Jan. 15, 2015).
[28] *See* 82 Fed. Reg. 54232, 54255-56 (Nov. 16, 2017).
[29] *See* 83 Fed. Reg. 1098, 1134-36 (Jan. 9, 2018).
[30] *See* 77 Fed. Reg. 9532, 9562 (Feb. 17, 2012).
[31] As of 2010, there were no areas of the country in Nonattainment of the CO standard. Areas formerly Nonattainment have all been designated "maintenance" areas, which are subject to certain CAA requirements for two ten-year maintenance periods after achieving compliance with the standards to assure continued attainment. https://www.epa.gov/co-pollution/applying-or-implementing-outdoor-air-carbon-monoxide-co-standards#designations The Minneapolis/St. Paul Metropolitan Area is a maintenance area for CO. https://www3.epa.gov/airquality/greenbook/cbcs.html#MN
[32] Because the last review in 2011 retained the original NAAQS adopted in 1971, we do not expect this standard to change in the future.
[33] *See* 76 Fed. Reg. 72097, 72111 (Nov. 22, 2011), which designated all of Minnesota as attaining the standard, except a portion of Dakota County.

based on the reductions to be achieved.

In addition, if future further emission reductions are needed, it is possible that the state would evaluate whether any upgrades are available to existing controls to further reduce air emissions.[34] Based on the timeline for the next NAAQS reviews shown above, if a standard is made more stringent in the future, and if Minnesota does not meet that standard in areas where our plants operate, further emission reductions might be considered at Xcel Energy's Upper Midwest coal and natural gas plants in the mid to late 2020s.

B. Interstate Transport of Air Pollution

The CAA also requires that NAAQS SIPs include provisions that prevent sources within a state "from emitting any air pollutant in amounts which will … contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to any" NAAQS.[35] The EPA has developed programs for the Eastern U.S. that would reduce interstate transport of pollutants emitted by Electric Generating Units (EGUs) that are precursors to ozone and fine particles. NO_x is a precursor to ozone and fine particle formation, while SO_2 is a precursor to fine particle formation.

The Cross-State Air Pollution Rule (CSAPR) was designed as a "cap-and-trade" program that reduces overall emissions from EGUs. This means that total emissions from EGUs in a state or region are limited (the cap), and each ton of emissions allowed is represented by an emission allowance that can be transferred among EGUs (the trade). A cap-and-trade program thus reduces total emissions to the capped amount, but provides flexibility for EGUs to meet their individual emission reduction requirements through installation of control equipment, purchase of emission allowances from other EGUs, or a combination of both.

Depending on EPA's analysis of an upwind state's contribution to Nonattainment in downwind states, CSAPR imposes one or both of the following emission limitations: (1) summer season NO_x emissions (to address ozone), and/or (2) annual NO_x and SO_2 emissions (to address fine particles). In Minnesota's case, the impact of concern has been fine particle Nonattainment areas in downwind states, rather than ozone. The CSAPR has applied since 2015 to Minnesota for fine particle precursors and to Wisconsin for fine particle precursors and ozone. NSP-Minnesota holds sufficient emission allowances to meet CSAPR requirements, while NSP-Wisconsin has

[34] In general, upgrades to existing pollution control technology are far less expensive than installation of an entirely new retrofit control system.
[35] CAA, 42 U.S.C. section 7410(a) (2)(D)(i)(I).

complied through operational changes and some allowance purchases.

EPA has considered further revisions to the CSAPR program as may be needed to address the 2008 ozone NAAQS and the 2012 particle NAAQS. EPA decided that further reductions through CSAPR are not needed to address the 2012 particle NAAQS,[36] and recently decided that further reductions from current emission levels are not needed to address the 2008 ozone NAAQS.[37] It is not known whether or when EPA might consider further emission reductions as part of implementing the 2015 ozone NAAQS.[38]

C. Visibility Impairment in National Parks and Wilderness Areas

Visibility impairment is caused when sunlight encounters pollution particles in the air. Some light is absorbed and other light is scattered before it reaches an observer, reducing the clarity and color of what the observer sees. The CAA established a national goal of remedying existing and preventing future visibility impairment from man-made air pollution in specified "Class I" areas – national parks and wilderness areas throughout the United States, including the Boundary Waters Canoe Area and Voyageurs National Park in Minnesota. The visibility programs focus on reducing emissions of PM, SO_2 and NO_x as pollutants that can result in visibility impairment from EGUs.

The EPA has taken a two-step approach to implement the visibility program. The first step, "reasonably attributable visibility impairment" (RAVI), was implemented in the 1980s to address visibility impairment reasonably attributable to a specific source. The EPA adopted regulations for this program designed to address RAVI, defined as "visibility impairment that is caused by the emission of air pollutants from one, or a small number of sources."[39]

The second step was designed to address widespread, regionally homogeneous haze

[36] On March 17, 2016, EPA issued guidance for states to analyze interstate pollution impacts and, if needed, to develop plans to address those impacts. EPA stated that few areas would have problems meeting the 2012 particle NAAQS, and plans to address any need for upwind reductions on a case-by-case basis. *Information on the Interstate Transport "Good Neighbor" Provision for the 2012 Fine Particulate Matter National Ambient Air Quality Standards under Clean Air Act Section 110(a)(2)(D)(i)(I),* Office of Air Quality Planning and Standards, at 3.
[37] *See* 83 Fed. Reg. 65878 (Dec. 21, 2018).
[38] On March 27, 2018, EPA issued guidance for states to design their own plans to address interstate air pollution impacts as part of their SIPs under the 2015 ozone NAAQS. https://www.epa.gov/airmarkets/memo-and-supplemental-information-regarding-interstate-transport-sips-2015-ozone-naaqs If in the future states submit plans that EPA does not approve on this issue, EPA could consider developing its own plan at some future date.
[39] 40 C.F.R. section 51.301. Following an allegation that the Sherco plant might have a RAVI-type of impact, NSP-Minnesota entered into a settlement agreement that agreed to tighten SO2 emission limits on all three Sherco units to resolve the allegation. The new limits have been implemented at the Sherco plant. *See* 40 C.F.R. section 52.1236(e), adopted on March 7, 2016 (81 Fed. Reg. 11668).

that results from emissions from a multitude of sources. In 1999, the EPA adopted its Regional Haze Rule (RHR) to address this type of visibility impairment. State environmental agencies are required to submit SIPs that develop and implement their strategy to reduce emissions that may contribute to regional haze. RHR SIPs also must include reasonable progress goals and periodic evaluation/revision cycles designed to make appropriate progress toward the national goal of no human-caused visibility impairment in Class I areas by 2064. These SIPs must be revised approximately every ten years to continue making reasonable progress toward reaching the 2064 national goal.

The Minnesota Pollution Control Agency (PCA) developed, and EPA approved, Minnesota's regional haze plan for EGUs for the first ten-year planning period of the program. The PCA's plan for Sherco Units 1 and 2 required combustion controls to reduce NO_x (Over-Fire Air (OFA), combustion controls and Low- NO_x burners) and scrubber upgrades to reduce SO_2. These controls have been installed and are in operation to reduce emissions from these units.

The PCA will also be required to revise its SIP by 2021 to consider additional emission reductions that may be necessary to continue to make reasonable progress during the next ten year planning period toward achievement of the national visibility goal by 2064.

Our system is equipped with almost all of the pollution control equipment that could be required in future regional haze planning cycles. With the planned retirement of Sherco Units 1 and 2, the only additional control equipment that could be required would be SCR technology to further reduce NOx emissions from Sherco Unit 3. Depending on the date of required compliance, any need to install an SCR to address Regional Haze compliance would depend on unit retirement dates. The Regional Haze program provides some flexibility to agree to a unit retirement some years later than an SCR might otherwise be required, because of the long-term nature of this program. With the proposed 2030 retirement of Sherco 3, we believe unit retirement may be acceptable in lieu of SCR. Additionally, a full analysis may render the controls not cost-effective based on the reductions to be achieved.

In addition, if future further emission reductions are needed, it is possible that the state would evaluate whether any upgrades are available to existing controls to further reduce air emissions. Our remaining coal plants all have scrubbers installed to control SO_2 emissions and have air pollution control equipment to control PM emissions. All three Sherco units are equipped with NO_x combustion controls that have significantly reduced NOx emissions from the units. The King plant and our combined cycle gas plants are also equipped with SCR technology to control NO_x emissions.

D. Regulation of Hazardous Air Pollutant Emissions

Both state and federal regulations require reductions in Hazardous Air Pollutant (HAP) emissions from power plants. In 2006, the Minnesota Legislature passed the Minnesota Mercury Emissions Reduction Act (MMERA). The MMERA provided a process for implementation and cost recovery for utility efforts to reduce mercury emissions at certain power plants, in our case the King and Sherco generating facilities. In 2012, the EPA adopted its final rule establishing National Emission Standards for HAPs from coal- and oil-fired power plants. This rule is often referred to as the Mercury and Air Toxics Standard (MATS), and compliance was required by 2015. Mercury controls have already been installed and are operational on all three Sherco units and at King.[40]

The MATS also set emission limits for acid gases and non-mercury metals. PM is a surrogate for non-mercury metal emissions and SO_2 is a surrogate for acid gas emissions. The Sherco and King plants meet these standards using control technologies and through operational practices.

In 2011, the EPA adopted emission limits for HAPs from industrial boilers to regulate boilers and process heaters fueled with coal, biomass and liquid fuels. These standards apply to biomass combustion at Bay Front Units 1 and 2 as well as to several small heating boilers located at our facilities. Compliance was required by early 2016.

III. WATER

A. Cooling Water Intake Structures

Section 316(b) of the federal Clean Water Act (CWA) requires the EPA to develop regulations governing the design, maintenance and operation of cooling water intake structures to assure that these structures reflect the best technology available for minimizing adverse impacts to aquatic species. The regulations must address both impingement (the trapping of aquatic biota against plant intake screens) and entrainment (the protection of small aquatic organisms that pass through the intake screens into the plant cooling systems).

[40] The CAA requires that EPA review standards such as MATS each eight years to determine if control technology has improved and if the residual emissions left after compliance with the MATS pose additional residual risk to the public. EPA recently proposed to find that, based on its review, no revisions to the MATS are required. 84 Fed. Reg. 2670 (Feb. 7, 2019).

The EPA released a 316(b) rule on May 19, 2014, along with a Biological Opinion issued by the U.S. Fish and Wildlife Service (FWS) and National Marine Fisheries Service (NMFS), and published the final rule in August 2014. The rule requires companies:

- To adopt one of seven options addressing impingement of biota at the entrance to cooling water intake structures, with approval by state or federal National Pollutant Discharge Elimination System (NPDES) permit writers;
- To minimize entrainment of biota into the structures, as directed by the permit writer taking a number of factors into account;
- To implement the impingement, entrainment, and other measures as soon as practicable after the entrainment measures have been identified, with interim milestones the permit writer may set, or for new units upon commencing operations;
- To provide extensive information in permit applications, including source water physical and biological data, intake structure and system data, proposed impingement compliance methods and supporting study plans, previously conducted entrainment studies, and the operational status of the plants; and
- For plants that withdraw more than 125 million gallons per day, to provide two-year comprehensive entrainment characterization studies, technical feasibility and cost evaluation studies, benefit valuation studies, and studies of non-water quality environmental and other impacts, with peer review of the last three.

The rule does not mandate the use of closed-cycle cooling for existing facilities. However qualifying closed-cycle systems will satisfy the final rule's impingement and likely will satisfy its entrainment requirements. The definition of qualified closed-cycle cooling has been broadened to include existing impoundments of waters of the U.S., if sufficiently documented as having been designed to provide a recirculating cooling function or if built in uplands, and to delete references to specific cycles of concentration, percentage flow reduction, and continuous flow constraints.

Regarding Endangered Species Act (ESA) provisions, the final rule requires permit writers to provide copies of applications to the FWS and NMFS, so these agencies can provide input within 60 days on endangered and threatened species and critical habitat potentially affected by intake structures and recommended permit conditions. If permit writers incorporate those conditions and permittees conduct all measures recommended by the Services, the permit will provide "incidental take" authorization. The FWS/NMFS biological opinion provided with the final rule states that the final

rule is not likely to jeopardize listed species or destroy or adversely modify designated critical habitat.

The definition of "existing facilities" would include nuclear uprates and other repowered and significantly modified units, even if the turbine, condenser, or fuel are replaced. However, replacement units—essentially newly built, stand-alone units constructed at existing facilities regardless of change in generation capacity, cooling water flow, or use of an existing intake structure—would be considered a "new" unit and subject to closed-cycle cooling equivalent requirements.

The final rule provides a *de minimis* exception for impingement mortality requirements for very low impingement rates, but cautions that ESA-listed species may not be taken. The rule also provides less stringent impingement standards for low-capacity utilization units.

Upper Midwest system power plants that use greater than 2 million gallons per day of surface water are required to comply with the rule. This includes Sherco, Monticello, Riverside, High Bridge, Black Dog, King, Prairie Island, Red Wing, Wilmarth, Bay Front and French Island. Additionally, three plants may be required to reduce entrainment mortality: Monticello, King and Black Dog. The Sherco plant is already a closed-cycle cooling facility and as such, will not likely be required to make significant cooling water intake structure upgrades to comply with the rule.

B. Thermal Discharge

The EPA regulates the impacts of heated cooling water discharge from power plants under CWA Section 316(a). States with authority to implement and enforce CWA programs (e.g. Minnesota, Wisconsin) have state-specific water quality criteria including thermal discharge temperature parameters to protect aquatic biota. Plants must operate in compliance with the thermal discharge temperature parameters. No changes have been made to the thermal discharge temperature parameters in Minnesota. In 2010, Wisconsin implemented new water quality standards regulating the thermal discharge temperature from facilities with state-issued NPDES permits. The new requirements are being incorporated into facility permits as the permits come due for renewal.

Our Bay Front plant in northern Wisconsin was the first Xcel Energy plant to receive new thermal discharge limits, in 2012. Preliminary modeling of the plant discharge indicated that there could challenges to meeting the new requirements. Field monitoring of the discharge showed that the plant was complying with the new thermal discharge limits during normal operations.

French Island does not currently have to comply with the thermal rules. Preliminary evaluation indicates that French Island will have challenges to achieve compliance during the late summer and early fall periods of the year. The existing permit issued in 2018 requires a thermal monitoring plan (due 2020) with monitoring (due 2021). Monitoring data are due with permit application submittal (September 2022). Negotiations with the Wisconsin Department of Natural Resources during permit reissuance will determine what, if any, thermal limits are required.

C. Effluent Limitation Guidelines

As part of the NPDES process, the EPA identifies technology-based contaminant reduction requirements called Effluent Limitation Guidelines (ELGs). The ELGs are used by permit writers as the maximum amount of a pollutant that may be discharged to a water body and apply to power plants that use coal, natural gas, oil or nuclear materials as fuel and discharge treated effluent to surface waters, as well as to utility-owned landfills that receive coal combustion residuals. ELGs are periodically updated to reflect improvements in pollution control and reduction technologies.

The EPA revised the ELG rule on September 30, 2015 with two implementation deadlines. Impacted facilities are required to comply with the new requirements between 2018 and 2023. September 2017, EPA issued a rule postponing certain compliance dates of the 2015 ELG rule while EPA reconsiders portions of the rule. Specifically, EPA delayed the "no earlier than" compliance date so that facilities could not be compelled to comply with rule. EPA plans to issue a revised rule before the 2023 compliance due date and may propose a new compliance timeline.

EPA's 2015 final rule updated the ELGs for flue gas desulfurization systems (FGD), bottom ash transport water (BATW), flue gas mercury control systems (FGMC) and fly ash transport water (FATW) that discharge to surface waters. The final rule addressed discharges directly to surface waters and indirectly to surface waters via municipal wastewater treatment plants. The 2015 rule imposed prohibitions on discharging FATW and BATW either directly or indirectly to surface waters. The rule reduced the levels of contaminants allowed in FGD wastewater discharges. The changes were based on a technology evaluation conducted by EPA. The 2015 final rule had limited impact on our Upper Midwest power plants, with only one unit, the Allen S. King plant, being required to make capital improvements to address the prohibition on discharging BATW. King is studying options for converting the bottom ash system to a dry handled or fully recycled system. The Sherburne County plant is unaffected until the all coal units are retired at which time there may be residual water in the scrubber solids ponds that may need to be managed onsite

without directly or indirectly discharging the wastewater.

D. Waters of the United States

In 2015, the EPA and the U.S. Army Corps of Engineers (USACE) issued a rule revising the regulatory definition of "waters of the United States" (WOTUS). The rule significantly expanded the universe of land features and water bodies that are subject to CWA jurisdiction. Under the CWA, federal permitting and oversight are required for any activity having the potential to impact WOTUS. Multiple suits were filed against the rule resulting in the 2015 rule being stayed in 28 states, but not in Minnesota. In February 2019, EPA and USACE issued a proposed rule that would revise the 2015 rule.

Our review of the EPA's 2015 final rule indicates that the new definition would impact the Company in a number of ways by adding complexity, cost and delay to project permitting. Current operations would also be impacted by the imposition of new regulatory requirements to previously exempt on-site or adjacent water bodies or ditches. We expect the rule would:

- Increase the difficulty of siting some projects, since many more areas will need to be avoided or be subjected to extensive and time-consuming CWA permitting;
- Complicate certain distribution line routing/re-routing work by triggering a lengthy permitting process before work can be conducted in or near WOTUS – for example, when the Company is required to reroute our lines due to state and local highway projects;
- Complicate the process to site, permit and construct wind and solar facilities, particularly in areas that have isolated water features. Additional time and cost will be incurred to either obtain the permits or to avoid areas that would trigger the need for federal permitting; and
- Increase cost and potential reliability issues as existing facilities, especially substations, must be retrofitted with additional oil-spill prevention and containment features to prevent an oil release from reaching WOTUS.

We are still evaluating the February 2019 proposed rule, but it appears to improve the clarity of the WOTUS definition, making it easier to define what water features will require federal permitting. Our analysis is not yet complete. EPA expects to finalize the proposed rule in 2020.

IV. COAL COMBUSTION RESIDUALS (ASH)

Coal Combustion Residuals (CCRs), often referred to as coal ash, is residue from the combustion of coal in power plants. Two common types of CCRs are fly ash and bottom ash. Fly Ash is a light material with the consistency of talcum powder that is carried from the boiler with the flue gas. This material is captured by pollution control equipment and may be combined with solids generated from air quality control systems designed to reduce SO_x and NO_x emissions. Bottom ash consists of the heavier materials collected from the bottom of the boiler. CCRs are either recycled for beneficial reuse or disposed of appropriately as non-hazardous industrial waste.

Currently the CCRs resulting from the coal combustion at Sherco Units 1 and 2 are disposed of wet within a permitted, engineered, lined surface impoundment as a non-hazardous industrial waste. The fly ash generated from Sherco Unit 3 is disposed of within a permitted, engineered, lined ash landfill located on plant property. The bottom ash generated from all Sherco units is stored within a lined impoundment as a non-hazardous waste until it can be beneficially used as a construction material or properly disposed on site.

The fly ash from the A. S. King plant is transported for disposal at a permitted, engineered, lined commercial landfill as a non-hazardous industrial waste, while the bottom ash from this facility is beneficially utilized in the manufacture of products. Xcel Energy's operations are subject to federal and state laws that impose requirements for handling, storage, treatment and disposal of wastes. These laws regulate CCRs as a non-hazardous waste under Subtitle D of the RCRA. While Xcel Energy's NSP-Minnesota disposal and storage facilities have been regulated by the Minnesota Pollution Control Agency (PCA) for several decades, they have only recently become subject to regulation under EPA's new CCR Rule.

EPA's CCR Rule became effective on October 19, 2015. This rule was promulgated in response to environmental concerns regarding structural failures and releases of ash directly to the environment from large surface impoundments (e.g. the 2008 Tennessee Valley Authority Kingston ash Impoundment failure and the 2014 release from Duke's Dan River Plant), allegations of inconsistent oversight by the states, and the potential for releases from unlined ash impoundments and landfills to impact drinking water sources.

The CCR rule establishes minimum design and operating requirements for CCR landfills and surface impoundments that are comparable to Minnesota's current

requirements under State rules, site-specific permits and operating plans, with specific differences discussed in subsequent paragraphs. Under this rule regulated landfills and surface impoundments are referred to as CCR Units.

The CCR Rule requires ongoing ground water monitoring of each regulated CCR Unit. The rule also defines groundwater protection standards which if exceeded may lead to corrective action. Currently the results from the CCR Rule ground water monitoring program have shown no exceedances of CCR ground water protection standards (GWPS), meaning that no corrective action is required at this time. The CCR Rule liner performance criteria are different than that established under the PCA's state program. As a consequence the Sherco Bottom Ash clay lined impoundment, is deemed lined under the state rule but is deemed unlined under the CCR Rule. Consequently Xcel Energy is in the process of replacing this impoundment with a new, lined impoundment that meets EPA and PCA requirements. Xcel Energy had previously anticipated the need to replace this impoundment and had plans to replace it by 2023. In order to comply with EPA's CCR Rule requirements Xcel Energy accelerated this project to have the new lined bottom ash impoundment available for use by October 31, 2020. Closure of the existing bottom ash impoundment is scheduled to be completed as originally planned in 2025.

Coal operations ceased at the Black Dog site in April 2015. CCR discharges to the three small impoundments present at the site ceased prior to October 19, 2015. These impoundments were closed by removal on December 12, 2016. The CCR materials removed from the impoundments were disposed of in an off-site, lined landfill. The CCR rule requires the completion of groundwater monitoring at closed CCR sites. Groundwater sampling under the detection monitoring program for this site has commenced and a determination as to whether there is a statistically significant increase (SSI) of groundwater constituents over background concentrations for Black Dog Impoundments 1-3 is due by April 17, 2019.

APPENDIX I – SUPPORTING INFRASTRUCTURE – TRANSMISSION & DISTRIBUTION

The goal of a sustainable, cleaner energy future depends upon sufficient infrastructure to support delivery of renewable and distributed generation resources and customer reliability. In particular, modernized transmission and distribution systems are critical to our ability to serve our customers in a reliable and safe manner, deliver growing levels of choice, increase renewable energy, meet the challenges of emerging technologies, and take a holistic view of resource planning.

As we actively prepare our distribution system for the needs of the future, we consider the need for thoughtful investments to meet our core obligation, safely and reliably delivering energy to our customers. We also are focused on adopting smarter technologies to further enable distributed energy resources (DER) on our system. We also face new challenges and opportunities for the transmission grid as traditional baseload units retire, large scale renewables significantly increase, and DER are increasingly adopted. In some cases, such as increasing consideration of distribution-level DER on the transmission grid, changes in the market and planning constructs are underway. Other changes are just coming into view and the planning constructs have not yet caught up. We are adapting our planning practices in the interim to ensure reliability and resilience, and we expect substantial new transmission will be needed to support the transformation that is underway.

Overall, we envision building toward an integrated grid that supports the Company's clean energy transition, leveraging the strength of an interconnected system to make the best use of available resources while continuing to serve our customers with resilient and reliable power. We discuss our transmission and distribution systems in greater detail below, including the ways we expect planning to become more integrated over time.

I. TRANSMISSION

The Xcel Energy Operating Companies NSP-Minnesota and NSP-Wisconsin operate an integrated transmission system (the NSP System) comprising more than 8,400 miles of transmission facilities operating at voltages between 23.7 kilovolts (kV) and 500 kV and approximately 550 transmission and distribution substations. The NSP System serves retail customer loads in Minnesota, North Dakota, South Dakota, Wisconsin, and Michigan. The NSP System is wholly within the Midcontinent Independent System Operator (MISO) footprint, which is part of the Eastern Interconnection.

The transmission grid in the Upper Midwest has seen significant development over the last 10-15 years. These changes have increased both resilience and capabilities to transport renewable energy from the geographic locations where it is abundant to customer load centers, such as the Twin Cities Metro area. But, as discussed in this Appendix, in Appendix J1: Baseload Study, and in conjunction with the Reliability Requirement we developed for this Resource Plan (Appendix J2), the grid is facing new challenges as traditional baseload units retire, large scale renewables significantly increase, and distributed energy resources (DER) are increasingly adopted.

Below, we provide a brief overview of the NSP System transmission grid and our transmission planning efforts to ensure we maintain customer reliability as the grid transforms and the lines between distribution and transmission blur. We then discuss the challenges in maintaining reliability in *every hour of every day* when the resource adequacy construct relies on an average contribution for a single future planning year. While this is reasonable for firm, dispatchable resources, it does not adequately recognize the intermittent nature of renewable resources – particularly as penetration levels grow – and as we discuss, results in gaps in meeting customers' energy requirements. We then discuss the Reliability Requirement that we developed for this Resource Plan to address this challenge and better ensure grid stability and resilience, and customer reliability. We also discuss the challenges and opportunities associated with interconnecting and efficiently utilizing the substantial new renewable generation we will need to meet our goals, given the current state of the MISO interconnection queue and transmission limitations. Finally, in the balance of this section, we discuss timely issues and summarize our Baseload Study.

A. Transmission System and Planning Overview

The Transmission Business Unit centrally manages Xcel Energy's transmission systems (i.e., NSPM, NSPW, Public Service Company of Colorado, and Southwestern Public Service Company) so that energy is safely and reliably transmitted from generating resources (both Company-owned and third-party owned) to the distribution systems serving our customers. While transmission planning is considered separately from resource planning, these two functions are necessarily interrelated, just as the generating resources and transmission infrastructure on the grid are interrelated. Transmission needs are driven by multiple factors including increased customer electric demand, new or retiring generator interconnections that adjust the flows on the existing transmission system, and generation resource choices and the availability of transmission to meet the demand for these resources. The interconnected nature of the transmission system also means that neighboring utilities' decisions (either transmission or generation) have impacts on the NSP System. Finally, as DER grows, even small retail customer changes at the distribution level

may impact the transmission system.

As demonstrated in the Biennial Transmission Plan we submit to the Commission in odd-numbered years, we are constantly reviewing and studying our system to optimize operations and prepare for the future. We independently—and in conjunction with MISO—analyze different futures to assess the system and determine any necessary build-outs, in both short- and long-term planning horizons. Based on these analyses and subsequent implementation, between 2010 and 2018 we invested more than $3 billion in our transmission system. Much of our transmission investment over the recent past has been in implementing the CapX2020 initiative and participating in MISO Multi-Value Projects (MVP), which substantially increased transmission capabilities in the Upper Midwest.

1. Planning Initiatives

MISO and the Company perform ongoing and specialized studies to evaluate necessary projects to address issues in the overall MISO system, including the NSP System.

From these studies and our own technical study efforts in support of the Baseload Study we undertook with this Resource Plan, we believe significant additional transmission development will be necessary as we and other utilities retire baseload generating units and add significant renewable resources to the grid toward our commitment to a clean energy future. We also believe changes to the current planning constructs are necessary to properly reflect the trends underway, to ensure system stability and resilience, and customer reliability.

a. Company Biennial Transmission Projects Report

Pursuant to Minn. Stat. § 216B.2425, every other year, the Company – along with the other Minnesota Transmission Owners[1] – submits a Biennial Transmission Projects Report to the Commission reporting on the status of its transmission system. The Biennial Transmission Projects Report lists specific present and foreseeable future transmission inadequacies; identifies alternatives to address system inadequacies;[2]

[1] American Transmission Company, LLC, Dairyland Power Cooperative, East River Electric Power Cooperative, Great River Energy, Hutchinson Utilities Commission, ITC Midwest LLC, L&O Power Cooperative, Marshall Municipal Utilities, Minnesota Power, Minnkota Power Cooperative, Missouri River Energy Services, Northern States Power Company, Otter Tail Power Company, Rochester Public Utilities, Southern Minnesota Municipal Power Agency, Willmar Municipal Utilities.

[2] Minnesota Transmission Owners define "inadequacy" as essentially a situation where the present transmission infrastructure is unable or likely to be unable in the foreseeable future to perform in a

identifies general economic, environmental, and social issues associated with the alternatives; and summarizes the input that transmission owners and operators gather from the public and local governments to assist in developing and analyzing alternatives.

The 2017 Biennial Transmission Projects Report was filed with the Minnesota Public Utilities Commission in Docket No. E999/M-17-377 on November 1, 2017, and can be found at the Minnesota Department of Commerce's eDockets website at www.edockets.state.mn.us/EFiling or at www.minnelectrans.com. The 2017 report lists more than 90 separate inadequacies throughout the state, including more than 50 newly-identified inadequacies since the filing of the 2015 Biennial Transmission Projects Report. Of the inadequacies identified, 13 involve Xcel Energy.

b. Ongoing MISO Studies

MISO Transmission Expansion Plan (MTEP). MISO has an annual transmission planning process which results in identification of needed transmission facilities.

MISO Generation Interconnection Studies. MISO performs generation interconnection studies to identify facilities necessary to connect new generation resources.

MISO Economic Planning Studies. As part of its planning process, MISO conducts a *Market Congestion Planning Study (MCPS).* The purpose of this study is to determine whether there are transmission projects that could remove transmission constraints and thus more efficiently use available generation resources. The *MCPS* results are reported as part of the annual MTEP report. During the *MCPS* process, projected economic and power flow models are developed which, when analyzed, determine the total production costs that are incurred to provide energy to the MISO load. Transmission constraints – the transmission elements that limit the amount of power that can be transferred between the unused, lower-cost generation and customers – are identified. Through stakeholder discussions, transmission projects are proposed that could mitigate the constraints. The costs for these proposed transmission projects are determined and compared to the amount of production cost savings that could be realized if those projects were in service. The resultant benefit to cost ratio of the projects indicates whether the proposed solutions should be considered for further evaluation for constructability and reliability analysis. Stakeholder review and comments are compiled, and a decision on whether to recommend a *MCPS* project be included in the upcoming MTEP report is made.

consistently reliable fashion and in compliance with regulatory standards.

c. CapX2020 and MVP Regional Development Initiatives

The CapX2020 initiative was a coordinated transmission development effort by a partnership of 11 regional utilities. The results of this coordinated initiative began to be implemented in 2009 and concluded in late 2017. Including the planning, this initiative spanned 13 years, and involved 800 miles of transmission and $2 billion of investment in Minnesota, North Dakota, South Dakota, and Wisconsin.

The approximate lengths, general locations, and in-service dates (ISD) of the CapX2020 projects are as follows:

- *Fargo – St. Cloud – Monticello (ISD mid-2015).* An approximately 240 mile, 345 kilovolt line between Fargo, North Dakota and Alexandria, St. Cloud and Monticello, Minnesota.
- *Brookings County – Hampton (ISD mid-2015).* An approximately 230 mile, 345 kilovolt line between Brookings, South Dakota and the southeast Twin Cities, plus a related 30-mile, 345 kilovolt line between Marshall, Minnesota and Granite Falls, Minnesota. This project is also a MISO multi-value project (MVP).
- *Hampton – Rochester – La Crosse (ISD late 2016).* An approximately 150 mile, 345/161 kilovolt line between Hampton in the southeast Twin Cities, Pine Island near Rochester, Minnesota, and La Crosse, Wisconsin.
- *Bemidji – Grand Rapids (ISD late 2012).* An approximately 70 mile, 230 kilovolt line between Bemidji and Grand Rapids, Minnesota.
- *Big Stone South – Brookings County (ISD late 2017).* An approximately 70 mile, 345 kilovolt line between Brookings, South Dakota and Big Stone City, South Dakota. This project is also a MISO MVP.

MISO MVP is a project type and cost allocation methodology developed through extensive stakeholder discussions in the 2009-2010 timeframe for portfolios of projects that meet one or more of the following three goals:

- Reliably and economically enable regional public policy needs
- Provide multiple types of regional economic value
- Provide a combination of regional reliability and economic value.

The MVP portfolio was intended to enable the delivery of the renewable energy required by public policy mandates, in a manner more reliable and economic than it would be without the associated transmission upgrades. The initial MVP portfolio

was approved in December 2011 and combines reliability, economic and public policy drivers and results in a transmission solution that provides benefits in excess of its costs throughout the MISO footprint.

Xcel Energy was a participant in the following MVP projects:

- Big Stone South – Brookings County 345kV (CapX2020)
- Brookings County – Hampton 345kV (CapX2020)
- La Crosse - Madison 345kV (with ATC, also called Badger Coulee)

With the addition of the CapX2020 projects and MISO MVPs, sufficient transmission capacity has existed for the Company to meet its Renewable Energy Standard (RES) requirements to-date. These projects have improved reliability in the region, addressed local reliability issues, and provided a foundation for the interconnection of new generation resources – particularly the renewable resources that have significantly grown over this timeframe. However, many of these lines planned in the early 2000s and completed over the recent past are already fully- or nearly-fully subscribed.

2. NERC and MISO are Recognizing Potential Resource and Planning Deficiencies

The North American Reliability Corporation (NERC) conducts a reserve margin analysis across all system operators in North America in a report called the Long Term Reliability Assessment (LTRA). The December 2018 LTRA indicated that MISO is one of three regions that are projected to drop below their reference reserve margin levels by the year 2023, unless certain measures are taken.[3] This report indicates that inclusion of Tier 2 resources (those that are in more advanced stages of planning but not yet under construction) would likely allow for the MISO footprint to preserve system reliability. However, the unprecedented rate of announced, but not yet evaluated, baseload generation retirements and uncertainty in future firm capacity additions creates a tension between maintaining reliability and transitioning away from baseload generation. NERC also recently concluded a special reliability study on the compound effects baseload generating resource retirements on the grid.

[3] See "NERC Long Term Reliability Assessment 2018" at 14. Available at: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2018_12202018.pdf

3. MISO RIIA Study Initiative

In preparation for an expected future grid with high levels of non-dispatchable renewable penetration and declining baseload generation, MISO is undertaking additional studies with respect to its system's reliability and resource adequacy of its system. In 2017, MISO initiated a special initiative called the *Renewable Integration Impact Analysis* (RIIA) that is still underway. We incorporated insights from these studies into our Baseload Study that informed our Preferred Plan. RIIA study seeks to inform future long-term planning by understanding what the power system will need to operate reliably with these high levels of variable resources – specifically by examining operational adequacy, transmission adequacy, system stability, and resource adequacy limitations.

a. Renewables Integration Becomes Significantly More Complex Between 30 and 40 Percent Penetration Levels

In Phase I, the study examined a scenario in which variable generation achieves a 40 percent share of the total capacity on the MISO system. It found that the complexity of operating such a system reliably is significantly higher than that of even a system with 30 percent variable resources. Under the circumstances studied, the system experienced more dynamic stability issues and other operational stressors, and resource adequacy requirements increased. For example, the modeled system exhibited high levels of energy curtailment and very high ramping rates in the hours when variable resources were not always available to meet demand. In this scenario, loss of load projections were narrowed to fewer likely hours during the year, but the probability of occurrence increased significantly over the current state. This points to the value that flexible, dispatchable resources supporting grid stability continue to provide in these circumstances; while they will run for fewer hours as renewable levels on the grid increase, they are needed – and must be able to respond quickly, moving from minimum generation levels to higher levels of output to meet these fluctuations in net load quickly.

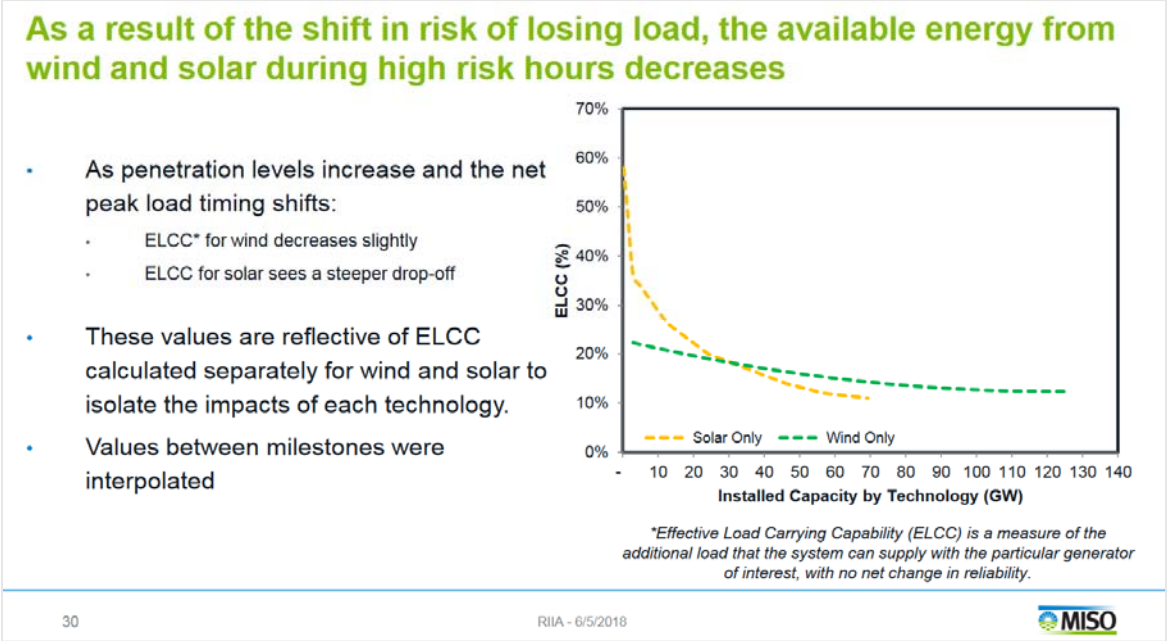
b. Peak Value of Renewables Declines at High Penetration Levels

At high levels of wind and/or solar adoption, the RIIA study found that the accredited capacity values assigned to these resources for resource adequacy purposes degraded – sometimes significantly from current levels. As discussed below, MISO's resource Effective Load Carrying Capability (ELCC) is currently evaluated as an annual average, and forward values are not projected. In reality, however, the capacity value these resources provide to the grid is not consistent – and, as we and other industry members are learning – the capacity values are also subject to diminishing

marginal returns. When a single variable resource type increases its penetration level on the grid, each incremental unit of capacity inherently provides a little less capacity benefit to the system than the previous unit.

The appropriateness of these values in reflecting actual grid conditions is therefore dependent on the pace at which wind and solar penetration increases on the grid – and subsequently, how MISO conducts review and adjusts the values. For example, MISO's RIIA study estimates that solar in particular would experience steep ELCC reductions within the first 10 gigawatts installed – and this value continues to drop off at higher levels of adoption.[4] Further, in particular for these variable assets, the realized capacity value may change throughout the year in accordance with seasonally variable environmental conditions.

Figure 1: Modeled wind and solar ELCC as penetration increases[5]



The operational realities surrounding future variable resource additions and their seasonal aspects aside, we continue to use the MISO-determined accredited capacity levels in our planning. As MISO's planning construct is currently limited to one forward-looking value, this presents a risk as we plan our future system. Applying this single value to a 15-year planning period – now knowing that the value of these resources will degrade as we and others add variable renewables to the MISO system

[4] https://cdn.misoenergy.org/20180418%20PAC%20Item%2003d%20174068%20RIIA190532.pdf
[5] MISO. "Renewable Integration Impact Assessment" Workshop presentation June 5, 2018. Available at: https://cdn.misoenergy.org/20180605%20RIIA%20Workshop%20Presentation213125.pdf

– what appears to be a net capacity surplus today, may look quite different in future assessments.

We additionally note that we may encounter other changes to current resource adequacy accreditations for other use-limited resources in the future as well. In general, resources such as demand response (DR) and energy storage would be subject to declining ELCC values as they become more prevalent on the system, in the same way wind or solar ELCCs realistically decline.[6] Notably, MISO is also considering changes to how it accounts for DR capacity accreditation overall, such as enforcing more stringent testing requirements. MISO is also following up on actual performance during DR events, which may result in accredited value reductions going forward. Both these factors mean that the DR we currently register with MISO and depend on as a baseline resource in our portfolio may not yield the same benefits in future years as we have historically expected.

We see emerging challenges and uncertainties in the broader MISO market and industry that indicate that the present planning constructs to ensure reliability are not fully equipped to address. Large numbers of renewable generation projects are in the MISO queue for interconnection study and facing substantial upgrade costs to connect to the grid. We are also facing a transition on the grid, with many of the current abundant baseload/large central generating stations retiring, and high levels of renewable resources coming online and pending in the MISO interconnection queue – and perhaps long-term, DER. This generation transformation changes the flows and impacts the reliability attributes of the grid in ways we and the industry are just beginning to understand. We discuss these issues in greater detail in the following sections.

B. Current Regional Planning Constructs Must Adapt

MISO is charged with several responsibilities, chief of which is overseeing wholesale energy markets in the member region and planning for bulk system reliability (i.e. transmission planning, generator interconnection, and ensuring sufficient reserve margins). Many aspects of MISO's operations affect how we conduct resource planning, but here we focus primarily on system reliability constructs that will be increasingly tested as we and others transition to a fuel mix that relies on high levels of variable renewable resources.

As we have discussed, MISO and its system reliability oversight organization, NERC,

[6] See Appendix P2: RESOLVE and RECAP Low Carbon Scenario Analysis (E3) for further discussion on how marginal ELCC for DR and energy storage resources may decline as adoption increases.

undertake studies to determine the appropriate level of reserve capacity that should be maintained, what effect a resource retirement has on the broader system, and how increasing renewable adoption will change how they analyze and ensure grid reliability. All of these studies point toward an increasingly complex grid that will have to be carefully managed through the transition to a lower-carbon future. Trends are emerging that raise questions regarding whether and how planning constructs may need to adapt to ensure the system remains reliable as baseload generating units continue to retire and be replaced by carbon-free, but variable, renewable energy.

One of MISO's core responsibilities includes administering resource adequacy requirements to enable the Company and other Load Serving Entities (LSEs) across the region to fulfill their obligation to serve customers reliably. MISO's Planning Reserve Margin (PRM) analysis is one important piece of the current reliability planning paradigm. The PRM is an estimation of how much generating capacity, over and above expected customer load, needs to be present on the system to ensure reliability in all but the most extreme circumstances (called a 1-in-10 year Loss of Load Expectation or LOLE). In the 2018 LOLE report, MISO established reference PRM values for both installed capacity (ICAP) and a value that derates the installed capacity value to account for potential outages (UCAP). These UCAP values are also called "accredited capacity." The UCAP PRM for the NSP System for the 2018-2019 planning year was 8.4 percent, which means that the total available capacity on the system needs to be 8.4 percent higher than the expected system peak load to ensure reliability.[7] LSEs, including the Company, apply this PRM to their system planning to determine their capacity obligation to MISO.

MISO bases the accredited capacity values on the expected average contribution each resource will provide to the grid. For firm dispatchable resources, the UCAP values are determined based on historical individual unit operational performance. For intermittent, or variable resources, UCAP values are based on the average performance of each wind or solar resource project/farm. MISO also performs probabilistic analyses of how much capacity from variable resources can be counted on to contribute to peak demand across the year, and captures this in the ELCC. These administratively-set values have a significant impact on how we achieve our carbon reduction goals while maintaining affordable and reliable service. Currently, MISO assigns our wind generation an average ELCC value of 15.7 percent, meaning that for every 100 MW nameplate of installed wind, only 15.7 MW can be counted as capacity toward the PRM. For new solar resources, in the absence of an observed

[7] Note that these are 2018/2019 values. We discuss these two measures of PRM and how we apply them to the NSP System for this Resource Plan in the Minimum System Needs section.

historical value, MISO assigns the current initial year default ELCC of 50 percent.[8]

There are two primary issues with the current resource adequacy construct that we believe have the potential to impact reliability and resilience, and for which we have taken steps in this Resource Plan to mitigate. First, the PRM relies on an average capacity value for each resource. The variable and intermittent nature of renewable resources means that they are not available at all at times. Relying on them to perform 24 hours a day, 7 days a week – particularly as renewable levels rise and current baseload units retire – presents an unacceptable risk to reliability. Second, with significant increases in renewable resources underway, the industry is beginning to recognize that renewable resource contributions to meeting the system peak declines as their levels increase.

MISO's present resource accreditation process only establishes the ELCC for the next planning year. This short-term approach fails to account for the declining value those resources will provide toward meeting customers' needs over the long-term. Average capacity values for variable resources will not ensure sufficient energy for our customers every hour of every day. Instead, maintaining an adequate level of flexible, dispatchable resources is necessary to effectively integrate high levels of renewables is necessary.

We also know that high levels of renewables result in a declining peak contribution and can create system instability. As MISO has studied high levels of renewable penetration on the grid with its RIIA study, it has recognized that its capacity accreditation framework – the manner by which it assesses variable renewables' ability to contribute to peak demand needs – will likely change as these resources become more prevalent on the grid. However, MISO has not yet developed sufficiently robust forward guidance for resource planning processes to account for how those values might change in the future, creating uncertainty in the resource planning process.

C. Reliability Requirement

In response to the planning gaps identified above, we developed a Reliability Requirement, which we discuss in detail in Appendix J2 and summarize below.

As the Company increases the amount of renewable generation in our system, it is

[8] We performed a solar ELCC study, which was designed to determine potential ELCC values for incremental small scale solar generation installations. *See* Xcel Energy Compliance Filing, Docket No. E999/CI-15-115 (August 17, 2018).

important to recognize that these resources cannot alone reliably provide customers the energy they demand every hour of every day, or maintain the stability of the grid. Until such time as new technologies develop to fully transition the grid to carbon-free resources, some level of load-supporting, firm dispatchable resources is necessary for grid resilience and customer reliability.

As noted above, renewable resources like wind and solar are inherently variable and intermittent, and as penetration of these resources increases, their value to meet peak customer needs decreases. These concerns are not limited to the NSP System, but rather run throughout MISO's footprint – and in other regions with increasing levels of renewables. Within MISO and on the NSP System specifically, the gap between renewable resource performance and customer needs has been most pronounced during (but is not limited to) winter months. Although MISO is beginning to recognize these challenges, its current planning constructs do not yet incorporate any measures to address them. We have therefore developed a Reliability Requirement to inform this Resource Plan and mitigate risks to customer reliability and system resilience as MISO determines how to incorporate these issues into its planning process.

The Reliability Requirement we developed for this Resource Plan ensures we have the right mix of resources on our system every hour of every day to meet our customers' needs. We apply the Requirement in our Strategist modeling, and note that while this concept is essential until MISO evolves its capacity construct to provide better direction – the Requirement has little effect in our modeling for this Resource Plan. The model does not select any firm dispatchable additions as a direct result of the Reliability Requirement until 2031. Figure 2 below outlines the general calculation of the Reliability Requirement.

Figure 2: NSP System Reliability Requirement Calculation – 2020 Example

Peak Demand Proxy – 6,400 MW
Minus Firm DR (Winter) Proxy – (200) MW
Minus Firm Market Supply Proxy – (500) MW

Reliability Requirement – 5,700MW
(Firm dispatchable resources)

We discuss the Reliability Requirement in detail in Appendix J2.

D. Regional Transmission Capabilities are Limited

The current state of grid interconnection processes and transmission capabilities in MISO introduces complexity to our planning processes and how we execute on the plan. An overflowing project queue, delayed interconnection studies, and transmission system limitations impose challenges to the economic viability of new renewable generation, and by association – our ability to execute on our clean energy transition plans. MISO is taking action to address a number of these challenges. There are some mitigation measures we expect to utilize in the near-to-medium term, which include carefully managing our interconnection rights at existing sites. In the longer term, however, we see a lack of new transmission development as a barrier to achieving our clean energy goals.

1. Generator Interconnection Queue Delays and Interconnection Costs

The MISO generator interconnection process is designed to allow generators reliable, non-discriminatory access to the electric transmission system, in a timely manner, while maintaining transmission system reliability. Recently, as the number of proposed projects in MISO has expanded significantly, this process has been mired in delays. Delay impacts are particularly evident in the Definitive Planning Process (DPP) phases, where MISO undertakes generation interconnection studies. Current studies are a number of months behind due to the large number of projects in the queue, and a generator interconnection process that allows late withdrawals from the queue.

Despite some recent process reforms, MISO has not been able to keep pace with the expanding queue. And when projects do make it through the DPP, they are sometimes assigned high transmission system upgrade costs that challenge the projects' economic viability. As of early June 2019, there was over 100 GW of new capacity in the active MISO queue, the vast majority of which was of wind and solar projects.[9] Each cycle of the DPP is handling expanding levels of requested capacity. For example, the recently completed cycle for the MISO West region started out with 31 projects totaling 5,700 MW. The April 2019 DPP study cycle, scheduled to begin in March 2020, includes 58 projects totaling 8,800 GW in the same area.[10] While the level of proposed new renewable projects is a positive indication of aspirational renewable development in the region, MISO has also indicated that a substantial amount of this capacity is speculative, in early stages of project development, or

[9] MISO "Generator Interconnection: Overview." Updated as of June 1, 2019, at: https://cdn.misoenergy.org/GIQ%20Web%20Overview272899.pdf
[10] *See* MISO "Definitive Planning Phase Estimated Schedule." Updated as of June 1 2019. Available at: https://cdn.misoenergy.org/Definitive%20Planning%20Phase%20Estimated%20Schedule106547.pdf

duplicative requests.

Further, the existing transmission system's capability to interconnect new projects without substantial infrastructure upgrades is limited, and thus, the generation interconnection planning studies indicate there will likely be costly upgrades assigned to the prospective generators. In the past, initiatives such as CapX2020 and MISO MVPs socialized a substantial level of transmission infrastructure investment across a large swath of benefitting MISO members, and created the ability to integrate large amounts of new renewable energy. However, renewable resources, and wind power in particular, expanded on the MISO grid faster than expected. As a result, the capacity that CapX2020 and the MVPs created has been largely used. Since these early initiatives, few new transmission lines have been proposed or approved for the purposes of renewable integration.

Generally speaking, this translates to substantial transmission upgrade costs being assigned to the generation projects in the queue. To illustrate, in the recently completed MISO West DPP cycle, the 5,700 MW of studied projects were expected to incur approximately $3.2 *billion* in transmission upgrades if all of them were to interconnect to the system.[11] Such high transmission system upgrade costs can render projects uneconomic, forcing them to withdraw from the queue and requiring additional MISO study on the remaining projects.

2. *Physical and Process Limitations between Regions Further Slows Progress on Clean Energy Development*

Limitations on transmission infrastructure and coordination, both within MISO and between MISO and the Southwest Power Pool (SPP), illustrate further challenges. Within MISO, the transmission system is showing constraints and thus slowing progress toward a cleaner energy future across the Upper Midwest system. Currently, wind generation from the western part of MISO flows toward the load centers in the east, such as the Twin Cities Metro area and load centers beyond the transmission interconnection between Minnesota and Wisconsin. However, existing west-to-east transmission capacity is, at times operating at its limit. The transmission interface across the Minnesota-Wisconsin border in particular is currently stability-limited, and trying to force additional renewable energy through these lines could result in voltage collapses in Northern Wisconsin that would destabilize the grid. Curtailing this energy at its source in the west is operationally and economically inefficient – keeping

[11] *See* "MISO DPP 2016 August West Area Phase 1 Study." Report Number: R008-18. Siemens, September 20, 2018, at xvii.
https://cdn.misoenergy.org/GI_DPP_2016_Aug_West_Phase1_SIS_Report277263.pdf

us from fully utilizing the inexpensive and clean energy to which we have access. However, without additional transmission development, we will more frequently encounter this problem as we add more renewable generation to our system.

Further, coordination (or historical lack thereof) between MISO and SPP introduces challenges to increasing and utilizing more clean energy. First, for projects that can be considered interregional in nature, a project must currently meet economic benefit hurdles in a joint review, as well as separate MISO and SPP regional evaluations. This slows the process significantly, and may overestimate the amount of interconnection upgrades required, adding to project uncertainty and cost. Second, although our load and generation are fully within MISO, the nature of power flows inevitably results in some of our energy entering the SPP system. In turn, both MISO and SPP may charge to transmit that energy from the point of generation to the load, challenging a project's economic viability or raising customer costs for projects already online.

Finally, MISO and SPP disagree on what should happen when one region or the other has to "lean" more on the system than its contracted delivery amounts for a certain time. Where SPP would levy penalties in this scenario, MISO views this situation as a normal and acceptable result of an integrated grid. All of these issues increase transaction costs and uncertainty for a given generation project coming online, and represents a potential barrier to efficiently bringing additional renewable generation to the grid.

3. MISO is Taking Action to Address the Current Process Issues

In response to direction from FERC and a recognition of the challenges described above, MISO is undertaking several actions that could serve to mitigate challenges to bringing new, clean resources online. In essence, these actions allow generation owners to leverage existing interconnection agreements to maximize utilization, and fit renewable additions into the relatively few remaining open spaces on the grid. While we expect these processes to mitigate some of the near-term challenges to additional renewable capacity, they do not address all challenges – in particular, our ability to depend on neighboring regions for renewables and maintaining reliability; we expect that longer term solutions will eventually need to be developed.

a. Generator Replacement Process

Interconnection study delays and speculative queueing are challenges not only to projects that are actually commercially-viable, but also to generation owners who are looking to retire aging assets. Companies that are required to meet a certain level of reserve capacity, like Xcel Energy, face potential compliance and commercial risk if

we retire existing assets without the ability to re-utilize that interconnection capacity.

Recognizing these issues, MISO filed, and in May 2019 received approval for, a proposed Replacement Generator Process as part of its Attachment X tariff. This modification intersects with Attachment Y with regard to generation replacement and interconnection rights of current generation owners when a resource retires. The change to Attachment X allows current generation owners to retain and reuse the interconnection rights when a resource retires, within certain technical and timing limitations on the new generator.[12] The new generating units could be developed on the same site, or on a site in close proximity that uses the same grid interconnection point. Per the new tariff language, the replacement generation resource would need to go into service not later than three years after the existing generator retires. Importantly, these replacement projects would be studied outside the traditional DPP timeline, because the transmission infrastructure in the area was built to accommodate the large amount of generation associated with the current generating facility – and customers should be able to continue to take advantage of this infrastructure that they have already paid for rather than fund alternative network upgrade costs. This avoids the significant delays and costs associated with the DPP process.

Maximizing use of existing interconnection rights is essential to timely and cost-effective achievement of the fleet transformation that we set in motion with this Resource Plan. This Tariff change is an important development that will help to facilitate the transformation in a timely and cost-efficient manner for our customers.

b. FERC Order 845 Opens Additional Opportunities for Generation Owners

In 2018, FERC issued Order 845, *Reform of Generator Interconnection Procedures and Agreements*, that also opens additional opportunities for generation owners to add resources to the system outside the normal interconnection queue process.[13] First, the Order directs all transmission providers to develop a procedure to allow interconnection customers to use surplus availability at an existing point of interconnection without that new project entering the full MISO queue and planning process, within certain technical limitations. MISO has referred to surplus interconnection availability as "Net Zero" interconnection because the addition of

[12] In summary, these changes allow for transfer of interconnection rights from a retiring generation resource to a replacement resource that: (1) is located at the same point of interconnection as the retiring resource, (2) is less than or equal to the generating capacity of the retiring resource, and (3) does not result in an adverse impact to the transmission system. *See*: https://www.ferc.gov/CalendarFiles/20190515181059-ER19-1065-000.pdf

[13] *See:* https://www.ferc.gov/whats-new/comm-meet/2018/041918/E-2.pdf

this new project would not result in an overall increase to the interconnection capacity requirements of the site; rather, it would be expected to increase the overall *utilization* of the interconnection site. While MISO allowed Net Zero resources prior to FERC 845, the new Order also allows existing interconnection rights owners the first right to utilize the surplus availability on that interconnection. It also revises the definition of a generating facility to explicitly include energy storage resources. These actions work to support generation owners increasing renewable utilization on existing interconnections, and could support future project hybridization (e.g. solar and storage or wind and storage).

c. Substantial Challenges Remain

We expect that generator replacement, Net Zero, and other FERC Order 845 implementation efforts will alleviate some of the barriers to planning and executing on a future with substantial renewable additions. However, these do not address the underlying challenges around queue length and timeline, intra-MISO and interregional seams congestion challenges, and integrating high levels of renewables reliably and affordably. MISO has recently attempted to mitigate the queue volume challenge by proposing process reforms that increase the stringency of entering this phase of interconnection process; however, while recognizing the challenges MISO faces, FERC recently rejected the proposal.[14] While the Company and others have begun contemplating new MVP-like projects, the lack of alignment across MISO and long lead-times required for such projects mean that these challenges are unlikely to be sufficiently resolved in the near-term.

E. Summary – 2020-2034 Upper Midwest Resource Plan Baseload Study

With this Resource Plan we provide a Baseload Study as Appendix J1. We undertook this study as an outcome from our most recent Resource Plan in which the Commission required the Company to continue its study of potential baseload resource retirements.[15] We started this work as part of our last Resource Plan, as we took action to transition our fleet to achieve dramatic reductions in carbon emissions. Specifically, we studied the technical implications of retiring two of our coal plants – Sherco Units 1 and 2. In conjunction with this Resource Plan, we performed technical analyses to more broadly examine the issue of orderly retirement of our remaining baseload generating units – namely, A.S. King, Sherco Unit 3, Monticello Nuclear, and Prairie Island Units 1 and 2.

[14] *See* FERC "Order Rejecting Tariff Revisions re: Midcontinent Independent System Operator, Inc. under ER19-637." Available at: https://elibrary.ferc.gov/idmws/file_list.asp?accession_num=20190319-3076
[15] *See* Docket No. E002/RP-15-21, Order Point 14(a) (January 11, 2017).

To understand the technical impacts of retiring one or more baseload generating units, we perform engineering analyses on simulations of the Unit changes that assess the results against established industry reliability and operating criteria. When performing technical studies, we simulate a number of varied conditions that can consider changes in customer loads, projected changes to the generation mix, and ways to use the transmission system most efficiently.

The Baseload Study in this Resource Plan is comprised of four primary components:

- **Midcontinent Integrated Systems Operator (MISO) Attachment Y2 preliminary retirement studies**, which assessed various single Unit and combined Unit retirement scenarios for thermal and voltage concerns,
- **Xcel Energy Transmission Reliability studies**, which examined system stability and response impacts associated with baseload generating resource changes on the NSP System and on neighboring systems,
- **Industry insights**, including the North American Electric Reliability Corporation (NERC) *Generator Retirement Scenario Special Study* and the MISO *Renewable Integration Impact Analysis* (RIIA), which provide important insights into the combined effects of baseload generator retirements in a region and grid impacts at increasing levels of renewables penetration, and
- **A focused Strategist analysis**, which examined the economic implications of various Unit and combined Unit retirements at different points in time.

The technical studies generally analyze the way power flows over the grid and search for places where the system might overload or fail, assuming specific circumstances. While these studies are essential and provide important insights, our decades of operating and studying the existing system also provides valuable insights and perspective toward assessing potential impacts from NSP System grid changes. We incorporated this experience into our analysis of impacts. We also supplemented our technical study efforts with relevant industry initiatives that examine the compound impacts of aging baseload retirements and increasing levels of renewable generation – similar to the issues facing the NSP System. The studies use the best available information at the point in time that they were conducted. However, the grid is dynamic, and expected conditions will change when new generation comes online, existing generation retires, new transmission lines are constructed, or existing lines are reconfigured; in addition, reliability measurement criteria may change. The results therefore are a point-in-time representation of the technical issues we expect would occur in a studied scenario.

The MISO Y2 and our Reliability Studies identify grid impacts and potential transmission mitigations necessary to resolve the respective issues the studies identified. MISO performed its Y2 Studies in accordance with their Business Practice Manuals, which generally focus on thermal and voltage issues.[16] We used the MISO planning level estimated mitigation costs from the Y2 studies as an input to our Strategist modeling of the baseload unit retirements. While these may not be the final mitigations, they provide a proxy of potential costs to inform the economic aspect of our Baseload Study. Our technical studies supplemented the MISO analysis to examine traditional NERC reliability measures such as system stability and response. This is an important complement to the MISO Y2 studies to provide a more robust look at potential impacts from baseload changes on the NSP system and regional MISO grid.

The results of our Baseload Study informed the Preferred Plan we propose in this Resource Plan, which includes the following baseload actions: (1) Retire our remaining two coal units early – King in 2028 (nine years early) and Sherco 3 in 2030 (ten years early), and (2) Extend the operation of Monticello nuclear 10 years through a license extension, to 2040.

Other conclusions and insights from this Study include:

- The retirement of our current baseload units must be orderly, and will be impacted by decisions other MISO generation owners make regarding their baseload units.
- We must maintain sufficient firm dispatchable, load supporting resources to ensure customer reliability and to support integration of higher levels of renewable resources.
- Changes in the MISO planning construct are necessary to properly recognize the inherent variable and intermittent nature of renewable resources in meeting customer needs every hour of every day.
- Significant new regional transmission development will be necessary to support increased levels of renewable resources and to support the retirement of baseload units.
- From an economic perspective, the scenarios that included early coal retirements and nuclear extensions had the most favorable present value.

Insights gained from this Study also helped to inform our development of a Reliability

[16] *See* MISO Business Practice Manual BPM-020 at: https://www.misoenergy.org/Library/BusinessPracticesManuals/Pages/BusinessPracticesManuals.aspx

Requirement (discussed in Appendix J2), which bridges the gap between current regional planning requirements and necessary changes to account for: (1) the variable contribution renewable resources provide to the system, (2) the lack of long-term regional system planning guidance for the expected contribution of renewable resources as penetration levels rise, and (3) the need for sufficient firm dispatchable, load supporting resources to reliably integrate increasing levels of renewable resources.

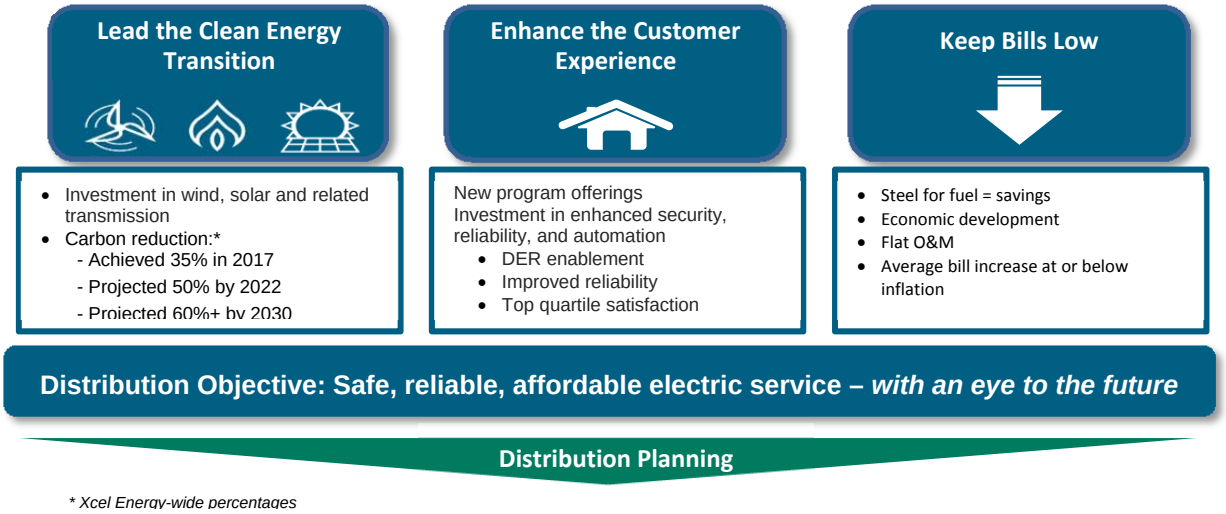
II. DISTRIBUTION

The electric utility industry is in a time of significant change. Increasing customer expectations and technological advances have reshaped what customers expect from their energy service provider, and how those services are delivered. Technologies that customers can use to control their energy usage, such as smart thermostats, electric vehicle (EV) chargers, smart home devices, and even smart phones, are evolving at a fast rate. Influenced by other services, customers have come to expect more now from their energy providers than in the past, including greater choices and levels of service, as well as greater control over their energy sources and their energy use.

At the same time, major industry technological advances provide new capabilities for utility providers to manage the electric distribution grid and service to customers. Electric meters are now equipped to gather more detailed information about customer energy usage, which utilities can leverage to help customers better understand and manage their usage. Other advanced equipment on the grid is able to sense, communicate, and respond in real time to circumstances that would normally result in power outages. Grid operators can also get improved data to better and more proactively plan and operate the grid. These advancements form the foundation for a flexible grid environment that helps support two-way power flows from customer-connected devices or generating resources (such as rooftop solar) and provides utilities with a greater ability to adapt to future developments.

The foundation on which these capabilities rest is safe, reliable energy. Our strategic priorities of enhancing the customer experience, leading the clean energy transition, and keeping customer bills low are embedded in everything that we do – including the way that we plan our distribution system.

Figure 3: Xcel Energy Strategic Priorities – Applied to Distribution



Distribution planning has historically – and still largely today –involved analyzing the electric distribution system's ability to serve existing and future electricity loads by evaluating the historical and forecasted load levels, and utilization rates of major system components such as substations and feeders. Customers traditionally have had limited information about their energy usage and few choices in how they received information, had questions answered, and paid utility bills or conducted other necessary business with their utilities. For the most part, customers were content to receive a monthly paper bill from their utilities and were unaware and unengaged in whether the energy came from renewable or non-renewable sources.

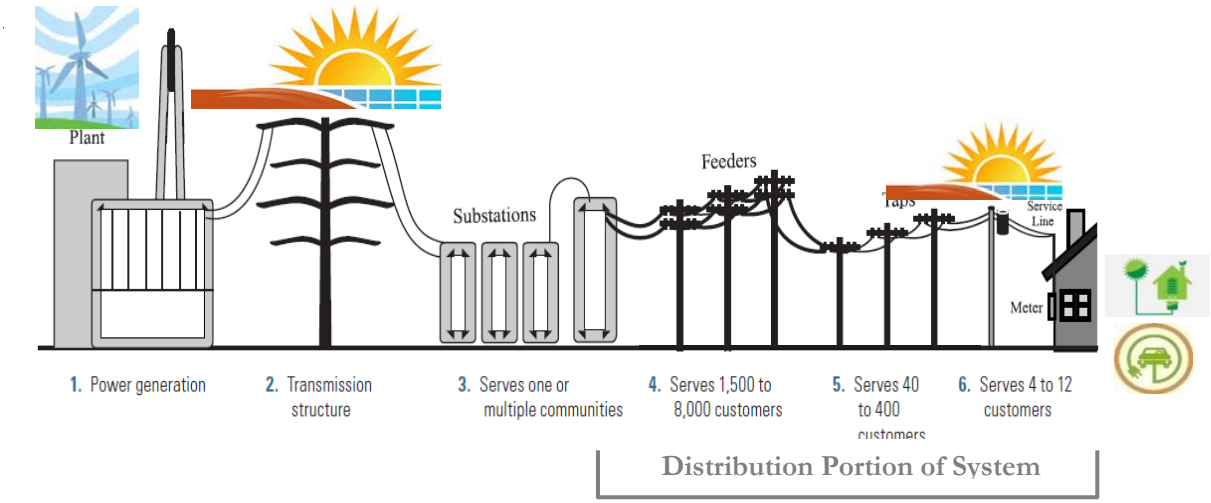
Now, instead of planning just for load, utilities will need to analyze the system for future connections that may be load *or* generation. Also, utilities will increasingly need to view their operations and customer tools from their customers' perspectives. This step change in the distribution utility business will require utilities to plan their systems differently, which will involve not only new processes and methodologies but also new and different tools and capabilities.

Like other aspects of the industry that are transitioning and advancing, we are on the forefront of integrated distribution planning. We submitted the first Integrated Distribution Plan (IDP) in Minnesota November 1, 2018 – which was also among some of the first IDPs nationally. We are taking steps to align and integrate our distribution, transmission, and resource planning processes. We also are in the process of evaluating and procuring the next generation of distribution planning tools, which are needed to increase our forecasting and analysis capabilities and impact the integration of planning processes.

A. System Overview

The electrical grid is composed of generating resources, high voltage transmission, and the distribution system, which is the vital final link that allows the safe and reliable flow of electricity to serve our customers. We provide an illustration of a modern electrical grid below.

Figure 4: Illustrative Electrical Grid



The poles, lines, and cables that comprise the distribution system connect individual residents and business to the larger electrical grid. The system has been developed for the efficient distribution of power, with lines routed as directly as possible. Geography, however, plays a dominant role in the ultimate design of the system; the location of lakes, road and developments dictate the siting of much of the distribution infrastructure.

Distribution substations are sized for anticipated load at a particular site, and often consist of one to three transformers. Site selection for substations is based on the availability of a transmission source, proximity to the load being served, total ownership costs and reliability considerations. Incremental transformers and feeders may be planned at substation sites to meet future load demand. Where possible, redundancy is built into the system to maintain reliability. Taps are the smaller line segments that leave the mainline and fuses or reclosers are installed at those connection points, which open if a fault develops on the tap. This prevents the remainder of the system on that feeder from having their service interrupted, thus isolating the outage to just the customers beyond that fuse. At the customers' site, service transformers feed lower voltage secondary conductors. These conductors

deliver the low voltage power to meters at customers' homes and businesses.

The NSPM electric distribution system serves 1.5 million customers (1.3 million in Minnesota) – and is composed of 1,177 Feeders, approximately 15,000 circuit miles of overhead conductor, and over 11,000 circuit miles of underground cable.[17] The distribution portion of the grid, and the services that the Distribution organization provides, are generally the aspects of our electric service that are most visible to our customers. In terms of reliability, we rank nationally in the 1st quartile.[18]

Key Distribution functions include operating the distribution system, restoring service to customers after outages, performing routine maintenance, constructing new infrastructure to serve new customers, and making upgrades necessary to improve the performance and reliability of the distribution system. We are also out in the community during and after severe weather events as part of our industry-leading storm response efforts to ensure safety, and to promptly restore service to customers.

Key overall Electric Distribution business priorities are:

- *Operational Excellence.* Improve reliability performance level.
- *Grid Modernization.* Install key equipment and systems to operate the new modern grid including monitoring and control, Advanced Distribution Management System, and system efficiency. Targeted renewal of aging, unreliable, or obsolete components and systems (i.e. underground cable, poles, 4kV systems)
- *System Health.* Targeted maintenance of key assets designed to improve reliability and safety – wood poles, substations transformers & breakers, vegetation management.
- *System Capacity Additions.* Installation or reinforcement of key substations and feeders to serve new load and provide backup under emergency conditions (focus on high consequence events).

Distribution priorities and budgets recognize that customers want reliable and uninterrupted power. We therefore must not only proactively maintain our system by making capital improvements when necessary to improve reliability and safety for our customers – we must also manage our budgets to be able to respond to outages

[17] In this context, the number of customers is based on the number of electric meters.
[18] Results for the NSPM operating company, as measured by SAIDI and SAIFI. *See IEEE Benchmark Year 2018, Results for 2017 Data* at:
http://grouper.ieee.org/groups/td/dist/sd/doc/Benchmarking-Results-2017.pdf

caused by severe weather, mandatory work such as relocation of our facilities, and other conditions that cannot be foreseen with a high degree of accuracy. While the immediacy of customer reliability is a reality and a primary focus, in addition to these core activities, our investment plan reflects strategic investments to advance distribution grid capabilities, increase our system visibility and control, and enable expanded customer options and benefits. We are also planning for enhanced distribution planning tools that will equip our system planners with the capabilities to perform DER scenario analysis in our annual planning processes, better facilitate our incorporation of non-wires analysis (NWA) into the analysis we perform to ascertain the best way to meet system capacity needs, and begin in earnest the integration of planning activities at all levels of the grid.

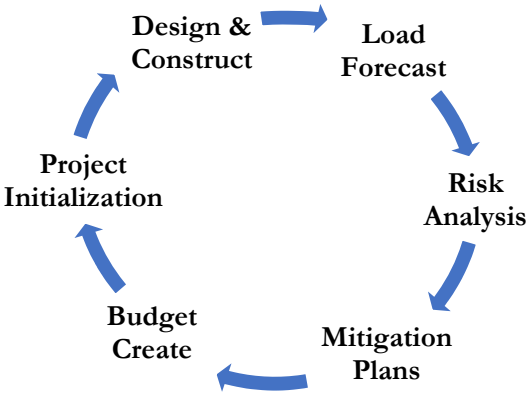
B. System Planning

An important aspect of distribution planning is the process of analyzing the electric distribution system's ability to serve existing and future electricity loads by evaluating the historical and forecasted load levels and utilization rates of major system components such as substations and feeders. We also consider Hosting Capacity analysis an important aspect of our system planning. We discuss both of these planning activities in this section.

1. Annual System Planning

We do this annually, and additionally conduct analyses during the year in response to new information, such as new customer loads, or changes in system conditions. The process begins with the forecast of peak customer load and concludes with the design and construction of prioritized and funded capacity projects, as illustrated in the below Figure.

Figure 5: Annual Distribution Planning Process



Planning Engineers rely on a set of tools to perform the annual full system snapshot, ongoing distribution system assessments – including assessment of specific DER interconnections – and long-range area assessments. We see our planning practices evolving to analyze future electricity *connections*, rather than just loads. However, we will need to advance our planning tools and capabilities to facilitate greater capabilities to factor-in DER and to more systematically be able to evaluate NWA. Enhanced planning tools have started to emerge in the industry, but will take some time to mature. Toward that end, we have been participating with others in the industry to examine the types of capabilities that may be needed. We also are in the process of evaluating and procuring the next generation of distribution planning tools, which are needed to increase our forecasting and analysis capabilities and impact the integration of planning processes.

2. *Non-Wires Alternatives*

Non-Wires Alternatives (NWAs) are emerging as another advanced distribution planning application. While a nascent concept only a few years ago, the United States has seen a significant rise in the number of NWA projects proposed and being implemented. States with high DER penetration and/or aggressive regulatory reform, like New York, California, Oregon, and Arizona, are leading the way. Decreasing DER costs in combination with slow or flat load growth may present opportunities for utilities to address pockets of load growth using DER over traditional build out of distribution infrastructure, like reconductoring, transformer replacement, or even new substations. Unlike traditional infrastructure projects, which typically offer fixed capacity increases at known locations, non-traditional solutions often have varying operating characteristics based on their location or the time of day they are used.

More tactically, NWA analysis processes consider several things: a set of criteria for

determining which traditional projects are suitable candidates for NWA, processes to develop portfolios of solutions (including both third party resources and non-traditional utility assets), a mechanism to evaluate the costs and benefits of the NWA relative to the traditional solution, procurement processes, and standards to ensure equitable reliability and performance. For implementation and deployment, currently we are seeing NWA solutions which require a disparate set of systems to separately operate the different elements of equipment that would comprise an NWA portfolio solution (e.g. a battery- only platform or demand response- only mode).

Without integration across different systems, this makes the facilitation of NWA a custom, one-off solution that requires extensive oversight and management. To-date, analysis we have performed has determined that the cost of incorporating DER as the primary risk mitigation is at this time still more costly than traditional solutions. However, as technology advances and manufacturing evolves, DERs have the potential to quickly become a cost competitive option. As such, we are working diligently with research groups, internal and external stakeholders, and other utilities that are also incorporating DER planning in order to refine the process of having NWAs solve traditional distribution system deficiencies.

3. Hosting Capacity

We recognize hosting capacity as a key element in the future of distribution system planning. We anticipate it has the potential to further enable DER integration by guiding future installations and identifying areas of constraint. In compliance with Minn. Stat. § 216B.2425 and by order of the Commission, we conducted and submitted annual hosting capacity studies in 2016, 2017, and 2018.[19] We use the EPRI DRIVE tool for our analysis. EPRI defines hosting capacity as the amount of DER that can be accommodated on the existing system without adversely impacting power quality or reliability – and introduced the DRIVE tool as a means to automate and streamline hosting capacity analysis. Our studies have provided hosting capacity results by feeder to serve three purposes: (1) provide an indication of distribution feeder capacity for DER, (2) streamline interconnection studies, and (3) inform annual long-term distribution planning.[20] We expect to continue to evolve our hosting capacity analysis to meet emerging trends and customer needs.

[19] *See* Distribution System Study, Docket No. E002/M-15-962 (December 1, 2016), Hosting Capacity Report, Docket No. E002/M-17-777 (November 1, 2017), and Hosting Capacity Report, Docket No E002/M-18-684 (November 1, 2018).
[20] See Integrated Distribution Planning Report Prepared for the Minnesota Public Utilities Commission, ICF International (August 2016).

C. Distributed Energy Resources

We continuously evaluate new technologies, new system designs, new equipment, and new operational methods in order to continue to meet the needs of the distribution system in a changing energy environment. These new technologies include emerging advanced grid tools or other advanced field devices with monitoring, controlling, and other capabilities that better enable DER and provide for a more adaptable system.

Some customers are choosing DER, which can reduce customer consumption and even provide energy back to our system from decentralized locations on the grid. Examples of DER include, but are not limited to: rooftop solar panels, energy storage, community solar gardens, or the energy efficiency and demand response enabled by a smart thermostat or time of use electric rate. We are anticipating and preparing for increasing DER penetration levels on our system.

Our customers' adoption of DER and new types of load mean that consumption patterns from our centralized power system are changing. This can represent an opportunity: if we can harness the benefits of these resources to make demand more flexible, we can use this to better match demand to energy production from our large, variable renewable resources. For example, we could utilize managed or "smart" charging of electric vehicles (EVs), to delay charging to off-peak hours or to times when renewable output is the highest. We could also use advanced metering technology alongside customer programs and tariffs to more readily enable load shifting away from peak hours.

DER is also coming onto our system in the form of electric transportation options – enabling not only flexible load opportunities but also broader economy-wide emissions reduction – and we have developed several programs and rate options to encourage that adoption. However, we still often do not have visibility into which technologies, and at what pace, customers will adopt and thus, how we should plan for that changing load to affect our grid needs in the future. While the opportunities are exciting, it is also important to recognize that customer adoption of DER and new types of load behind the meter introduces uncertainties in our planning processes, particularly if we do not have adequate visibility into how and when that new DER or demand is coming onto our system.

The distribution system was initially built to support one-directional flows of energy. Increased DER penetration levels pose new challenges to the distribution system to accommodate two-directional flows. As DER installations increase in an area, feeders or substations may require further analysis to ensure this equipment is adequate to continue providing sufficient power quality and reliable service. Safety is a key

concern with higher volumes of distributed energy, as are operational challenges presented by the variability of sources like solar photovoltaic and electric vehicles. DER is also increasingly expected to impact the transmission system, so distribution and transmission planning processes are becoming increasing interrelated.

The Federal Energy Regulatory Commission (FERC) has engaged in the DER trend through its Order No. 841, which addresses participation of storage resources at the transmission and at the distribution level in wholesale markets. We support Order No. 841 as it relates to resources interconnected at transmission level, but have concerns about its implementation as it relates to storage resources interconnected at distribution level.[21] We also have concerns about FERC's proposal in Docket No. RM18-9-000, Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators, which would expand the requirements of FERC Order No. 841 to all types of DER interconnected at distribution level, not just storage resources.[22]

We addressed what we see as current challenges, which become more significant at higher penetration levels, in comments submitted to FERC. These challenges include:

- *Metering.* Participation of distribution-interconnected storage resources raises the question about how metering will distinguish between charging for wholesale purposes as opposed to charging for retail usage in the case of dual-use facilities. Charging for retail usage should be subject to state-regulated retail rates while charging for wholesale purposes would, under Order 841, be subject to FERC regulated wholesale rates. We are not aware of any metering arrangement that can distinguish between charging for wholesale purposes and charging for retail purposes in the case of a dual-use facility. It should be incumbent upon the resource owner to provide sufficient documentation to ensure that any dual-use resource can be metered in a manner that can distinguish between charging for retail use as opposed to charging for wholesale use. Otherwise, cost shifts to other retail customers will occur as a result of such a resource avoiding payment of full retail rates when it is charging a storage resource for what will ultimately be usage for a retail purpose.

[21] XES filed a request rehearing of various aspects of FERC Order No. 841 as it relates to resources interconnected at distribution level. A copy of XES's request for rehearing is available at this link: https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14651369

[22] A copy of XES's comments in FERC Docket No. RM18-9-000 is available at this link: https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14682284. These comments largely capture input provided in XES's original comments in Docket Nos. RM16-23-000 and AD16-20-000 and XES's request for rehearing in those dockets. FERC declined to accept these comments into the record in Docket No. RM18-9-000 because FERC deemed they were duplicative.

- *Distribution Operations.* Distribution system operators (DSO) need to have the capability to monitor activities of DER in the wholesale market and potentially take action to curtail market sales if such sales will impair reliable distribution system operations. The need for such capabilities will increase as DER penetration increases. The mechanisms to manage these operations will require enhanced communications systems between the DSO, DER, and market operator; software that can monitor distribution system impacts and identify reliability issues and solutions; and additional operations personnel to effectively manage the impacts of DER participation in markets. Cost causation principles dictate that the DER owners and operators should be responsible for the costs associated with these enhancements because such costs would not be incurred "but for" the participation of DERs in wholesale markets. However, absent fairly significant DER penetration levels it is not clear how these costs can be effectively allocated and recovered. At low penetrations there will simply be an insufficient number of customers to bear the costs of these infrastructure upgrades. FERC has not proposed a mechanism to address this issue. In the meantime, DSO will have to find ways to manage DER resource participation reliably, cost-effectively, and in a manner that does not shift costs to other customers.
- *Distribution system upgrades.* Existing distribution systems were not built to manage large outflows of energy that would be associated with market sales. Further, distribution systems are not as flexible as transmission systems and therefore are less able to effectively handle the types of system flows that will occur with DERs participating in markets. Distribution interconnection studies will be more complex and will identify potentially significant feeder and substation upgrades needed to enable market participation by DERs. The costs of such upgrades should be directly assigned to the DER causing such costs to be incurred.
- *Wholesale market issues.* In addition to the direct distribution-level impacts of DERs participating in markets, there are a variety of other issues that must be addressed at the wholesale market level. These issues include the ability to determine where individual DERs involved in an aggregation are located in order to ensure that resources are paid the appropriate nodal price, whether technology exists to effectively manage the state of charge of storage resources, and whether market software can effectively be deployed to manage large numbers of relatively small resources.

MISO was required to make a compliance filing with FERC by December 3, 2018 and has a year thereafter to implement provisions of its compliance filing. One of the key

aspects of MISO's compliance filing was relationship between MISO, the DER, and the applicable DSO. FERC is currently evaluating MISO's plans to implement Order 841. Implementation is required by the end of 2019 absent an extension. The Company is also evaluating whether additional steps may be needed to handle the interface between itself, the owners of DER resources, and MISO. Issues that the Company is evaluating include direct assignment of distribution system upgrade costs incurred due to DER participation in wholesale markets, distribution wheeling rates, the need for a DER to establish to the satisfaction of the utility that it has metering capability needed to ensure that it does not charge a storage resource at wholesale rates for retail usage, mechanisms to limit DER output to the extent that reliability of the distribution system is compromised by the DER's activities, and cost recovery for services provided by the distribution system operator to the DER.

We plan to evaluate this issue further and take appropriate steps to move forward to ensure that DER participation in wholesale markets is not subsidized by other retail customers and that such participation is conducted in a manner that does not threaten reliability of the distribution system.

We are taking action to improve our planning tools and modernize our system to more readily integrate increasing levels of DER that we believe are inevitable. We discuss these plans as part of our overall advanced grid initiatives in Part _ below.

D. Advanced Grid Initiative

We are on the forefront of many of the issues and changes underway in the industry and have developed our advanced grid initiative to address them. In addition to the significant steps we have taken to implement and improve our hosting capacity analysis, we are in the process of implementing an Advanced Distribution Management System (ADMS). The ADMS is foundational to advanced grid capabilities that will provide the visibility and control necessary for enhanced planning and significant DER integration. We are also implementing a Time of Use (TOU) pilot, which implements new residential TOU rates, and the installation of Advanced Metering Infrastructure (AMI) meters, in two communities in the Twin Cities metropolitan area, providing select customers with pricing specific to the time of day energy is consumed. This pilot also provides participants with increased energy usage information, education, and support to encourage shifting energy usage to daily periods when the system is experiencing low load conditions.

We also are poised to propose further foundational advanced grid capabilities, including a full AMI implementation, a secure and robust Field Area Network (FAN),

and significant reliability improvements for customers through Fault Location, Isolation, and Service Restoration (FLISR). In addition to transforming the customer experience, these foundational investments will allow us to advance our technical abilities to deliver reliable, safe, and resilient energy that customers value. As an example, FLISR and ADMS will reconfigure the grid to reduce the numbers of customers affected by an outage and provide better information to outage restoration crews to speed up their response or avoid those outages in the first place. These foundational investments also lay the groundwork for later years. The secure, resilient communication networks and controllable field devices deployed today through these investments will become more valuable in the future as additional sensors and customer technologies are integrated and coordinated.

We envision that our customer strategy will leverage the more refined customer usage data captured by AMI meters and communicated to utility systems through the FAN to enable new rate, billing, and program options that allow customers to adjust their usage to save money or participate in cost saving programs, using their devices. AMI and FAN also will improve our existing customer portal (MyAccount) information to provide more personalized insights to help customers understand how and where energy is being used and provide ways to help them save money.

However, fundamentally we must replace our present Automated Meter Reading (AMR) system. While it has delivered substantial value for customers since it was implemented in the mid-1990s, our vendor has announced that the technology will no longer be supported after the early-2020s – and they plan to discontinue support for AMR technology entirely in the mid-2020s. At the same time, the AMI technology and market have matured, which has driven many other vendors to also discontinue support of AMR. According to the U.S. Energy Information Administration, AMI adoption surpassed AMR in 2012, and the gap has widened as AMR rollouts have flattened.

We expect three primary outcomes from our deployment of advanced grid infrastructure and advanced technologies: (1) a transformed customer experience, (2) improved core operations, and (3) facilitation of future capabilities.

Transformed customer experience. Advanced grid investments combine to provide greater visibility and insight into customer consumption and behavior. We will utilize this information to transform the customer experience through new programs and service offerings, engaging digital experiences, enhanced billing and rate options, and timely outage communications. These options will provide customers greater convenience and control to save money, access to rates and billing options that suit their budgets and lifestyles, and more personalized and actionable communications. We expect our

early initiatives will focus on the execution of services that benefit all customers. Other customer choice programs enabled or enhanced by advanced grid initiatives may include smart thermostats, home area networks, rooftop solar, community solar gardens, optimized EV charging, and other DER offerings.

Improved core operations and capabilities. We also will improve our core operations, making investments to more efficiently and effectively deliver the safe and reliable electricity that our customers expect. While we have historically provided reliable service, we need to continue to invest in new technologies to maintain our performance in the top third of U.S. utilities, particularly as we deliver power from more diverse and distributed resources, and as industry standards continue to improve.[23] Our advanced grid investments provide technologies to manage the complexities of a more dynamic electric grid through additional monitoring, control, analytics, and automation. This will benefit customers through less frequent, shorter, and less impactful outages; more effective communication from the Company when they are impacted by an outage; and reduced costs from our more efficient use and management of assets.

Facilitation of future capabilities. Designing for interoperability enables a cost-effective approach to technology investments and means we are able to extend our communications to more grid technologies, customer devices, and third-party systems in a stepwise fashion, which unlocks new offerings and benefits that build on one another. This building-block approach, starting with the foundational systems, is in alignment with industry standards and frameworks (such as the Department of Energy's Next Generation Distribution Platform (DSPx) framework).[24] It also allows us to sequence the investments to yield the greatest near- and long-term customer value while preserving the flexibility to adapt to the evolving customer and technology landscape. By adhering to industry standards and designing for interoperability, we are well positioned to adapt to these changes as the needs of our customers and grid evolve.

Adherence to industry standards also allows us to better secure the grid and the devices we have connected to it. The increasing number of interfaces associated with grid modernization increases our cybersecurity exposure. As we move forward into the next generation of intelligent, interactive electric distribution, every facet of the electric network must be evaluated for cybersecurity risk. All aspects of the advanced grid must be inventoried, securely configured, and monitored regularly and

[23] See Leading the Energy Future 2017 Corporate Responsibility Report, Page 85, Xcel Energy (May 2018).
[24] See Modern Distribution Grid, Volume III: Decision Guide, U.S. Department of Energy Office of Electricity Delivery and Energy Reliability (June 2017).

thoroughly.

These investments also will produce a wealth of customer and grid data, which will, in turn, enable us to provide the new services described here and enhance existing services. These data-related efforts have begun, and next steps will include identifying the analytics capabilities needed to add additional value to customer offerings or improve utility operations. Data analytics in the utility industry continues to mature, so as grid modernization investments are deployed, these capabilities will evolve as well.

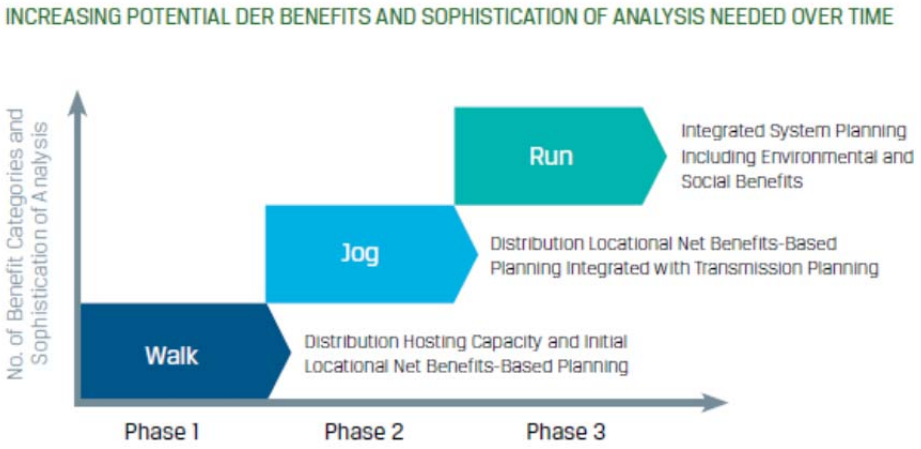
E. Transmission and Distribution Planning are Becoming More Interrelated

Although increasing DER penetration levels will drive integrated resource planning and distribution planning closer together, there are fundamental differences in how these two planning activities assess and develop plans to meet customers' needs. Distribution planning, like Integrated Resource Planning (IRP), charts a path to meet customers' energy and capacity needs, but is more immediate and subject to emergent circumstances because distribution is the connection with customers. Unlike IRPs, five-year plans are considered long-term in a distribution context; and, IRPs are concerned with size, type, and timing, whereas the primary focus of distribution planning is location. Thus distribution loads and resources are evaluated for each major segment of the system – on a feeder and substation-transformer basis – rather than in aggregate, like occurs with an IRP. Before a greater integration of distribution planning, transmission planning, and IRP can occur, distribution planning will need to become even more granular than it is today to address the challenges – and harness the benefits – of DER.

Today, the distribution and transmission planning groups work together as their respective planning processes impact or rely on one another. For example, distribution planning supplies transmission planning with substation load forecasts that are an input into the transmission planning process. These two groups also interact when distribution planning identifies the need for additional electrical supply to the distribution system – and similarly with interconnections, distribution is on point, and involves the appropriate planning resource as needed. The work that we are doing now on customer adoption-based of DER and electrification is helping to bring these planning processes closer together – and we believe will result in better informed sensitivities to ultimately inform both IRP and IDP. However, there are fundamental differences in these planning processes that will continue to challenge integration, at least in the near-term.

Minnesota is among a few states, including California, New York, and Hawaii, on the forefront of advancing its distribution planning as part of its grid modernization efforts. However, each is driven by differing policies and considerations; each is taking a different approach; and, each may result in its own solution that may not fit the circumstances elsewhere. While there are no definitive answers at this point, experts generally agree that a deliberate, staged approach to increased sophistication in planning analyses – commonly referred to as "walk, jog, run" – is important. The below Figure illustrates he stages below.

Figure 6: Staged Approach to Enhanced Planning Analyses



(*Source*: ICF White Paper, *The Value in Distributed Energy: It's all About Location, Location, Location* by Steve Fine, Paul De Martini, Samir Succar, and Matt Robison.

Movement from one stage to another is generally driven by growth in volume and diversity of distribution-connected, DER, the level of evolution of supporting planning practices and tools, and integration with other planning efforts, such as transmission, or resource planning.

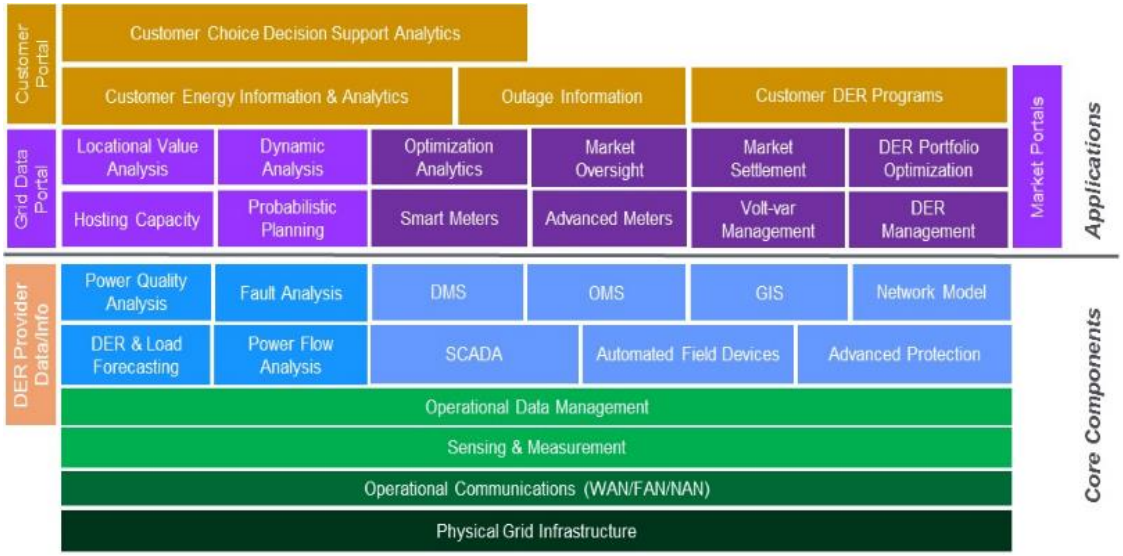
Similarly, the Berkeley Lab report, *Distribution Systems in a High Distributed Energy Resources Future, Planning, Market Design, Operation and Oversight* proposes a three-stage evolutionary structure for characterizing current and future state DER growth, with stages defined by the volume and diversity of DER penetration – plus the regulatory, market and contractual framework in which DERs can provide products and services to the distribution utility, end-use customers and potentially each other.[25] The report emphasizes the need to ensure reliable, safe and efficient operation of the physical electric system, DERs and the bulk electric system, which correlates to Minnesota utility requirements under Minn. Stat. § 216B.04 to furnish safe, adequate, efficient,

[25] Future Electric Utility Regulation series (Report No. 2), by Paul De Martini and Lorenzo Kristov (October 2015). *See* https://emp.lbl.gov/publications/distribution-systems-high-distributed

and reasonable service. The report describes Stage 1 as having low adoption of DERs, where the focus is on new planning studies when DER expansion is anticipated, which also correlates to where we are in Minnesota presently.

The U.S. Department of Energy (DOE), as part of its collaboration with state commissions and industry to define grid modernization in the context of states' policies is developing a guide for modern grid implementation that similarly recognizes foundational elements upon which increased utility tools and information and changes in infrastructure planning, grid operations, energy markets, regulatory frameworks, ratemaking, and utility business models rest, as shown in the below Figure.

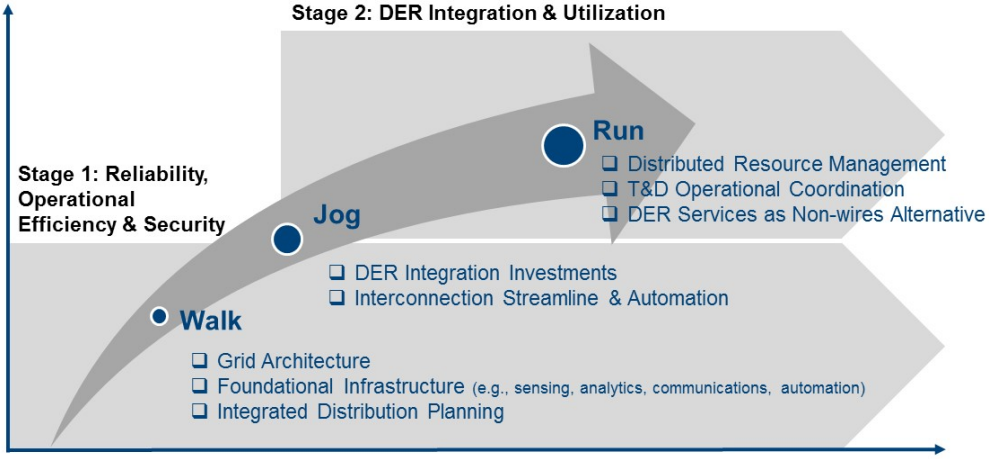
Figure 7: Platform Considerations



Source: *Considerations for a Modern Distribution Grid*, Pacific Coat Inter-Staff Collaboration Summit by DOE Office of Electricity Delivery & Energy Reliability (May 24, 2017).

The DOE's efforts also recognize timing and pace considerations, as shown in Figure 8 below.

Figure 8: Timing and Pace Considerations



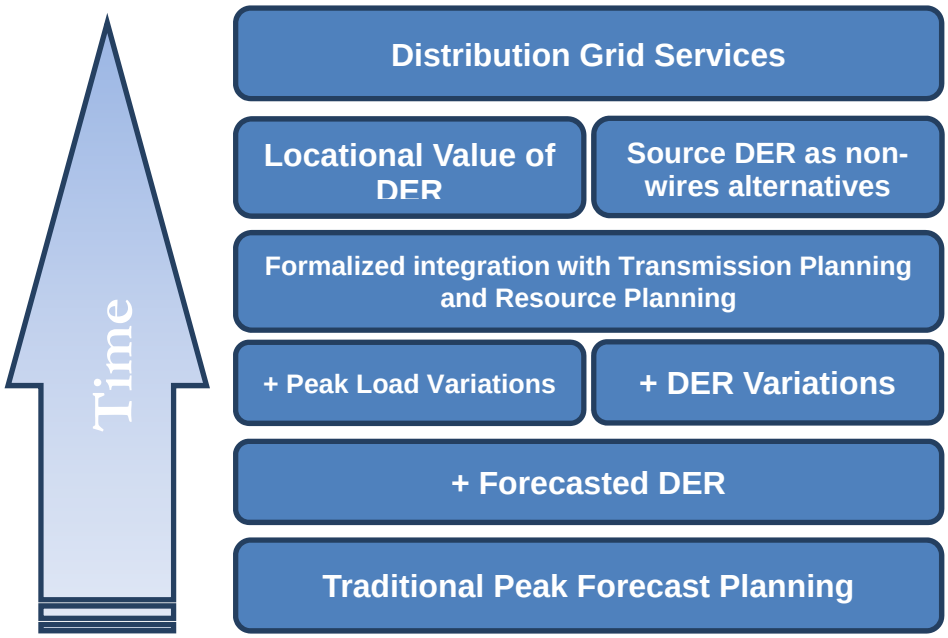
Source: *Considerations for a Modern Distribution Grid*, Pacific Coast Inter-Staff Collaboration Summit by DOE Office of Electricity Delivery & Energy Reliability (May 24, 2017).

As part of the May 24, 2017 Pacific Coast Inter-Staff Collaboration Summit, DOE observed that the U.S. distribution system is currently in Stage 1, with the issue being whether and how fast to transition to Stage 2. Underlying this question however, is the issue of identifying customer needs and state policy objectives – with a goal to implement proportionally to customer value – all of which will differ significantly across states. We agree that Minnesota is in Stage 1. We are focused on foundational infrastructure and starting to evolve our planning tools to enable integrated distribution planning.

A potential progression in planning practices could involve the evolution shown in Figure 9 below, with the drivers of progress being:

- Customer value, such as need, public policy, and cost/benefit,
- Utility readiness, including proper foundational tools and systems, and
- Supporting regulatory frameworks that address cost recovery, and any changes in federal or state market operations, etc.

Figure 9: Potential Evolution in Planning Practices



We expect this progression will need to occur over time as tools improve, policy drivers become clear, and customer value is determined.

Evolving distribution planning to be more like integrated resource planning will need to be thoughtful and planful. Today, IRPs are grounded in Minnesota statutes and rules – and chart a long-term direction of how load can be served in a broad service area. The IRP process is grounded in Minn. R. 7843, which prescribes the purpose and scope, filing requirements and procedures, content, the Commission's review of resource plans, and plans' relationship to other Commission processes, including certificates of need and the potential for contested case proceedings.[26] These processes work for IRPs due to the long-term nature of macro resource additions and changes.

However, distribution planning is more immediate; its full planning horizon correlates to the five-year action plan period of an IRP, which is generally a continuation of past

[26] Minn. R. 7843.0500, subp. 3 prescribes the factors for the Commission to consider in reviewing IRPs. "The Commission shall consider the characteristics of the available resource options and of the proposed plan as a whole. Resource options and resource plans must be evaluated on their ability to: maintain or improve the adequacy and reliability of utility service; keep the customers' bills and the utility's rates as low as practicable, given regulatory and other constraints; minimize adverse socioeconomic effects and adverse effects upon the environment; enhance the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations; and limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control."

IRPs. Distribution systems are utilities' point of connection for customers. While an unexpected loss of a macro system component, such as a power plant, can often be covered by the MISO system without interruption of power to customers, loss of a distribution system component often results in a power outage to the customers it was serving. While there is some redundancy in the system to avoid this circumstance, the types of issues addressed by distribution planning are typically much more immediate than IRPs – and do not have a back-up like MISO. Therefore, evolving distribution planning practices will need to be thoughtful – and ensure the focus remains on the immediacy of customer reliability.

While the timeline remains uncertain, it is clear that the distribution grid of the future will look and perform differently than it has over the past 100+ years. Minnesota is in the forefront on the issue of advancing its distribution planning practices with other leaders such as California, New York, and Hawaii. Lessons learned from these states that Paul De Martini, ICF International, shared as part of his presentation at the Commission's October 24, 2016 grid modernization distribution planning workshop included:

- Changes to distribution planning should proactively align with state policy objectives and pace of customer DER adoption.
- Define clear planning objectives, expected outcomes and regulatory oversight – avoid micromanaging the engineering methods.
- Define the level of transparency required for distribution planning process, assumptions and results.
- Engage utilities and stakeholders to redefine planning processes and identify needed enhancements.
- Stage implementation in a walk, jog, run manner to logically increase the complexity, scope, and scale as desired.

No one state has yet figured out the progression of distributing planning enhancements; each is taking a different approach to address the complexities inherent in implementing changes at the right pace and that is proportional to both customer and grid needs – and that realizes net value and benefits for all customers. While the national perspective and other state actions provide helpful points of reference, Minnesota has long been a leader in developing supportive regulatory frameworks to align achievement of policy objectives with business objectives. The increasing complexity of our industry requires a rethinking of the current framework to ensure it is still aligned.

We support the evolution of the grid, and are taking actions to evolve our planning tools and improve our foundational capabilities to support our customers' expanding energy needs and expectations. We support a shift toward more integrated system planning, where utilities assess opportunities to reduce peak demand using DER and to supply customers' energy needs from a mix of centralized and distributed generation resources. However, at a measured pace that correlates to Minnesota policy objectives and customer value.

We are currently evaluating our existing planning processes and tools to determine how to better align and integrate the distribution, transmission, and resource planning processes in the future. Fundamentally, they are rooted in contradictory planning paradigms – with resource planning concerned with size, type, and timing, distribution concerned with location, and transmission somewhere in between. In the near term, we are using the same customer adoption-based DER forecasts and electrification in the IRP and the IDP to the extent practicable – with the IRP having the ability to consider sensitivities. As these planning processes continue to evolve together, it will allow greater ability to consider more potential outcomes – and think about how we can design an optimal portfolio of resources that best meets our overall customer load needs under a range of potential outcomes.

III. CONCLUSION

Our transmission and distribution systems are critical to our ability to serve our customers in a reliable and safe manner, and to deliver growing choice and increasing renewable energy. As we actively prepare our distribution system for the needs of the future, we consider the need for thoughtful investments to meet our core obligation, safely and reliably deliver energy to our customers, and adopt smarter technologies to further enable DER on our system. We recognize and will continue to respond to customer interest in increased DER.

The transmission grid is also facing new challenges and opportunities as traditional baseload units retire, large scale renewables significantly increase, and DER are increasingly adopted. In some cases, such as increasing consideration of distribution-level DER on the transmission grid, changes in the market and planning constructs are underway. Other changes are just coming into view and the planning constructs have not yet caught-up. Overall, we envision building toward an integrated grid in the future that supports the Company's clean energy transition – leveraging the strength of an interconnected system to make the best use of available resources and continue to serve our customers with resilient and reliable power.

APPENDIX J1 – XCEL ENERGY BASELOAD STUDY

I. INTRODUCTION

In our last Resource Plan, we discussed the rapid evolution of our industry due to changing technology, enhanced customer expectations, and the increasing consensus around the importance of carbon reduction. In that plan, we described our vision of an energy future that transitions our generation fleet such that we will achieve a dramatic reduction in carbon. We explained that taking action now to transition our fleet mitigates the costs and risks of retiring a significant proportion of our baseload generation in the same time period. We specifically proposed to accelerate our transition away from coal by ceasing operation of our Sherburne County (Sherco) Units 1 and 2 in 2026 and 2023, respectively.

We provided robust technical analysis supporting our proposed retirement of those coal units, including Midcontinent Independent System Operator (MISO) preliminary retirement studies, a technical analysis that we performed in conjunction with Siemens Power Technologies, and an analysis of our Black Start Plan. We concluded that the most cost-effective way to mitigate technical issues resulting from the unit retirements and continue to meet our customers' load requirements would be to build an intermediate natural gas-fueled plant at the existing Sherco site. The Commission approved our proposed schedule to retire Sherco Units 1 and 2,[1] and found that more likely than not there will be a need for approximately 750 MW of intermediate capacity coinciding with the retirement of Sherco Unit 1 in 2026.[2]

The Commission also required further study of an orderly and cost-effective retirement of our remaining baseload units in our next Resource Plan, as follows:[3]

> In its next resource plan filing, Xcel shall… describe its plans and possible scenarios for cost-effective and orderly retirement of its aging baseload fleet, including Sherco, King, Monticello, and Prairie Island.

The Baseload Study we performed in support of this Resource Plan builds on the outcomes of our previous plan and includes industry insights, and technical and

[1] *See* In the Matter of Xcel Energy's 2016-2030 Integrated Resource Plan, ORDER APPROVING PLAN WITH MODIFICATIONS AND ESTABLISHING REQUIREMENTS FOR FUTURE RESOURCE PLAN FILINGS, Ordering Point No. 7, Docket No. E002/RP-15-21 (January 11, 2017).
[2] *Id.* at Ordering Point No. 8. While the Order also addressed next steps for the replacement generation at Sherco, legislation was passed as part of the 2017 Legislative Session that in summary, allows the Company to proceed with the construction of the replacement unit at Sherco in accordance with the parameters specified in the legislation, and without a certificate of need. [Laws of Minnesota 2017, chapter 5—H.F. No. 113, section 1]
[3] *Id.* at Ordering Point No. 14(a).

economic analyses of retirement of our Allen S. King plant, Sherco Unit 3, Monticello Nuclear, and Prairie Island Nuclear Units 1 and 2.

To understand the technical impacts of retiring one or more baseload generating units, we perform engineering analyses on simulations of the Unit changes that assess the results against established industry reliability and operating criteria. The studies use the best available information at the point in time that they were conducted. However, the grid is dynamic, and expected conditions will change when new generation comes online, existing generation retires, new transmission lines are constructed, or existing lines are reconfigured; in addition, reliability measurement criteria may change. The results therefore are a point-in-time representation of the technical issues we expect would occur in a studied scenario.

The Baseload Study we conducted is comprised of four primary components:

- **Midcontinent Integrated Systems Operator (MISO) Attachment Y2 preliminary retirement studies**, which assessed various single Unit and combined Unit retirement scenarios for thermal and voltage concerns,
- **Xcel Energy Transmission Reliability studies**, which examined system stability and response impacts associated with baseload generating resource changes on the NSP System and on neighboring systems,
- **Industry insights**, including the North American Electric Reliability Corporation (NERC) *Generator Retirement Scenario Special Study* and the MISO *Renewable Integration Impact Analysis* (RIIA), which provide important insights into the combined effects of baseload generator retirements in a region and grid impacts at increasing levels of renewables penetration, and
- **A focused Strategist analysis**, which examined the economic implications of various Unit and combined Unit retirements at different points in time.

The results of this Baseload Study informed the Preferred Plan we propose in this Resource Plan, which includes the following baseload actions: (1) Retire our remaining two coal units early – King in 2028 (nine years early) and Sherco 3 in 2030 (ten years early), and (2) Extend the operation of Monticello nuclear 10 years through a license extension, to 2040.

Other conclusions and insights from this Study include:

- The retirement of our current baseload units must be orderly, and will be impacted by decisions other MISO generation owners make regarding their baseload units.

- We must maintain sufficient firm dispatchable, load supporting resources to ensure customer reliability and to support integration of higher levels of renewable resources.
- Changes in the MISO planning construct are necessary to properly recognize the inherent variable and intermittent nature of renewable resources in meeting customer needs every hour of every day.
- Significant new regional transmission development will be necessary to support increased levels of renewable resources and to support the retirement of baseload units.
- From an economic perspective, the scenarios that included early coal retirements and nuclear extensions had the most favorable present value.

Insights gained from this Study also helped to inform our development of a Reliability Requirement (discussed in Appendix J2), which bridges the gap between current regional planning requirements and necessary changes to account for: (1) the variable contribution renewable resources provide to the system, (2) the lack of long-term regional system planning guidance for the expected contribution of renewable resources as penetration levels rise, and (3) the need for sufficient firm dispatchable, load supporting resources to reliably integrate increasing levels of renewable resources.

We believe the increasing trend toward a clean energy future, along with rapidly advancing technologies and aging generation assets will significantly change the generation mix in Minnesota and across the United States over the next 15-plus years. We have done a comprehensive analysis of the impacts of cost-effective and orderly retirement of our baseload fleet in compliance with the Commission's Order – and in support of our clean energy vision.

The plan we propose in this Resource Plan sets the NSP System on a trajectory to a clean energy future that will continue to power our customer's lives and possibilities with energy they can trust to be safe, reliable, affordable, and progressively clean. It also provides strategic flexibility to adjust as technologies continue to develop; as the industry collectively furthers its understanding of the impacts from the significant changes in the generation mix that are underway; and, while we and others ready the grid with increased transmission capabilities.

This Baseload Study is organized as follows:

I. Introduction
II. Grid Function, Design, and Attributes

III. The Grid is Evolving
IV. Xcel Energy Baseload Retirement Study
V. Summary and Conclusions

II. GRID FUNCTION, DESIGN, AND ATTRIBUTES

The electric "grid" is a large complex machine consisting of generation, transmission and distribution facilities that operate across a very large geographic area. The NSP System is part of MISO, which is part of the Eastern Interconnection that connects the generation and transmission assets of the electrical grids from the Rocky Mountains to the East Coast and from Canada to the Gulf of Mexico. This interconnected network of generating resources and transmission infrastructure works together to seamlessly respond and adjust to dynamic and sometimes adverse circumstances to provide an adequate and reliable supply of electricity to customers. Each resource and system component plays a unique role based on its size, type and location on the system – and because the grid is so integrated, generation changes made to one utility's system impact other portions of the system.

At its core, to preserve system stability and customer reliability, the system must balance generation with changing load conditions and fluctuations caused by other disturbances. Large generating units like our current baseload units afford the capability for the system to "ride through" these disturbances by virtue of their sheer mass. Without the inertia, or resistance to a change in state of motion, afforded by these large units, system stability could be compromised. Similarly, the frequency regulation of the transmission system is governed by the connected generating units. If system frequency deviates beyond allowable levels, protective devices will disconnect generation and/or customer load from the rest of the system. These disconnections can further exacerbate any imbalance between load and generation, which may cause cascading events.

A. Traditional Grid Function

Transmission, in its most basic sense is the connection between generation resources and the customer demand it is intended to serve. Because of that, the transmission system that we have today was traditionally meant to send power from large centralized power stations to the load centers utilizing high voltage transmission lines. These power stations were typically located by the areas of higher customer demand, which would minimize the amount of transmission needed to serve that demand. During the early electrification era, which made modern conveniences like electric lighting commonplace, each utility built, owned and operated their own generation resources and transmission systems meant to serve their customers.

During, and after this initial phase of electrification, growing customer demand for electricity was the primary driver for new, larger and more efficient generation resources and transmission sources meant to deliver that power. Demand growth was overall fairly steady, which allowed for effective long-term planning process to develop. Because of this predictability and the efficiencies found through economies of scale, most generation resources consisted of large coal, nuclear, or hydro facilities. Smaller, more nimble units were also utilized to supplement these large, centralized resources to meet the added stress of summer loads. Regional Coordination, and the "grid" as we know it today, was not a consideration for power companies at this time.

As these individual power companies began to identify efficiencies through coordination with other local power companies that could reduce costs, the full value the centralized power stations provided to the system was also realized. These large scale synchronous generation resources provided the backbone of the stable system we have today. The ability of these generators to provide the primary system support for adverse system conditions such as faults and loss of transmission elements, allowed for increased interconnection between local utilities and greater system reliability.

After the Northeast Blackout in 1965, the benefits of greater coordination, both locally and regionally, were recognized, and Power Pools were formed to share excess resources that each area had. To increase the ability of these resources to be shared amongst the Power Pool members, large bulk transmission facilities were developed to interconnect neighboring utilities and allow for large amounts of power to be transferred in emergencies. As a way to ensure these resources were not stretched too thin, Power Pools also set the amount of generation resources each company was required to keep in order to maintain adequate supply of power.

B. Grid Oversight and Evolution

As the initial phase of electrification was in full swing, the United States Congress established the Federal Power Commission (FPC) to coordinate the hydroelectric project under federal control. The Federal Power Act and Natural Gas Act, passed in 1935 and 1938 respectively, granted the FPC the power to regulate the sale and transportation of electricity and natural gas across state lines. Because of the chronic brownouts of the 1960's and the OPEC embargo in the 1970's, the FPC was reorganized and designated as the Federal Energy Regulatory Commission to oversee federal energy policy and the deregulation of the natural gas industry. The first FERC Order directed specifically at the restructuring of the electric industry was issued in 1996 as Order No. 888. Known as the Open Access Order, the intention of Order

888 was to ensure open and non-discriminatory access to the electric transmission system and encouraged the development of Price Exchanges to increase transparency in energy clearing prices.

Order 888 was followed shortly after by Order 889 to require the posting of transmission availability on a public bulletin board, referred to as the Open Access Same-Time Information System, or OASIS. The issuance of these Orders led to the development of Independent System Operators (ISOs) to facilitate the new requirements, in large part for existing Power Pools, set in place by Orders 888 and 889. In 1999, FERC issued Order 2000, which encouraged participation in Regional Transmission Organizations (RTOs) with the expectation that these RTOs would establish whole electricity markets to enable efficient use of the available resources and transmission system.

1. The Energy Policy Act of 2005 Created the Present FERC

The last major development, which led to the FERC we know today, was the passing of the Energy Policy Act of 2005, which greatly increased the authority FERC had over the jurisdictional entities across the country. This included the enforcement of transmission system reliability standards, the ability to levy fines for non-compliance, and other increased authorities. Today, FERC regulates interstate transmission of electricity, natural gas, and oil. Since the passing of the Energy Policy Act of 2005, FERC has issued several major orders to ensure the planning of the most efficient and cost effective transmission system possible through long-term planning requirements as well as ensuring the fair and non-discriminatory operation of wholesale electricity markets across the country.

2. NERC Oversees and Enforces Grid Reliability

NERC, created through FERC's increased authority under the Energy Policy Act of 2005, is a non-profit entity that oversees the eight regional reliability systems that stretch from Canada to Mexico. NERC is designated by the FERC as the Electric Reliability Organization, which is the independent entity that develops and enforces mandatory standards for the reliable operation and planning of the bulk electric system (BES) throughout North America. NERC's primary responsibility is to develop power system standards, the monitoring and enforcement of those standards, and ensure power system operators are qualified through training.[4] Analysis of BES impacts from new generation and transmission facilities and changes to existing generation or transmission facilities are measured against NERC standards and

[44] NERC is also responsible for investigating power system outages that have a significant impact.

requirements. We provide an abbreviated outline of NERC Event Category definitions below:

Table 1: Abbreviated List of NERC Event Category Definitions[5]

P1	Single Contingency – Loss of one of the following: * Generator * Transmission Circuit * Shunt Device * Transformer * Single Pole of a DC line
P2	Single Contingency – * Opening of a line section w/o a fault * Internal Breaker fault (non-Bus-tie-Breaker) * Bus Section fault * Internal Breaker Fault (bus-tie Breaker)
P3	Multiple Contingency – Loss of one of the following: * Generator * Shunt Device * Transmission circuit * Single pole of a DC line * Transformer
P4	Multiple Contingency – (*Fault plus stuck breaker*) Loss of multiple elements caused by a stuck breaker (non-Bus-tie Breaker) attempting to clear a Fault on one of the following: * Generator * Bus Section * Transmission Circuit * Loss of multiple elements caused by a stuck breaker (Bus-tie * Transformer Breaker) attempting to clear a Fault on the associated bus * Shunt Device
P5	Multiple Contingency (*Fault plus relay failure to operate)* – Delayed Fault Clearing due to the failure of a non-redundant relay protecting the Faulted element to operate as designed, for one of the following: * Generator * Shunt Device * Transmission Circuit * Bus Section * Transformer
P6	Multiple Contingency (*two overlapping single contingencies)* – Loss of one of the following: * Transmission Circuit * Shunt Device * Transformer * Single pole of a DC line
P7	Multiple Contingency (*Common Structure)* – The loss of: * Any two adjacent (vertically or horizontally) circuits on common structure * Loss of a bipolar DC line

NERC additionally authorizes regional entities, which in the Upper Midwest is the Midwest Reliability Organization (MRO). The MRO is a regional entity spanning from Manitoba and Saskatchewan Canada through the United States Midwest. The MRO is primarily tasked with ensuring compliance with reliability standards for the BES. The MRO conducts individual company assessments for any possible areas of improvement or violations.

[5] For a full description of NERC's event categories, *please see*: http://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-4.pdf beginning at page 8.

3. Midcontinent Independent System Operator

The first regional transmission organization to obtain approval by FERC was the Midwest (now Midcontinent) Independent System Operator (MISO); MISO is the ISO for the Upper Midwest. MISO is an independent, not-for-profit company authorized by FERC to provide open-access transmission service, operate the transmission grid, administrate a wholesale energy market, and perform regional transmission planning in 15 states throughout the Midwest, southern United States, and Manitoba, Canada.[6] The Xcel Energy operating companies that comprise the NSP System (Northern States Power Company-Minnesota and Northern States Power Company-Wisconsin) are signatories to the MISO Transmission Owners Agreement and are therefore members of MISO and thus subject to MISO Tariffs and requirements.

MISO's primary function is to ensure open and fair access to the transmission system. In addition, MISO administers the wholesale energy market for the same region.

C. Grid Basics

In this section, we provide an overview of the NSP System, factors effecting reliability, and the role played by baseload generating resources on our system.

1. NSP System Transmission Overview

The Twin Cities metro area is surrounded by a double circuit 345 kV *bulk* transmission system that extends from Benton County in the north, east to Chisago County, south to Dakota County, west to Scott County, and back north to Becker, Minnesota. This 600 mile ring of 345 kV lines encompassing nearly 1,300 square miles forms the backbone of the bulk transmission system feeding the Twin Cities load center. This 345 kV ring is connected through several bulk 345 kV lines tying to our neighboring utilities, and a 500 kV bulk transmission line to Manitoba Hydro in the north. These tie-lines connect the Twin Cities load center to the MISO generation market and the Eastern Interconnection – providing important "back-up," should there be an unexpected event that requires the Company to rely on the grid to maintain reliability for our customers.

[6] Independent System Operators grew out of FERC Orders Nos. 888/889 where FERC suggested the concept of an Independent System Operator as one way for existing tight power pools to satisfy the requirement of providing non-discriminatory access to transmission. Subsequently, in Order No. 2000, FERC encouraged the voluntary formation of Regional Transmission Organizations to administer the transmission grid on a regional basis throughout North America (including Canada).

The 345 kV ring that surrounds the Twin Cities feeds the underlying Twin Cities 115 kV transmission grid, which connects to our low voltage distribution system that delivers the power directly to businesses, houses and other loads. The transmission system and the lower voltage distribution system in the Twin Cities area has developed over the past 100 years to serve the growing area, and is constantly being analyzed and updated to ensure optimal and reliable power delivery.

Our BES is currently anchored at the corners by several large coal and nuclear generators that act as the baseload generation for the NSP System. They include Sherco and Monticello in the northwest, and King and Prairie Island in the east and southeast. Together these plants provide over 4,350 MW of capacity[7] and over 29,000 GWh of energy to our customers, which represents 47 percent of the NSP System accredited generating capacity and 65 percent of the system energy.[8] This generation is supplemented by several natural gas generating plants located on the 115 kV system in the Twin Cities. These generating units include Riverside, Highbridge, Black Dog, and Blue Lake.

The 500 kV line that ties into Chisago County substation in the northeast connects the hydro power produced by Manitoba Hydro to the Twin Cities load center. A significant proportion of our wind power is located in southwest Minnesota and is tied into the Twin Cities through a number of lines developed over a period of years to connect the wind-rich areas in southwest Minnesota and South Dakota to the Twin Cities load center. A robust transmission system such as this facilitates the provision of reliable, low cost power to our customers from a diverse mix of generation resources, and mitigates risk from catastrophic events.

The existing grid is a valuable asset and an enabler that has and will continue to support the evolution and growth of our system. The grid has facilitated integration of substantial wind generation onto the NSP System by absorbing the inherent fluctuations of this variable generation type over a large area. Transmission enables the transfer of wind and solar and other types of generation from where it is most effectively located to customer load located elsewhere where it can be utilized to the fullest extent.

2. A Reliable Grid Must Weather Unexpected Failures and Events

NERC defines a reliable BES as one that is able to meet the electricity needs of end-use customers even when unexpected equipment failures or other factors reduce the

[7] Nameplate capacity ratings.
[8] MISO accredited capacity values.

amount of available electricity, and divides reliability into two categories:[9]

- *Adequacy*. Adequacy means having sufficient resources to provide customers with a continuous supply of electricity at the proper voltage and frequency, virtually all of the time. Maintaining adequacy requires system operators and planners to take into account scheduled and reasonably expected unscheduled outages of equipment, while maintaining a constant balance between supply and demand.
- *Security*. For decades, NERC and the bulk power industry defined system security as the ability of the bulk-power system to withstand sudden, unexpected disturbances, such as short circuits or unanticipated loss of system elements due to natural causes. In today's world, the security focus of NERC and the industry has expanded to include withstanding disturbances caused by manmade physical or cyber-attacks. The BES must be planned, designed, built and operated in a manner that takes into account these modern threats, as well as more traditional risks to security.

Electrical system reliability can be defined as the ability of the electrical grid, which includes transmission, generation, distribution and related components, to serve customer load under any system condition. Maintaining a reliable electricity supply for customers requires that generation, load and electrical losses balance – and maintain a 60 Hz frequency. If the frequency varies only one or two tenths of a hertz from 60 Hz, it can cause damage to equipment, and automated protection schemes will disconnect pieces of the grid to avoid damaging equipment.

A strong transmission system improves the reliability of the electric power system, and facilitates a diverse and low cost resource portfolio for customers – allowing lower cost resources with diverse fuel types, and resource types not available in the immediate area to be efficiently transported to serve their needs. For example, wind resources need to be constructed where the wind is strongest and most consistent; large-scale solar resources where there is sufficient land and the most consistent sunshine – both of which are generally away from large population centers. A robust transmission system brings together varied generating units – some built to run continually, others only to run at peak times when they are most needed, and renewable resources on an intermittent basis – together into an integrated grid.

The system must also be able to facilitate both "active" and "reactive" power, which are typically produced by non-renewable generating unit types. Active power, measured in watts, is the form of electricity that powers equipment. Reactive power,

[9] http://www.nerc.com/AboutNERC/Documents/NERC%20FAQs%20AUG13.pdf

measured in volt-amperes reactive (VARs), is the energy supplied to create or be stored in electric or magnetic fields in and around electrical equipment. Reactive power is particularly important for equipment that relies on magnetic fields for the production of induced electric currents (e.g., motors, transformers, pumps and air conditioning). Reactive power can be transmitted only over relatively short distances, and thus must be supplied as needed from nearby generators. If reactive power cannot be supplied promptly and in sufficient quantity, voltages deteriorate and, in extreme cases, can result in a voltage collapse.

The grid must also be able to adjust to changing customer loads, the availability of diverse resources, and have sufficient redundancy built-in, making it capable to withstand the failure of its most critical lines, generators, or other components. As customer load changes over the course of a day, generation must change to accommodate the load at any given time. With the high penetration of renewables on the NSP System, we must ensure that we have adequate firm dispatchable, load supporting generation to both accommodate the load and whatever generation mix we have at each point in time. We must also maintain a spinning reserve – generation that is available at a moment's notice – to account for the largest contingency in the area.[10] Having large coal generating units has helped, because they have the ability to be "turned up" and "turned down" based on the level of renewable generation being delivered to the system at any given time. With our proposed plan to retire the remaining coal units on the NSP System, other load supporting generating resources will be needed to perform these important reliability functions.

3. Role of Baseload Generating Resources

As we have discussed, the ability to provide reliable electric service depends on a complex and interconnected network of generating resources and transmission infrastructure that provides capacity and delivers energy to customers. Each resource and system component in the network plays a unique role based on its size, type and location on the system. In fact, the Upper Midwest grid and the NSP System has been designed around the current baseload units, and relies on the unique aspects of these units to not only generate capacity and energy for our customers, but also to provide numerous essential system operational services.

When analyzing the impacts of ceasing operations at one of our existing coal or nuclear units, it is important to consider these operating and technical characteristics beyond just the unit's energy output. These include:

[10] Spinning Reserve is unloaded operating capacity available on units connected to and synchronized with the interconnected electric system and ready to take load immediately in response to a frequency deviation.

- *Power Deliverability.* The existing transmission system has been developed to be able to receive the approximately 2,400 MW of power injected from Sherco,[11] 671 MW injected from Monticello, 598 MW injected from King, and 1,150 MW injected from Prairie Island and to deliver it to various area substations to meet the electrical power demands of customers.[12] This power deliverability capability is often referred to as "transfer capability" or "thermal limits" of the system. Transmission systems are made capable of receiving and moving power from specific generators at specific locations; changing generator characteristics or locations requires corresponding changes to grid capabilities.

- *Dynamic Stability.* The transmission grid is a vast interconnected machine with many parts. There are a mix of large and small gears in this machine, all spinning at the same rate (i.e. synchronous), simultaneously producing and delivering electricity to customers. Generating units are the spinning gears in this machine. Large generators like Sherco Unit 3 and King have large spinning shafts that provide a strong backbone for the machine's operation. With enough of these big "gears" spinning, the machine can stay electrically stable and continue operating without interruption when small gears drop in and out of operation (like when the wind stops blowing or sun stops shining), or when another big gear drops out, or a "contingency," happens to some part of the machine. These large gears are also more likely to stay connected to the grid during a contingency than the small gears because large rotating masses have more inertia and are therefore not as easily jarred, or disrupted by a disturbance. Having the large gears in place also enables more small gears to be connected to the machine because they don't have as much impact with the large gears in place. The large generating units thus provide "dynamic stability" to the grid.

- *Fault Current.* Large synchronous generating units provide "fault current," which is necessary for the system protection equipment to function properly. If the system has too little fault current, it is difficult for system protection systems to differentiate customer load from an electric fault, which could cause the protection system to not function properly.[13] The protection system is the overarching electrical monitoring scheme that assesses the real time condition of the transmission grid and acts to prevent damage to system components and prevent cascading failures. The large generating units operating today are important sources of fault current, and the protection

[11] Nameplate capacity ratings of entire site. SMMPA owns 41% of Unit 3 (approximately 380 MW).
[12] Nameplate capacity ratings.
[13] For example, the protective equipment could misinterpret the load as a fault, and de-energize an unfaulted circuit.

system and existing deployed assets rely on sufficient fault current for the protection system and other electrical facilities to work as designed. Many of the electric devices that are deployed on the grid and in service today, such as wind generators and other assets, are engineered and designed to function properly with the amount of fault current that has been historically available on the grid. Therefore, changing the amount of fault current on the grid could not only impact protection systems, but could also impact other electric assets.

- *Black Start Capability.* In the event of a major regional grid outage, firm dispatchable generating units with a secure fuel source are an integral resource to restoring power to the electrical grid, or "restarting the machine." Only firm dispatchable generating units of a certain size that are capable of creating and absorbing reactive power are eligible to perform black start functions. Once Sherco Units 1 and 2 retire, the Sherco Combined Cycle (CC) will be an important part of our black start plan. Renewable generation, such as solar and wind are not currently considered eligible Target Units due to their inherent intermittent nature, and their inability to provide or absorb reactive power. A large battery energy storage system can be configured to be technically capable of providing black start service, likely as part of a relatively small Initial Black Start Unit. However, they may not yet be economically viable for this purpose. There are also technical concerns with regard to how batteries can absorb reactive power, which would be needed if the battery was not paired with another type of generation asset.

- *Voltage Support.* The real time conditions on the transmission system are constantly changing and require ongoing adjustments to maintain voltages at required levels. Large synchronous power sources like our current baseload units, provide significant system voltage support along with necessary "reactive power." Reactive power is required to start and run motors, like in air conditioners and industrial equipment (called "inductive loads"). Large population centers generally require large generating units located reasonably nearby to support system voltage effectively. As in the dynamic stability discussion, without enough large units in place, the machine isn't as capable and robust when it runs.

- *System Regulation.* System regulation essentially means the ability of the system to respond to changes in usage, i.e. keeping the generators and loads matched at all times. Combined cycle generating units have the electrical characteristics to provide this fast response balancing in real time. The system frequency, required to be maintained at 60 Hz in the US grid, is an active measure of this balance. When there are changes to the generation/load balance, as when wind speeds drop or a large industrial load comes online, the frequency drops if

there is insufficient regulation capability on the system. This is another aspect of the dynamic stability of the system, typically in a longer timeframe.

The National Academies of Sciences, Engineering, and Medicine observed that large-scale interconnected generating units have two significant advantages:

(1) *Reliability*. By interconnecting hundreds or thousands of large generators in a network of high-voltage transmission lines, the failure of a single generator or transmission line is usually inconsequential, and

(2) *Economics*. By being part of an interconnected grid, electric utilities can take advantage of variations in the electric load levels and differing generation costs to buy and sell electricity across the interconnect. This provides incentive to operate the transmission grid so as to maximize the amount of electric power that can be transmitted.

However, large interconnections also have the undesirable side effect that problems in one part of the grid can rapidly propagate across a wide region, resulting in the potential for large-scale blackouts such as occurred in the Eastern Interconnection on August 14, 2003. Hence there is a need to optimally plan and operate what amounts to a giant electric circuit so as to maximize the benefits while minimizing the risks.[14]

D. Planning Overview

The MISO long-term planning process, defined in Attachment FF to the MISO Tariff, is an eighteen month, overlapping process through which annual transmission expansion plans are developed and approved. This process is made up of three distinct long term planning efforts: Reliability Planning, Economic Planning and Resource Adequacy. MISO has recognized that its present planning processes require update to recognize the increasing levels of renewable resources on the grid, as well as increasing levels of energy efficiency, demand response, and distributed energy resources (DER). We discuss this further in Part III below.

1. Reliability Planning

As a NERC registered Transmission Planner, the Company works jointly with MISO and neighboring utilities to develop long term transmission plan to ensure a reliable transmission system. This is accomplished through several local and regional planning efforts, as follows:

[14] National Academies of Sciences, Engineering, and Medicine 2016. *Analytic Research Foundations for the Next-Generation Electric Grid*. Washington, DC: The National Academies Press, page 10. https://doi.org/10.17226/21919

Biennial Transmission Projects Report. In compliance with Minn. Stat. § 216B.2425, the Company participates in the Biennial Transmission Project Report efforts with other Transmission Owners. Starting in 2001, this effort completed its ninth iteration with the 2017 report. In 2003, the Minnesota Public Utilities Commission established six transmission planning zones across the state in 2003. Those six transmission planning zones are the Northwest Zone, the Northeast Zone, the West Central Zone, the Twin Cities Zone, the Southwest Zone, and the Southeast Zone. The Biennial Report identifies the present and reasonably foreseeable transmission "inadequacies" in the transmission system that exist in each of these six transmission planning zones. With information about each inadequacy identified provided. The Biennial Report also provides an update on the status of the utilities' efforts to meet state Renewable Energy Standard deadlines. We summarize our most recent Biennial Report in Appendix I: Supporting Infrastructure: Transmission & Distribution.

NERC Transmission Planner Registration. To satisfy the obligations associated with the Transmission Planner registration with NERC, the Company also participates in the annual Minnesota Transmission Assessment and Compliance Team (MNTACT) to perform annual long-term transmission planning studies in accordance with federal, state and local transmission reliability standards and criteria. The Company utilizes the results of these analyses to inform the regional planning efforts undertaken by MISO.

MISO Membership and FERC Order Obligations. In accordance with the obligations of MISO membership and FERC Orders 890 and 1000, the Company also participates in regional long-term planning efforts facilitated by MISO. While these efforts replicate work already undertaken by the Company in other planning efforts, participation in MISO reliability planning process provides an open and transparent planning process that allows input and discussion amongst a wide range of stakeholder and public advocacy groups. Based on the requirements of the MISO Transmission Owners agreement, MISO approval is also required for inclusion of new transmission facilities under MISO's functional control.

2. Economic Planning

In addition to the long-term transmission reliability analyses, participation in the MISO planning processes also includes an annual economic-based planning analysis to identify inefficiencies in the transmission system leading to less than ideal wholesale electricity market dispatch. Starting with a stakeholder-approved set of wide-ranging future scenarios, this analysis first identifies these areas of system inefficiencies – after

which, stakeholder submitted solutions are analyzed to determine if there is a cost effective solution. The Huntley–Wilmarth 345 kV Project is an example of a cost effective solution analyzed to develop the most cost-effective market possible.[15]

3. Resource Adequacy

The Resource Adequacy process facilitated through the MISO process is designed to ensure enough capacity is available to meet the needs of all consumers in the MISO footprint during all time frames and at just, reasonable rates. Although the responsibility for resource adequacy, MISO's process provides support in their members individual resource adequacy efforts and provide forums to increase transparency into these more localized efforts. These support efforts include calculation of the Planning Reserve Margin, which defines the level of reserve generation capacity needed to ensure an adequacy supply of energy based on probabilistic analyses. Also facilitated in this process is the Deliverables to the Planning Resource Auction, including peak forecasted demand and Import/Export limitations for the following year.

Through the participation and outcomes of the different planning processes the Company participates in, several vital pieces of the long-term planning picture are analyzed and updated on an annual basis. This enables development of the most cost effective and efficient solutions and direction in the long-term use of the transmission system at a local, regional and interconnection-wide level.

4. Black Start

At a high level, a Black Start Plan specifies the process we use to restore our grid to full operation without relying on the external transmission network, following a full- or partial-black out. Black Start Plans are required by NERC, developed in concert with neighboring utilities, and are subject to review and approval by MISO. Developing such a plan involves developing models, strategies and procedures to configure the system such that one or more generators can be brought online – and at the same time, picking-up sufficient customer load to satisfy the generator's minimum requirements for stability. The longer the system is down, the harder it is to restore, so we work to determine the most efficient paths possible.[16]

The restoration is initiated under the instruction of the Transmission Operator and

[15] *See* Docket No. E002, ET6675/CN-17-184 or www.huntleywilmarth.com)
[16] The longer the system is down, equipment and facilities cool. Additional impacts include effects such as the fact that substation batteries will only keep the substations operational for a limited time. If the substation batteries deplete, we cannot easily isolate or energize the substation.

proceeds under the general guidance of a site specific restoration plan. Not all power generation units have, or are required to have, this Black Start capability. Black Start-capable generating units have specific configurations, additional on-site emergency generators and must be held to the highest reliability standards to ensure responsiveness in the face of an emergency.

III. THE GRID IS EVOLVING

A. The Introduction of Energy Markets

The electrical transmission system has moved from being a locally-owned and operated power system that was weakly tied to one another through high-voltage transmission lines to a regional model focused on efficiency and reliability.

Through the incorporation and membership in the regional RTOs, locally-owned transmission facilities have been turned over to the function control of regional grid operators to participate in open and effective wholesale energy markets. Through the creation and operations of the wholesale electrical markets, MISO has effectively delivered a more efficient system. Where the old power pool had reserve requirements up to and exceeding 25 percent of the utility's demand, MISO – using modern modeling and markets operations – has been able to significantly reduce spinning reserve requirements (the most costly reserve requirement) for the region. In addition to the more efficient use of existing resources, this construct has allowed for more of the older, less efficient power plants to retire while maintaining system reliability.

MISO's open access Generator Interconnection Queue allows for new generation that has requested interconnection service to be studied for inclusion into the transmission system. This process ensures that there is a fair and transparent process for all generators to have unbiased access to the regions transmission system and allows competitive participation in the wholesale energy market. MISO's Wholesale Energy Market allows for the region to have the lowest cost generation mix available at the time while maintaining system reliability through a process referred to as a Security Constrained Economic Dispatch (SCED). One key aspect of market participation enables each generator owner to bid into the market at competitive prices ensuring the lowest wholesale energy cost for the customers across the MISO footprint. We discuss the current status and challenges with the MISO interconnection queue that are creating uncertainty for planning purposes in Appendix I: Supporting Infrastructure: Transmission & Distribution.

B. Shifting Resource Types and Mix

One major benefit realized through the implementation of an open and competitive wholesale energy market is the ability for zero-emission and renewable sources of generation being allowed to compete on a fair and equitable basis with more traditional forms of generation. Due to this, renewable development has grown in the MISO region largely through expansion of wind resources to-date – with significant growth in solar expected. The current significant wind resources are primarily in southwest Minnesota and northern Iowa, but over time have also expanded to almost every part of the MISO system.

1. Rapid Increase in Renewables

In the year 2000, there were approximately 2,500 MW of wind on the transmission system across the entire United States. Today, there is over 18,000 MW of wind just in the MISO footprint – with solar power now also being added to the mix. The initial drive for renewables was created through the development of public policy initiatives that allowed for tax credits to make the renewables more cost competitive against the more traditional coal and nuclear prices and set renewable energy goals for utilities subject to those local regulations. More recently, renewable forms of generation resources have been selected purely as the most economic resources. In addition to the more competitive renewable costs, public opinion has driven the push for a more carbon-neutral set of generating resources.

Since the first wind turbines were installed, the price for wind has dropped dramatically. As manufacturing processes have improved, and supply chain efficiencies incorporated, some economies of scale were realized, driving lower costs for new wind turbines. In addition to solely reducing installation costs, improvements in the power electronics have improved the performance of the new wind turbines to help with system reliability. Solar from both small and large utility-scale resources are increasingly part of the resource mix. Public policies for new solar coupled with dropping prices and tax incentives are helping to drive the increase. Solar has the added benefit of its peak output being closely correlated with peak demand.

Energy storage is just starting to be used in utility-scale settings, with processes only just now being developed to incorporate these technologies into long-term planning efforts. There are several energy storage methods that are being studied for commercial applications, one of which is battery storage. Battery storage is already being tested and incorporated in some electric markets around the world. Battery storage offers the ability to store excess power created that cannot reach customers at the time of generation, and release that stored energy when the system demands it.

Batteries have several benefits, including the ability to store power for the purposes of helping with grid stability through power electronics and small scale power injections and withdrawals as well as shifting energy production to hours with high demand. While batteries will play a roll in our carbon reduction goals, current technologies in the early stages of commercial use, and because of this, have not yet incorporated manufacturing and supply chain efficiencies that have made wind and solar generation resources more cost competitive.

2. The Changing Generation Mix is Putting Pressure on Area Reserve Requirements

In the wake of the electrical system transforming from local power pools to regional markets that include increasing levels of non-traditional and renewable resources, there has been an increase in the rate of retirements of aging baseload generating units. Most of the generation replacing these traditional, dispatchable units are from intermittent resources such as wind and solar. Because these intermittent resources are dependent on fuel availability (wind blowing or sun shining), their replacement of retired dispatchable units is putting extra pressure on the reserve requirements for the region, since wind and solar cannot be counted on at all times. While MISO recognizes this and is studying issues related to high renewable penetrations in its RIIA study, its planning construct has not yet adapted to recognize this reality. We discuss the RIIA study below, and in Appendix J2, along with our development of a Reliability Requirement as a bridge until the MISO planning construct changes.

In addition, most of the best locations to develop cost-effective wind and solar resources are located away, and in some cases, far away from populated areas and thus load centers. This requires a robust network of large bulk electric transmission lines to bring the renewable power to the load, which means that significant transmission development will be needed to support increasing levels of renewables. However, the more transmission infrastructure between the renewable resources and the load centers, the greater the risk that those resources will be unavailable to the load centers when needed. This is because long transmission line(s) are more likely than a short line to be impacted by severe weather or some other event that along the line – making it unavailable to deliver the energy from the resource(s). This reality lowers the accreditation of the renewable resource(s) – and increases the reserve requirements for the area.

3. Growing Penetrations of Distributed Energy Resources

In addition to baseload retirements and the rapid expansion of renewable generation resources, growing reliance on DER, including DR, introduce strains to the transmission system that have not been historically encountered. While both of these

resources represent important and useful tools in planning for a reliable and cost-effective power system, they have indirect and sometimes counter-intuitive impacts on the transmission system. In levels that do not produce what would be considered reverse flows, resources originating on the distribution system and flowing onto the transmission system look similar to a localized reduction in demand on the transmission system. From a high level, this should only result in a reduction in the generation required to meet the demand. However, because of low market offer prices for renewable resources in the MISO market, when this localized reduction in demand occurs, it serves to increase long distance transfers on the transmission system, causing strain on those facilities.

4. *Planning Impacts of the Shifting Resource Mix*

A part of the MISO planning processes is an annual analysis of reserve levels. Planning reserves are the margin by which resources exceed expected customer demand. MISO's Resource Adequacy process establishes the margin by which each utility's resources are required to exceed demand in order to cover potential uncertainty in the availability of resources or level of demand.[17]

Reserve analysis is also incorporated into the NERC Long-Term Reliability Assessment (LTRA), which is an annual report highlighting national and regional trends and potential risks over a 10-year assessment period. While it is fairly common for a planning region to drop below the reference reserve margin levels in later years of the assessment period, the 2018 LTRA report specifically calls out MISO as one of three regions that are projected to drop below their reference reserve margin levels earlier than normally encountered – specifically by the year 2023.[18]

This report indicates that inclusion of generation with high likelihood of being incorporated into the MISO system (known as Tier 2 resources in the LTRA) would likely allow for the MISO footprint to preserve system reliability.[19] That being said, there has been an unprecedented rate of baseload generation retirements announced, but that are not yet taken into account in this analysis. There is also uncertainty regarding future capacity accreditation levels for renewable resources, particularly, as

[17] Factors affecting availability and demand include: Planned maintenance, Unplanned or forced outages of generating facilities, Deratings in resource capabilities, Variations in weather, and Load forecasting uncertainty.

[18] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2018_12202018.pdf

[19] NERC defines Tier 2 resources as being in the interconnection queue and having a signed/approved completion of a feasibility study, signed/approved completion of a system impact study, signed/approved completion of a facilities study, requested Interconnection Service Agreement, or is included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to RTOs/ISOs).

well as the potential for increased reserve requirements. This all combines to cast doubt on whether those Tier 2 resources relied upon in the LTRA alone are sufficient to provide adequate reserves to mitigate the identified risk. Further, when considering the findings from NERC's *Generator Retirement Scenario Special Study*, we believe there is an increased level of risk that baseload generation retirement requests may result in system support resource (SSR) (or something similar) designations[20] – as was the case with our Sherco Units 1 and 2 MISO Attachment Y2 study, discussed in our last Resource Plan.

C. Early Studies Did Not Fully Contemplate the Level of Change Underway

When the wind generation was first injecting energy into the system, it was in small amounts that were able to utilize the existing bulk and non-bulk AC power system. The existing AC power system was developed to deliver energy to customers from large centralized power stations usually located next to areas of the highest customer demand. As more and more renewables were added to the system the AC grid has had to morph into more a hybrid system that shifts power back and forth depending on the generation pattern for the day.

Early studies done on the system did not anticipate the impact that rapid adoption of renewables would have on the existing system. These studies also tended to underestimate the early retirement of existing resources that provide important support to the system. We discuss these early studies below.

1. Upper Midwest Transmission Development Initiative

The Upper Midwest Transmission Development Initiative (UMTDI) was developed in 2008 as a coordination effort between the States of Iowa, Minnesota, North Dakota, South Dakota and Wisconsin tasked with accomplishing two major tasks: (1) Establish a plan that will guide and encourage the construction of interstate transmission lines to serve the upper Midwest region's commitment to cost-effective renewable generation while maintaining reliability, and (2) Develop an equitable cost-sharing methodology for new transmission facilities.

A final report from the initiative provided five high-level areas that represented barriers to development of transmission to enable renewable generation:

- *The need for certainty in regional planning for transmission.* Developers and regulators

[20] In MISO, in some cases, a generator may be designated as a System Support Resource (SSR), which is determined by the presence of unresolved violations of reliability criteria that can only be alleviated by the SSR generator and where no other mitigation is available.

need to know what the rules are for transmission planning. In the absence of such certainty, development stalls and the potential for inaccurate decision-making arises.

- *The right balance between remote and local renewable generation.* There is a need to cost effectively balance highly efficient renewable energy resources far from customers with local renewable energy resources closer to population centers.
- *Large transmission projects are expensive and will impact electric rates.* Billions of dollars of transmission investment may be necessary. Minimizing these costs through sound planning is critical to ensure that projects get built cost effectively.
- *Large transmission projects can cause large land-use impacts.* Transmission projects require the acquisition of sizeable tracts of land for right-of-way easements. Such acquisitions garner strong reactions from landowners and neighbors and the public at large. While recognizing that each state has the ultimate siting authority for transmission lines
- *Cost allocation for the needed transmission is contentious.* Arguably the largest hurdle to new construction is how the costs get distributed. In the absence of an equitable formula, projects will not get built, or parties not benefiting from the projects will end up paying for them.

Due to the significant overlap between the UMTDI effort and Regional Generation Outlet Study (RGOS) and Regional Expansion Criteria and Benefit Task Force being performed by MISO at the same time, the group transitioned its efforts to focus on advocacy in those regional efforts.

2. MISO Regional Generation Outlet Study

Beginning in 2008, MISO initiated the RGOS in response to the passing of Renewable Portfolio Standards by several of the MISO member states mandating the expansion of renewable energy resources in state utility portfolios. The purpose of this study was to determine a best fit solution in the form of a transmission overlay encompassing all MISO states – premised on a distributed set of wind zones – each with varying capacity factors and distances from load.

Despite this early and comprehensive study work, the unprecedented growth of renewable generation and the earlier than expected retirement of baseload generation have resulted in impacts to the current system that have far exceeded what was projected in the RGOS analyses.

3. Regional Expansion Criteria and Benefits

Concurrently with the development of the RGOS overlays, the MISO stakeholders developed the first significant round of cost allocation principles for transmission projects. This provided a formal process for assigning cost responsibility for transmission upgrades to in a way that is roughly commensurate with beneficiaries.

4. Minnesota Renewable Energy Integration and Transmission Study

In 2013, the Minnesota Renewable Energy Integration and Transmission Study (MRITS) was initiated to build upon prior work with respect to the integration of renewable energy, specifically looking at a potential increase of the Minnesota Renewable Energy Standard (RES) to 40 percent by 2030, and higher levels beyond that timeframe. The purpose of this study was to determine the reliability impacts of increase variable generation development as well as determining associated cost impacts.

The study consisted of three core analyses:

- *Power flow analysis* was utilized to develop a conceptual transmission plan, including transmission expansion required for both interconnection of additional variable resources as well as required expansion to allow the energy from those resources to reach the wider region.
- *Dynamics analysis* was utilized to determine issues with system stability and system strength.
- *Production Cost analysis* to determine more operationally focused challenges to the integration of significant levels of variable resources.

The results of this study stated that 40 percent of Minnesota's retail electricity sales can be reliably accommodate with upgrades to the existing system at the time of the analysis.

However, while there were several important pieces of information gleaned from the MRITS study, the unprecedented expansion of variable generation that has occurred combined with the retirement of several large baseload generators that was not fully anticipated at the time of this study, has made the assumptions that went into this analysis outdated – and as such, the full results cannot be directly applied to today's transmission system.

D. MISO Processes Must Further Evolve

To accommodate the rapid expansion of renewable generation resources in the region, MISO's generation interconnection process has undergone several process improvements, but does not yet fully reflect the state of the evolving grid. As additional variable generation replaces firm dispatchable resources, issues such as weak signal strength and system instability become more likely. Current interconnection processes study only two conditions (summer/peak and shoulder); current resource adequacy processes assign fixed annual capacity values to variable resources based on their *average* contribution to the grid. These practices do not properly assess other grid conditions for potential reliability impacts – nor do they recognize the portion of time that variable resources will provide less or no energy and capacity to serve customers.

When a large batch of inverter-based generation performs outside of what is expected, models typically show that the system can survive adverse conditions. But in 2016, the Australia power system experienced storm damage that forced several transmission lines to open. The wind farms that were being relied upon on at that time were not able to survive multiple ride-through capability cycles, and started to trip offline – resulting in a large-scale power outage in southern Australia. While there are standards and practices in place in the Eastern Interconnection, MISO and Minnesota transmission systems to help avoid this same scenario, the rapid escalation of renewable resources and the earlier than expected retirement of baseload generation places a greater strain on the transmission system to deliver more remote sources of generation, and increases the likelihood of events similar to the Australia power outage occurring on the local transmission system.

MISO's early generation queue was done in order of requests. While this process allowed for concrete identification of issues caused by individual generator interconnection requests, it was a slow and tedious process of study after study, followed by restudies when the inevitable request withdrawal happened.

As the rapid development of renewables continued, MISO shifted to group studies process to help deal with the volume of requests. This greatly increased the ability of the MISO process to analyze larger sets of interconnection requests, but failed to address the issues of restudies, queue parking and withdrawals. The most recent iteration of generator interconnection process changes incorporated elements to remove the ability to suspend requests, set higher hurdles for continuation through the process and incent early withdrawals of projects that are unable to complete the interconnection process at that time. While these studies are sufficient to determine network upgrades to allow interconnection of the requested facilities, they are

performed with models of the existing system *at the time* of the study, which does not include future generation retirements, unless they are formally-confirmed.

Current generator interconnection studies are based on two conditions, summer and shoulder, and determine the system improvements needed for each study group. This is to represent two of the most strenuous scenarios for the transmission system – one during peak customer demand, in which all resources are employed to meet that demand – and the other, a scenario representing lower customer demand and high renewable generation output, leading to high levels of power transfers across the transmission system. Even though these two strenuous scenarios are analyzed, there are system conditions that exist that put a large strain on the system and are not studied as part of the generation interconnection process.

For example, MISO experienced a low wind day July 29, 2018, where wind produced below the accredited levels for more than 100 consecutive hours. Another example is during the most recent polar vortex when the vast majority of wind turbines shut down due to extreme cold temperatures, and output dropped sooner than the forecast had predicted. As a result, firm dispatchable resources were needed to fill the gap left by the forecast error and lack of wind. We discuss these case study days further in conjunction with the Reliability Requirement in Appendix J2.

As the grid further evolves to include increasing levels of renewable resources, there will be an increased need to identify impacts and propose solutions that ensure reliable delivery of energy every hour of every day, rather than relying on limited snapshots. These events that limit the availability of resources below what is expected are extreme and may represent only a small portion of potential operating conditions, but maintaining a reliable system through *all conditions* will be important in the changing future.

IV. XCEL ENERGY BASELOAD GENERATING RESOURCES STUDY

Order Point No. 14(a) of the Commission's January 11, 2017 Order in Docket No. E002/RP-15-21 required Company in its next Resource Plan to study the future of its baseload generating resources, and describe its plans and possible scenarios for cost-effective and orderly retirement of its aging baseload fleet, including Sherco, King, Monticello, and Prairie Island. In this section, we outline the four-pronged approach we took to conduct this analysis.

A. Overview

Aging baseload generator retirements and increasing levels of renewable generation

on the grid are trends underway in the industry that are not yet fully understood. The current transmission system is developed, operated and maintained in accordance with several sets of standards and processes to ensure the safe, reliable and efficient delivery of power. Some of these include standards and recommendations from the Institute of Electrical and Electronics Engineers (IEEE), the National Electric Safety Code (NESC), the Nation Electric Code (NEC) and countless industry standards referred to as "Good Utility Practice." One of the most impactful to the development, planning and operation of the transmission system is the standards set by NERC, which through the authority of FERC, has the ability to enforce the established NERC standards under penalty of fines. NERC standards touch on everything from system modeling requirements to system operations, including both physical and cyber security standards. Embedded in these standards are local system practices and protocols from which the standards are formulated.

While these standards and protocols have worked well in the past, the changes underway on the grid are introducing new challenges. This requires additional foresight in planning processes to ensure reliable delivery of power to customers utilizing a cost-effective transmission system. Although the trend toward high penetration levels of intermittent generation has been commonplace for several years, the industry is just starting to analyze the impacts of these changes from a holistic point of view. MISO and individual utility planning and study practices will need to adapt to ensure we continue to have a resilient system and strong customer reliability.

That said, the work that we have done with this Baseload Study provides helpful insights into this complex intersection of the future grid. Further studies and an orderly plan will be key to ensuring reliability and resilience through the clean energy transition we envision for our system.

B. Approach

The NSP System has been developed over the past 100 years to serve the growing area, and is constantly being analyzed to ensure optimal and reliable power delivery. We have a great deal of experience both in studying the existing grid and operating it in many varying conditions (during high load, low load, high transfers, low transfers, storm conditions, outages or equipment). However, as noted above, planning and study practices have not fully adapted to trends underway. We believe however, that our technical and economic approach combined with relevant industry insights in this Study provides helpful insights to an orderly and cost-effective retirement of our current baseload generating units.

The components of our Study are as follows:

- **Midcontinent Integrated Systems Operator (MISO) Attachment Y2 preliminary retirement studies**, which assessed various single Unit and combined Unit retirement scenarios for thermal and voltage concerns,
- **Xcel Energy Transmission Reliability studies**, which examined system stability and response impacts associated with baseload generating resource changes on the NSP System and on neighboring systems,
- **Industry insights**, including the North American Electric Reliability Corporation (NERC) *Generator Retirement Scenario Special Study* and the MISO *Renewable Integration Impact Analysis* (RIIA), which provide important insights into the combined effects of baseload generator retirements in a region and grid impacts at increasing levels of renewables penetration, and
- **A focused Strategist analysis**, which examined the economic implications of various Unit and combined Unit retirements at different points in time.

When performing technical studies, we simulate a number of varied conditions that can consider changes in customer loads, projected changes to the generation mix, and ways to use the transmission system most efficiently. The studies generally analyze the way power flows over the grid and search for places where the system might overload or fail, assuming specific circumstances. While these studies are essential and provide important insights, our decades of operating and studying the existing system also provides valuable insights and perspective toward assessing potential impacts from NSP System grid changes. We have incorporated this experience into our analysis of impacts. We also supplemented our technical study efforts with relevant industry initiatives that examine the compound impacts of aging baseload retirements and increasing levels of renewable generation – similar to the issues facing the NSP System.

The MISO Y2 and our Reliability Studies identify grid impacts and potential transmission mitigations necessary to resolve the respective issues the studies identified. MISO performed its Y2 Studies in accordance with their Business Practice Manuals, which generally focus on thermal and voltage issues.[21] We used the MISO planning level estimated mitigation costs from the Y2 studies as an input to our Strategist modeling of the baseload unit retirements. While these may not be the final mitigations, they provide a proxy of potential costs to inform the economic aspect of our Baseload Study. Our technical studies supplemented the MISO analysis to examine traditional NERC reliability measures such as system stability and response.

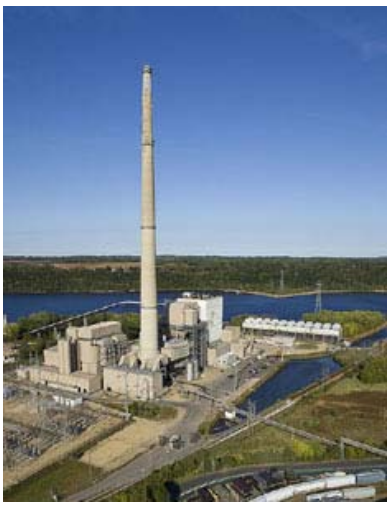
[21] *See* MISO Business Practice Manual BPM-020 at:
https://www.misoenergy.org/Library/BusinessPracticesManuals/Pages/BusinessPracticesManuals.aspx

This is an important complement to the MISO Y2 studies to provide a more robust look at potential impacts from baseload changes on the NSP system and regional MISO grid.

All studies are essentially an attempt to predict what is going to happen in the future – and the conditions and underlying assumptions of a dynamic system are subject to change. These technical studies used the best information available at the time they were initiated. However, while the studies provide important insights, there are inherent limitations in any study effort. Technical studies simulating the removal/ absence of a generating unit(s) on the grid can only practicably analyze potential impacts with a point-in-time model in a limited set of grid conditions (i.e., peak, shoulder, etc.). Therefore, while they provide important insights for the limited number of scenarios studied, it is important to supplement the technical studies with industry insights and engineering judgement. We have attempted to offset these limitations by taking a multi-faceted approach to our Study, and note that further studies more proximate in time to the potential retirement dates will be necessary to determine actual impacts and actual mitigations.

C. Xcel Energy Baseload Resources Fleet

1. A. S. King



This plant was named in honor of Allen S. King, former president and chairman of Northern States Power Company, a predecessor to Xcel Energy. The King plant underwent a significant rehabilitation from 2004-2007 as part of Xcel Energy's Metro Emissions Reduction Project (MERP).

<u>Key Facts</u>

- *Power Production Capability:* 598 megawatts
- *Commercial Operation:* 1968
- *Generation Type:* Coal
- *Location:* Oak Park Heights, Minnesota, on the St. Croix River

In addition to generating electricity, A. S. King supplies hot water to neighboring Andersen Windows, a large window manufacturer. Located on the border of Minnesota and Wisconsin, King also provides stability to the Upper Midwest transmission grid.

2. Sherburne County (Sherco) Generating Station

The Sherco plant is comprised of three generating Units with a total nameplate capacity of approximately 2,400 MW. Sherco is the largest plant in the Company's fleet in terms of square feet, steam production, and power generation capability. Units 1 and 2 are scheduled to retire in 2026 and 2023, respectively. This Resource Plan proposes to retire Unit 3 in 2030. Unit 3 is 41 percent owned by Southern Minnesota Municipal Power Agency, composed of municipal power companies operating on a cooperative basis.

Key facts

- Power Production Capability: 2,457 MW
  - Unit 1 – 765 MW
  - Unit 2 – 765 MW
  - Unit 3 – 927 MW
- *Commercial Operation:* Unit 1 - 1976; Unit 2- 1977; Unit 3 - 1987
- Generation Type: Steam Turbine
- *Location:* Becker, Minnesota, 45 miles northwest of the Twin Cities, on the Mississippi River

3. Monticello Nuclear Generating Station

The Monticello facility is among Xcel Energy's lowest-cost sources of electric generation on a per-megawatt basis and produces virtually no greenhouse gas emissions. As a base load 'always-on' plant, it runs essentially 24 hours a day, 7 days a week, except during refueling outages, which occur about every two years. Monti is a boiling water reactor plant is located on a 215-acre site 40 miles northwest of the Twin Cities. The plant generates approximately 10 percent of the electricity used by Xcel Energy's customers in the Upper Midwest.

Key Facts

- *Power Production Capability:* 671 Megawatts
- *Fuel Type:* Nuclear
- *Location:* Monticello, Minnesota

The plant received a 40-year operating license from the federal Nuclear Regulatory Commission in 1970, and it began commercial operation in 1971. In 2006, the NRC renewed the Monticello plant's license for 20 years, which allows operations until 2030. This Resource Plan proposes to extend the operation of the Monticello plant an additional 10 years, which will require a license extension from the NRC.

4. Prairie Island Nuclear Generating Station

The two pressurized water reactors at the Prairie Island facility generate about 20 percent of the electricity used by Xcel Energy's customers in the Upper Midwest. Prairie Island is among our lowest-cost sources of generation on a per megawatt-hour basis, and does not produce any greenhouse gas emissions. The plant runs essentially 24 hours a day, seven days per week, except during refueling outages, which occur approximately every 18 months and last about four to six weeks. The plant is about 40 miles southeast of Minneapolis-St. Paul and generates enough electricity to power about 1 million homes.

Key Facts

- *Power Production Capability:* 1,186 megawatts (593 MW per Unit)
- *Fuel Type:* Nuclear
- *Location:* Red Wing, Minnesota

The Unit 1 reactor began operating in December 1973 and the Unit 2 reactor in December 1974. The Nuclear Regulatory Commission first licensed the reactors for 40 years of operation and extended those licenses for an additional 20 years, until 2033 and 2034.

The Prairie Island and Monticello nuclear generating plants help Xcel Energy avoid producing hundreds of millions of tons of greenhouse gases or emissions. The plants avoid 13 million tons of carbon dioxide annually compared to fossil fuel plants, the equivalent of removing 2 million cars from the road each year.

D. Industry Studies and Outlook

We also considered industry trends and relevant studies on the effects of aging baseload units and the cumulative effects of higher renewables penetrations. Two of these studies were the MISO *Renewable Integration Impact Assessment* (RIIA) study, which is ongoing, and the December 2018 NERC *Generator Retirement Scenario Special Reliability Assessment.*

1. Industry Study – MISO Renewable Integration Impact Assessment

In 2017, MISO initiated a detailed exploration of assumptions regarding the way the electrical grid will work in the future in light the "profound" change in the types of generating resources across its operating area and the implications that such a shift means for long-standing power system design and operational practices. Under current practices, renewable resources are relied on mostly for their energy production attributes, but as they continue to replace existing assets, they will be expected to increase their contribution to grid reliability.

Given the current structure (physical infrastructure, operational practices, regulations, etc.) of the electric system in MISO and beyond, there are limitations on the maximum penetration of renewable energy. The complexity of overcoming these limitations are dependent on the types and distribution of renewable resources, the current layout of existing assets, and the actions of neighboring regions. Because the exact points of these limitations are not yet known, a framework is needed to examine renewable integration over a wide range of penetration levels, starting with the system we have today and examining penetration levels up to very high percentages of annual energy. This framework, when completed, will reflect and inform the conversations that MISO and other entities within the electricity sector have been having on the impacts of the evolving resource mix on the BES.

The study has three focus areas: (1) Resource Adequacy, or the ability to maintain the Planning Reserve Margin; (2) Energy Adequacy, or the ability to operate within generator limits such as ramp rates, min/max capacity, etc., transmission limits/ratings, and system limits such as energy balance and operating reserves; and (3) Operating Reliability, or the ability to operate the system within acceptable voltage and thermal limits and the ability to maintain stable frequency and voltage, and meet system performance requirements. The study is being conducted in phases, with each phase examining increased levels renewable penetration. Phase II was completed in Q1 2019, and examined region-wide renewable penetrations in the 40-50 percent range.

This is being accomplished by identifying "milestones" or inflection points of integration complexity, initially identified through four modules:

- *Operational Adequacy*. Simulation of the Day-Ahead (DA) and Real-Time (RT) to examine the Ancillary Services Market (ASM), including aspects such as ramping, emergency/dump energy, reserve requirements, congestion, etc..
- *Transmission Adequacy*. Analysis of the power system utilizing more traditional power system analyses. This analysis examines peak demand, shoulder demand and low demand scenarios to assess the ability of the transmission system at each milestone.
- *System Stability*. Analysis of the very short term capabilities of the transmission system to maintain system stability. This analysis utilizes scenarios similar to the Transmission Adequacy module, but focuses on the sub-second to multiple second response timeframe to determine the ability to maintain voltage and transient stability and ensure adequate system response capability is available.
- *Resource Adequacy Limitations*. Determination of the impacts to resource reserve margins and load carrying capability of intermittent resources and interdependencies between resource types.

These modules are being applied through three Phases that study these impacts at increasing levels of renewable resources.

a. Key Takeaways To-Date

One of MISO's key conclusions to-date is that integration complexity increases dramatically between 30 percent and 40 percent. At a 40 percent MISO-wide renewables penetration level, curtailments are encountered during almost all non-summer days, reaching nearly 7,000 GWh of curtailments in the worst month of the base case at this level. Other interim conclusions relevant to our study of an orderly cost-effective transition of our baseload units thus far include:

- Renewable integration complexity increases sharply from 30 percent to 40 percent penetration. Currently synchronous baseload units provide necessary services to the grid that mitigate the impacts of the inherent variability of renewable generation.
- As wind and solar penetration increases, its contribution to peak load conditions reduces because the risk of losing load compresses into a smaller number of hours and shifts to later in the day (from 3:00 p.m. to 6:00 p.m). As a result, the available energy from wind and solar during high risk hours

decreases, and the marginal contribution of renewables reaches a plateau. We discuss this further in Part IV.D below, and in conjunction with the Reliability Requirement we developed for this Resource Plan, discussed in Appendix J2. This issue is both a current and future risk to system resilience and reliability that is not currently addressed in the MISO planning construct.

- As renewable penetration grows, renewable curtailment becomes increasingly significant; enhanced transmission reduces curtailment. With increased levels of renewables inevitable to achieve significant carbon reductions, substantial transmission development will be necessary.
- As renewable penetration increases, the number of thermal units online increases during off-peak hours despite a decrease in average output – and fewer thermal units are operating at their minimum stable level.
- Thermal overloads and voltage violations increase as penetration levels increase, with solution complexity (cost of the transmission fixes) also increasing with penetration level. North Dakota and parts of Minnesota start to show severe thermal and short circuit issues due to vast amount of wind resources sited in those locations and relatively limited transmission capacity.
- Diversity of technologies and geography improves the ability of renewables to meet load.
- Overall, the 40 percent scenario increased the instances of dynamic stability issues, operational stressors, and resource adequacy requirement increases.

In observing that the level of renewable resources in the MISO footprint is growing at a rate of about 1.5 GW per year since being nearly non-existent in 2005, MISO acknowledged challenges along the way – and is taking action to evaluate the impacts of renewable resources growing to even higher levels over the long-term. As described by MISO, its RIIA assessment will give MISO and its stakeholders specific areas around which to focus effort and help inform the sequencing of actions required to manage certain renewable penetration levels. The assessment will illustrate specific areas of system weakness, show when those weaknesses could become problematic and identify potential means to address them – and will seek to facilitate a broader conversation about renewable integration impacts on the reliability of the electric system.[22] The study is now continuing on to Phase III.

[22] *See* https://www.misoenergy.org/planning/policy-studies/Renewable-integration-impact-assessment/#t=10&p=0&s=&sd=

2. *Industry Study – NERC Special Reliability Assessment – Generation Retirement Scenario*

Below we summarize a recent special report from NERC that implies there may be potential for delay or cancellation of announced retirements due to insufficient system support services provided by synchronous generation being available in some regions.

NERC published a Generation Retirement Scenario Special Reliability Assessment December 18, 2018 as part of its ongoing efforts to assess the potential implications of the changing generation resource mix on the reliability of the North American BES. In initiating this special assessment NERC observed that the BES is undergoing a significant transformation, marked by growth in new natural gas, wind, and solar resources replacing retiring fossil-fired and nuclear generating resources. The drivers underlying this shift that NERC cited include federal and state policies, continued low natural gas prices, wholesale market forces, customer preference, and low and improving technology costs.

NERC also observed that managing generator retirements and the transition to replacement resources is a complex process. The report characterizes the changes currently underway with the generation resource mix as "revolutionary," and observes that the changes alter the operating characteristics and constraints of the BES. The report stresses that these changing characteristics must be well understood and incorporated into planning to assure continued reliability.[23]

NERC's key conclusion is that the generator retirements that are occurring disproportionately affect large baseload, solid-fuel generation (coal and nuclear). If these retirements happen faster than the system can respond with replacement generation, including any necessary transmission facilities or replacement fuel infrastructure, significant reliability problems could occur. Resource planners at all levels should use their full suite of tools to manage the pace of retirements and ensure replacement infrastructure can be developed and placed in service. Ensuring reliability throughout a significant retirement transition will likely include construction of new transmission and fuel infrastructure

This NERC study underscores the importance of taking a measured approach to baseload unit retirement that includes thorough examination of potential reliability implications. This also supports our belief that appropriate analysis may require supplemental study beyond the studies prescribed in present protocols.

[23] Executive Summary, NERC Special Reliability Assessment: Generation Retirement Scenario (December 18, 2018).

As part of its oversight and governance activities, NERC also conducts an annual reserve margin analysis across all system operators in North America in a report called the LTRA, discussed earlier in this Study. The 2018 LTRA indicated that MISO is one of three regions that are projected to drop below their reference reserve margin levels by the year 2023, unless certain measures are taken.[24] This report indicates that inclusion of Tier 2 resources (those that are in more advanced stages of planning but not yet under construction) would likely allow for the MISO footprint to preserve system reliability. However, the unprecedented rate of announced, but not yet evaluated, baseload generation retirements and uncertainty in future firm capacity additions creates a tension between maintaining reliability and transitioning away from baseload generation.

E. MISO Retirement Studies

The current process for retirement of generation resources in the MISO footprint is generally governed by Attachment Y to the MISO Tariff. Preliminary retirement studies fall under Attachment Y2, which is a confidential MISO analysis to determine if any adverse system impacts would occur as a result of potential generating resource retirement – without/prior to committing to retire or suspend the resource. If adverse impacts are identified, they provide an indication of the mitigations that would need to occur prior to actual unit retirement. As we discuss below, we submitted requests for several Attachment Y2 studies as part of this Baseload Study.

Final determination of adverse impacts however, occurs with an Attachment Y notice – or new provisions under Attachment X of the MISO Tariff, if the notice of retirement includes replacement generation. In May 2019, FERC approved changes to the Attachment X Tariff that allows current generation owners to retain and reuse the interconnection rights when a resource retires, within certain technical and timing limitations on the new generator.[25] The new generating units could be developed on the same site, or on a site in close proximity that uses the same grid interconnection point. The resulting studies under this provision of Attachment X, the generation replacement is considered as part of MISO's analysis of potential adverse impacts. We discuss Attachment X and its importance in achieving the fleet transformation we

[24] *See* "NERC Long Term Reliability Assessment 2018" at 14. Available at: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2018_12202018.pdf

[25] In summary, these changes allow for transfer of interconnection rights from a retiring generation resource to a replacement resource that: (1) Is located at the same point of interconnection as the retiring resource, (2) Is less than or equal to the generating capacity of the retiring resource, (3) Does not result in an adverse impact to the transmission system. *See*: https://www.ferc.gov/CalendarFiles/20190515181059-ER19-1065-000.pdf

envision in Appendix I: Supporting Infrastructure: Transmission & Distribution provide with this Resource Plan.

1. Preliminary Retirement Studies of NSP System Baseload Units

Attachment Y2 studies assess current, point-in-time system impacts in the absence of the identified generating resource(s). The study impacts are measured based on the criteria set forth in the MISO Business Practices Manuals, The studies assess transmission system performance to identify any violations of planning criteria due to the unavailability of the generation resource. The relevant MISO Transmission Owner and/or regional reliability criteria are used for monitoring such violations. The Attachment Y2 studies are not intended to determine long-term system reliability impacts, which is why we supplemented them with other reliability studies to provide further insights into impacts from potential retirement scenarios. It is important to note that the assumptions used in the MISO Y2 studies are based on expected conditions at the time they were initiated in 2018, plus the addition of certain pending and proposed generating units, including the Sherco CC and our approved and in-progress wind projects.[26]

For purposes of this Baseload Study, we submitted seven Attachment Y2 study requests with MISO – all of which use a retirement date of May 31, 2027, on models developed to depict 2030 system conditions as follows:

Y2 Baseload Unit(s) Retirement Scenarios
Sherco Unit 3
Allen S. King (King)
Prairie Island (PI)
Monticello (Monti)
All Nuclear (Monti and PI)
All Coal (Sherco 3 and King)
All Coal and All Nuclear

2. Y2 Study Results

Generally, the studies found that reconductoring (or line rebuilds) and transformer replacement would be needed to achieve adequate performance for all the scenarios analyzed. In addition, the observed voltage violations would require installation of

[26] MTEP17 (built for the 2017 MISO planning cycle) model series 2027 scenarios that were scaled to represent 2030 load levels. The model also included the following pending and proposed generating units: Crowned Ridge 1 Wind, Crowned Ridge 2 Wind, Crowned Ridge 3 Wind, Blazing Star 1 Wind, Blazing Star 2 Wind, Sherco CC.

extensive reactive devices throughout the region due to the loss of dynamic reactive support from the large amount of retiring resources.

The studies also found that if Xcel Energy were to retire all of its remaining baseload units about the same time, which would be the majority of the large power producing units in the Upper Midwest, it would put a substantial strain on the BES to import power from the rest of MISO. It would also substantially impact MISO's ability to balance out the system to allow for the needed high renewable transfers to other parts of MISO. The Y2 study that examined the combined retirement of the Monticello Unit 1, Prairie Island Units 1 & 2, King Unit 1 and Sherco Unit 3 at the same time stated the following:

> The combined retirement…causes extensive thermal overloads and numerous voltage issues that would require substantial reinforcements to fully address the issues and permit retirement. It is unlikely that the large number of upgrades needed to alleviate thermal overloading and voltage issues would be completed before the planned retirement date resulting in the need for one or more generators to be retained as System Support Resources.

MISO currently is able to use the large Xcel Energy baseload generating units to help balance out the system and provide significant amounts of system response – allowing for high renewable transfers to other parts of MISO. On low wind days, the large generating units are also needed to replace the lost energy from the renewable sources to reliably serve customers' needs. An orderly retirement schedule with sufficient lead times is necessary to ensure reliability mitigations and adequate support of renewables integration and transfers, including generator replacements and transmission development.

Incremental retirements identified more manageable impacts. In the case of a King-only or Sherco 3-only retirement, neither resulted in thermal or voltage degradation such that the Unit would be designated as a SSR.[27] However, the All Coal/King and Sherco 3 combined study found the need for an estimated $38.2 million to address several thermal overloads. The Monticello Y2 study showed some thermal overloads that could be addressed with system readjustment. Some voltage issues would additionally need to be addressed before it could retire. The retirement of Prairie Island would require some voltage mitigation, but there were no thermal overload

[27] In some cases, a generator may be designated as a System Support Resource (SSR), which is determined by the presence of unresolved violations of reliability criteria that can only be alleviated by the SSR generator and where no other mitigation is available. Evaluation of mitigation solutions will consider the use of operating procedures and practices such as equipment switching and post-contingent Load Shedding plans allowed in the operating horizon.

issues. Retirement of all nuclear units would result in some thermal and voltage issues that would need mitigation before they could be retired.

As noted above, the All-Coal and All-Nuclear Retirement scenario resulted in major thermal and voltage violations. This scenario would require significant system upgrades to eliminate all of the thermal and voltage issues; the MISO planning level estimates for all transmission facilities improvements to address the steady state thermal and voltage issues was estimated to be $299.3 million. As transmission development, permitting and construction processes generally involve rather long timeframes of 5-7 years on the low end and as much as 15-20 years in some cases, we expect that addressing all of the system violations would involve an extensive effort over a relatively long timeframe to be complete.

That said, the MISO system is dynamic and expected conditions will change when new generation comes online, existing generation retires, new transmission lines are constructed, or existing lines are reconfigured. These results are indicative of issues requiring mitigation at the time of these studies. A more comprehensive analysis will be necessary in conjunction with a notice under Attachment Y or Attachment X in closer proximity to the planned retirements to determine final adverse impacts and to develop mitigation options.

The Y2 Studies identified planning level costs, which are estimates provided only as an indication of the upgrades needed to mitigate issues caused by the retirement(s) and are based on assumptions that include new proposed generation resources without any of the associated network upgrades.[28] The Y2 reports clarify that further analysis is required in a subsequent retirement study to fully consider only those interconnected resources with executed interconnection agreements in order to more accurately determine costs of the mitigation upgrades.

For purposes of this Baseload Study, we incorporated the MISO planning level estimated costs from the Y2 studies into our economic modeling of the baseload retirement scenarios. We outline our Strategist analysis in Part G below, and discuss it in more detail in Chapter 4: Preferred Plan, Chapter 5: Economic Modeling Framework, and Appendix F2: Strategist Modeling Assumptions & Inputs.

[28] Costs specified in the Attachment Y2 studies are based on the "MISO Transmission and Substation Cost Estimation Guide for MTEP" except where costs were established for previously identified upgrades and are subject to change.

F. Xcel Energy Transmission Reliability Studies

As discussed above, the MISO Y2 study process focuses on maintaining transmission system elements within their thermal and voltage limits.[29] While this provides a thorough analysis of the impacts of the retiring generation resource in those two areas, it does not adequately capture the impacts that resource(s) has on the stability of the power system, which requires a more focused area of study around the retiring resource.

Historically, limiting the study to voltage and thermal assessments was sufficient. This was because individual generating unit changes had limited impact on overall system reliability because there were excess capabilities from the remaining generation fleet to replace/adequately perform the necessary stability services. However, as the system moves further away from large synchronous generating facilities, system stability and response becomes a significantly greater risk for generation retirement than voltage violations or thermal constraints. Therefore, a more robust study that includes consideration of other grid impacts is necessary to ensure system reliability and resilience. The complementary studies we undertook studied other grid impacts of various generation retirement scenarios using a more traditional NERC reliability assessment approach.

Combined with the Y2 results, these studies provide a more robust analysis of the potential retirement of our remaining baseload units. The results from our analysis indicate the following:

- There will be several thermal and voltage violations that will need to be addressed to remain NERC compliant.
- The location of resources plays a large part in the ability of the system to respond to faults. In the absence of large synchronous resources replacing retiring units in place, significant transmission infrastructure development will be necessary. See Figures 2 and 3 (Stability Plots) below.
- While a zero baseload future may be able meet certain aspects of a reliable power system, current technologies cannot maintain system stability, adequately recover from contingencies, nor can they ensure reliable service to customers every hour of every day without the assistance of a sufficient level of synchronous generation.

Final system impacts will depend on the scenario, the specific Unit retirement(s), and

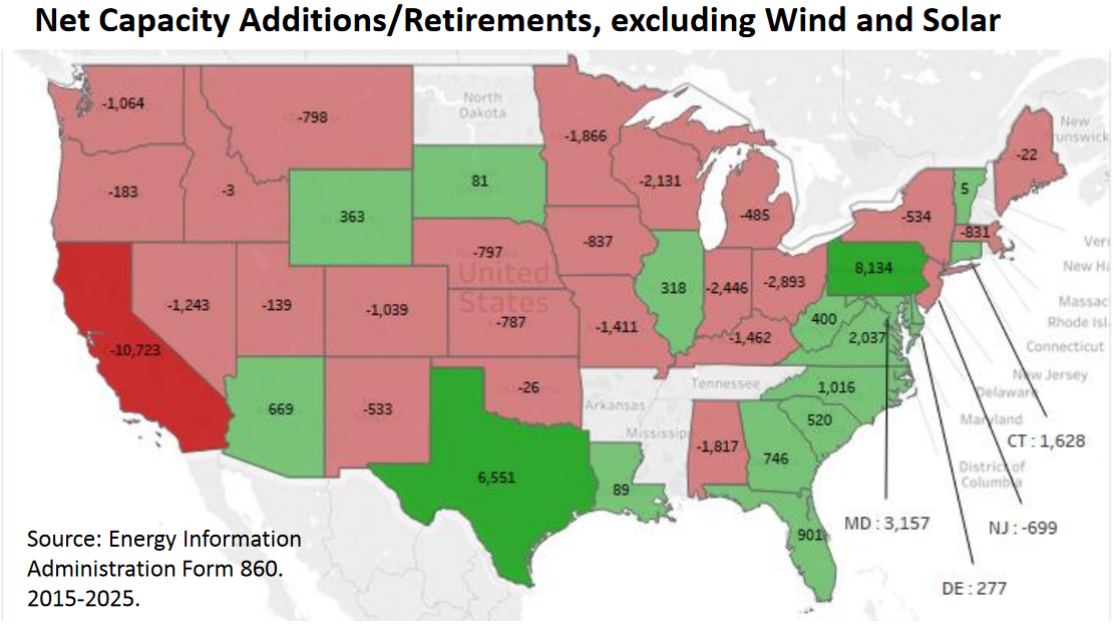
[29] MISO will perform limited stability analysis upon request.

what, if anything, will replace the Unit(s).

1. Approach

We undertook these studies at a point in time in the industry when there are more large generating units retiring than being added to the grid. As shown below, the capacity availability in the MISO states is projected to fall by nearly 8,700 MW by 2025 from 2015 totals.

Figure 1: Net Capacity Additions, Excluding Wind and Solar



With the trend of declining levels of large synchronous generating units being largely replaced with renewable and intermittent resources in mind, we undertook two study efforts to determine the impact of baseload retirements on the Upper Midwest grid:

- **Metro Stability Study** – analyzed the capability of the Twin Cities metro area to remain stable utilizing a scenario in which large scale baseload retirements took place both on the NSP System, as well as neighboring systems.
- **NSP Resource Contribution to System Stability** – analyzed the stability of the Upper Midwest grid when only the NSP System reduced its baseload generating resources.

These technical studies simulate a number of varied conditions that consider changes in customer loads, projected changes to the generation mix, and ways to use the

transmission system most efficiently. The studies generally analyze the way power flows over the grid, and search for places where the system might fail to maintain a stable power signal, assuming specific circumstances. Study 1 focused on regional (neighboring utilities') changes to determine local (Twin Cities Metro) impacts. Study 2 was to determine the regional impact of NSP System changes.

2. Study 1: Metro Stability Study

The goal of this study was to determine the minimum amount of system services required to maintain a stable major demand center, which in this case was the Twin Cities Metro area, with major changes to the surrounding system. The results indicate that while a zero baseload future may be able meet certain requirements for a reliable power system, the current technologies on the system today cannot maintain system stability without the assistance of a sufficient level of synchronous generation.

a. Study Assumptions and Approach

For the purposes of this Study, we utilized three natural gas generators located at strong points on the system to determine the *minimum amount* of system services necessary to maintain a stable major demand center with major changes to the surrounding system.[30] We performed the stability assessment using the 2018 MTEP dynamic model, representing light load with 90 percent wind output conditions in the year 2023. We assumed no load growth between 2023 and 2030 to limit the number of variables potentially affecting the results.

Consistent with the industry trends and our clean energy vision, we expect substantial additions of renewable energy to be added to the system as we transition the our generating fleet. For purposes of this Study, we assumed the addition of 5,800 MW of nameplate renewable generation dispatched at 4,440 MW to depict a higher reliance on renewable energy resources – and which would replace the assumed retirements. We show the renewable additions in Table 2 below.

[30] This does not take into account maintenance, forced outages, or economic factors into the ability of those services to be provided in all hours by the three units utilized in the analysis, which can increase the total number of units required to provide sufficient levels of service in all hours.

Table 2: Stability Study – Renewable Generation Additions Modeled

				Number of Megawatts	
Location	**State**	**Fuel**	**kV**	**Nameplate**	**Dispatched (Pgen)**
Alexandria	MN	Solar	345	100	60
Quarry	MN	Solar	345	100	60
Chub Lake	MN	Solar	345	100	60
Prairie Island	MN	Solar	345	200	120
North Rochester	MN	Solar	345	150	90
Byron	MN	Solar	345	150	90
Pleasant Valley	MN	Solar	345	150	90
Sheas lake	MN	Solar	345	100	60
Wilmarth	MN	Solar	345	100	60
Adams	MN	Solar	345	100	60
Cedar Mountain	MN	Solar	345	150	90
Big Stone	MN	Solar	345	150	90
Hazel Creek	MN	Solar	345	150	90
Lyon County	MN	Solar	345	150	90
Nobles	MN	Solar	345	150	90
Split Rock	MN	Solar	345	150	90
Owatonna	MN	Solar	161	100	60
Fort Ridgley	MN	Solar	115	100	60
Chanarambie	MN	Solar	115	100	60
Brookings	SD	Solar	345	150	90
Lyon County	MN	Wind	345	350	315
Hazel Creek	MN	Wind	345	250	225
Nobles	MN	Wind	345	250	225
Split Rock	MN	Wind	345	250	225
Lakefield	MN	Wind	345	200	180
Cedar Mountain	MN	Wind	345	250	225
Pleasant Valley	MN	Wind	345	250	225
Mchenry	ND	Wind	230	200	180
Ellendale	ND	Wind	345	200	180
Bison	ND	Wind	345	300	270
Big Stone	SD	Wind	345	400	360
Brookings	SD	Wind	345	300	270
Total				5,800	4,440

Table 3 below shows the resource retirements we applied in this analysis, which are intended to reflect a regional trend of baseload unit retirements in the Upper Midwest. These are not intended to represent actual Unit retirement plans; these are only assumptions utilized to develop a model representing the intended scenario.

Table 3: Generation Turned Off In Analysis

Bus Name	Pgen (MW) in MTEP Model	New Pgen (MW)
[PR IS31G 20.000]	553	0
[PR IS32G 20.000]	552	0
[MNTCE31G 22.000]	592.9	0
[FEP CT G 18.000]	63.4	0
[FEP ST G 13.800]	50	0
[ARNOLD1G 22.000]	651	0
[OTTUMW1G 24.000]	457.3	0
[COL G1 22.000]	585	0
[COL G2 22.000]	585	0
[WES G4 19.000]	600	0

b. Study Methodology and Results

We then introduced faults on the system to assess the ability of the grid to recover and return to a normal state. We outline the fault events that we analyzed in Table 4.

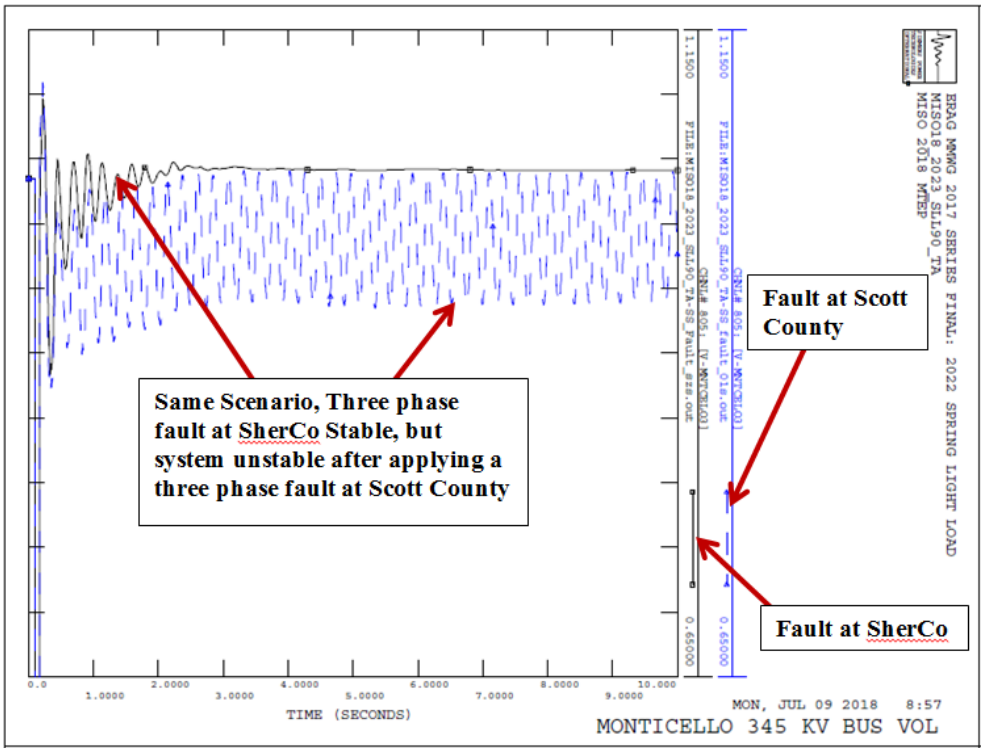
Table 4: Major Faults Analyzed

Fault Name	Fault Description	Result
Fault_01s	Normal close in 3 phase fault on Scott County - Helena 345 kV line near Scott County	Unstable
Fault_02s	Normal close in 3 phase fault on Scott County - Helena 345 kV line near Helena	Unstable
Fault_03s	Loss both Cedar Mountain – Helena circuit with normal clearing	Unstable
Fault_szs	Normal close in 3 phase fault on SherCo - Coon Creek 345 kV line near SherCo	Stable

Figure 2 illustrates the importance of location and siting on system stability. This scenario is demonstrating the effect of a single fault on the system. The black line represents a fault near our Sherco facility, which in this scenario has our future Sherco CC online; the system recovers rather quickly. The blue line represents a similar fault at Scott County, where there is no nearby generating resource – and the system

becomes unstable.

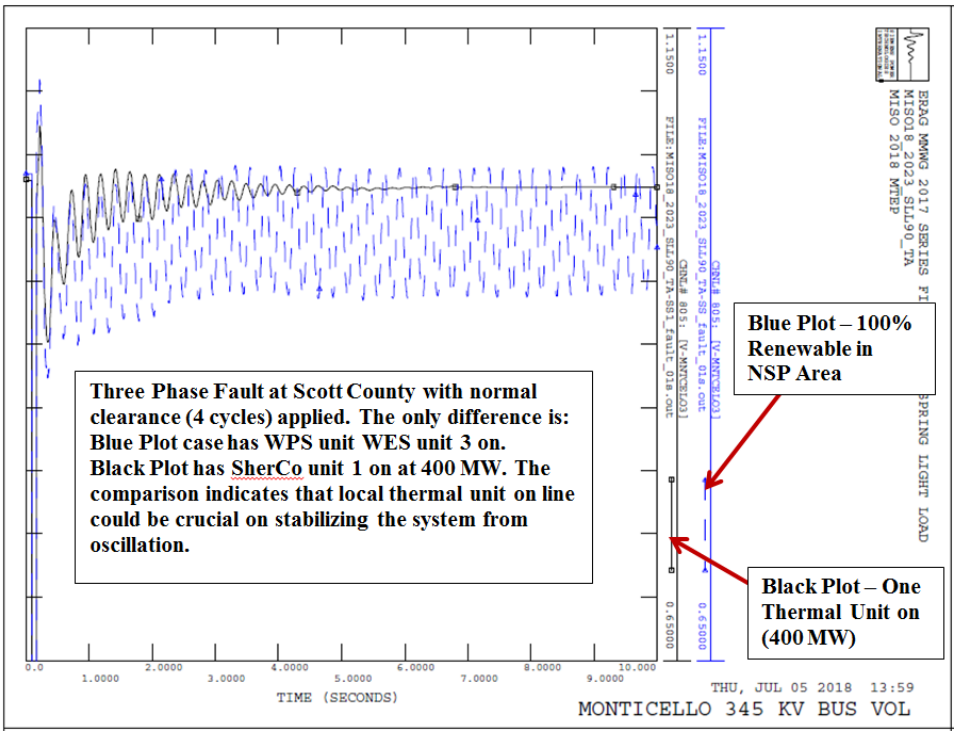
Figure 2: Stability Plot – Importance of Resource Siting on Stability



The results of this scenario demonstrate that the system remains stable when a fault occurs on a part of the transmission system where sufficient system stability services – in this case, a large synchronous generator – are available nearby. Whereas, experiencing a fault at a location with distant synchronous resources connected through long transmission lines to demand centers greatly increases the risk of system instability.

Similar to how system stability differs based on the location of the fault in relation to a system stability resource, the location of synchronous resources plays a large part in the ability of the system to respond to faults. As shown in the stability plot in Figure 3 below, the system response to a fault at Scott County is unstable when relying on energy imports from non-NSP System resources. When we moved a same-sized resource to a location nearer to the Twin Cities Metro area, the system regains stability with little issue after experiencing the same fault.

Figure 3: Stability Plot – Importance of Resource Siting on System Response



As the transition to increased reliance on renewable resources continues, replacement of synchronous resources at current resource locations or substantial transmission infrastructure development will be fundamentally essential to the reliable delivery of energy.

c. Step-by-Step Re-Aaddition of Gas Units in Metro to Regain System Stability

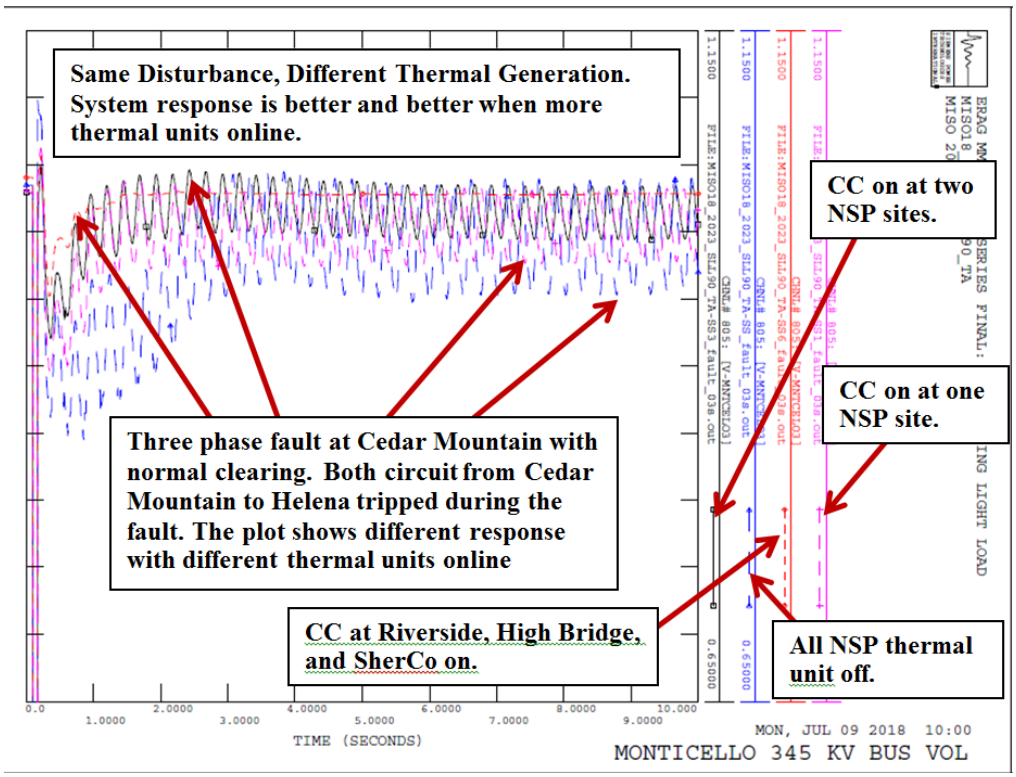
Moving away from the specific locational aspects of faults and resources, we analyzed a wider range of events of differing severities to determine what is needed to maintain system stability with high reliance on renewable resources.

To determine the level of stability services needed, we stepped through turning generating units retired in earlier scenarios back on to analyze the impacts under severe conditions. In this scenario, we turned-off all of the Upper Midwest synchronous generating units, and a major transmission path for renewable generation to get to the Metro area.

As shown in the results of this analysis below, while a zero baseload future may be able meet certain requirements for a reliable power system, the current technologies

on the grid today cannot maintain system stability without the assistance of a sufficient level of synchronous generation. An equivalent level of system services as provided in the model by Riverside, High Bridge, and the Sherco CC are all required to be operating at all times to ensure the system remains stable and can sufficiently recover from contingencies on the transmission system.

Figure 4: Incremental Steps to Result in 3-Unit Metro Equivalent Services



Every generation resource on the system can have significant impacts on the stability of the system, which may differ based on the order in which they are retired or replaced. This study demonstrates that it is vital to perform a system stability analysis, and resolve any issues, for each potential unit retirement proximate to the planned retirement, so the analysis as closely as possible mirrors expected actual conditions at the time of unit retirement.

3. Study 2: NSP Resource Contribution to System Stability

The second study also analyzed the stability of the grid in the Upper Midwest – however when only the NSP System reduced its baseload generating resources. In this analysis, we analyzed the effects of local/NSP System baseload reductions on a regional basis. Our objective with this Study was to determine the importance of

retaining sufficient system services in high demand areas (such as the Twin Cities Metro area) in order to understand the role that current NSP System baseload generating resources have on the stability of the Upper Midwest BES and the ability of non-metro locations to remain stable in low Metro-area baseload scenarios.

The results of this analysis found that the reduction in synchronous generation resources on the NSP System can have wide-ranging impacts on system stability and reliability. In particular, the retirement of NSP System baseload units without similar replacements at or near their current locations results in insufficient margin on the system during summer peak scenarios and system instability in light load scenarios.

a. Study Assumptions and Scenarios

We analyzed light load, summer shoulder, and summer peak scenarios for the year 2023 in this study. Renewables in the NSP System are modeled at an 80 percent level in all three models, while the existing natural gas CCs are turned-on to represent 20 percent firm dispatchable generation in each model. We outline the dispatch assumptions we made in the three different load scenarios in Table 5 below.

Table 5: Dispatch Assumptions

Year	Season	Load Level	20% Thermal
2023	Light Load	5,150 MW	1,030 MW
2023	Summer Shoulder	7,195 MW	1,440 MW
2023	Summer Peak	10,250 MW	2,050 MW

As with Study 1, we applied baseload unit retirements in this analysis that are not intended to represent actual retirement plans. Rather, the assumptions in Table 6 below were only used to develop a model representing the intended scenario.

Table 6: Generation Turned-Off in Analysis

Baseload Generator	Year 2023		
	Summer Light Load	Summer Shoulder	Summer Peak
Sherco #1	Offline	478.3 MW	730 MW
Sherco #2	Offline	427.2 MW	730 MW
Sherco #3	Offline	608 MW	925 MW
King	Offline	560 MW	560 MW
Monticello	593 MW	637 MW	637 MW
Prairie Island 1	553 MW	553 MW	553 MW
Prairie Island 2	552 MW	552 MW	552 MW

Table 7 below outlines the resources we used to replace energy supply in the absence of the assumed retirements above.

Table 7: Additional Generation Assumptions

Bus Number	Bus Name	Unit	2023		
			Summer Light Load	Summer Shoulder	Summer Peak
600007	RIVRS77G 16.000	7	160 MW	160 MW	Online
600070	RIVRSIDEG9 718.000	9	158 MW	158 MW	Online
600071	RIVRSIDG10 718.000	10	158 MW	158 MW	Online
600065	HBR C71G 18.000	7	162 MW	162 MW	Online
600066	HBR C72G 18.000	8	162 MW	162 MW	Online
600067	HBR S73G 13.800	9	226 MW	226 MW	Online
600012	BLK D72G 13.800	2	N/A	115 MW	Online
600164	J399 BLK D7618.000	6	N/A	214 MW	Online
600047	G261 MEC-CT115.000	1	N/A	N/A	Online
600172	G261 MEC CT215.000	1	N/A	N/A	Online
600046	G261 MEC-ST 19.500	1	N/A	N/A	Online

In this Study, we compare the transmission line outages to a Base scenario that has no outages, as follows:

- Base: No Outages
- Outage #1 (PO1): Sheas Lake – Helena 345 kV line
- Outage #2 (PO2): Scott County – Helena 345 kV line
- Outage #3 (PO3): Chub Lake – Helena 345 kV line

Finally, Table 8 below outlines the various faults that we analyzed for each of the above Outage Scenarios.

Table 8: Faults Analyzed

Name	Description
Fault_PI	5 Cycle 3 PH fault at PI
Chisago-345	5 Cycle Three phase fault at Chisago
Fault_eks	5 Cycle Three phase fault at King
Fault_odell	5 Cycle Three phase fault at CRANDAL
Fault_01s	5 Cycle Three phase fault at SherCo
Fault_05s	5 Cycle Three phase fault at Helena on Helena - Sheas Lake line
Fault_04s	4 Cycle Three phase fault at Chisago 500 kV
Monti-slf2	SLGF at Monticello
Monti-3ph2	5 Cycle Three phase fault at Monticello
Fault_pys	SLGF at PI
fault_02s	5 Cycle Three phase fault at Helena on Helena - Scott County line
Fault_03s	5 Cycle Three phase fault at Helena with common structure out
Fault_mcs	SLGBF fault at Sherco on Coon Creek #3 line with 8M40 Stuck
Fault_mts	SLGBF fault at Monticello with 8N6 stuck
Fault_pcs	SLG fault at King-Eau Claire line with a breaker failure at king
Fault_n03s	12 Cycle SLG fault at Red Rock 345 kv bus with failure of 8P24
Fault_mw3s	3 phase fault at Wilmarth on Wilmarth - Sheas Lake 345 kV line
Fault_mqs	SLGBF fault at Sherco on Unit #3
Fault_mjs	SLGBF fault at CHISAGO
Fault_m6s	5 Cycle 3 PH fault at Parkers Lake 345 kV
Fault_m5s	10 Cycle 3 PH fault at Coon Creek 345 kV bus with failure of 8M40
Fault_m4s	10 Cycle 3 PH fault at Terminal
3P_Terminal_TR9_B3s	3 phase fault at Terminal 345 kV bus, normal clearing
3P_Adams_Mitch	Three phase fault at Adams
3P_Briggs_NorthMad	Three phase fault at Briggs Road
3P_Brookings_Hawks	Three phase fault at Brookings County
3P_ChubFault_OpentoHelena	Three phase fault at Chub lake on Chub Lake - Helena line
3P_HelenaFault_OpentoChub	Three phase fault at Helena on Chub Lake - Helena line
3P_Lakefield_Huntly	Three phase fault on Lakefield JCt - Huntley line
3P_Lakefield_LakeJct	Three phase fault on Lakefield JCt - Lakefield line
3P_Lakefield_Obrien	Three phase fault on Lakefield JCt - Obrien line
3P_Sioux_SplitRock	Three phase fault on Sioux - Split Rock line
3P_Split_Nobles	Three phase fault on Split Rock - Nobles County line
SLG_Alexandria_BKR3325	SLG fault at Alexandria with breaker 3325 stuck
SLG_Hawksnest_8N82_Stuck	SLG fault at Hawksnest with breaker 8N82 stuck
SLG_Lakefield	SLG fault at Lakefield with breaker stuck
SLG_Wilmarth_8S23_Stuck	SLG fault at Wilmarth with breaker 8S23 stuck

b. Study 2 Results

In general, the lack of system margin from the significant absence of synchronous generation results in the inability of the system to recover from system events.

This lack of margin is also evident when analyzing the loss of a major transmission source to the Twin Cities Metro area. If enough of these sources are unavailable, the system can become unstable, even with non-NSP System baseload generation resources available as they are today. In addition to the reliability and stability implications of insufficient resource availability in the correct locations, heavy reliance on renewable resources located only in the highest capacity factor/highest concentration locations, such as southwestern Minnesota, results in a less resilient system. In these scenarios, utilizing the current transmission system creates a single point of failure that can result in an inability to operate the system. This further demonstrates that it is likely that significant transmission development will be necessary as current baseload generating resources retire and renewable resources take an increasingly large role on the Upper Midwest grid.

Table 9 below shows the results for the scenarios (Base, PO1, PO2, PO3) for each of the outage events – with the yellow highlights being thermal overloads. We note that in Summer Peak conditions for PO1 and PO2, the model could not converge toa solution, meaning significant upgrades would be required if only to create a stable enough system and enable the analysis of other system impacts.

Table 9: Thermal Overload Results

Facility	2023 SLL				2023 SH90				2023 SUM			
	Base	PO1	PO2	PO3	Base	PO1	PO2	PO3	Base	PO1	PO2	PO3
Helena – Scott County 345 kV	1078 MW	678 MW	N/A	1602 MW 118%*	1545.2 MW 118%*	1158.5 MW	N/A	2232.5 MW 173%	1737.3 MW 138%	No Solution	No Solution	2323 MW 188%
Helena – Chub Lake 345 kV	720 MW	394 MW	1391 MW	N/A	1001 MW	695.2 MW	1931 MW 117%	N/A	868.5 MW			N/A
Sheas Lake – Helena 345 kV	1040 MW	N/A	809 MW	905.4 MW	1125.3 MW	N/A	780.4 MW	930 MW	1721.8 MW 137%			1544.5 MW 125%

*The line rating is calculated based on the bus voltage

Similar to the thermal overloads above, Table 10 outlines the voltage violations in the same grid conditions, scenarios, and outage conditions. In this case, the violations occur only in summer peak conditions. However, again, there are two cases where the model was unable to solve the violation.

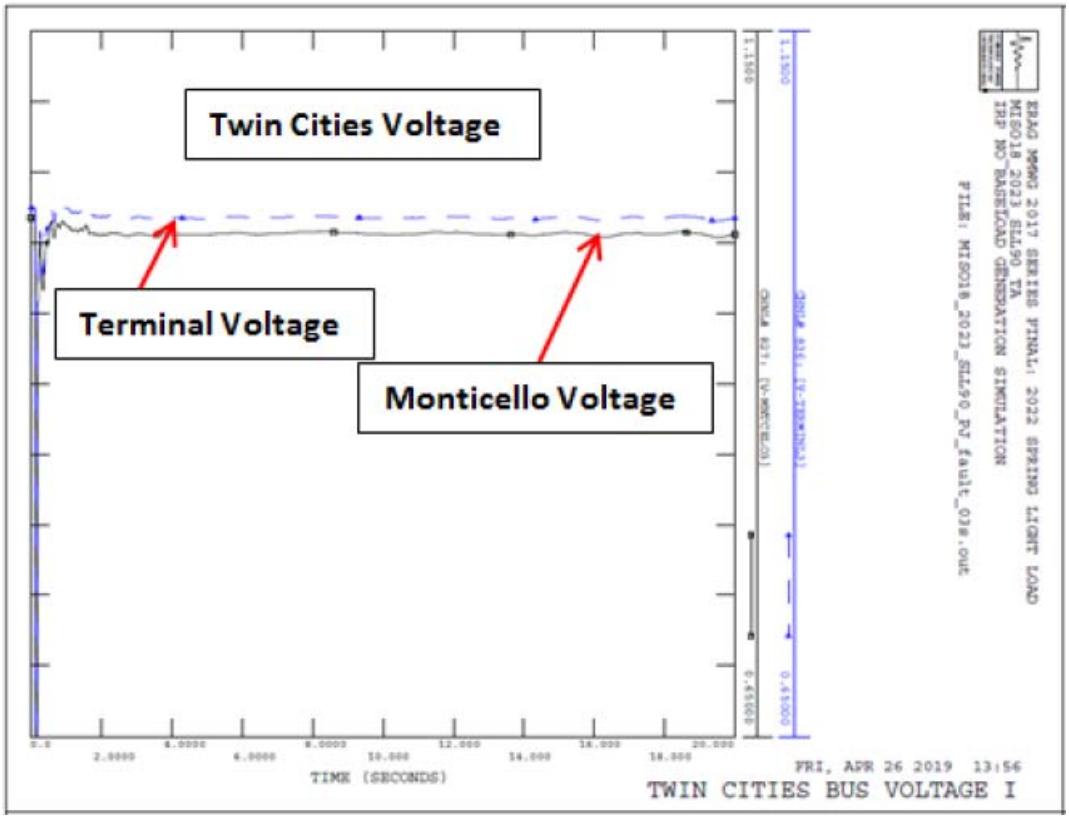
Table 10: Voltage Violation Results

Facility	2023 SLL				2023 SH90				2023 SUM			
	Base	PO1	PO2	PO3	Base	PO1	PO2	PO3	Base	PO1	PO2	PO3
Helena 345 kV	1.006	1.011	0.987	0.990	0.954	0.954	0.920	0.938	0.921	No Solution	No Solution	0.896
Sheas Lake 345 kV	1.001	1.006	0.986	0.988	0.951	0.978	0.924	0.938	0.917			0.898
Scott County 345 kV	1.015	1.017	1.016	0.999	0.968	0.972	0.975	0.948	0.940			0.910

As a result of increased reliance on renewable resources sited in locations to take advantage of higher capacity factors, the transmission system between those high capacity factor/concentration areas and areas of high energy usage become overly stressed, resulting in violations of facility ratings. As is the case in the summer peak scenarios, insufficient margin is available to come to a solution during higher demand scenarios.

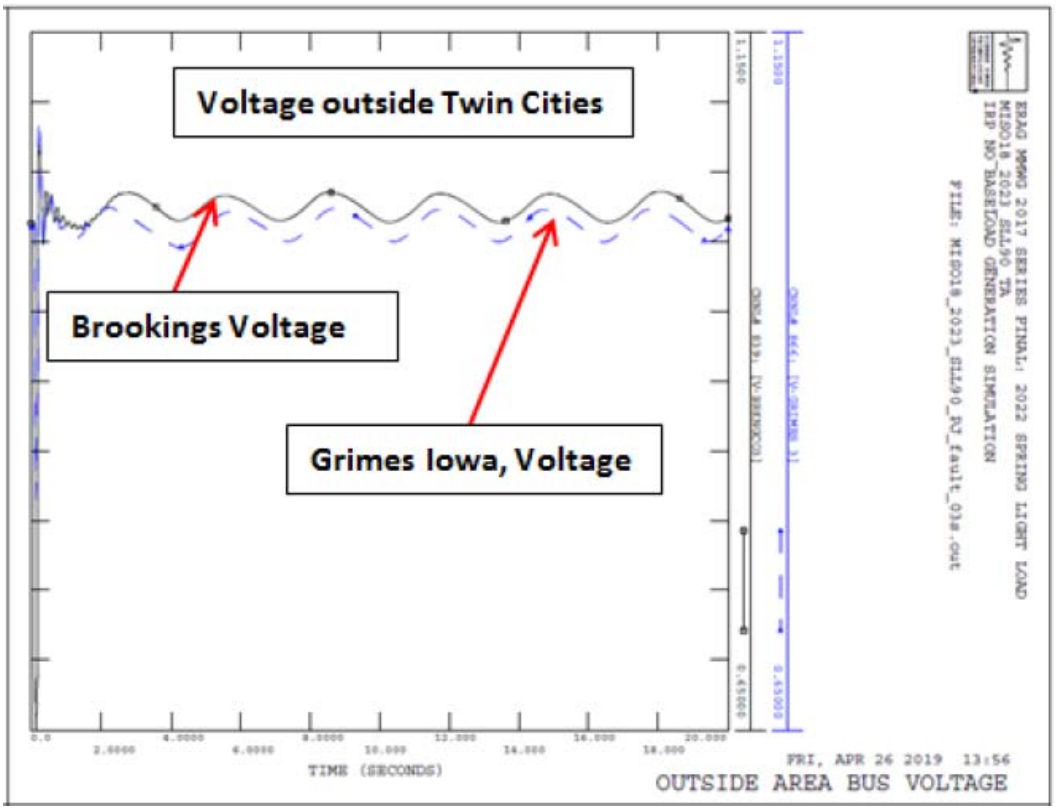
The stability plots in Figures 5 and 6 below show this effect. While the Twin Cities Metro area is able to mostly recover from an event, in all system disturbances tested, the ability of the system in southwest Minnesota and Iowa where there are large concentrations of renewables experience difficulty recovering voltage stability in light load cases.

Figure 5: Stability Plot – Insufficient System Damping
Twin Cities Metro Area Voltage



Damping is the flattening of the line as time progresses. Figure 5 above and Figure 6 below show that, while the Twin Cities Metro area can maintain stability, other areas outside of the Twin Cities Metro are unable to do so.

Figure 6: Stability Plot – Insufficient System Damping Outside Twin Cities Metro Area Voltage



While the scenarios developed for the light load cases were able to fully solve, despite some inability to remain stable, the summer scenarios with high levels of energy demand that are shown as "no solution" in yellow highlight in Tables 9 and 10 above resulted in system collapse due to insufficient resource margin available on the system to rebalance and regain stability after an event is experienced..

Figures 7 and 8 below demonstrate the system collapse, which is would result in widespread power outages and require black start procedures for MISO Load Resource Zone 1 to rejoin the grid once the system regained stability.

Figure 7: System Collapse – Summer 2023 P01 Case

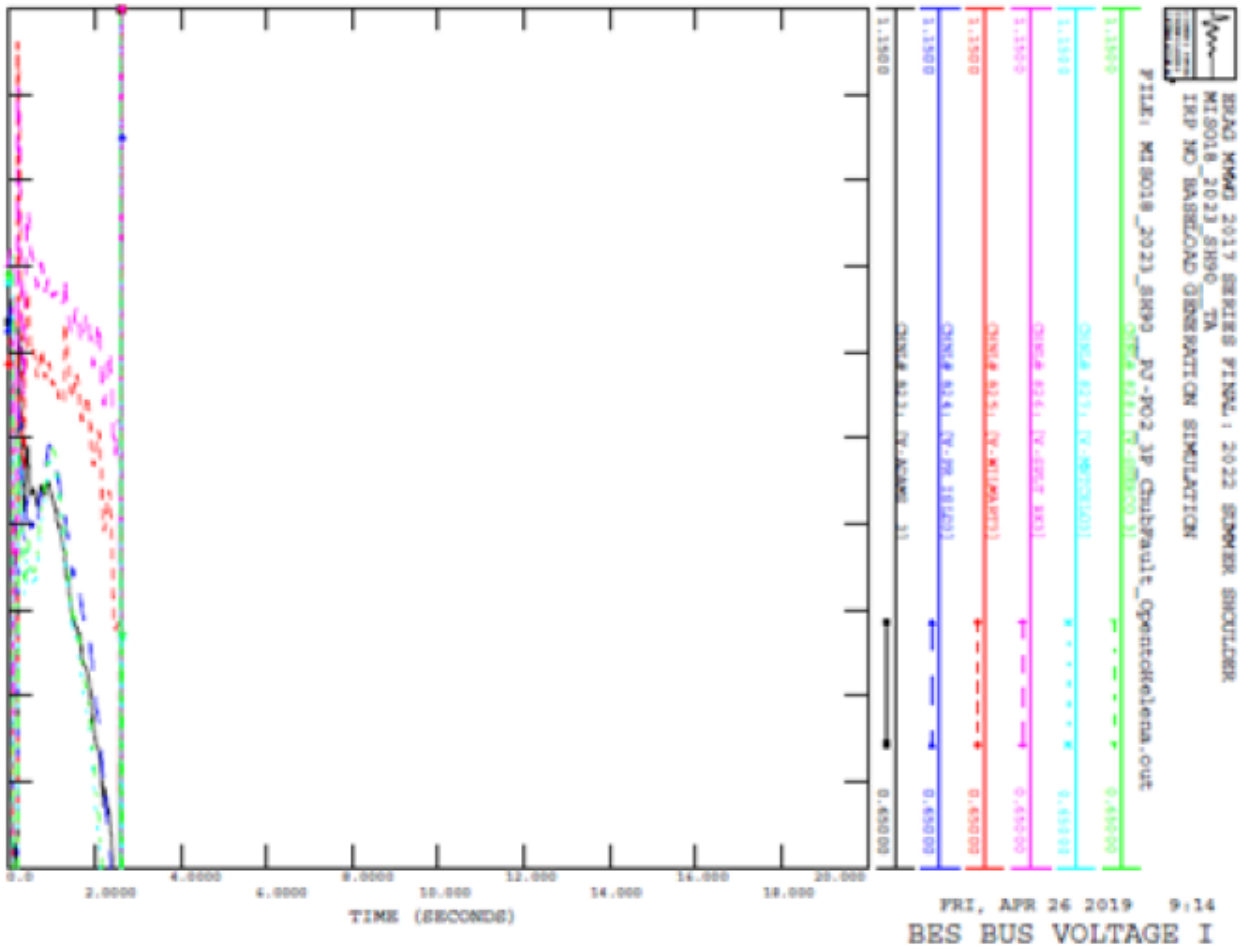
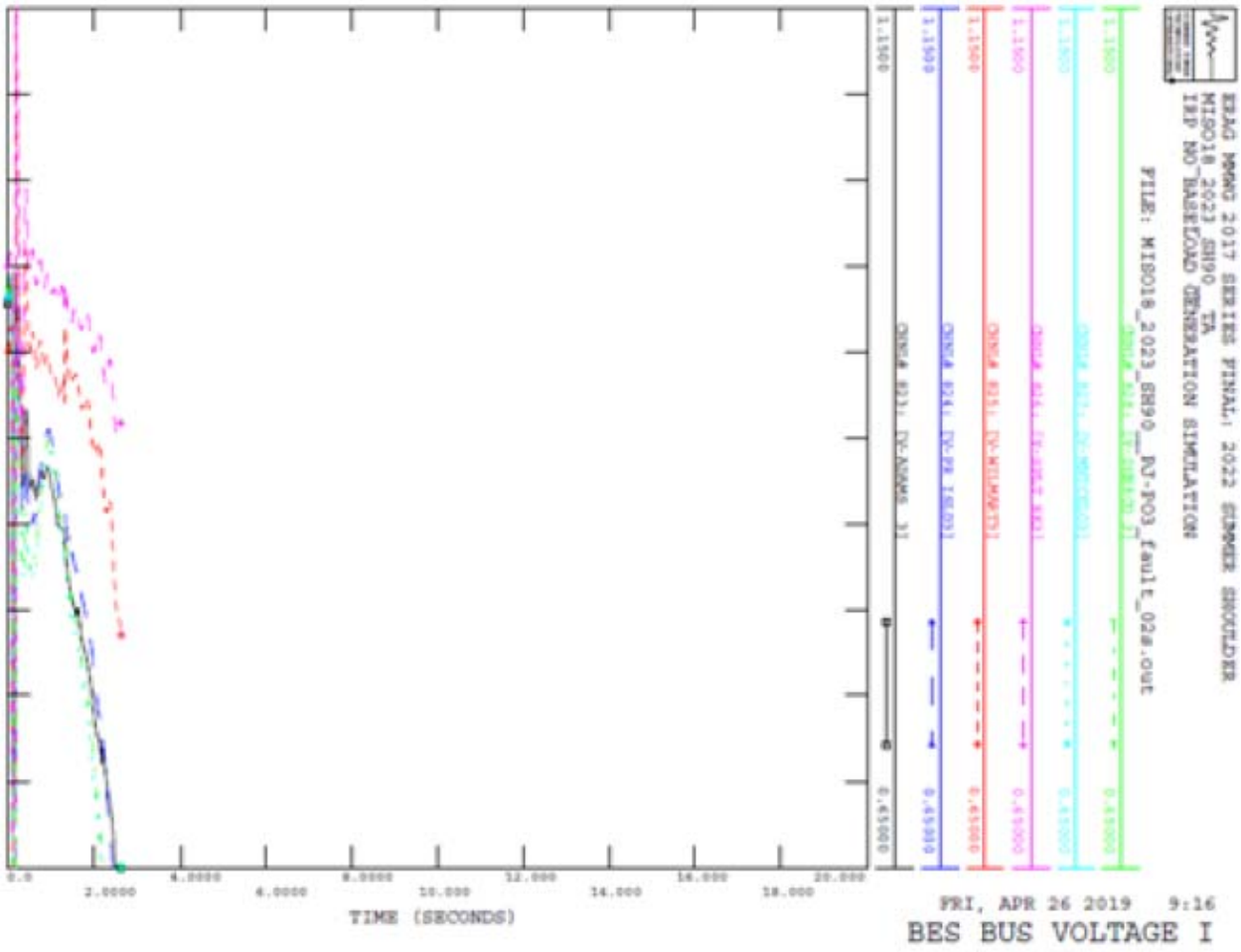


Figure 8: System Collapse – Summer 2023 P02 Case



4. Summary of Results

As shown by the results of this analysis, the reduction in synchronous generation resources on the NSP System can have wide-ranging impacts on system stability and reliability. In particular, the retirement of NSP System baseload units without similar replacements at or near their current locations results in insufficient margin on the system during summer peak scenarios, and system instability in light load scenarios.

The lack of system margin results in the inability of the system to recovery from any of the system events analyzed in either the base summer peak scenario or the prior outage summer peak scenario. This lack of margin is also evident when analyzing the loss of a major source to the Twin Cities metro area. If enough of these sources are unavailable, the system can become unstable, even with non-NSP System base load generation resources available as they are today.

In addition to the reliability and stability implications of insufficient resource availability in the correct locations, heavy reliance on renewable resources located only in the highest capacity factor locations results in a less resilient system. In these scenarios, utilizing the current transmission system results in a single point of failure that can result in an inability to operate the system. Additional transmission development will likely be necessary to improve system resilience and facilitate increased levels of renewable resources in the Upper Midwest.

These two efforts help to better understand the impacts of increased baseload retirement on system stability and reliability trend toward the same conclusion. Without sufficient dispatchable and synchronous generation resources available to maintain sufficient margin, the system cannot remain stable resulting in even minor disturbances leading to the potential for cascading failures and system collapse. In addition, increased reliance on renewable resources without utilizing current interconnection rights and transmission system capabilities will result in significant transmission expansion required to maintain system reliability and ensure the safe, resilient and cost effective delivery of power.

G. Strategist Baseload Economic Analysis

To help inform our Preferred Plan with an economic view of an orderly, cost—effective baseload retirement schedule, we developed fifteen Strategist scenarios with varying combinations and timing of baseload unit retirements. These scenarios also identified the size, type, and timing of new resources needed to continue meeting customers' needs and achieve our 2030 carbon reduction goals.

We compared these scenarios to a Reference Scenario, which is essentially an extension of our most recent Resource Plan with respect to all of the baseload units retiring at their currently scheduled retirement dates.[31] These scenarios are generally grouped into "families," which we outline below. First, however, we summarize the retirement dates for the respective baseload units in the Table 11.

[31] The Scenarios and Sensitivities are discussed in Chapter 5: Economic Modeling Framework and Appendix F2: Strategist Modeling Assumptions & Inputs.

Table 11: Economic Analysis – Baseload Unit Retirement Date Assumptions

Baseload Unit	Current Schedule/ Reference Case	Early Retirement	Life/License Extension
A.S. King	2037	2028	NA
Sherco Unit 3	2040	2030	NA
Monticello	2030	2026	2040
Prairie Island Unit 1	2033	2024	2043
Prairie Island Unit 2	2034	2025	2044

Early Coal Family. These scenarios are designed to evaluate the economics of retiring King and/or Sherco 3 early.

- Scenario 2 *(Early King)* – King is retired early; Sherco 3 and the nuclear units are unchanged.
- Scenario 3 *(Early Sherco 3)* – Sherco 3 is retired early; King and the nuclear units are unchanged.
- Scenario 4 *(Early All Coal)* - King and Sherco 3 are retired early; the nuclear units are unchanged.

Early Nuclear Family. This family of scenarios is designed to test the economics of retiring Monticello and/or Prairie Island early, either alone or together – and with the combination of early coal retirements.

- Scenario 5 *(Early Monticello)* – Monticello is retired at the end of 2026; coal and Prairie Island are unchanged.
- Scenario 6 *(Early Prairie Island)* – Prairie Island is retired by the end of 2025; coal units and Monticello are unchanged.
- Scenario 7 *(Early All Nuclear)* – Prairie Island and Monticello are both retired early; coal units are unchanged.
- Scenario 8 *(Early All Baseload)* – All baseload units (coal and nuclear) are retired early.

Extend Nuclear Family. This family of scenario is designed to test the economics of re-licensing Monticello and/or Prairie Island and extending the operational life by ten years beyond the current end of license dates.

- Scenario 9 *(Early Coal, Extend Monticello)* – All coal is retired at the early dates; Monticello is extended for 10 years; Prairie Island is unchanged.

- Scenario 10 *(Early King, Extend Monticello)* – King is retired early; Monticello is extended for 10 years; Sherco 3 and Prairie Island are unchanged.
- Scenario 11 *(Early Coal, Extend Prairie Island)* – All coal is retired early; Prairie Island is extended for 10 years; Monticello is unchanged.
- Scenario 12 *(Early Coal, Extend All Nuclear)* – All coal is retired early; Monticello and Prairie Island are extended.
- Scenario 13 *(Extend Monticello)* –Monticello is extended; King, Sherco 3, and Prairie Island are unchanged.
- Scenario 14 *(Extend Prairie Island)* – Prairie Island is extended; King, Sherco 3, and Monticello are unchanged.
- Scenario 15 *(Extend All Nuclear)* – Both Monticello and Prairie Island are extended; King and Sherco 3 are unchanged.

After identifying the scenarios for analysis, we utilized the Strategist modeling tool to identify sets of resources needed to continue to meet customer needs for each scenario, along with their resultant costs and emissions impacts. We also included the planning level mitigation cost estimates from the MISO Y2 studies – and we applied the Reliability Requirement, discussed in detail in Appendix J2.

From a modeling perspective, the Present Value Revenue Requirement (PVRR) and Present Value Societal Cost (PVSC) results are primary indicators of the economics of various scenarios, or paths forward. The modeling indicated that the nuclear extension scenarios paired with early coal retirements yielded the most attractive present value compared to the Reference Case. This economic view of various options provided helpful insights that informed the Preferred Plan we propose in this Resource Plan, which correlates to Scenario 9.

In summary, the baseload retirement aspects of our Preferred Plan include:

(1) Retirement of our remaining two coal units early: King in 2028 (nine years early) and Sherco 3 in 2030 (ten years early).

(2) Operating our Monticello unit through 2040 (10 years longer than its current license) and operate both Prairie Island units through the end of their current licenses (PI Unit 1 to 2033 and PI Unit 2 to 2034).

We discuss results of our Strategist modeling in more detail in Chapter 4: Preferred Plan and Appendix F2: Strategist Modeling Assumptions & Inputs of this Resource Plan.

V. CONCLUSION

We believe the increasing trend toward a clean energy future, along with rapidly advancing technologies and aging generation assets will significantly change the generation mix in Minnesota and across the United States over the next 15-plus years. We have done a comprehensive analysis of the impacts of cost-effective and orderly retirement of our baseload fleet in compliance with the Commission's Order – and in support of our clean energy vision. The results of this Baseload Study informed the Preferred Plan we propose in this Resource Plan, which includes the following baseload actions: (1) Retire our remaining two coal units early – King in 2028 (nine years early) and Sherco 3 in 2030 (ten years early), and (2) Extend the operation of Monticello nuclear 10 years through a license extension, to 2040.

Through this work we believe the retirement of our current baseload units must be orderly, and will be impacted by decisions other MISO generation owners make regarding their baseload units. It will be important to maintain sufficient firm dispatchable, load supporting resources to support integration of renewable resources, and ensure customer reliability and system resilience. Changes in the MISO planning construct are necessary to properly recognize the inherent variable and intermittent nature of renewable resources in meeting customer needs every hour of every day. Finally, we also believe significant new regional transmission development will be necessary to support increased levels of renewable resources and to support the retirement of baseload units.

APPENDIX J2 – RELIABILITY REQUIREMENT

As the Company increases the amount of renewable generation on our system, it is important to recognize that these resources cannot alone reliably provide customers the energy they demand every hour of every day, or maintain the stability of the grid. Until such time as new technologies develop to fully transition the grid to carbon-free resources, some level of load-supporting, firm dispatchable resources is necessary for grid resilience and customer reliability.

As penetration of variable and intermittent resources like wind and solar increase on the grid, it requires a new planning paradigm. The traditional method of planning on a capacity-basis for a single system peak will no longer ensure we meet our customers' needs in every hour. Our planning needs to become energy-oriented and be able to match available generation and customer load as available resources and customer load go up and down every day. A winter peak, while much lower than summer, can be just as challenging to meet if we do not have sufficient resources at the time of the peak. The January 2019 polar vortex is an example of this – but severe winter weather is not the only time this issue can occur. As we discuss below, it can also occur on an otherwise normal winter or summer day.

This planning concern is not limited to the NSP System, but rather across all of MISO's footprint – and in other regions with increasing levels of renewables. Although MISO recognizes these challenges, its current planning constructs do not fully incorporate measures to address them. We have therefore developed a Reliability Requirement to inform this Resource Plan and mitigate risks to customer reliability and system resilience as MISO determines how to incorporate these issues into its planning process. The Reliability Requirement will ensure we have a sufficient level of dispatchable load supporting resources that can quickly respond to fill gaps between customer demand and energy supply at times of low or non-existent renewable generation. In short, it ensures that we can serve customers with reliable energy every hour of every day.

Below, we discuss the specific system conditions and events we believe call for the addition of the Reliability Requirement. We also discuss how we derived this requirement, and how we applied it in the modeling underlying this Resource Plan. Because the Reliability Requirement involves consideration of the level of market reliance we can reasonably depend on, we start with an overview of MISO and its resource zones.

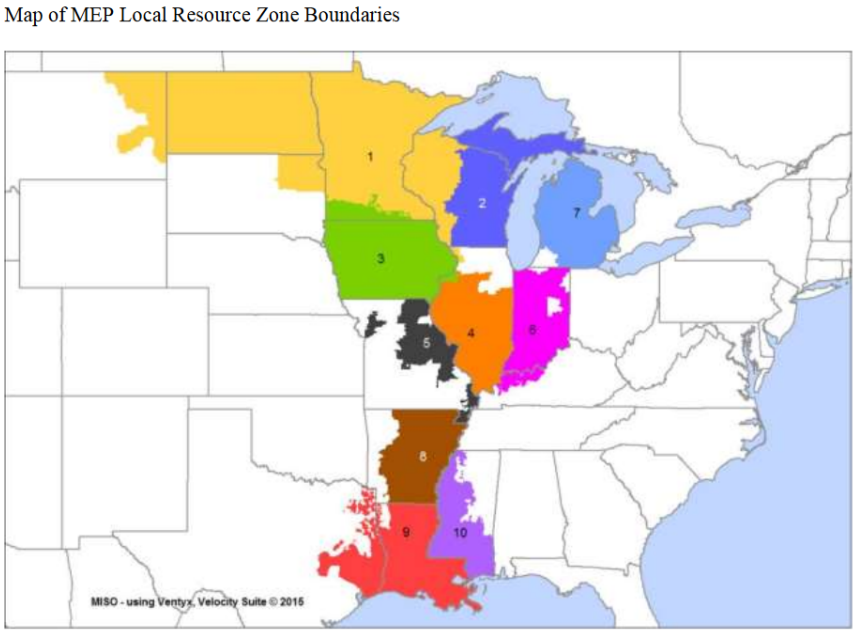
I. MIDCONTINENT INDEPENDENT SYSTEM OPERATOR OVERVIEW

The current wholesale energy market in MISO is a subsection of the Eastern Interconnection, which is the electric transmission grid that spans from the east coast of the United States to the central plains and from the Hudson Bay in Canada to the Gulf of Mexico. Wholesale energy markets, including MISO, rely on a large pool of resources with geographically diverse needs and resources that aim to allow excess resources in one part of the footprint to meet customer demand in another through use of the transmission grid. This diversity helps to mitigate the need to locate generation in close proximity to areas of demand, and can level variability in renewable resources by taking advantage of weather differences across the entire market's footprint.

While today's interconnected grid of transmission facilities reliably transfers large amounts of energy over long distances to meet customer demand, the grid was not originally developed to serve regular (*i.e.,* "base system") customer demand across distant geographies for significant durations throughout the year; nor was it designed to serve customers from densely-sited renewable generation, like it does now. And while these individual systems are interconnected, the there is not sufficient transmission infrastructure to be able to operate the MISO footprint like one of the original utility footprints. Therefore, one of the reliability measures that MISO instituted was to develop Local Resource Zones (LRZ) and inter-LRZ transfer limits to ensure ongoing reliable system operation.

The Figure below portrays the geographic diversity of the current MISO footprint and shows the different LRZs by number and color.

Figure 1: MISO Local Resource Zones



Source: Attachment WW of the MISO Tariff.

The NSP System is in LRZ1 along with Dairyland Power Cooperative, Great River Energy, Montana-Dakota Utilities, Minnesota Power, Ottertail Power Company, and Southern Minnesota Municipal Power Association.

This has worked well, however, the fundamental nature of the resource side of the equation is changing, which drastically changes the dynamics on the grid. There are more distributed, intermittent generating sources – and large synchronous generating units are retiring from the system. Inverter-connected resources at high levels of penetration generally do not provide the system services necessary for utilities to operate reliably. Without the inertia from the large generating units, system stability could be compromised – and the system is much more susceptible to the effects from what traditionally would have been inconsequential disturbances. As the level reliance on these interver-based resources continues to increase, new approaches to system planning are needed, as the current state of those processes cannot sufficiently address the differences in these resource types.

II. CURRENT MISO RENEWABLE CAPACITY VALUE DETERMINATIONS

On today's system, MISO has an annual processes to assign capacity values to generating resources that vary by resource type, and that establish resource adequacy

requirements for load serving entities such as the Company. These values come from the availability of the resource type as evaluated over a long base of operating experience at a specific hour of the year. The set of resources with specific performance attributes are put into a Loss of Load Expectation (LOLE) study and mixed with simultaneous probabilities (i.e. Monte Carlo type analyses) of when those outages may occur across the grid. This analysis also considers transmission performance capabilities and thus probabilities of loss of a transmission element. These analyses combine to ensure that the chosen resource mix and the specific grid will allow for load to be served to a load loss standard usually of no more than one day loss in 10 years. These capacity valuation mechanisms include the MISO Effective Load Carrying Capability (ELCC) analysis[1] and Wind and Solar Capacity report. The resource capacity values are commonly known as "accredited" amounts of capacity that can be relied upon to meet customer demand for planning purposes. MISO's resource adequacy process also establishes the margin by which the Company's resources are required to exceed demand in order to cover potential uncertainty in the availability of resources or level of demand.

If there are larger amounts of resources with the same performance attributes included in this analysis, the probability of loss of all those resources at the same time increases – and thus, the probability of impact on the load loss standard increases. For transmission for example, a consideration is the proportion of longer lines, which are more susceptible to weather or other types of disruptions, compared to shorter lines. As we discuss in more detail below, this is the reason that higher proportions of intermittent or variable resources erodes the capacity value for *more* of that resource – because the probabiblity of loss increases. Diversity in the type and location of a resource mix has always been important, and that will only become more important as the grid continues to evolve.

MISO's current resource adequacy requirements do not consider this expected marginal decline in load carrying capability from renewables as penetration increases, which we believe could ultimately result in a resource deficiency. The capacity accreditation also does not take into account the seasonal and weather-related variability that we have observed in both winter and summer instances, where renewables have vastly underperformed their expected contribution to load. In these circumstances, firm dispatchable, load supporting resources have been needed to fill the gap. Our Reliability Requirement is intended to recognize this new normal that is emerging. We outline the current MISO processes that determine resource adequacy requirements and capacity accreditation for wind and solar resources below.

[1] ELCC is a measure for estimating a resource's capacity value to meet customer needs with no net change in reliability.

A. Loss of Load Expectation Study

A Loss of Load Expectation (LOLE) study is intended to assess the overall probability that there will be a shortage of power, and is defined as the expected number of days per year for which the available generation capacity is insufficient to serve the demand at least once per day. The MISO LOLE is performed annually, analyzing a two-year horizon. From this study, several threshold requirements used in resource planning efforts are established for the following year – including a margin of resources the Company is required to maintain over and above its expected customer demand. This resource adequacy margin is the amount of generating capacity, over-and-above expected customer load that needs to be present on the system to ensure reliability in all but the most extreme circumstances; this margin does not however, currently account for the intermittent nature of renewable resources. As we describe below, renewable resources are assigned an accredited capacity value based on their annual average contribution to the system peak, rather than their ability to contribute to customer needs every hour of every day.

After these general obligations have been determined, we consider the type of resources suitable to meet that requirement. MISO's tariff and business practices set forth procedures to enable various types of resources to be used to achieve our requirement. These resources are referred to as "Planning Resources," which include the following sub-types:

- *Capacity Resources*: Physical Generation Resources (i.e. physical assets and purchase agreements), External Resources if located outside of MISO's footprint, and Demand Response (DR)resources participating in MISO's energy and operating reserves market, available during emergencies.
- *Load Modifying Resources*: Behind-the-Meter Generation and Demand Resources available during emergencies, which reduces the demand for energy supplies coming from the load-serving entity (LSE).
- *Energy Efficiency Resources*: Installed measures on retail customer facilities designed and tested to achieve a permanent reduction in electric energy usage while maintaining a comparable quality of service.

The Planning Reserve Margin (PRM) process establishes PRM values on both an installed capacity (ICAP) basis, which reflects the nameplate capacity of a resource, and on an unforced capacity (UCAP) basis, which incorporates the resource's operation, maintenance and utilization characteristics. Utility planning for system needs, including the planning we do as part of Minnesota Integrated Resource

Planning process, focuses on UCAP values, so we can plan to the measure of a resource's reliable contribution to system needs.

Physical generating resources and registered DR are assigned a UCAP value by applying a discount to their installed capacity. For a generator, the discount represents its forced outage rate. For DR, MISO uses a documented process of assessing the resource's observed responsiveness and effectiveness at reducing load. Intermittent Resources—including large-scale Solar, Wind, and Hydro–are assigned UCAP values that are determined by the individual unit's historical performance during the peak hours of the planning period.[2] As we discuss above, we are entering a new planning paradigm, and planning for a single system peak will no longer ensure customer reliability.

B. Wind and Solar Capacity Credit Report

Using the data from the LOLE study, MISO creates an annual Wind and Solar Capacity Credit Report that establishes MISO-wide capacity values for all wind and solar resources for the next planning year. MISO currently uses a probabilistic analysis as the first step in determining the ELCC for wind and solar resources. The second portion of the analysis utilizes a deterministic approach using historical wind resource output data, which incorporates the resource location. Combining these two sets of analyses, MISO then aggregates the characteristics to the nearest Commercial Pricing Node (CPNode) to determine a localized Wind Capacity Credit for each CPNode.

The 2018 report utilized installed wind capacity as of June 30, 2018, which included 18,210 MW of nameplate generating capacity assigned to 215 individual CPNodes. The values from this report are intended for incorporation into the following planning year – in this case, 2019. These values are as follows:

- Wind Capacity Credit (MISO system-wide):[3] 15.7%
- Solar Capacity Credit:[4] 50%

[2] Currently, these units are measured on historical performance during the operating hours of 1500 to 1700 in the months of June-August over the three most recent summers. Each site must have one complete historic period of data prior to unit accreditation.

[3] The calculation of the Wind Capacity Credit is the Individual CPNode Capacity Credit % = Peak Metric * K, where K is the coefficient representing the ratio between the calculated ELCC and the sum of the individual CPNode peak metrics.

[4] As of December 2018, MISO had a registered total of 313 MW of installed solar capacity. Because of the relatively low volume, MISO assigns each new solar unit a 50 percent capacity credit until additional operational data is available.

MISO also conducts studies on an LRZ-level to ensure regional reliability.

C. Relevant Regional Planning Considerations

MISO has the largest geographical footprint of any regional transmission organization. This provides valuable geographic diversity and access to additional resources when needed for back-up purposes. However, there are limitations on the amount of energy that can be shared between LRZs, and the amount of energy that can be imported or exported between MISO and other regional transmission organizations. As a result, MISO has developed localized studies that address the resources needed within each LRZ, as well as the limitations on transferring energy between LRZs, as follows:

- *Local Reliability Requirement.* This value is calculated to determine the amount of resource capacity needed on a LRZ level to ensure reliable service of customer demand during peak usage.
- *Capacity Transfer Limitations.* Capacity Import Limitation (CIL) and Capacity Export Limitation (CEL) values are determined through a capacity transfer study that signals the levels of capacity that can be both imported into a LRZ and exported to a LRZ while maintaining reliability.

Despite its broad geographic diversity, MISO remains susceptible to variations in resource availability based on, among other things, weather. As we have explained, today's interconnected grid is not the same as the traditional utility-specific grids that were built to serve local customer loads. There is not sufficient transmission infrastructure within MISO to transfer any resource type any distance – nor can it import limitless resources from other regional grids. Weather has taken out all of a certain type of resource – specifically wind, in the case of the 2019 polar vortex. Similarly, a day in July 2018 was an especially windless day and in one hour, the wind turbines that were online were taking more power than they were producing. This hour was also part of an approximately *110 hour* sustained stretch in which the combined output of all wind resources in the MISO footprint fell well below the accredited values used in present planning processes.

Individual utilities therefore must consider what level of reliance on the MISO market is reasonable to fulfill their system needs without exposing their customers to potential shortfalls or high prices, particularly in the event of high system stress conditions. We take our responsibility to ensure we have access to a sufficient level of resources in all grid conditions to meet our customers' needs seriously. The future

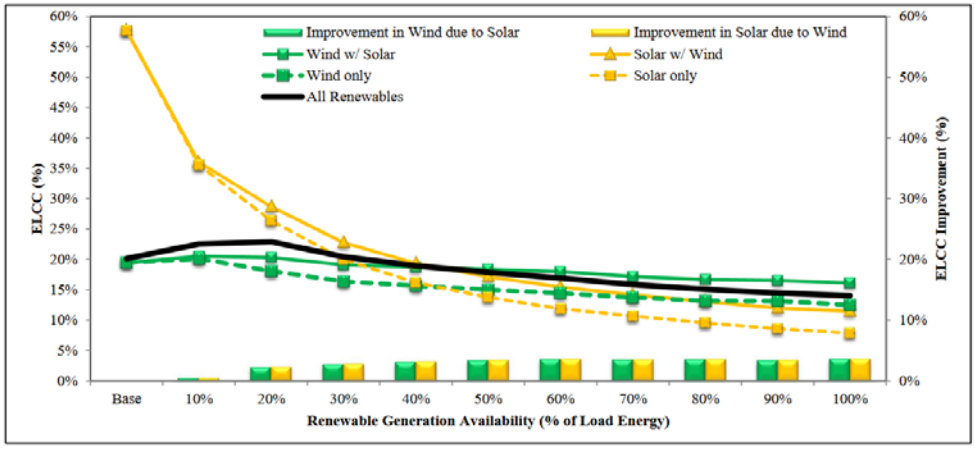
MISO grid will rebalance the new resource mix and the new transmission configuration needed to support it. We expect there will be many transitional stages between now and then to achieve this resource shift reliably. Determining our level of market reliance as part of our Reliability Requirement is a necessary part of this transition.

III. HIGH LEVELS OF RENEWABLES RESULT IN DECLINING CAPACITY VALUE

The industry is beginning to recognize and adapt planning processes to incorporate declining capacity values for wind and solar resources as penetration levels increase. However, MISO has not yet changed its planning processes to account for these limitations.

In 2017, MISO initiated its *Renewable Integration Impact Assessment* (RIIA) to examine issues surrounding effective integration of high levels of renewable resources. The figure shown below is an excerpt from an April 18, 2018 MISO presentation showing that, as wind and solar approach 100 percent penetration, their ELCC values decline significantly and approach 10 percent. When the generation fleet is diversified by including both wind and solar, the relative ELCC value for each is higher, but there is still a significant decrease in value as combined penetration approaches 100 percent.

Figure 2: MISO RIIA Study Finding –
Declining ELCC Value for Wind and Solar Resources



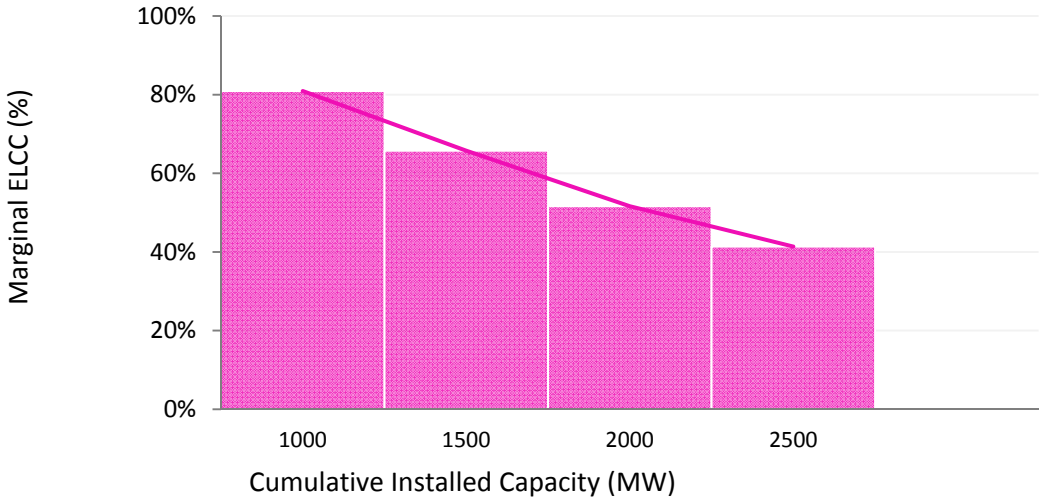
Source: MISO April 18, 2018 RIIA presentation at page 8.[5]

Notably, solar and wind are not the only resources whose capacity values decrease as

[5] https://cdn.misoenergy.org/20180418%20PAC%20Item%2003d%20RIIA174068.pdf

penetration increases. As shown in the analysis performed by E3 in connection with this Resource Plan, demand management programs also have decreasing relative effectiveness as participation increases.

Figure 3: E3 Marginal ELCC (%) – Four-Hour Demand Response



Source: E3 RECAP Analysis

Although early in the process and mainly focusing on their Resource Availability and Need (RAN) initiative,[6] MISO also recognizes that its current approach of using historical load shapes to predict the long-term future is no longer sufficient as Distributed Energy Resources (DER), Demand Response (DR), and energy efficiency become more prevalent. MISO likewise acknowledges that impact of these resources on demand, energy, and corresponding load shapes needs to be better understood and accounted for in its planning construct.

IV. RECENT ACTUAL LOW RENEWABLES PERFORMANCE EVENTS

In addition to these future planning – or accreditation – limitations, the actual performance of renewable resources reveals certain limitations with their ability to ensure reliability under all conditions and at all times without the support of some amount of dispatchable generation. To show this, we consider a number of actual case studies from the last 12 months below.

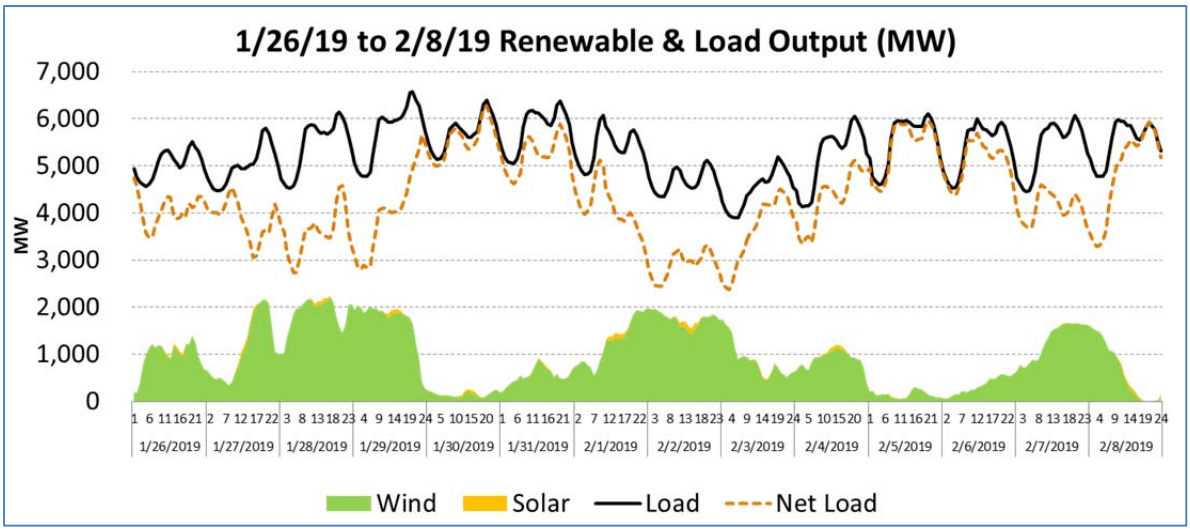
[6] The purpose of the MISO RAN initiative is to assure the conversion of committed capacity resources into sufficient energy every hour of the Planning Year.

A. Winter Case Study Events

In the past, winter months traditionally matched well with renewable resource production. In winter, we typically experience lower system demand and increased transfer capabilities, (meaning the ability to effectively transfer large amounts of renewable energy from where it is produced to load centers such as the Twin Cities Metro area). Additionally, wind resources generally achieve their highest efficiencies of the year over the winter months. However, as the penetration of renewable resources in the Company's fleet has increased and taken on a growing role in base energy production, winter has become an increasing concern. As we discuss below, during the 2019 polar vortex and an otherwise "normal" winter (and summer) day, firm dispatchable resources were needed to fill sustained periods of time where renewable resources were not producing at their accredited levels.

Given the variability of renewable generation, we have encountered times when the net customer load (which is the amount of customer demand not being met by renewable generation and for which firm dispatchable resources are needed) is near, or even equal to, the gross demand on the system. As shown below, this was the case during both the January 29-31, 2019 polar vortex, which was an extreme weather event marked by historically-severe and sustained cold temperatures combined with high winds, as well as February 5, 2019, a normal winter peak period.

Figure 4: Renewable Output and Load
January 26 – February 8, 2019



This illustrates why planning for a single system peak no longer works. We have to also plan to meet our customers' energy requirements on a net load basis – or the gap

between customer needs and variable resource availability every hour of every day.

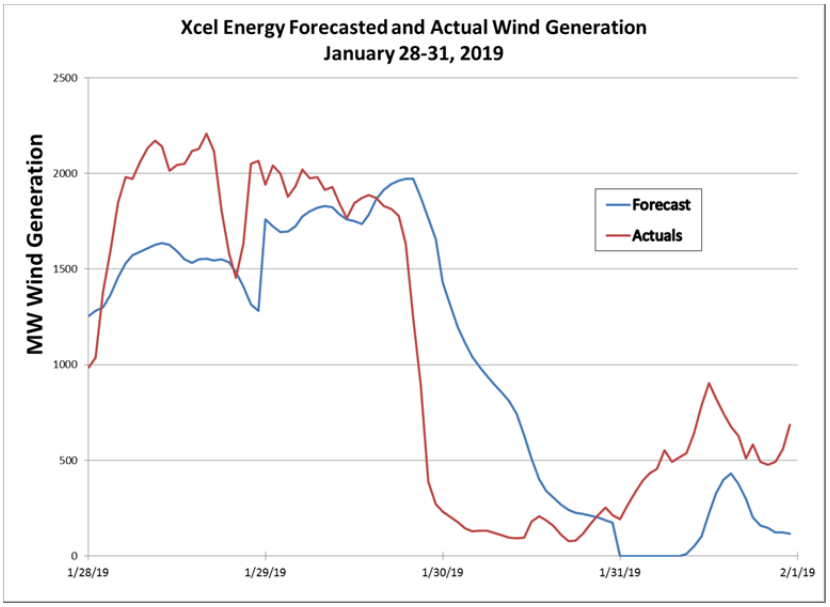
1. Extreme/Polar Vortex Event

The January 28 to February 1, 2019 timeframe, referred-to as the 2019 Polar Vortex, was marked by extreme cold temperatures over a sustained period of time across the northern United States, and specifically within the MISO footprint. The MISO region experienced ambient temperatures well below zero degrees Fahrenheit (F) for several consecutive days, with temperatures falling well below -20 degrees F in some areas. During this period, MISO experienced a resource deficiency and relied upon external resources and load control measures to reliably operate the system and balance generation resources with customer demand. Due to the duration and magnitude of the resource shortfall, neither DR nor energy storage could substantially contribute to reducing the Net Load.

The overwhelming majority of wind turbines now have operating temperature cutoffs at approximately -22 degrees F. MISO, however, did not have established measures to account for these limitations. As a result, and because of the high wind speeds during the polar vortex event, the MISO wind forecast projected upwards of 14 GW of wind generation to be online. However, the vast majority of wind turbines shut down in the early morning hours of January 30th, and output dropped to approximately 3 GW sooner than the forecast had predicted. As a result, firm dispatchable resources were needed to fill the gap left by the lack of wind.

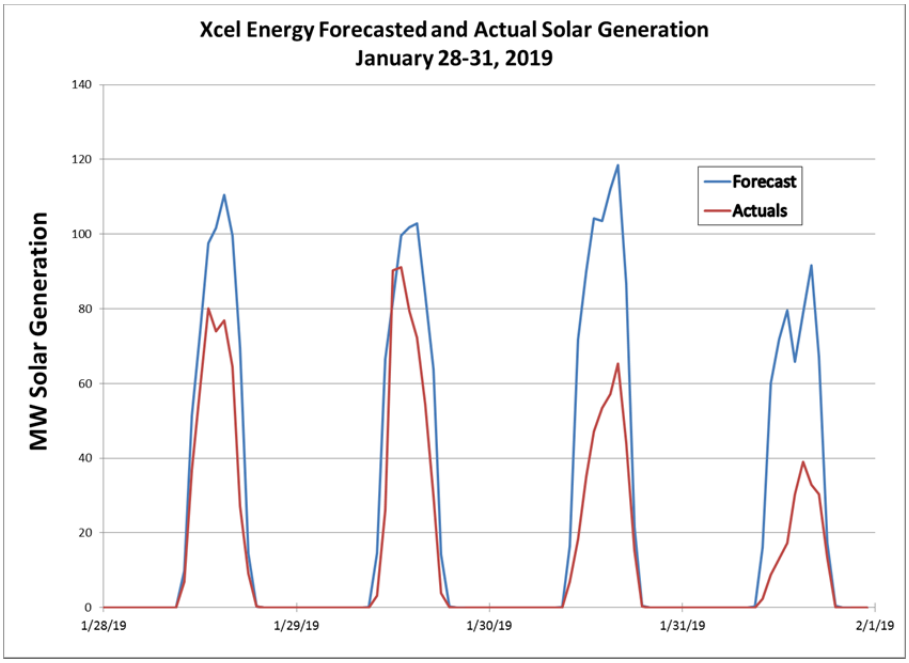
Figure 5 below shows the Xcel Energy wind actuals compared to the forecast during this period, which we note closely mirrored the MISO forecast and actuals.

Figure 5: Xcel Energy Wind Generation Actuals vs. Forecast
January 28-31, 2019



Solar generation performance is also affected by temperature, but does not involve cold weather cut-offs. Rather, solar panel efficiency drops off steadily once *panel* temperatures exceed approximately 42 degrees Celsius (107 Farenheit). Panel temperatures are typically approximately 20 degrees Celsius higher than the ambient air temperatures, thus solar production efficiency starts to decline when the ambient air temperature is in the range of 87-91 degrees Farenheit. PV Solar panel production works most efficiently during cold temperatures, with the obvious caveat that cloud cover and/or snow on the panels will reduce solar generation. We provide as Figure 6 below, a comparison of the Xcel Energy solar actuals compared to the forecast during the polar vortex period.

Figure 6: Xcel Energy Solar Generation Actuals vs. Forecast January 28-31, 2019



This solar forecast compared to actuals chart indicates a forecast error, especially for the last two days of the period. Our meteorologists attribute the error to a snow event at one of our larger solar facilities, where the conditions at the time were like those shown in Figure 7 below.

Figure 7: Snow Impacting a Large Solar Installation

Essentially, the solar panels that can "track" the sun are are built to maximize solar generation by continuously finding the optimal sun angle. Due to heavy snow in this situation, the panels were unable to move and the angle was insufficient to shed the snow cover, thus affecting actual production and not matching our forecast. In fixed-axis solar resources, there are options: (1) optimize to shed snow cover, which reduces the ability of that resource to produce energy; and, (2) optimize to output the most energy, which reduces its ability to shed snow cover. As we discuss below, winter solar performance is also affected by fewer light hours/shorter days and less optimal sun angles.

According to a report compiled by the MISO Independent Market Monitor (IMM), during this timeframe the MISO footprint used resource "reserves," which consisted of non-firm resources offered by neighboring regional transmission organizations into the MISO market. The level of these resources that MISO had to use to remain operational and avoid further emergency actions ranged from 5,000 MW to 11,500 MW – with an average of 6,500 MW on January 30th. The maximum offered reserve resources was 13,500 MW, which MISO nearly exhausted at one point in order to avoid a critical deficiency in available energy.

Although extreme, this weather event may reasonably be expected to occur again, and a disruption in electric service during a similar event in the future would have detrimental and serious impacts on our customers and public safety in general. We therefore believe this case study provides an important, recent example to consider as

we manage the transformation of our generation portfolio while prioritizing the reliability and stability of our system.

2. Normal Winter Day

In addition to cold temperatures affecting wind production, snow cover and icing also decrease wind and solar output in winter months; non-ideal sun angles and shorter days, and thus limited light hours, additionally impact solar production. While the polar vortex involved extreme weather conditions that affected wind production especially, February 5, 2019 was a normal winter day that offers another example where Gross Load was at, or near, Net Load (Gross Load minus contributing renewable resources) for a significant number of hours.

Between 7:00 a.m. and 11:00 p.m., there were 16 consecutive hours where Net Load was over 5,400 MW. Due to the duration and magnitude of this shortfall, neither DR nor energy storage could substantially contribute to reducing the Net Load, at least for the entire period. During this period, all wind and solar resources on the system combined to have an average hourly capacity factor of *six* percent, and there were particular hours when neither wind nor solar resources had a capacity factor greater than *three* percent. We provide the hourly capacity factors for wind and solar resources below.

Table 1: Hourly Wind and Solar Capacity Factors
February 5, 2019

Hour Ending	Wind Capacity Factor	Solar Capacity Factor
1	9%	0%
2	9%	0%
3	6%	0%
4	5%	0%
5	7%	0%
6	6%	0%
7	7%	0%
8	4%	0%
9	3%	0%
10	3%	3%
11	2%	6%
12	3%	6%
13	3%	5%
14	7%	5%
15	12%	4%
16	13%	2%
17	11%	1%
18	11%	0%
19	9%	0%
20	6%	0%
21	5%	0%
22	4%	0%
23	3%	0%
24	4%	0%

Because we currently have access to sufficient baseload and firm dispatchable resources on our system, we were able to serve customers reliably and affordably throughout the duration of this period.

3. Other Winter Conditions

In considering the resources available during periods of low wind generation, the Company also needs to assess availability of resources across MISO. The MISO footprint encompasses large areas that experience snow cover and extreme low temperatures in the winter months. This impacts the output of renewable resources throughout MISO in several ways.

Wind turbines are designed to cut-out at extreme cold temperatures to protect their operational mechanisms. During the 2019 Polar Vortex, temperatures dropped below the -22 degree F cutoff, causing wide-spread reduction of wind resources despite relatively high wind speeds.

Snow cover and icing negatively impact solar and wind generation resources. As discussed above, during the winter months in the Upper Midwest, snow and ice cover on solar panels significantly decreases the energy capabilities of those resources. Wind turbines are susceptible to blade icing, which causes decreased output or complete cessation. While these issues are limited to certain geographical areas, those same areas highly correlate with the most dense and highest average capacity-factor renewable resources in the MISO footprint.

Limited light hours combined with non-ideal sun angles reduce the output of solar resources in winter months. These conditions are prevalent throughout the MISO footprint, which combine to reduce the output of solar resources to fewer hours of the day, and lower levels of energy output when the sun is available.

B. Normal Winter Day Case Study Extrapolated to Higher Levels of Renewables

Consistent with our vision for 100 percent carbon-free energy in 2050, we studied these scenarios with higher levels of renewable resources than exist today. To do so, we replicated the operational scenarios encountered on February 5, 2019, but modeled with 5,000 MW of nameplate capacity wind and 5,000 MW of nameplate capacity solar resources. The results were very similar. For 13 of the 16 hours, the Net Load remained above 5,300 MW and all hours exceeded 5,000 MW of Net Load.

C. Non-Winter Case Study Event

Because low temperatures and other conditions unique to winter are not the only cause of low renewable generation in MISO, we also looked to the summer months as potential case studies. July 29, 2018 was an especially windless day. During the 8:00 a.m. hour, the entire MISO wind portfolio (over 17,000 MW at that time) had a combined output of *minus* 11 MW – meaning the wind turbines that were online were taking more power than they were producing. This hour was part of an approximately *110 hour* sustained stretch in which the combined output of all wind resources in the MISO footprint fell well below the accredited values used in present planning processes. We again encountered sustained low wind conditions in early 2019, with 370 hours of wind production below accredited values before May 1.

These case studies are supported by a recent University of Minnesota Research Brief about an initiative that examined conversion of home heating from gas to electricity – and supplying that electricity with renewable energy, which had been identified as a critical national decarbonization pathway.[7] The May 8, 2019 *Research Brief: Planning for the future of energy demand with renewable energy* reported that researchers at the University of Minnesota and three other institutions sought to understand whether enough renewable energy can be generated locally to meet most, if not all, of that increased electricity demand.

Researchers mapped out three scenarios: one that included battery and thermal energy storage options; an option that assumes no storage; and an option that overbuilds renewable supply by 150 percent of demand. They then ran models using data from four cities in three different climate zones, including Minneapolis, Minnesota.[8] The study found that for scenarios without storage, wind-based supply dominates the optimal mix for Minneapolis. The study also found that when 12-hour storage is available, renewable penetration increases from 54 percent to 70 percent in Minneapolis. In light of these findings, the Brief stated:

> However, no matter the scenario, the study found that the use of fossil fuels would still be needed to meet peak demand in cold climates like Minneapolis and Fort Collins. This is because renewable energy cannot be produced at the rate needed to meet demand during the coldest months..

Finally, the Brief reported that researchers suggest policymakers and/or low carbon energy system planners do the following:

- Take into account the geographic and climatic differences when finding the optimal mix of wind and solar generation,
- Consider incentives to invest in battery storage systems, which will increase the overall amount of demand that can be met with renewables,
- Count on a smaller, but nonetheless important, role for fossil fuel plants to meet peak demand.

V. KEY TAKEAWAYS

As this data shows, today's intermittent generating resources cannot alone meet

[7] *See* https://twin-cities.umn.edu/news-events/research-brief-planning-future-energy-demand-renewable-energy

[8] Other cities were New York City, New York, Fort Collins, Colorado, and Tallahassee, Florida.

demand at all times of the year, at least without excessive costs.[9] Even during historically good times of the year for renewable generation on the Company's system, the availability of these resources is inexorably tied to the variability of weather patterns, and at times they are simply not available.

Additionally, current storage technologies and demand management programs are also insufficient to meet the duration of real events like those discussed above. Current battery storage systems are limited (typically to 4 hour discharge periods) with significant time needed to recharge. Unless overbuilt many times over, these resources would not be able to provide energy for the full duration of such events; they also may not be able to recharge fast enough to be a viable resource during the consecutive periods of low renewable output. Similarly, and as discussed above, some of the most significant current demand management programs are specifically designed to reduce capacity needs during the system's overall peak during summer hours, and they would not be as effective, or effective at all, during winter periods.

These case studies and industry insights have highlighted gaps in present MISO planning constructs that – until MISO adapts – we must take into account to ensure system resilience and customer reliability. Fundamentally, we have a responsibility to ensure we have access to a sufficient level of firm dispatchable resources in all grid conditions that can flexibly adapt to variable renewable resource performance to meet our customers' needs. We take this responsibility seriously. We view these case studies as highlighting gaps in the present MISO planning construct. Until MISO determines how best to address these gaps, we believe it is incumbent on us as the utility to take steps to ensure that our system is resilient, that our customers will be reliably served, and that our customers are reasonably protected from high financial exposure in the market when the system is under stress.

VI. DEVELOPING THE RELIABILITY REQUIREMENT

In an effort to mitigate resilience and reliability risks, we analyzed the data from these case studies and created a reliability requirement for our modeling that reflects a reasonable amount of reliance on MISO resources and demand response to meet our system needs. The intent of this requirement is to supplement our system planning process to ensure we have sufficient resources available to reliably serve our

[9] Simply increasing the amount of solar and wind generation on the Company's system is an unrealistic approach to addressing capacity shortfalls. In order to have sufficient capacity to meet the customer demand discussed in the scenarios above, the Company would need in excess of 180,000 MW of nameplate capacity wind and solar generation. And, even this amount of renewable generation may be insufficient given the declining capacity value of renewable generation, as discussed above, and the probability there will be times with extremely low levels of wind and sunlight.

customers' energy needs every hour of every day – regardless of weather.

Establishing this reliability requirement involves a number of steps:

1. Establishing a level of peak demand to serve as a proxy for the most likely conditions where we would expect to have a gap between renewables performance and customer load.
2. Assessing the contribution we can reasonably expect from duration-limited resources like DR or energy storage to fill-in the gap.
3. Determining the extent to which it is reasonable, from a financial and operational risk perspective, to rely on the MISO market to make-up at least a portion of the gap.
4. Using these inputs to derive the level, of firm dispatchable resources that are needed to reasonably assure reliability. It is this level of firm dispatchable resources that ultimately forms the Reliability Requirement that we incorporated into our modeling for this Resource Plan.

We discuss the components of this calculation below.

A. Proxy Peak Demand

The first step in determining the Reliability Requirement was to approximate the customer peak demand we should expect during inevitable high stress MISO market scenarios. Although winter is not the only season in which we have experienced low renewable output relative to expected contributions, it is when we most expect weather conditions to impact wind turbine and solar panel performance (i.e. blade icing and snow cover). We therefore determined that the NSP System winter peak demand – or approximately 6,400 MW – would be an appropriate proxy and starting point to ultimately determine the resource types and amounts that we can reasonably rely on to fill the gap.

B. The Role of Duration-Limited Resources

Today, the Company is able to draw on DR and likely in the future, other time-limited resources such as storage to meet our customer needs. But, while these resources can help fill the gap to some extent, it would not be prudent or practical to fully rely on them to guarantee system reliability.

As discussed above, demand management programs have lower availability in winter months. As with all components of the Reliability Requirement, the DR proxy was

designed to avoid unrealistic assumptions of demand response availability. This proxy, therefore, allows for the support of demand management programs up to the point where they can no longer be considered firm resources. We included a demand response proxy of approximately 200 MW in our modeling.

C. MISO Market Reliance

As noted above, resources from the MISO market may also be available to fill the gap between customer load and low renewables performance, although transfers within and between LRZs are constrained in accordance with MISO's identified system capabilities. This is a valuable benefit of being part of a regional market. However, we expect that that other resources and loads in MISO and LRZ1 will experience similar conditions – particularly if an event is weather-related. We do not believe it would be reasonable or in our customers' best interest to rely on the market to fulfill the resource gaps caused by the unavailability of intermittent resources – especially in high-stress scenarios. It is therefore important to determine an appropriate and reasonable level of reliance on market resources during a high-stress scenario. Notably, these high stress times frequently happen in periods of extreme cold when our system is even more critical than normal. This market reliance issue will only become more important as utilities retire firm dispatchable resources that today aid reliability during these times of system stress.

Using a combination of MISO planning data and the IMM analysis of excess resources during the 2019 Polar Vortex event, we derived a level of MISO market reliance for the NSP System to incorporate into our RRP calculation.

Table 2: Planning Parameters to Derive NSP System Level of Market Reliance – High Stress Scenarios

Relevant Planning Parameter	2019-2020 Planning Year Values
MISO Peak Demand	125,501 MW
LRZ1 Peak Demand	17,780 MW
NSP System Peak Demand	9,129 MW
NSP System Peak as Percent of MISO	*7.27%*
NSP System Peak as Percent of LRZ1	*51.3%*
Polar Vortex Event – Minimum Excess Resources	5,000 MW
Polar Vortex Event – Average Excess Resources	6,500 MW
NSP System Share of Excess Resources (7.27% of Min. and Avg. Excess Resources)	364-473 MW
NSP System Market Reliance Level	**500 MW**

From the IMM analysis of the 2019 Polar Vortex event, we know the minimum (5,000 MW) and the average (6,500 MW) MISO-wide excess resources that were used during this event. These are important values to understand, as they were the level of excess non-firm resources made available from outside of MISO and needed by MISO to avoid a critical energy deficiency.

If similar operational events and system demands were experienced across large areas of the full MISO footprint during a high-stress event, and assuming that reliance on external resources would be split based roughly on each utility's portion of total demand, the Company would be able to rely on only 7.27 percent of any excess generation in the MISO system. Therefore, to derive the NSP System share, we applied the NSP System load ratio share to the minimum and average levels of excess resources from this event, which equates to a minimum of 364 MW and an average of 473 MW. From here, we assumed some additional customer efficiency might lower our peak or operational efficiencies might increase external energy available to the NSP System, and thus determined that 500 MW would be a reasonable level of MISO market reliance during a high stress scenario.

After approximating the contribution from these sources, we are able to determine the quantity of firm, dispatchable resources we need to maintain on the NSP System to assure reliability.

D. Some Level of Load Supporting Resources are Needed

The calculation of the Reliability Requirement results in a minimum level of firm

dispatchable resources necessary to adequately support customer loads. We discuss how we apply the Requirement to our modeling in Chapter 3: Minimum System Needs. We clarify here however, that while this concept is essential until MISO evolves its capacity construct, the Requirement has little effect in our modeling for this Resource Plan. The model does not select any firm dispatchable additions as a direct result of the Reliability Requirement until 2031, which is near the end of the planning period. This long runway leaves ample time for MISO and its stakeholders to address this aspect of its planning and provide additional direction.

That said, we demonstrate the calculation of the Requirement we applied in our modeling for this Plan in Figure 8 below.

Figure 8: NSP System Reliability Requirement Calculation – 2020 Example

Peak Demand Proxy – 6,400 MW
Minus Firm DR (Winter) Proxy – (200 MW)
Minus Firm Market Supply Proxy – (500 MW)

Reliability Requirement – 5,700MW
(Firm dispatchable resources)

We are confident that this is a reasonable and appropriate approach to determining a minimum level of firm dispatchable, load supporting resources necessary to maintain a reliable supply of power during high-impact low-frequency events like the 2019 Polar Vortex – as well as other typical summer or winter weather days that happen to have low renewable performance.

VII. SUMMARY

As the Company increases the amount of renewable generation in our system, it is important to recognize that these resources cannot alone reliably provide customers the energy they demand every hour of every day – or maintain the stability of the grid. MISO is beginning to recognize these challenges and that its current planning constructs do not yet address these issues. In the interim, our Reliability Requirement ensures we have the right mix of resources on our system every hour of every day to meet our customers' needs.

PUBLIC DOCUMENT
NOT PUBLIC DATA EXCISED

Attachment J3 is marked as "Non-Public" in its entirety and is provided with Critical Energy Infrastructure Information (CEII) redacted. Attachment J3 contains information regarding the MISO area grid, including specific information about the Xcel Energy and other transmission owner systems as it relates to the potential retirement of Xcel Energy's Allen S. King and Sherburne County Generating Plant (Sherco) Unit 3. While MISO has redacted all CEII from the report, Xcel Energy maintains that the balance of the information is "security information" as defined by Minn. Stat. § 13.37, subd. 1(a).

Pursuant to Minn. R. 7829.0500, subp. 3, the Company provides the following description of the excised material:

1. **Nature of the Material**: Prepared study.
2. **Authors:** The study was prepared by MISO.
3. **Importance:** The study contains security information.
4. **Date the Information was Prepared**: The study was finalized November 14, 2018

NOT PUBLIC DATA EXCISED

PUBLIC DOCUMENT
NOT PUBLIC DATA EXCISED

Attachment J4 is marked as "Non-Public" in its entirety and contain redactions to CEII for the same reasons noted for Attachment J3. Xcel Energy maintains that the balance of the information is "security information" as defined by Minn. Stat. § 13.37, subd. 1(a).

Pursuant to Minn. R. 7829.0500, subp. 3, the Company provides the following description of the excised material:

1. **Nature of the Material**: Prepared study.
2. **Authors:** The study was prepared by MISO.
3. **Importance:** The study contains security information.
4. **Date the Information was Prepared**: The study was finalized November 27, 2018

NOT PUBLIC DATA EXCISED

APPENDIX K – XCEL ENERGY RESOURCES: NUCLEAR

I. NUCLEAR

Carbon-free nuclear generation has been a cornerstone of our generation fleet for nearly fifty years, and its continued role on our system is critical to ensuring that we continue to make progress in reducing our carbon emissions. Our Preferred Plan therefore includes the extension of operations at the Monticello nuclear plant until 2040, along with the continued operation of Prairie Island through its current operating licenses (which expire outside the planning period in 2033 and 2034). By continuing the operation of these plants and extending our Monticello license, we can continue to drive the substantial carbon-free benefits that our nuclear fleet provides while saving our customers money by leveraging existing assets on our system that are leading the industry in terms of performance.

In this section, we discuss the importance of our nuclear generation fleet to our environmental and resource planning objectives. We also provide an update on the strong performance of our nuclear fleet since our 2015 Resource Plan, as well as our capital and O&M forecasts, and we discuss the results of our Strategist modeling in connection with our nuclear strategy. Finally, we discuss the economic, community, and employment benefits associated with relicensing Monticello, and we outline the regulatory processes associated with relicensing at the NRC and seeking authorization from this Commission to obtain additional dry fuel storage capacity to support extended operations.

A. Nuclear's Role in Reducing Carbon Emissions

Xcel Energy has been on the path toward significant carbon reduction for more than a decade and, since 2005, we have reduced carbon emissions 38 percent company-wide. In order to achieve our goal of an 80 percent reduction of carbon emissions by 2030, we need to retire our coal-fired generation before 2030, replace those assets with low- or no-carbon resources, and preserve the carbon-free generation that is already part of our system. Our Monticello and Prairie Island nuclear plants—which total 1,688 MWs in baseload capacity—comprise more than half of our existing carbon-free generation and one-third of our total generation. Our reliance on these

plants avoids the emission of 7 million tons of carbon dioxide each year, which is equivalent to removing 1.5 million cars from the road (or more than 20 percent of all registered vehicles in Minnesota as of 2016).

The Company simply cannot achieve similar levels of carbon reduction without nuclear generation on our system. As discussed in our Baseload Study, we will need a significant amount of firm dispatchable generation on our system in order to ensure around-the-clock reliability as we move toward a portfolio that is predominantly renewable and intermittent. We therefore believe any near- or medium-term replacement of our nuclear resources would require some amount of incremental natural gas generation, which would negatively impact our progress on reducing carbon emissions. Moreover, given MISO's current transmission expansion issues, it is far from certain that we could get sufficient renewable projects through the MISO queue in time to replace our nuclear resources. And even if that were possible, it would require substantial renewable additions beyond those already contemplated in our plan, along with supporting transmission infrastructure. Replacing the carbon free energy from Monticello with renewable resources would require over 1,000 MW of wind or nearly 3,000 MW of solar resources along with $400 million in additional transmission investment based on our Resource Plan assumptions. Additionally, these energy only replacement estimates do not account for additional capacity costs that may be required to firm the renewable replacement or local reliability costs that would be required in the event of a Monticello retirement. The costs of adding these resources would have a significant impact on the overall cost of our Preferred Plan and would very likely jeopardize our ability to achieve the carbon reductions we envision.

We recognize that technological developments like energy storage hold great promise and that reliable, renewable baseload energy may be on the horizon. Like others, we are excited by storage technology and its potential to further transform our system, and we are taking steps as part of this Resource Plan to ensure that we are prepared to take full advantage of better technology in the future. But these technologies are still developing and, while approaching economic on a smaller scale, are not yet economic at a scale amounting to even a fraction of our nuclear fleet. For this reason, we view nuclear as a resource that will facilitate our transition to even greater renewable

generation and storage opportunities in the longer term, while we continue to pursue aggressive carbon reduction in the near-term.

Meanwhile, our nuclear fleet adds important diversity to our generation portfolio and provides a hedge against not only gas price volatility but also the uncertainty of technological development, future renewable pricing, and the future of solar capacity values. It is also a critical piece of our reliability requirement, as it is not a fuel limited resource, is not subject to pipeline limitations during the winter season, and has a strong operating history during cold (and hot) weather events. Indeed, our nuclear fleet operated at 100 percent capacity factor from January through April of 2018 and again in early 2019 during the Polar Vortex, before Monticello began to coast down in advance of its April refueling outage. Similarly, the summer months of 2018 and thus far of 2019 saw the nuclear fleet operating at full power during peak summer loads.

B. Flexible Operations Pilot

In addition to providing the carbon-free baseload energy we have relied upon for nearly 50 years, we also believe our nuclear units can be operated more flexibly in the future to complement a generation portfolio that will be predominantly renewable. In fact, we are currently piloting an operational strategy to reduce the power output of our nuclear plants when wind and solar resources are generating significant energy.[1] Historically, natural gas plants and, more recently, coal units have been "ramped" up and down to balance energy demands with the amount of renewable energy available on the system at a given time. For decades, nuclear plants have been considered "must-run" baseload power in the context of the MISO regional power market, and we therefore have focused on running at maximum power around the clock. Today, given the increasing additions of renewable resources on our system, we believe our nuclear plants can provide additional value if they can be ramped down during periods of high congestion and low prices. By doing so, the Company can take full advantage of the renewable resources on its system—both now and in the future—and can deliver even greater value from our carbon-free nuclear plants.

[1] We are also part of an industry working group on Flexible Power Operations at EPRI to gain insight from around the industry on this issue.

In 2018, the Company launched an initiative to demonstrate our nuclear fleet's ability to enter MISO's "Day Ahead" market and successfully maneuver one unit at Prairie Island between 75 percent and 100 percent power. Working with MISO, Prairie Island Unit 2 maneuvered through a series of power adjustment and simulated its participation in the Day-Ahead market, and we have since demonstrated similar operational flexibility at Prairie Island Unit 1 and Monticello. In fact, Prairie Island Unit 1 is already participating in the MISO Day Ahead market, and we expect Monticello to join that market in September and Prairie Island Unit 2 to join it in the fall after its refueling outage. In total, this means we will be able to ramp our nuclear fleet by approximately 400 MW, which will add significant operational flexibility to our overall fleet.

We believe the timing of this transition in our nuclear operations is aligned with the Company's plans to incorporate significant wind additions over the next two years, as we complete the build-out of our 1,550 MW Wind Portfolio and our Dakota Range facility. Nuclear has proven its value as the foundation of our baseload fleet, and its carbon-free generation make it a critical part of our plan to achieve an 80 percent reduction in carbon emissions by 2030. We view flexible power operations as an expansion of nuclear's role in our fleet and in the Company's efforts to integrate substantial amounts of renewable additions during the planning period.[2]

C. Performance & Costs

More than ever, we understand that the future of our nuclear fleet depends on our ability to deliver performance at a reasonable cost. Since our 2015 Resource Plan, we have undertaken substantial efforts to adopt wide-scale changes in the way we approach plant operations —with the goal of "bending the cost curve". And with the assistance of third-party consultants with expertise in both nuclear operations and general cost containment and efficiency strategies, as well as our continued work with the Institute of Nuclear Power Operations (INPO) and Nuclear Energy Institute (NEI), we have achieved industry-leading results not only in the performance of our

[2] We are also in the early stages of exploring the possibility of using nuclear energy to produce hydrogen, which in turn could be used both in the transportation sector and as energy storage. Xcel Energy has partnered with two other utilities to explore the economics and overall feasibility of nuclear-driven hydrogen production, and an $8 million funding request is currently pending with the Department of Energy's Light Water Reactor Sustainability Group.

nuclear plants but also in the costs we are investing to achieve that performance. In short, our nuclear plants have never operated on a more consistent, efficient, and safe basis.

1. Safety

Beginning with safety, the NRC Reactor Oversight Process classifies U.S. nuclear reactors into various "Columns," which range from 1 (best) to 5 (worst). Both Monticello and Prairie Island are Column 1 plants with all green performance indicators. And while no plant can achieve the standards of perfection imposed by the NRC at all times over its operational life, we believe our track record demonstrates the Company's longstanding commitment to nuclear safety. Further, during the 2R30 refueling outage in 2017, Prairie Island achieved its best industrial safety record (no OSHA or First Aid injuries) and the lowest occupational radiation exposure in plant history, and both plants have received the Governor's annual safety award for several years running.

2. Capacity Factor

With respect to plant availability, Monticello achieved an average capacity factor of 96.5 percent over the past three years, including a record-setting 99.3 percent in 2018. Likewise, Prairie Island achieved a combined average capacity factor of more than 90 percent over the past three years, including a 100 percent capacity factor for Unit 2 in 2018. This data reflects strong and improved performance at both plants, and the increased availability of our plants drives substantial customer benefits given the fixed costs associated with nuclear fuel. Contributing to these capacity factors was improved performance during plant refueling outages, which were completed on time and on budget. For example, in 2017, Prairie Island's Unit 2 achieved a 37-day refueling outage, which is that unit's shortest refueling duration in 10 years. Likewise, we have experienced some of the longest runs of uninterrupted operation in the history of our nuclear fleet, including a record-setting 499 days at Prairie Island Unit 1 in 2016-2017, and a current run of 583 days (as of June 27, 2019) at Prairie Island Unit 2. In fact, Prairie Island Unit 2 is currently on the third longest run in plant history.

3. O&M and Production Costs

Importantly, we have achieved these safety and operational results without increasing our production costs. In fact, both O&M and total production costs at our plants have decreased significantly in recent years. Total O&M for our nuclear fleet went down by $7 million between 2015 and 2016. It then decreased again by another $26 million in 2017, and decreased yet again in 2018 by another $8 million.

In terms of production costs (fuel plus O&M) per MWh, we achieved reductions of more than 20 percent between 2015 and 2018.[3] Specifically, our fleet average nuclear production costs have gone from $37.86 per MWh in 2015 down to $29.44 in 2018 (Prairie Island has gone from $37.08 down to $28.53, and Monticello has gone from $39.11 down to $30.91).

Contributing to these results has been Xcel Energy's commitment to driving efficiency through its XE1 initiative, which focused on process development and refinement and the integration of technology to achieve efficiencies. Industry experience shows that successful nuclear organizations are highly process and outcome driven and that focused process improvement has the benefit of driving down costs while at the same time improving plant performance. Through our work with the external consultants and INPO, we have been able to effectively improve upon a number of processes and personnel behaviors that has enabled the plant to achieve better results with fewer resources.

4. Capital

We have also completed a long-term re-analysis of our capital budgets for both Prairie Island and Monticello, and we have made significant changes to our capital forecast relative to our 2015 resource plan. In our 2015 resource plan, we stated that our projected capital spend for Prairie Island was outpacing the estimates included in our 2012 Changed Circumstances filing. We specifically noted that our five-year capital expenditure forecast from 2016 through 2020 had increased by roughly $175 million above what was anticipated in 2012, and that our forecast for the 13-year period from 2021 through 2034 would likely need to increase by roughly $600 to $900 million. At

[3] These reductions in our nuclear production costs are directionally consistent with the nuclear industry as a whole, which has achieved a more modest average reduction of approximately $5/MWh since 2012.

the same time, we noted that our O&M costs were lower than previously modeled and that those decreases in O&M offset the increases in forecasted capital spend.

Today, we are in a position to materially reduce our capital forecasts. To date, we have spent $77 million less at Prairie Island than we anticipated in 2015. And relative to that 2015 Resource Plan budget, we now forecast spending approximately $475 million less in capital at our nuclear plants from 2019 through their current licenses relative to our 2015 forecast (approximately $245 million less at Prairie Island and about $230 million less at Monticello during this period, excluding incremental spend required for the ten-year extension).

The updates to our forecast reflect several years of work by numerous Company employees, leadership, and external consultants, as well as a recognition that we had to re-envision our approach to nuclear operations if our plants were going to remain competitive. The forecasts are based on a detailed, long-range capital budgeting process that was undertaken following our last Resource Plan. As part of this process, teams from nuclear engineering and capital projects assessed the condition of our plants and developed a long-range project forecast to support continued operations and aging management. These teams then worked with nuclear finance to develop budgets to support project needs, and probabilities were assigned to the various projects reflecting the likelihood each would be necessary to maintain the reliability of our plants. We then worked with independent consultants with expertise in nuclear operations to assess both our budgeting process and the overall level of our capital budgets, in order to ensure that our forecast were reasonable and aligned with industry norms.

We recognize that our stakeholders and the Commission will continue to monitor our performance and investments relative to our forecasts, and we anticipate an in-depth discussion regarding our Monticello forecasts in the context of a future certificate of need filing for additional dry cask storage. We anticipate filing that petition in the mid-2020s, at which point we will have an even longer track record of performance both in terms of capacity factors and spend. We look forward to demonstrating that our nuclear plants can continue to drive both environmental performance and benefits for our customers.

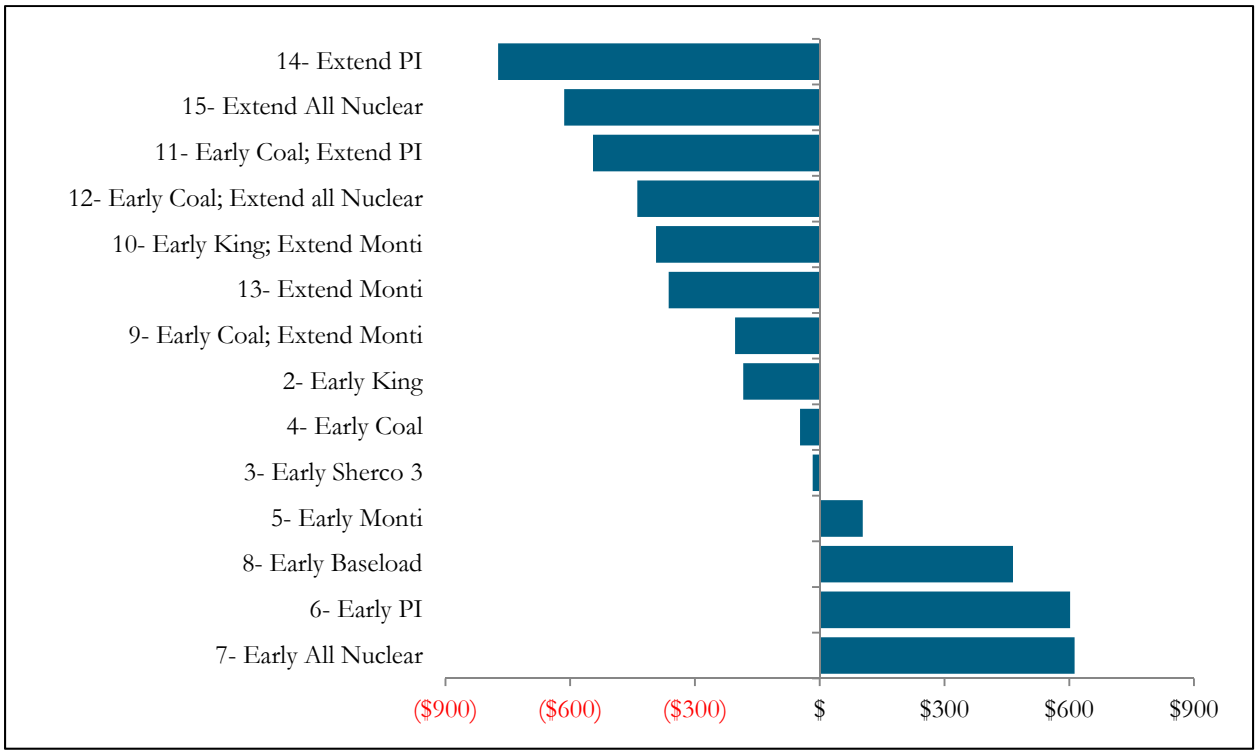
D. Benefits of Relicensing

Our Preferred Plan includes the operation of Prairie Island through its current licenses (expiring in 2033 and 2034) and a ten-year extension on the operation of Monticello (through 2040). The Strategist modeling of our plan demonstrates both that the continued operation of Prairie Island and the extension of Monticello are cost effective and expected to result in customer benefits. We discussed our Economic Modeling Framework in Chapter 5 but we briefly summarize the nuclear-specific results below.

As part of our economic analysis, we modeled scenarios that included early retirements, license extensions, and continued operation through current licenses for all three of our nuclear units. For the early retirement scenarios, we assumed a 2026 retirement date for Monticello and 2025-2026 retirement dates for Prairie Island Units 1 and 2, respectively. For license extensions, we limited our analysis to ten additional years of operations. While the NRC grants license extensions in 20-year increments, we believe it is prudent to limit our analysis to 10 additional years at this juncture, given the uncertainty of projecting more than 30 years into the future from both a budgeting and resource-planning perspective. Thus, the license extension dates are 2040 for Monticello, 2043 for Prairie Island Unit 1, and 2044 for Prairie Island Unit 2. We then combined these various scenarios with consideration of early coal retirements in order to develop a Preferred Plan.

In general, our analysis shows that extending operation of our nuclear plants is beneficial and least-cost when compared to other scenarios. The following table summarizes the Strategist results for each of the modeled scenarios:

Figure 1: Scenario PVRR Deltas from Reference Case ($2019 millions)



To be clear, our Preferred Plan is not the least cost scenario of the 15 options considered in terms of either PVSC or PVRR savings. The least-cost scenarios all include an extension of Prairie Island in addition to Monticello. But we believe the later retirement dates for Prairie Island—which are outside the planning period of the Resource Plan—give us additional time to consider this option before pursuing a license extension at Prairie Island.

Nevertheless, our Strategist modeling demonstrates that the extension of Monticello for an additional ten years is least cost and in our customers' interest. It also demonstrates that the continued operation of Prairie Island is superior to any of the early retirement scenarios. We believe these results provide strong support for our Preferred Plan and demonstrate the importance of our nuclear fleet from an overall resource planning perspective.

In addition to the economic benefits identified by Strategist, we believe it is also important to note the state, community, and employment benefits associated with our

nuclear fleet. Our plants employ approximately 1,400 staff in and around the Monticello and Red Wing communities, which translates into an estimated 4,200 additional jobs in other industries across Minnesota. The plants are also an important sources of tax base for their host communities, resulting in a combined total of approximately $42 million in state and local taxes annually. In total, Xcel Energy's nuclear operations contribute approximately $1 billion in annual economic benefits throughout the state. These and other benefits area summarized in NEI's April 2017 report titled "The Impact of Xcel Energy's Fleet on the Minnesota Economy," which looked at data from 2014-2016[4] and is included as Appendix O3.

In short, we believe our nuclear plants provide wide-ranging and substantial benefits not only to our customers but also the environment, the State of Minnesota, and the communities we serve. The continued operation of these plants, including a ten-year extension of operations at Monticello, is in the public interest, is consistent with state policy, and is necessary to achieve our carbon reduction goals at a reasonable cost.

E. Relicensing & Certificate of Need

Although 2030 is more than a decade away, the NRC relicensing process is a long-term project that must be commenced during the five-year action plan of this Resource Plan. In this section, we discuss the NRC process of relicensing Monticello for an additional 20 years, as well as the Certificate of Need filing we will make for additional dry fuel storage.

The Atomic Energy Act authorizes the NRC to issue licenses for commercial power reactors to operate for up to 40 years.[5] These licenses can then be renewed for additional 20-year periods of "extended operation" under the NRC's License renewal rule (10CFR Part 54). Both Monticello and Prairie Island successfully received NRC approval for initial license extensions and are currently operating under the extended licenses. Approximately 90 percent of plants in the United States have already

[4] The 1,400 staff and $42 million in state and local taxes referenced above reflects updated information as through 2018.

5 Economic and antitrust considerations, not limitations on nuclear technology, determined the original 40-year term for reactor licenses. However, because of this selected time period, some systems, structures, and components may have been engineered on the basis of an expected 40-year service life. As such, a renewed license requires "aging management programs," to monitor and manage the effects of continued operation on these equipment and structures.

renewed their licenses once, extending their operation to 60 years. Most of these plants will soon reach the end of their 60-year term, and many are in the process of considering a subsequent license renewal (SLR), which would extend a plant's operation from 60 to 80 years.

To obtain an SLR, a plant must provide the NRC with an assessment of the technical aspects around plant ageing and demonstrate that it can continue to operate safely.[6] This includes review of system metals, welds and piping, concrete, electrical cables, and reactor pressure vessels. The renewal process also includes an evaluation of potential environmental impacts associated with an additional 20 years of operation. The NRC verifies evaluations through inspections and audits, and its review of license renewals is expected to last anywhere between 22 and 30 months.

That said, there is no requirement that the NRC complete its review within this time frame. There is, however, a five-year safe-harbor provision that allows operators to ensure that a plant's license will not expire during the NRC review process.[7] Specifically, 10CFR2.109(b) provides that the existing license for a plant will not be deemed to have expired during the SLR review process, provided that the licensee filed its application at least five years before the expiration of the current license. Additionally, we note that the NRC is currently reviewing three plants that have already submitted SLRs as part of a pilot program that is intended to pave the way for efficient processing of relicensing applications in the 2020s. We expect that the three pilot plants will receive license extensions in early 2020.

We intend to comply with the five-year safe-harbor in order to ensure that Monticello can continue operating throughout the entirety of the SLR review process. And because the five-year clock does not begin to run until an application is deemed "sufficient," we intend to submit our SLR application an additional six months early so that any completeness issues can be resolved before the five-year mark. Based on our experience with the first extensions for Prairie Island and Monticello, we further anticipate that it will take approximately three years to prepare the license renewal

[6] Each reactor's original license is based on a specific set of requirements, depending primarily on design. This set of requirements is called the plant's "licensing basis." The licensing renewal process provides continued assurance that the current licensing basis will maintain an acceptable level of safety for the period of extended operations.

[7] Once a license expires, a nuclear plant cannot return to operation, so it is important to comply with the safe harbor in order to avoid license expiration during the pendency of an SLR application.

application itself. This means we need to begin the SLR application process in mid-2021, so that we can submit the application to the NRC in mid-2024 (five-and-a-half years before the current license expiration in 2030.

We recognize that the Commission's ultimate decision as to the extension of Monticello will occur in the context of a Certificate of Need for additional dry cask storage, and we anticipate filing that petition in the mid-2020s when we are farther along in the SLR submittal preparation for the NRC review. However, because our work to prepare the SLR application will occur between 2021 and 2024, we are requesting that the Commission approve this work as part to of our proposed five-year action plan. In total, we estimate that the application renewal process will cost approximately $40-50 million, and we have accounted for this cost in our Strategist modeling. We will justify the reasonableness and prudency of these costs in a future rate case.

Meanwhile, we will continue to lead the industry in exploring used fuel strategies, including consolidated interim storage and transportation issues that may facilitate additional used fuel management options not yet available in the industry. Just two months ago, Xcel Energy hosted an NEI nuclear transportation table top exercise that simulated shipping casks across the county to an interim storage site. This first-of-its-kind exercise involved the participation of several organizations—including the NRC, state commissions, host communities, tribal governments, and other utilities—all of whom will be important partners as we work on fuel management options. Thus, while we have the expertise and facility to safely store used fuel on site at our plants into the future, we will continue to lead the industry in exploring alternative transportation and storage opportunities.

F. Conclusion

This Resource Plan filing represents the first of many steps that will be required to obtain the necessary approvals to extend the Monticello operating license. This process will involve an extended dialogue with our stakeholders and regulators, both at the NRC and our state Commissions. We look forward to engaging with our stakeholders around the role of nuclear in our energy future.

Our specific request in this Resource Plan is to approve a five-year action plan that includes the preparation of an SLR license application, so that we can proceed on a timeline that allows for the potential relicensing of Monticello until 2040. If the Commission approves this plan, we will be back in the coming years to seek a Certificate of Need for additional dry fuel storage. At that time, we would expect to have a more in-depth discussion regarding the detailed capital and O&M forecasts, as well as the impacts of continued operations on the local communities, the state, and our customers.

APPENDIX L – XCEL ENERGY RESOURCES: SHERCO CC

I. INTRODUCTION

We are moving forward with project development for a Combined Cycle (CC) gas plant at the Sherco site that will replace part of the capacity retiring at current Sherco Units 1 and 2, as discussed in our previous resource plan. The Sherco CC will give us an important firm dispatchable resource necessary to successfully reduce our Upper Midwest NSP System carbon emissions by 80 percent from 2005 levels by 2030 and transition to 100 percent carbon-free in 2050 – while ensuring reliable and affordable electric service to support our economy and communities. This transition will put us in many untested circumstances, where it will be critical to have viable system options to provide flexibility to respond. No one yet knows what that future looks like – and we are confident that it relies on technologies that are not yet developed. It is prudent and responsible, and our obligation as a public utility, to ensure we are planning and implementing viable infrastructure options that will help to drive a successful and economic transition to a stable future state.

Our previous Resource Plan stated that, in order to retire the coal-fired units, there were certain grid reliability issues that would need to be resolved, as well as community support objectives to meet. Those issues remain true today. There have also been several developments since our last Resource Plan that reinforce and highlight the system benefits the Sherco CC will provide.

Overall, building a new CC at the Sherco site is the most appropriate holistic solution to serve grid needs when the Sherco coal units retire, for the following reasons:

- It will provide system needs including voltage support, power deliverability, and system regulation in the absence of Sherco Units 1 and 2.
- It will provide replacement capacity for our black start restoration path.
- It will facilitate our carbon reduction plan in three ways. First, in providing the grid support the Monticello nuclear plant needs (and which will be absent if the Sherco Units are not replaced). Second, by facilitating the integration of large renewable additions contemplated by our Preferred Plan. Third, by avoiding the costly and lengthy transmission upgrades that would be required if we built new units on a greenfield site.
- It will satisfy, in part, the system's need for sufficient firm and dispatchable capacity as our coal units retire and do so in a way that is superior to CTs

because of the lower heat rate and emission profile.

- It will help us fulfill our commitments to the Becker community as we transition away from legacy coal-fired baseload assets.

We discuss each of these factors in more detail below, and we also provide an update as to the status of the Sherco CC project.

II. THE NEED FOR THE SHERCO CC AS DISCUSSED IN OUR LAST RESOURCE PLAN

In our last Resource Plan, we proposed to retire Sherco Units 1 and 2, which provide approximately 1,400 MW of stable, baseload generating capacity to our system. Given the amount of energy and firm capacity these two baseload units provide, we undertook an in-depth analysis to determine the grid needs that would arise upon their retirement.

The specific studies the Company undertook included an Attachment Y2 study, performed by MISO, and a separate study by Siemens Power Technologies International. The Y2 is a non-binding, informational study that identifies any reliability impacts of a potential future status change of a generating unit(s) – in this case, Sherco Units 1 and 2. The MISO Tariff requires that any generation retirement be studied and approved by MISO to ensure that it results in no adverse effects to the reliability of the system, and we commenced the Y2 study when we first contemplated retiring Sherco Units 1 and 2. The focus of this study was on the impacts to the broader MISO grid if one or both of Sherco Units 1 and 2 ceased operation.

We retained Siemens to study the effects of potential phased retirement of one or both Sherco Units on the transmission system, technical implications (including voltage analyses and transient stability analyses) and upgrade costs associated with replacement of one or both Units at alternate locations on the NSP System, and the potential impacts of the cumulative effect of additional larger generation unit retirements on the NSP System, in particular the Monticello Nuclear Plant due to its proximate location in Sherburne County and one Prairie Island Unit in combination with Sherco Units 1 and 2.

Below we briefly discuss the studies' findings and note that each of the issues identified by the retirement of the Sherco Units below is solved by the Sherco CC – holistically and at a prudent cost to our customers. For a more in-depth discussion of these reports, please see Attachment D to the Company's January 29, 2016

Supplement to its 2015 Integrated Resource Plan in Docket No. E002/RP-15-21.

A. Voltage Support

The Y2 study found that retiring the existing units (with no replacement solution) would result in significant violations of the prevailing voltage and thermal ranges. Analysis of bulk electric system (BES) impacts from new or changing generation and transmission facilities are measured against standards and requirements established and enforced by the North American Reliability Corporation (NERC), per authority from FERC.[1]

The real-time conditions on the transmission system are constantly changing and require ongoing adjustments to maintain voltages at required levels. As large synchronous power sources, Sherco Units 1 and 2 also provide system voltage support and reactive power. The system must be able to facilitate both "active" and "reactive" power. Active power, measured in watts, is the form of electricity that powers equipment. Reactive power, measured in volt-amperes reactive (VARs), is the energy supplied to create or be stored in electric or magnetic fields in and around electrical equipment. Reactive power is particularly important for equipment that relies on magnetic fields for the production of induced electric currents (e.g., motors, transformers, pumps and air conditioning). Due to physics, reactive power can be transmitted only over relatively short distances, and thus must be supplied as needed from nearby generators. If the correct level of reactive power cannot be supplied promptly and in sufficient quantity, voltages deteriorate and, in extreme cases, can result in a voltage collapse.

The issues identified by the Y2 study were significant enough that MISO would likely designate the units as System Support Resources (SSR) and not allow them to retire as planned, if an alternate mitigation was not in place. These violations would also be in conflict with the Monticello nuclear plant's operating license. To move forward with the Sherco retirements, MISO and/or the Nuclear Regulatory Commission (NRC) would require that the Company mitigate the identified voltage and thermal violations in another manner, generally requiring either new firm generation on site or significant transmission system upgrades.

B. Power Deliverability

The Siemens' analysis confirmed that the system operates well with significant

[1] We discuss NERC's role in more detail in Appendix J1: Baseload Study.

injection at the Sherco site and that replacing the retiring units at a different location would require transmission system upgrades and come with other tradeoffs (i.e. increased energy losses from a new unit placed further away from the Twin Cities' load center). Transmission systems are typically developed to receive significant amounts of power from specific injection sites and then move the power over long distances to meet areas of demand. This amount of power than can be moved is often referred to as "transfer capability," and changing generator characteristics or locations impacts the performance of the surrounding grid by impacting Transfer Capability.

Our system was designed to receive significant injections of power from the Sherco site and then deliver energy out from it to areas of customer demand, including the Twin Cities metro area. The Siemens study confirmed that replacement of Sherco Units 1 and 2 with a large generating unit that provides similar benefits to the NSP System as the existing Sherco Units (like a combined cycle) will cost-effectively meet the physical system requirement to ensure voltage, frequency, and reliable service for our customers.

C. System Regulation

The Siemen's analysis also addresses the heavy reliance of the system on Sherco Units 1 and 2 for system regulation. System regulation essentially refers to the ability of the system to maintain reliable operation through changes in usage and production. In other words, equipment that provides system regulation ensures that the grid is keeping generation and load in balance at all times.

To maintain this balance, there is a need for system resources that are flexible and responsive to dispatch signals. Currently, the system relies heavily upon units like Sherco Units 1 and 2 to provide this type of regulation. The overall system frequency, required to be maintained at 60 Hz in the U.S., is an active measure of this balance. When there are sudden large changes to the generation and load balance, such as a generating unit dropping offline or an event that disrupts operation of a transmission facility, the frequency of the grid can fluctuate up and down depending on the size of the disturbance. The grid requires sufficient system regulation, which means its ability to respond instantly to changes in usage – i.e., keeping the generator and loads matched at all times. Insufficient system regulation can cause disturbances like these to make the system unstable. However, the Sherco CC addresses these system regulation issues because of its electrical characteristics that provide this fast response balancing in real time, similar to Sherco Units 1 and 2 today.

D. Black Start

In addition to the needs identified by the studies discussed above, Sherco Units 1 and 2 also play a critical role in our system when it comes to black start planning. In the event of a major outage, the existing Sherco Units 1 and 2 units are an integral "Target Unit" in our grid restoration plan. Once an "Initial Unit" (i.e. the unit that jumpstarts the grid) is re-started, Sherco Units 1 and 2 can be started and run at low loads and provide the necessary capabilities to restart other key generators, such as Sherco Unit 3, in the restoration path.

Only dispatchable units of a certain size that are capable of creating and absorbing reactive power are eligible to provide this function, and there are few viable alternatives in our current system. Nuclear units, for example, can only come online after the system is fully stable, and thus are not used as Target Units. Renewable generation, such as solar and wind, are generally not able to provide these services effectively, nor for the duration needed to serve as the Target Unit, due to their inability to create and absorb sufficient levels of reactive power – and because they are weather-dependent and not firm and dispatchable. A large battery energy storage system can technically be configured to be capable of providing black start service, likely as part of a relatively small initial black start unit. However, current battery technologies may not yet be economically viable for this purpose. There are also technical concerns with regard to how batteries can absorb reactive power, which would be needed if the battery was not paired with another type of generation asset.

While the Blackstart Plan can be re-routed if needed, constructing the proposed CC at Sherco provides the most efficient restoration path, and avoids other upgrades that would be required to re-route the path. As we noted in our January 29, 2016 Resource Plan Supplement in Docket No. E002/RP-15-21, altering the path away from the Sherco site would require various equipment upgrades on our transmission system and potentially the addition of new generation elsewhere if transmission upgrades could not fully mitigate this need. Selecting a less efficient path would also lengthen the overall restoration period, which may result in other restoration challenges during cold weather events.

III. EMERGENT ISSUES IN THIS RESOURCE PLAN

Since the last Resource Plan, the system conditions discussed above and underlying our need for a new CC at Sherco have not changed in any material way. In fact, we see many of the reliability issues identified becoming more relevant and pronounced in light of our aggressive carbon goals and the transmission interconnection

constraints that have emerged in recent years. Below, we discuss the issues new to this Resource Plan, which we believe further confirm the need for the Sherco CC.

A. Monticello Extension

Extending the Monticello nuclear plant's operational life for 10 years past its current retirement date helps us retain zero emissions baseload power on the system while we integrate additional intermittent renewables (in particular, solar PV) in 2025 and beyond. However, as discussed in our last Resource Plan, we need a large grid-stabilizing resource to ensure we can operate Monticello within the requirements of our NRC operating license. And the transmission issues outlined in our previous Resource Plan filing have also not improved. In fact, the MISO generator interconnection queue is more congested now than it was in 2016, with substantial new renewable generation proposed but very little additional transmission capacity dedicated to integrating those resources. This would very likely impact our ability to site necessary stabilizing resources in a greenfield location near Monticello, and any new unit would likely be responsible for substantial transmission upgrade costs to interconnect to the broader grid—assuming it could even make it through the MISO queue in time to facilitate a 2026 retirement of Sherco Unit 1.

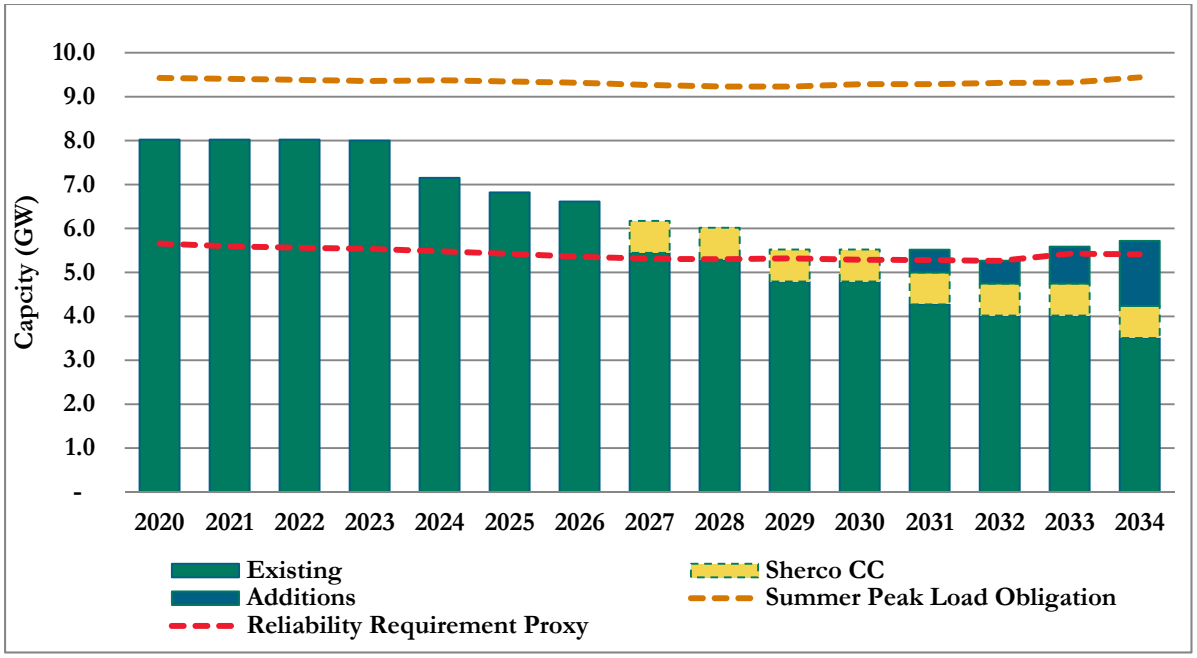
B. Reliability Requirement

Not only is the Sherco CC beneficial in supporting the proposed Monticello extension, it also helps ensure that we have sufficient load supporting, firm dispatchable resources on our system for grid resilience and reliability purposes. As we increase the amount of renewable generation on our system, these resources alone cannot reliably provide customers the energy they demand every hour of every day – or maintain the stability of the grid. Until MISO planning constructs fully incorporate measures to address the emerging challenges associated with increasing levels of renewables, we have incorporated a Reliability Requirement into our planning for this Resource Plan (See Appendix J2). Our Preferred Plan does not show a need for additional load supporting resources until 2031, which is partially so because the Sherco CC is already modeled as a part of our future resource portfolio.

As seen in Figure 1 below, if we were to forego building the Sherco CC, we would begin to see a firm capacity deficit relative to the Reliability Requirement by 2029, with the gap widening post-2030 when Sherco Unit 3 retires. Given technologies available today, this need would be most cost-effectively be filled by gas combustion turbines (CT). However, CTs also typically run at higher heat rates, with higher levels of emissions than CCs. While we have said we can wait until future cycles to

reevaluate and determine which technologies may be able to meet these needs in the post-2030 timeframe, we have a responsibility to ensure we meet our customers' needs now. The confluence of Monticello and grid stability needs, and proposed coal retirements further support that the Sherco CC is an appropriate choice to provide that system reliability service in the near term.

Figure 1: Projected Firm Capacity as Compared To Summer Peak and Reliability Requirement[2]



We are facing a long transition from today to 2030 – and even longer to 2050 – with significant changes at multiple stages. We must have operation options that give us flexibility to respond to many unknowns that are sure to come. The Sherco CC will help us make this transition responsibly, while we monitor developments and take advantage of technologies, such as hydrogen and other carbon-free fuels when they become commercially-viable. We discuss some of these resources in Appendix F6: Resource Options.

C. Renewable Integration Support

As we begin to integrate even higher levels of variable renewables on our grid, the

[2] Note that our Preferred Plan modeling also includes MEC's full capacity throughout the planning period, which may result in an additional gap if the proposed acquisition is not approved. The firm supply depicted here also includes DR additions per the Preferred Plan.

value of a dispatchable intermediate resource like the Sherco CC increases. Our Preferred Plan includes 4,000 MW of new renewable development, some of which would be added as early as 2025. Adding substantial new variable renewable resources requires us to maintain a subset of resources that can provide both fast ramping capabilities and the longer duration energy needs, for times when these variable renewables are not available. Moreover, these renewable additions will occur during the same period in which we are retiring over 2,400 MWs of coal-fired generation (1,360 MW of previously planned coal retirements from Sherco Units 1 and 2, and another 1,045 MW of retirements by 2030 proposed at Sherco Unit 3 and King. As we replace increasing amounts of existing coal generation with cleaner fuels, the Sherco CC will support our transition by allowing us to reduce and ultimately eliminate dependence on coal units for these balancing and integration needs going forward.

Additionally, as the MISO region realizes substantially higher levels of renewables, planning constructs need to change from today's single system peak capacity construct – and adapt to the diminishing marginal returns these variable resources can provide. MISO has itself acknowledged in its *Renewable Integration Impact Assessment* (RIIA) study that, at higher levels of renewable adoption on the grid, the ELCC of wind and solar resources will decline.[3] The firm capacity the Sherco CC will provide will become even more valuable in meeting our customers' needs every hour of every day as we navigate this transition while maintaining reliability.

D. Community Impact

Aside from significant grid support benefits discussed above, the Sherco CC also will partially offset the community tax and employment losses in Becker and Sherburne County that will result from the early retirement of the existing Sherco Units (including our proposal in this Resource Plan to retire Sherco Unit 3 in 2030). It also provides options for continued industrial steam supply to the Liberty Paper recycling facility located nearby. In addition, the Sherco CC could also provide options for our Sherco Unit 3 partner, Southern Minnesota Municipal Power Agency (SMMPA). These host communities and partners have been an integral part of our system for nearly 45 years, and we are committed to partnering with them as part of our upcoming baseload transition in hopes of mitigating the impacts of our Sherco retirements. Building a new CC unit at Sherco offers us the opportunity to meet our grid needs and serve the public interest, while also mitigating the impacts to these host communities and partners.

[3] *See* Chapter 2: Planning Landscape and Appendix J1: Baseload Study for more detail.

IV. ALTERNATIVE OPTIONS

While it is possible to meet some of the identified grid needs with alternate investments, the Sherco CC provides a path to meet all of these needs holistically and at a prudent cost to our customers. Below we discuss the three alternatives we evaluated: (1) a Synchronous Condenser (SC), (2) renewables-plus-storage, and (3) alternative greenfield CC solutions. We discuss each of these alternative options briefly below and will expand this discussion in detail in our upcoming Sherco CC regulatory filing.

A. Synchronous Condenser

With respect to voltage support, one potential alternative solution would be the conversion of one existing generating unit into a Synchronous Condenser (SC). A SC is a motor, whose shaft is not connected to anything but spins freely. Its purpose is not to produce electric power, but to adjust conditions on the electric power transmission grid. Our initial analysis indicated that a SC may provide the required continuous voltage support the Monticello plant requires as well as the requisite inertia (due to its large rotating mass) to meet the grid's stability needs. However, a SC would not be able to address the thermal support Monticello requires or the black start capabilities the system requires.

In addition, our Preferred Plan proposes to retire Sherco Unit 3 in 2030. This has two key implications for the viability of a SC as an alternate investment to the planned Sherco CC. First, our Preferred Plan includes a proposal to pursue a Monticello nuclear operating license extension that would allow us to operate that plant through 2040. Both the Monticello license extension and our proposal to retire Sherco Unit 3 in 2030 are fundamental components of our carbon reduction goals. The SC design we studied, however, would not be able to provide the grid services we need to remain compliant with our nuclear operating license after Sherco Unit 3 retires. Indeed, it is not clear that the NRC would approve a relicense with only SC support, as opposed to a generating facility. And even if it were approved with only SC support, the SC would need to be much larger than previously anticipated in order to provide similar grid stability benefits after all the 2,400 MW of existing Sherco generation retire. Further, a SC provides reactive power by consuming power. Because of this, a SC does not address the need for firm dispatchable resources to meet our customer's capacity and energy needs. In this way, the Sherco CC provides a much greater value to the overall system.

Second, the three existing Sherco Units are key components of our current Black Start Plan, and a SC on its own cannot replace this functionality. We noted in our last Resource Plan that our Black Start Plan is substantially dependent on capacity at Sherco Units 1 and 2 being Target Units, and providing sufficient output to support restarting Sherco Unit 3 and then the remainder of the NSP system. Retiring Sherco Units 1 and 2 would require re-designing our restoration path and potentially substantial associated transmission upgrades, if not replaced with another type of firm and dispatchable generation. The Sherco CC helps us to bridge that gap after Sherco Unit 1 retires in 2026. Now that we are also planning to retire Sherco Unit 3, the Sherco CC becomes even more essential in maintaining our black start capabilities. Because the SC does not generate real power, it cannot provide the Black Start functionality that we need for our system.

B. Renewables Plus Storage

Given the Company's clean energy goals, we also considered whether or not a paired renewables-plus-storage facility could provide a viable alternative solution to the Sherco CC. While the renewable plus storage might provide adequate capacity and energy, a SC may also be needed to meet the grid reactive power voltage support needs discussed earlier. We anticipate storage being a key part of our system in the longer term, however, such a solution is not currently cost-effective at the scale required for this application – and would be much more complex to implement and operate. It is also not clear whether the NRC would allow a storage facility to serve as the external support required by our nuclear operating license for Monticello. Even assuming it was approved, though, the external support unit is required to be available for a duration exceeding the longest potential outage that Monticello could encounter. In normal operational conditions, outages for refueling at the plant could be expected to last approximately 30 days. This duration is far longer than currently available storage solutions could be reasonably expected to provide support, much less provide it at a reasonable cost. Even a solution that could, for example, provide continuous grid support of this magnitude for a single 24-hour period would be exorbitantly expensive.

In this example, such a plant would require a battery configuration that could provide hundreds of MW of full discharge capabilities for multiple cycles. And while we expect the cost and capabilities of battery technology to improve over the planning period, it is highly unlikely they would improve sufficiently to make this a more cost effective solution than the Sherco CC. The Sherco CC will be able to provide continuous support to the broader grid and Monticello across many consecutive days – indeed months - without needing to pull significant energy from another on-site

generator, or the broader grid. Today's short-term energy storage solutions simply cannot provide this level or kind of support. Future technologies may make this type of solution much more viable and economic. However, with grid stability and reliability at stake, we do not see a renewables-plus-storage solution as a viable alternative to the Sherco CC at this time.

C. Alternative Greenfield CC

As discussed in more detail in Appendix I: Supporting Infrastructure-Transmission and Distribution, the existing transmission system's capability to interconnect new projects without substantial infrastructure upgrades is very limited, and thus, the generation interconnection planning studies indicate there will likely be costly upgrades assigned to the prospective generators. The value of our Sherco interconnection is incredibly valuable due to the potential for upgrade costs assigned to greenfield projects as well as the time component associated with the interconnection process.

In 2018, we asked an independent engineering consultant to help us evaluate the cost and feasibility of building a greenfield CC plant. Six potential sites were examined. Overall, the study led us to the conclusion that building a greenfield CC would not be an economically favorable alternative, nor would a plant likely be able to be placed in-service in the timeframe we needed. As greenfield sites, we would have to gain new interconnection rights and conduct transmission system upgrades that would present significant challenges not only to building a cost competitive solution to the Sherco CC, but also to achieving the 2026 in-service date we need to transition Sherco Unit 1 off the system. The study determined that, across these six potential locations, the average required transmission system upgrade costs for a selected site would amount to more than $500 million.

To put the plant in service by the time Sherco Unit 1 retires, the study determined we would need to see a 60 percent withdrawal rate from the MISO interconnection queue as it existed at the time of evaluation.[4] In our experience, it would be unrealistic to expect transmission upgrades, and any necessary transmission and plant permitting and interconnection processes, to be completed in an appropriate timeframe for a greenfield site option to be viable. Thus, this was determined to not be a favorable alternative to the Sherco CC.

[4] The Interconnection Cost Estimate Study performed by Excel Engineering is provided in this filing as Appendix R.

V. CURRENT STATUS

The Company is currently in the project development stage with regard to moving forward on the Sherco CC. We expect this plant to utilize the best available technology for the design specifications at the time of construction, based on technology information from the major equipment suppliers in the market. When it is built and put into service, we also expect the plant to be the most efficient gas generator, with the lowest carbon emission rates, in our generation fleet and that it will be competitive in the MISO Upper Midwest market as well.

The project specifications are based on a 2x1, wet-cooled, unfired design condition. We have used internal estimates and currently available technology information to include the plant, and estimated associated new infrastructure required, in the Strategist-modeled portfolios presented in this Resource Plan. However, these cost estimates are preliminary and subject to updates as we progress through the project development process. In preparation to move forward with the project, we are currently working with consultant engineering firms to develop more targeted and up-to-date cost estimates for the new generation facility and required firm natural gas supply infrastructure, and to better define expected project schedules. We expect these inputs to inform our project development plans moving forward, as we thoroughly evaluate equipment and infrastructure supply options and make any relevant filings to the Commission.

We also note that there are several steps we are preparing to complete with regard to generator interconnection rights for the Sherco CC, and this process will also affect how the Sherco CC development process moves forward. We expect we will need to file a MISO Attachment X generator interconnection request in order for the CC to utilize the same interconnection rights currently assigned to the Sherco coal units. This must be filed at least one year prior to the existing unit ceasing operation, and the new unit must go into service not more than three years after the existing unit(s) cease to operate. We plan to meet these requirements so that we can avoid the lengthy interconnection queue process.

When we file these details with MISO, that initiates any reliability studies required under the MISO Tariff – the results of which MISO will share within 180 days of the request.[5] The Tariff currently provides that these studies will evaluate whether the

[5] The Attachment X Tariff provides that the Transmission Owner [MISO] shall use Reasonable Efforts to complete the Replacement Impact Study and Reliability Assessment Study and share results with the Interconnection Customer within one hundred eighty (180) Calendar Days of the request.

replacement generating facility has a material adverse impact on the transmission system when compared to the existing generating facility and the performance of the transmission system, and to determine if thermal and/or voltage violations of applicable NERC standards and MISO planning criteria are caused by removing the existing generating facility from service prior to the commercial operation date of the replacement generating facility. Upon completion of these studies, Xcel Energy Transmission will subsequently study any required facilities upgrades or changes – and MISO will incorporate these into the new Generator Interconnection Agreement we receive for the Sherco CC.[6]

VI. CONCLUSION

The need to build new firm capacity at the Sherco site has not abated since our last resource planning cycle. The Sherco CC is an important bridge to the future. No one yet knows what that future looks like – and we are confident that it relies on technologies that are not yet developed. The Sherco CC will give us the necessary flexibility that help us through all the different transitional stages to come, without risking grid resilience and customer reliability. Without the Sherco CC, we will be challenged to maintain the clean baseload power provided by our Monticello unit into the future, and challenged to integrate the thousands of megawatts of new solar power proposed in our Preferred Plan, while retiring the last of our coal units.

For these reasons, we included the Sherco CC as a baseline resource in our Preferred Plan and in the additional scenarios we analyzed. We are moving forward with project development internally, including working with engineering consultants to develop more detailed estimates for the cost to build the CC and secure the associated firm gas supply for the site. These estimates will be used to help ensure the project is completed at a reasonable cost to our customers. We plan to bring forward a detailed filing to the Commission in the coming years, which will present the most up-to-date information for this project.[7]

[6] The evaluation currently consists of two studies: i) a Replacement Impact Study as set forth in Section 3.7.2.1 of the GIP, and ii) a Reliability Assessment Study as set forth in Section 3.7.2.2 of the GIP.
[7] As authorized by HF 113, filed February 28, 2017.

Xcel Energy®
Destination
Building the Future
2050
CORPORATE
RESPONSIBILITY
REPORT

Forward-looking Statements

Except for the historical statements contained in this report, the matters discussed herein are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements, including the 2019 EPS guidance, long-term EPS and dividend growth rate, as well as assumptions and other statements are intended to be identified in this document by the words "anticipate," "believe," "could," "estimate," "expect," "intend," "may," "objective," "outlook," "plan," "project," "possible," "potential," "should," "will," "would" and similar expressions. Actual results may vary materially. Forward looking statements speak only as of the date they are made, and we expressly disclaim any obligation to update any forward-looking information. The following factors, in addition to those discussed elsewhere in this Annual Report on Form 10-K for the fiscal year ended Dec. 31, 2018 (including the items described under Factors Affecting Results of Operations; and the other risk factors listed from time to time by Xcel Energy Inc. in reports filed with the SEC, including "Risk Factors" in Item 1A of this Annual Report on Form 10-K hereto), could cause actual results to differ materially from management expectations as suggested by such forward-looking information: changes in environmental laws and regulations; climate change and other weather, natural disaster and resource depletion, including compliance with any accompanying legislative and regulatory changes; ability of subsidiaries to recover costs from customers; reductions in our credit ratings and the cost of maintaining certain contractual relationships; general economic conditions, including inflation rates, monetary fluctuations and their impact on capital expenditures and the ability of Xcel Energy Inc. and its subsidiaries to obtain financing on favorable terms; availability or cost of capital; our customers' and counterparties' ability to pay their debts to us; assumptions and costs relating to funding our employee benefit plans and health care benefits; our subsidiaries' ability to make dividend payments; tax laws; operational safety, including our nuclear generation facilities; successful long-term operational planning; commodity risks associated with energy markets and production; rising energy prices; costs of potential regulatory penalties; effects of geopolitical events, including war and acts of terrorism; cyber security threats and data security breaches; fuel costs; and employee work force and third party contractor factors.

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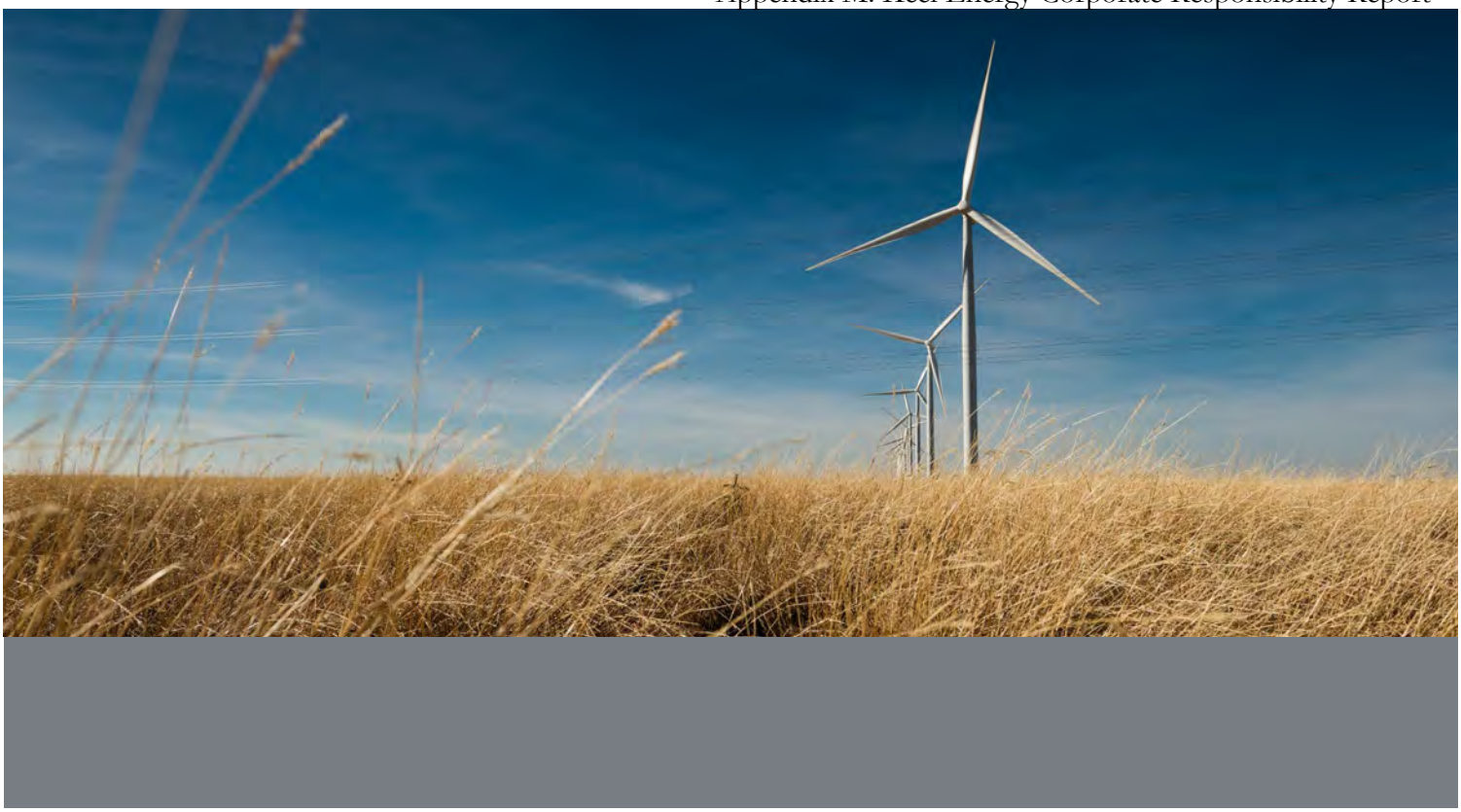


Who we are

Every day we power millions of homes and businesses across eight Western and Midwestern states. Our customers can count on us to be there 24/7 with safe, reliable energy. But, what we provide goes much deeper than that.

Based in Minneapolis, we are a recognized industry leader in delivering renewable energy and in reducing carbon and other emissions, efforts that have put us on a path to a more sustainable energy future. Through a growing range of innovative solutions, we continue to empower customers with energy options and alternatives to support their goals and objectives.

Destination 2050 is all about delivering on our bold vision for a carbon-free future. We are the first major U.S. energy provider to announce an aspiration to serve customers with 100% carbon-free electricity by 2050.

In a rapidly changing industry, we are taking a smart and thoughtful approach to how we produce and deliver energy, looking for better ways to serve our customers and anticipate their needs and expectations. Through our efforts, we are not just preparing for the future we are building it, today.

Our Vision

We will be the preferred and trusted provider of the energy our customers need.

Our Mission

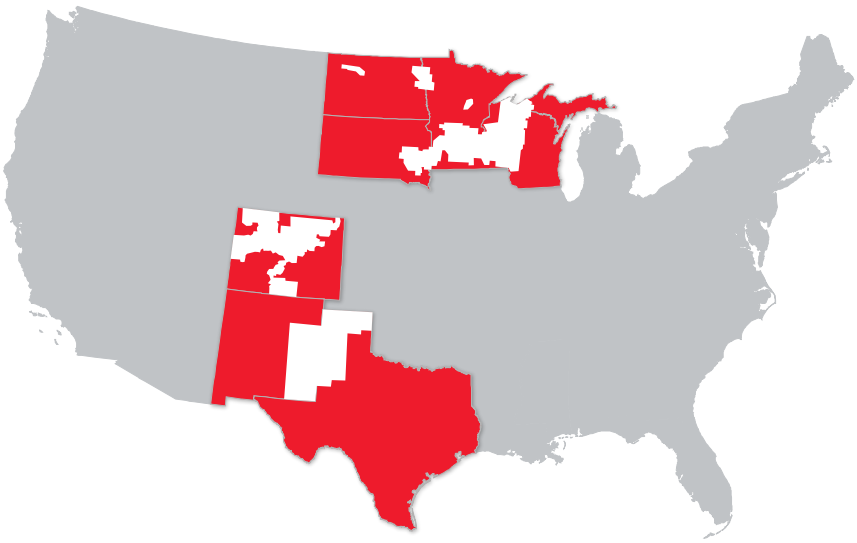
We provide our customers the safe, clean, reliable energy services they want and value at a competitive price.

Our Values

Our values reflect our core beliefs — who we are, how we conduct our business and the importance of our customers. They guide us in our work and in our interactions with each other. We are Committed, Connected, Safe and Trustworthy.

Our Service

Xcel Energy is a major U.S. regulated electric and natural gas delivery company with four utility subsidiaries. We serve 3.6 million electric and 2 million natural gas customers across parts of Minnesota, North Dakota and South Dakota (Northern States Power Company-Minnesota); Wisconsin and Michigan (Northern States Power Company-Wisconsin), Colorado (Public Service Company of Colorado); and Texas and New Mexico (Southwestern Public Service Company).



Message from the CEO

To Our Stakeholders:

For decades, the fundamental role of energy providers was simple: keep the lights on. But as energy has become more central to people's lives, expectations are far greater. Today our customers and communities depend on us to do much more — especially when it comes to leading the transition to clean energy and confronting the risk of climate change.

At the end of 2018, we became the first energy provider in the country to announce plans to serve customers with 100% carbon-free electricity by 2050. The theme of this report — Destination 2050: Building the Future — describes our bold vision for a carbon-free future while delivering the reliability and affordability that our customers need and expect.

A Carbon-free Energy Future

Clean energy matters to our stakeholders. It matters to us too. We've been at the forefront of the clean energy transition for the last 15 years. Since 2005, we've reduced carbon emissions by 38%, and the confluence of changing customer preferences, declining prices of clean technologies and the latest climate reports have accelerated our plans.

On our way to Destination 2050, we established a new interim goal to reduce carbon emissions produced from the electricity that serves our customers by 80% in 2030. We believe we can reach this 2030 target by using existing technologies. Removing the last 20% of carbon from the grid will require advances in technology to develop carbon-free, always-on energy sources. But I'm optimistic and believe we can get there.

To reduce carbon as quickly as possible without impacting reliability and affordability, we expect to continue our Steel for Fuel strategy of building large-scale renewables that deliver both economic and environmental benefits. We currently have a dozen wind farms under development with more on the drawing board. We also expect to expand our use of large-scale solar farms that provide the best consumer value. By 2030, we project renewable sources will generate at least 60% of our electricity. In addition to these renewables that serve all customers, we support customers who want more now by providing options to subscribe for up to 100% renewable energy through unique programs like Renewable*Connect in Colorado, Minnesota and Wisconsin.

Meanwhile, we have plans to retire four coal units in the early to mid-2020s — two in Minnesota and two in Colorado. Altogether, we are retiring half of our coal-fueled generation by 2026 — and are evaluating the feasibility of additional early retirements. As our energy mix changes with more renewables and less coal, we will continue to use more carbon-friendly natural gas as a bridge that supplies the back-up capacity to help integrate more renewables. We also plan to operate our carbon-free nuclear plants through their licensing periods in the early 2030s.

The easiest way to reduce carbon is to never produce it in the first place. We offer more than 150 energy efficiency programs to help our customers reduce their bills. In fact, five of those programs recently were acknowledged among the best in the country by the American Council for an Energy-Efficient Economy.

Companies like Xcel Energy are uniquely positioned to leverage our carbon-reducing expertise to other sectors of the economy. We're focusing our initial efforts on transportation, as we have several pilot projects under way to help make it easier for customers to purchase electric vehicles and produce 70% less carbon than gas-powered vehicles — and the results will get even better as we continue to transition away from fossil fuels. We have announced a $25 million investment in Minnesota to develop infrastructure needed to improve home charging and public charging capabilities and plan to expand these efforts soon to other states.

Building Stronger Communities

Just as EVs are beginning to gain traction, coal units are heading in the opposite direction. However, decisions to shut down a coal plant have significant ramifications to the employees who work there, along with the communities that benefit from the tax base.

Announcing plans years in advance is crucial to give these important stakeholders enough time to prepare for the change and provide economic development assistance where possible. A great example comes from Becker, Minnesota, where we announced the closure of two units at the Sherco Generating Plant. We have worked behind the scenes to provide economic development assistance to the local community through the construction of a natural gas-powered plant onsite, which will make up for lost generation, and to attract businesses. This includes Northern Metals Recycling, which is relocating from Minneapolis to Becker, and a large Google data center, pending approval.

As a local business, we're mindful of local spending that helps drive local economies. Last year nearly 70% of our purchasing was with businesses located in our service territory and 12% of our purchasing was with businesses owned by women, minorities or veterans. In addition, some of the projects we invest in, such as transmission lines and wind farms, create hundreds of local construction jobs and significant tax base.

Of course, we are also building the future by working with communities to help them reach their clean energy goals. We have partnered with several communities through our Energy Future Collaborations and Partners in Energy programs to help them reach their clean energy and sustainability goals.

This is in addition to providing reliable and affordable energy that our customers expect. These, along with a strong commitment to public safety, are table stakes in our industry. Last year, we delivered electric reliability that remains in the industry's top one-third, kept bills under the level of inflation and delivered our best-ever performance in gas emergency response. Another way we positively impact our communities is through our dollars and time. In 2018, the Xcel Energy Foundation and our employees donated more than $11 million and volunteered 90,000 hours with a focus on STEM education, economic sustainability, environmental stewardship and access to arts and culture.

Building our Future Workforce

To best serve our customers and solve tomorrow's energy challenges, we continue to build and train our workforce for the future. We are one team comprised of 11,000 employees. We recently refreshed our corporate values to better align with how we approach our jobs each day. Through a bottom-up approach, employees embraced our four values — Safe, Committed, Connected and Trustworthy — and demonstrate them each day when they come into work.

Through our performance management, professional development and recognition programs, we align employee responsibilities with our three strategic priorities: Leading the Clean Energy Transition, Enhancing the Customer Experience and Keeping Bills Low.

Employee safety is a core value for our organization and is at the forefront of everything we do. Although we achieved first-quartile employee safety in 2018, we had a few significant injuries. As a result, we re-doubled our safety precautions and expanded our communications efforts.

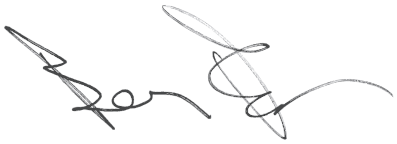
We are committed to hiring and retaining a diverse workforce. Thirty-four percent of our new hires were female, which is just slightly below first-quartile performance. Our hiring of people of color slightly increased to 24%, but remains short of our goals. We began developing customized diversity plans in five business areas, and we expect to build on that program in 2019. We also set a record with 66 high school interns and were named Employer of the Year by St. Paul-based Right Track, a youth training program.

Building the Future

Powering homes and businesses, driving economic development, supporting our communities and protecting the environment are fundamental to how we do business. We embrace the trust our customers place in us and our responsibility to deliver solutions to improve their lives. As you read our Corporate Responsibility Report, you will learn more about our progress and plans for building the future and fulfilling our economic, environmental and community responsibilities.

Thanks for your partnership on this important journey.

Sincerely,



Ben Fowke
Chairman, President and CEO

Corporate Responsibility Governance

How we define, govern and align corporate responsibility with our strategic priorities

For more than a century, Xcel Energy has had the privilege of serving customers and operating in hundreds of communities across its eight-state service territory. We have accomplished this by never losing sight of our responsibilities and the understanding that our success is uniquely tied to the success of those we serve.

Building the Future, Today

Our corporate vision is to be the preferred and trusted provider of the energy our customers need. To fulfill this, we view our success today and in the future not simply as a measure of profit but equally as our broader impact on the public good. We have a tremendous obligation and opportunity to power people's lives and possibilities with energy that they can trust to be safe, affordable and progressively clean. We work every day to deliver on these requirements for customers and other stakeholders through our focus on the following environmental, social and governance responsibilities.

Environmental Responsibility

Managing natural resources and protecting the environment

We are committed to minimizing and carefully managing our environmental impacts and providing transparent disclosure. As an early adopter of renewable energy, we are leading the clean energy transition and managing the risk of climate change through our bold vision to serve customers with 100% carbon-free electricity by 2050. By reducing carbon emissions, we also decrease other environmental impacts, such as air emissions, waste and water use. Our communities can count on us to protect the environment, and this includes supporting stewardship and conservation projects through our community investment — projects that further enhance and preserve the places where we live, work and do business.

Social Responsibility

Supporting the people and places we serve

We serve people, helping to run their homes and businesses and providing comfort and convenience. We continually strive to create value by offering products and services that our customers want and need, and operating in a way that protects the public and drives economic growth. We support our local communities as a partner in economic development, by assisting customers in need, and giving of our time, talent and financial resources. Building stronger communities is fundamental to our business.

Running a successful business and cultivating a strong workforce

Now more than ever, we are investing in the processes, technology and clean energy that will enhance our service for the future, while maintaining reliable, affordable energy. Our focus is on continuous improvement. This means carefully managing costs and a responsible supply chain, encouraging innovation and ensuring a secure and resilient energy grid for the future. As an employer, we provide a safe and rewarding workplace, one that values people and their contributions and reflects the diversity and strengths of our communities. We operate in a rapidly changing industry, driven by new technologies and evolving customer expectations. Cultivating a workforce that is equally dynamic, highly skilled and customer focused is one of our most important investments.

Governance

Maintaining strong governance practices

Our proven track record of strong financial and operational performance is rooted in a foundation of sound corporate governance and oversight. It starts at the top through a board that is diverse, engaged and experienced. With a strong independent lead director, 12 of our 13 board members are independent and five self-identify as female and/or minority. Together, they bring the diverse perspectives and experience our company needs to be successful. Through annual strategy sessions and other best practices, we effectively manage risks and opportunities, including those related to our environmental and social responsibilities. Throughout Xcel Energy, we continue to foster a culture of compliance and ethical business conduct — one that is founded in our values: Connected, Safe, Committed and Trustworthy.

Throughout our Corporate Responsibility Report, we demonstrate our leadership and progress in fulfilling our social and environmental responsibilities. We cover performance across 24 issues that are associated with these responsibilities and that are important to our industry and to those we serve. We put special emphasis on 10 focus areas that our stakeholders identified as being of most interest to them through a survey conducted in early 2017.

Aligning Corporate Responsibility with Corporate Strategic Priorities

Through our strategic planning process, the board of directors and executive leadership team identified three strategic priorities that represent the keys to our continued success in achieving our vision to be the preferred and trusted provider of the energy our customers need. These priorities include:

- Lead the clean energy transition
- Enhance the customer experience
- Keep bills low

Strong alignment exists between these strategic priorities and our corporate responsibility. The table below demonstrates this alignment to our corporate responsibility focus areas.

	Strategic Priorities	Corporate Responsibility Focus Areas
Social Responsibility	**Enhance the Customer Experience** • View our work through customers' eyes • Make it easy for customers to do business with us • Offer products and services that our customers value • Help strengthen our local communities **Keep Customer Bills Low** • Carefully manage our costs • Continuously improve how we work to improve efficiency without compromising safety or reliability • Keep total bill increases at or below the rate of inflation	**Affordable Energy.** Transform our cost structure to become more efficient and customer focused, while investing in projects that reduce fuel and other expenses for customers. **Reliable Energy.** Deliver strong system reliability and outage response capabilities. **Public Safety and Employee Safety.** Ensure individuals living and working near our facilities are aware of potential hazards and respond safely to them.
Environmental Responsibility	**Lead the Clean Energy Transition** • Serve customers with cleaner, reliable energy through increased ownership of wind and solar generation and continued operation of our nuclear fleet. • Invest in the grid, including advanced technologies and transmission that enable more renewable energy • Reduce carbon and other emissions, improving environmental performance • Encourage and help enable the electrification or implementation of low-carbon solutions in other industries	**Energy Efficiency.** Support customers and the communities we serve in attaining their energy conservation goals. **Renewable and Advanced Clean Technologies.** Increase the use of economic renewables and position the power grid as a platform for new energy services. **Greenhouse Gas Emissions and Air Quality.** Continue to pursue a cost-effective clean energy strategy to reduce carbon and other air emissions.
	The Foundation of All Our Efforts **Corporate Governance.** Ensure sound corporate governance and a culture of compliance by focusing on strong practices, independent oversight and shareholder rights.	

Corporate Responsibility Governance

Corporate responsibility is embedded throughout our organization and integrated into our governance processes. With strong leadership from our board of directors and executive management team, along with engaged leaders and organizations across the company, we are able to effectively manage risks and opportunities and drive strong performance across a spectrum of corporate responsibility issues.

The table below describes key aspects of our corporate governance that cover corporate responsibility.

Board Oversight	Our board of directors, led by the chairman, president and CEO, oversees corporate responsibility-related issues and initiatives. • Board committees and responsibilities related to corporate responsibility include: – The Governance, Compensation and Nominating and Audit committees oversee respectively the Code of Conduct and corporate compliance. – The Operations, Nuclear, Environmental and Safety Committee oversees environmental strategy and compliance, safety and operational performance, customer service levels and all aspects of excellence in delivering electricity and natural gas service to customers. – The Finance Committee oversees our clean energy investments, investor relations and financial health. • The board follows a regular meeting schedule that ensures it is able to consider and address key issues, including those related to corporate responsibility. In addition, it conducts an annual strategy session to consider new and emerging trends, consult with outside experts and assess current strategies and initiatives.
Executive Oversight and Management	The executive team plans and executes on strategies designed to achieve Xcel Energy's priorities, including corporate responsibility-related issues and initiatives. • The executive team is responsible for the strategic direction of the company and sets key initiatives, including growth plans, the clean energy strategy and other corporate responsibility efforts. They consider evolving customer trends and preferences, industry and technology needs affecting our business, developments in the external landscape and policy considerations. • Strategies and key initiatives are crafted and executed to strike a balance between reliability, affordability and environmental impact. • Our executive compensation is tied directly to company performance, specifically reliability, cost management, customer satisfaction, public and employee safety, achievement of carbon emission reduction goals and financial performance.
Business Area Management	While the entire organization supports our corporate responsibility efforts, specific issues are directly tied to individual areas to manage. We use effective performance management techniques and compensation design to align employees around successful execution of our goals and efforts. • General Counsel: Ethics and compliance • Corporate Secretary: Governance, ethics and compliance, strategic planning and disclosure • Operations: Energy affordability and reliability, fuel diversity, advanced grid and environmental performance • Customer and Innovation Office: Energy efficiency, customer programs and satisfaction, economic development, security and emerging technology • Human Resources: Labor practices, safety and community giving • Financial Operations: Risk management, investor relations and disclosure • Nuclear Operations: Nuclear generation, safety and waste management
Operating Companies	Our operating companies execute on our corporate strategy and develop and implement plans that address corporate responsibility and fulfill our economic, environmental and community responsibilities. • Operating company staff engages with stakeholders to help ensure mutual priorities and goals are addressed. • Policy staff develops strategy and engages on energy policy issues, including climate change, environmental policy and sustainability strategy. • Resource plans are developed and analyzed for meeting customers' future energy needs and achieving clean energy and other stakeholder priorities.

Stakeholder Engagement

As a regulated, public utility we can only be successful if we have insight into the needs and priorities of those who our business relies on and serves. Because of this, we regularly engage with our stakeholders and seek opportunities to better understand their interests, concerns and emerging trends. The feedback we receive from these interactions helps to inform our business plans and strategies.

Xcel Energy's stakeholders are those individuals and groups who affect or are affected by our business operations. They fall within the following general categories:

- Customers
- Employees
- Communities, including local government officials, non-profits and community organizations, and advocacy groups
- Legislators and regulators
- Investors

Our stakeholder engagement is far-reaching and transparent, with regular, ongoing business interactions and special meetings, presentations and proceedings before our state public utilities commissions. Our account management and state and local affairs and community relations teams have always engaged with large customers, city and county governments, influential organizations and individuals, state legislators and policy makers to discuss important service and energy-related issues and projects. We annually report on our lobbying and political contributions, which are governed by corporate policy. We also have a strong presence in our service territory through our community giving and volunteer support of community initiatives and programs.

In addition to our regular, ongoing engagement, we conducted a special survey in 2017 to better understand our local stakeholders and their priorities related to corporate responsibility. Results from the survey helped to inform the content and focus for this report, as well as our efforts in general.

How We Engage

The table below outlines our regular, ongoing engagement with stakeholders and our response to stakeholder interests.

Stakeholder group	Engagement	Key interests	Our response
Customers	• Customer Contact Center • Key account managers • Personal account representatives for customers in need • Customer advocate process • Surveys and focus groups • Customer communications and account information • Special events and meetings	• Energy service start and stop • Service reliability and timely outage response • Electric and natural gas safety • Energy affordability and money saving opportunities • Easy billing and online account management • Information privacy • Neighborhood construction or repair work • Renewable and clean energy	• Public safety materials, programs and advertising • Extensive energy-saving programs and tips • Online account management programs and the Xcel Energy app • Online outage map and improved outage communications • Construction project communications • Data privacy process • Renewable choice programs • Clean energy leadership and strategy

Stakeholder group	Engagement	Key interests	Our response
Employees	• Leadership meetings • Employee meetings and webcasts • Bargaining unit negotiations and communications • Employee surveys • Employee Communications • Quarterly performance connections	• Market-based compensation and benefits • Professional development • Communication • Recognition • Community involvement • Engagement in energy policy	• Total Rewards statement and tools, such as My Financial Future planning tool • Connect4Performance performance management • Professional development resources and tuition reimbursement • I Deliver and Innovator recognition awards • New employee orientation • Print, electronic and video communications • Volunteer activities and paid-time-off program • United Way campaigns and matching gift program • Business Resource Groups • Diversity and inclusion education • Wellness programs • Grassroots political events and political action committees
Communities	• Project-specific stakeholder meetings and open house events • Community relations staff • Partnerships and local memberships • Franchise agreements • Presentations and speaking engagements • Sponsorships and community events • Volunteer projects	• Public safety • Project input and communication • Community giving • Economic development and jobs • Support for community goals • Renewable and clean energy • Energy efficiency	• Public safety programs • Project communications • Xcel Energy Foundation giving and United Way campaigns • Employee volunteer programs and community board support • Programs for customers in need • Clean energy leadership and strategy • Renewable choice and energy efficiency programs

Stakeholder group	Engagement	Key interests	Our response
Legislators and regulators*	• Policy and legislative involvement • Governmental and regulatory staff • Regulatory filings and proceedings • Political action committees and grassroots employee events • Speaking engagements	• Affordable energy • Reliable energy service • Renewable and clean energy • Climate change and greenhouse gas emissions • Environmental protection • Responsible corporate governance	• Continuous improvement and cost management • Clean energy leadership and strategy • Renewable choice and energy efficiency programs • Corporate environmental policy and environmental management system • Voluntary emissions reduction initiatives • Highly rated corporate governance program
Investors	• Investor meetings, presentations and teleconferences • Participation at investor conferences • Website • Annual report, 10-K, 10-Q, proxy, financial press releases and other disclosures • Annual shareholder meeting	• Stock appreciation and company growth prospects • Meet earnings per share guidance • Meet long-term EPS and dividend growth objectives • Deliver a superior total shareholder return relative to our peer group • Solid credit ratings • Financing needs • Favorable regulatory environment • Transparency • Risk management	• Corporate strategy that includes a fair return on investment, utility business investment and stakeholder alignment • Clean energy leadership and Steel for Fuel strategy • Highly rated corporate governance programs • Investor relations communications and mobile app

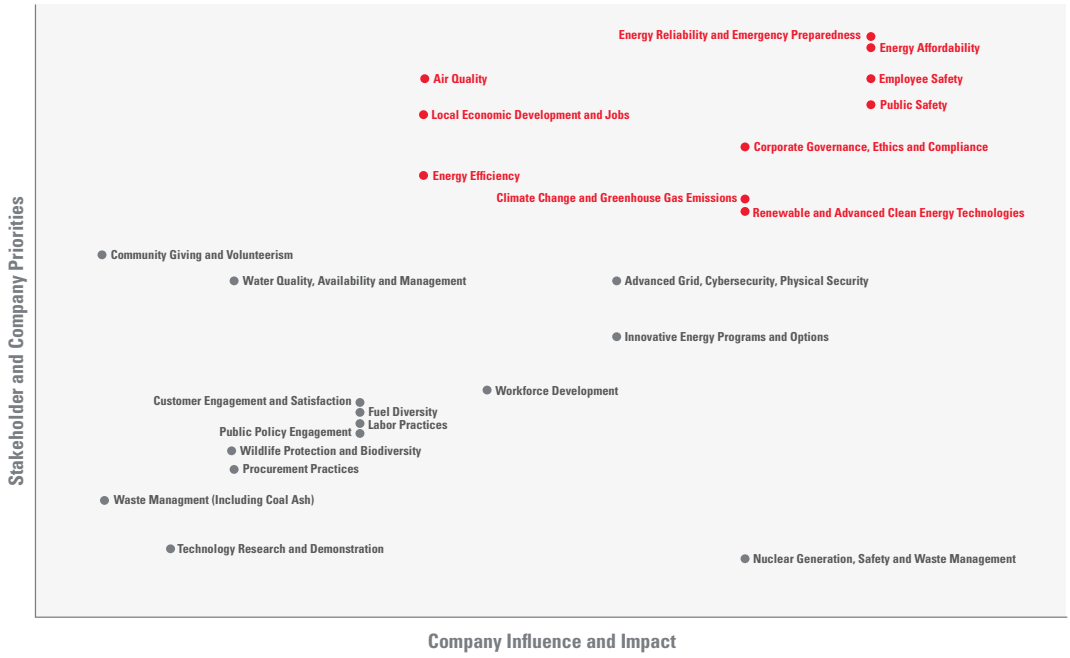
Identifying Areas of Focus for Corporate Responsibility

Based on stakeholder engagement, research and participation in a number of industry and sustainability forums, we have identified 24 major corporate responsibility issues for Xcel Energy. These issues closely align with the sustainability issues facing the entire electric sector, as identified through an extensive study conducted by the Electric Power Research Institute's Energy Sustainability Interest Group — of which, Xcel Energy is a member.

In early 2017, using the Global Reporting Initiative methodology to guide us, we conducted an online survey with nearly 1,000 stakeholders to understand which issues are currently most important to the individuals and organizations within our service territory, as well as within our own organization. The results are provided in the chart below.

While all of these issues are important, we consider the issues highlighted in red to be focus areas. They reflect the current priorities of our stakeholders and for our company where we can have a meaningful impact. Consequently, to the extent we are successful in addressing and managing these issues, we will be delivering real value.

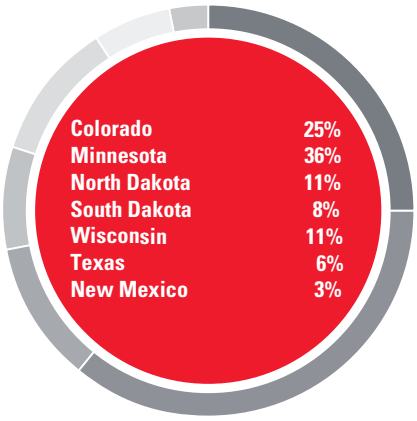
Corporate Responsibility Focus Areas



Methodology for Corporate Responsibility Survey

The corporate responsibility survey was conducted internally and designed to have stakeholders identify their top priorities for Xcel Energy's corporate responsibility efforts. Xcel Energy's executive leadership also answered the survey to understand our internal priorities. Altogether, the survey was distributed to nearly 1,000 internal and external stakeholders across our eight-state service territory. Approximately 26% of potential respondents participated. The respondents represented a good mix of our local stakeholder categories and our service territory.

Respondent by State



Respondent by Stakeholder

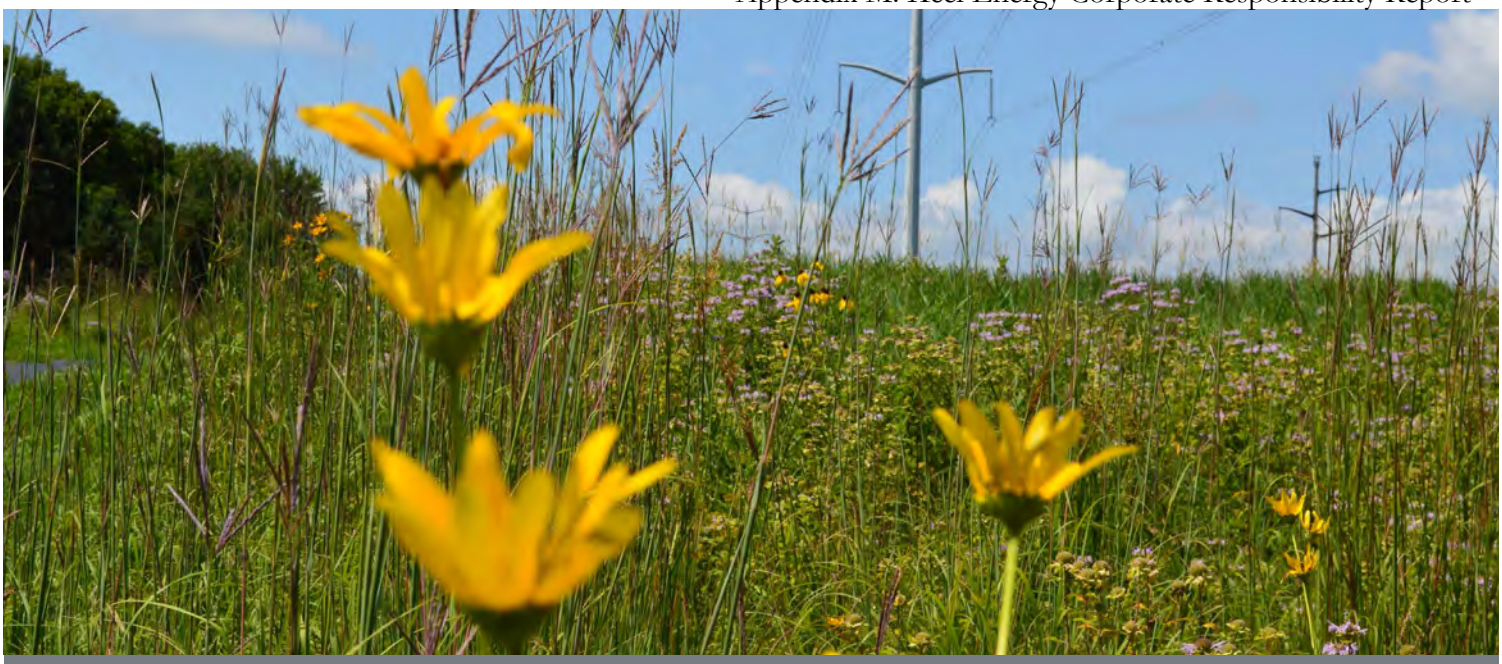
The survey was based on the 24 corporate responsibility issues we identified for our company. These issues were based on our experience through regular stakeholder engagement, research and participation in a number of industry and sustainability forums. Many of these issues align with industry research conducted by the EPRI Sustainability Interest Group.

Throughout the survey, respondents were asked to prioritize the corporate responsibility issues in different ways and had the opportunity to identify new issues. First, the respondents ranked their priority issue within five categories. These are the responses shown in the graph in the section above. Second, respondents listed their top five corporate responsibility issues without any categories. Lastly, respondents could add new issues and describe any sustainability goals that their own organizations may have and how Xcel Energy could help meet those goals.

Xcel Energy corporate responsibility issues and definitions, including 10 identified focus areas highlighted below.

Advanced Grid, Cybersecurity, Physical Security	Upgrading the power grid with advanced technologies to improve reliability and security; protecting important systems and infrastructure from unauthorized access or attack; drilling emergency scenarios both with and without external stakeholders to ensure effective response to potential events
Air Quality	Reducing air emissions other than greenhouse gases from our operations, including nitrogen oxides, sulfur dioxide, mercury and particulate matter, both through emissions controls and fleet transformation
Climate Change and Greenhouse Gas Emissions	Managing and reducing the greenhouse gas emissions from our operations, including carbon dioxide, methane and sulfur hexafluoride (SF6) through fleet transformation
Community Giving and Volunteerism	Giving both time and money to local nonprofit organizations; supporting energy assistance programs for customers in need
Corporate Governance, Ethics and Compliance	Ensuring adherence to the rules, practices and processes that direct and control our company; setting ethical expectations and values and monitoring adherence to applicable laws and regulations
Customer Engagement and Satisfaction	Working with customers to understand their needs and improve the service and products we provide; ensuring a positive customer experience with interactions that are focused, simple and transparent; meeting our scorecard objective of building customer loyalty
Employee Safety	Adopting, enacting, and promoting effective programs that protect the health and safety of employees and contractors
Energy Affordability	Ensuring electricity and natural gas bills are affordable for consumers
Energy Efficiency	Providing programs to help customers take control of their energy usage and save money, including traditional rebate programs and advanced home solutions
Energy Reliability and Emergency Preparedness	Providing electricity and natural gas with few to no interruptions; being prepared to quickly repair outages caused by storms or other incidents
Fuel Diversity	Minimizing dependence on any one energy source by using a diverse mix of sources to generate electricity
Innovative Energy Programs and Options	Offering programs that give customers choice over their energy sources, such as helping them access more wind and solar power or helping them fuel electric or natural gas vehicles
Labor Practices	Adopting responsible practices related to employee pay, benefits and equal opportunity
Local Economic Development and Jobs	Working with the community to attract and support new business development and economic growth

Nuclear Generation, Safety and Waste Management	Maintaining Xcel Energy's nuclear fleet that provides reliable, carbon-free electricity, in a way that ensures safety and emergency preparedness; safely handling and storing solid waste from nuclear generation
Procurement Practices	Doing business with responsible, local and/or diverse suppliers for the equipment, materials and services we purchase
Public Policy Engagement	Engaging and collaborating with policymakers and providing input on proposed legislation and regulations
Public Safety	Providing education to prevent accidental contact with electric power lines and natural gas pipelines; protecting the public around our facilities and facility operations; ensuring effective emergency response to public safety issues around our facilities
Renewable and Advanced Clean Technologies	Increasing electricity generation from clean, renewable energy sources, including wind farms and solar power plants; deploying advanced technologies to reliably manage higher levels of wind and solar energy
Technology Research and Demonstration	Participating in projects to test advanced energy technologies that have potential for providing customers with new products and services in the future; supporting industry research efforts through financial contributions, staff involvement and demonstration projects
Waste Management	Preventing and reducing waste produced from our operations, including coal ash; reusing or recycling waste instead of disposing of it in landfills; operating power plants fueled by waste
Water Quality, Availability and Management	Ensuring the availability of water for electricity generation and all other users; protecting water quality
Wildlife Protection and Biodiversity	Avoiding or minimizing impacts to protect species and their habitats; supporting raptor habitat and providing education and conservation opportunities on raptors
Workforce Development	Maintaining a workforce of the right size and skill profile, includes our talent management strategy and diversity and inclusion efforts; engaging in community efforts to develop pipeline of future employees; providing competitive employment opportunities and supporting diverse business resource groups



About this Report

Publication Date: May 2019
Reporting Period: Jan. 1 – Dec. 31, 2018
Date of Previous Report: May 2018 (for 2017)
Reporting Cycle: Annual
Report Boundary: Xcel Energy and its four regulated subsidiaries
Contact Point: corporateresponsibility@xcelenergy.com

Xcel Energy's annual Corporate Responsibility Report focuses on the company's environmental and social contributions, and is built on 24 issues that we have identified as important to our stakeholders and company.

This year marks the 14th year we have published the report. Our first Corporate Responsibility Report (formerly known as the Triple Bottom Line report) was published in April 2005, with the contents covering the 2004 calendar year. The report is published online, and to raise awareness for it, we print a highlights brochure that is distributed at our annual shareholders' meeting and at other events throughout the year.

How to Use this Report

Our ongoing goal for this report is to improve transparency and to meet the different information needs of the stakeholders that use it. With this in mind, we provide different levels of information.

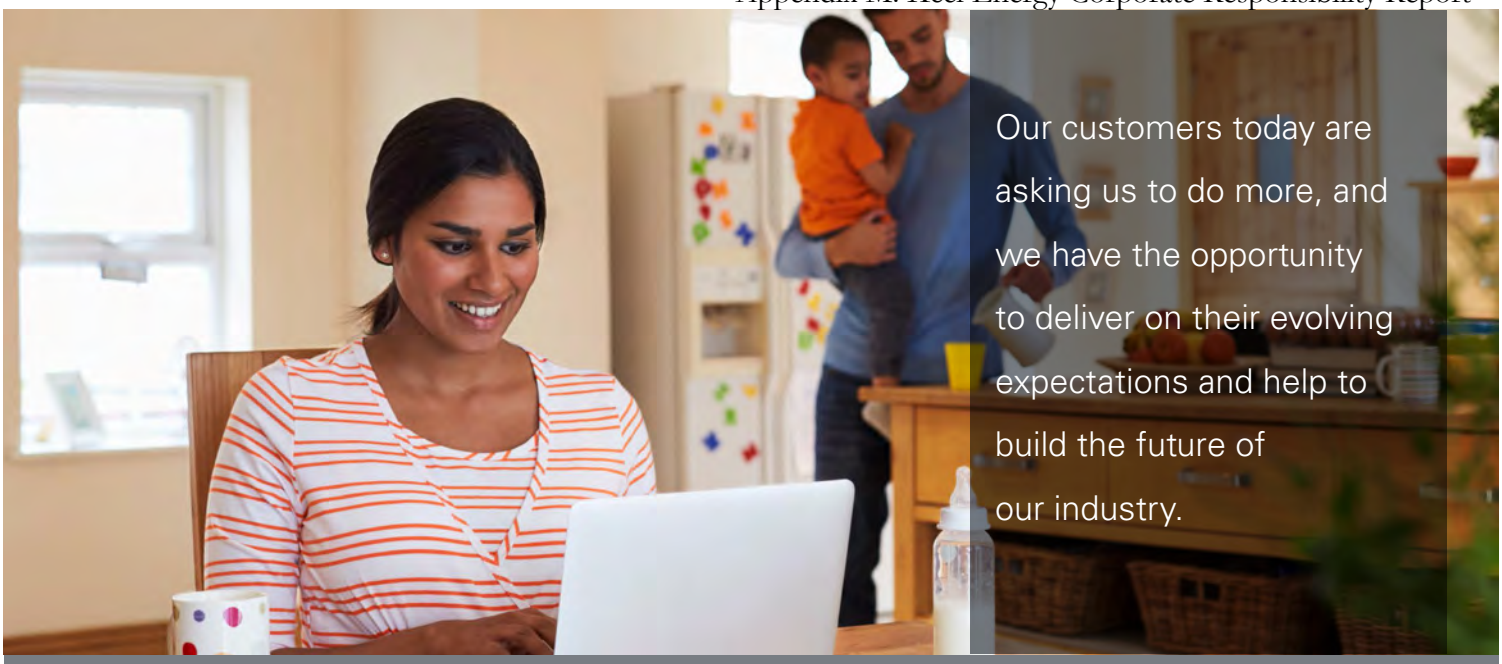
- The *CEO Message* from Xcel Energy's chairman, president and CEO, Ben Fowke, discusses our role in serving communities and our priorities and annual performance.
- The *2018 Highlights* page provides an introduction to Xcel Energy and a high-level look at our environmental, social and economic contributions for the year.
- The *Library of Briefs* offers a deeper discussion of our approach to managing specific topics — the content of the briefs covers the 24 corporate responsibility issues we identify in the Corporate Responsibility Governance section of the report.

- The *Corporate Responsibility Governance* section describes our corporate responsibility and how we govern it, along with our stakeholder engagement and 24 issues underpinning this report. It also demonstrates the alignment between with our corporate responsibility focus areas and corporate strategic priorities.
- For those interested in the numbers, we provide a *Performance Summary* that is a list of disclosures and also the *GRI Standards Content Index*.
- A full copy of the report, which includes all the content from this website, can be downloaded as a PDF. Past reports can be found in the report archive online.
- Xcel Energy publishes an Edison Electric Institute (EEI) environmental, social, governance and sustainability report, a new industry report that provides information in a measurable and consistent format for investors.
- Throughout the report, we also provide links to more information published in other corporate reports, such as the 2018 Annual Report, 2019 Proxy Statement or online at xcelenergy.com.

Global Reporting Initiative Guidelines

Xcel Energy continues to base its Corporate Responsibility Report on Global Reporting Initiative (GRI) guidelines, which we have used since 2008. This year's report is based on GRI's Standards in accordance with the Core option and the Electric Utilities Sector Supplement. We have tried to meet the intent and follow the standards as closely as possible; however, there are instances where we track information for disclosure differently or not at all, based on our company or stakeholder information needs.

Customers and communities



Customer engagement, satisfaction and energy affordability

Earning customer satisfaction and trust

Each and every time our customers engage with us, we want to make it easy for them and deliver a positive, best-in-class experience.

We understand that energy is a necessity in people's lives. Above all else, to earn their satisfaction and trust, we must first deliver on our responsibility to provide safe, reliable and affordable energy that is increasingly clean. This also means being there when customers need us most — whether they are experiencing a service outage, struggling to pay a bill or looking for ways to better manage their energy use.

Enhancing the customer experience is a strategic priority for Xcel Energy, and to fulfill it, we are focused on improving all levels and points of service for customers. We constantly manage the systems, processes and people we have in place to meet different customer needs and circumstances, and we are expanding the products and services we offer to support our customers even more.

2018 Results

- As we continue to focus on improving the customer experience during an outage, we worked to improve our internal processes in 2018. This included training employees on when and how to update estimated restoration times to provide customers with more timely and accurate information, coupled with reporting to emphasize process adherence. This ongoing effort is showing up in customer satisfaction perceptions. We moved ahead of 12 utilities in our peer set of 56 utilities from 2017 to 2018, placing us in the upper second quartile for outage communications.

- We continue to foster a workforce culture where all employees take ownership in ensuring a dependable, easy, enjoyable and personal experience for our customers. We launched Customer Experience Training, with more than 3,000 employees completing the in-person sessions that focus on: building a customer-centric mindset, ownership and personal accountability, and taking action. The goal is for all employees to complete the training in the next several years.
- Xcel Energy's average annual residential energy bills continue to be below the national average. Our average residential electric bills from 2009 to 2018 are 26% lower than average, and from 2008 to 2017, our natural gas bills are 14% lower than average.
- We provided approximately $51.9 million to customer energy assistance programs for the year that helped almost 198,000 individuals and families throughout our service area.

The Regulatory Compact

We operate under carefully regulated conditions that are determined in part by state public utilities commissions — a governing body that regulates the rates and services of utilities such as ours. In exchange for the exclusive right to provide electricity and natural gas services in certain regions, we agree to the following regulatory compact:

- **Duty to serve:** We cannot pick and choose our customers. We will provide service to any residence or business within our service territory that requests it under reasonable terms and conditions.
- **Cost of service pricing:** We cannot arbitrarily raise prices to levels beyond our costs. Pricing for our services is regulated by the costs we incur to deliver them.
- **Resource planning process:** Every few years, we go through a process to determine the resources necessary to serve customers' future energy needs. Resource plans must be reviewed and approved by regulatory commissions, and stakeholders can provide input on the plans through a public process.

In return, we are granted the ability to recover our costs of doing business and earn a reasonable rate of return. Although, this rate of return is not guaranteed — we have only the opportunity to earn it. To operate effectively in a closely regulated business like ours, it is imperative that we stay in sync with the current demands of the public and our policy makers.

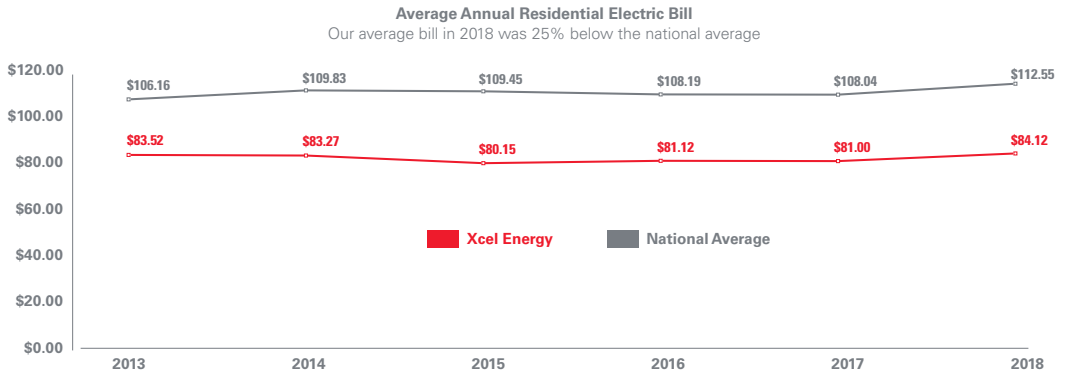
Managing Customer Energy Bills

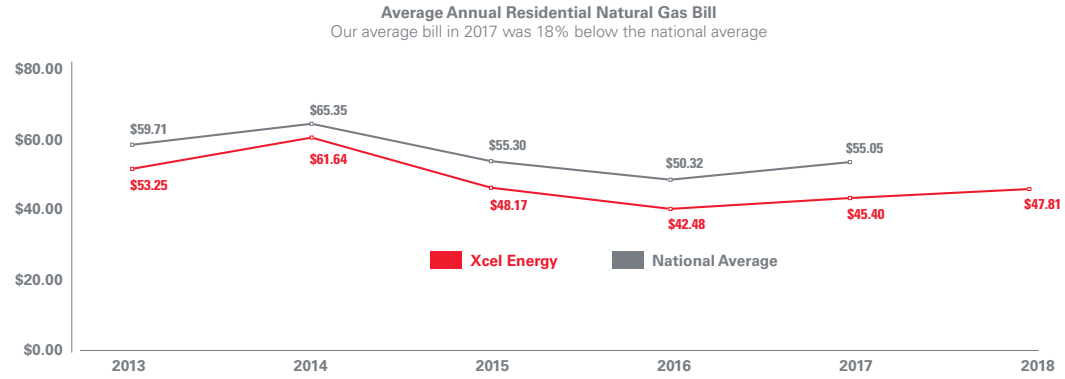
We continue to focus on the cost of service to deliver on our company's priority to keep energy bills low for customers. We saw an uptick in Xcel Energy's average residential electric and natural gas bills in 2018, although we continue to have among the lowest average residential bills in the country. We calculate that Xcel Energy customers over the past decade have spent $3,365 less on electricity and $1,007 less for natural gas compared to the national average.

Xcel Energy's lower than average customer bills are likely but not exclusively the result of:

- Our comprehensive portfolio of energy efficiency programs, as well as changing codes and standards that result in more efficient buildings and appliances
- Company-wide disciplined cost management
- Investments through our Steel for Fuel strategy, which calls for adding clean, renewable projects at a cost that is offset by the future fuel savings
- Growth in on-site or rooftop solar panels
- Increases in multi-family housing construction
- Weather differences, which can increase or reduce average bills for the year

Xcel Energy Comparison of Average Monthly Bills





Based on EIA bill trend data reported each year by utilities and revised by EIA in early 2019. Represents Xcel Energy annual average of monthly bills, excluding taxes and franchise fees; annual national natural gas bill information is not yet available.

Measuring Customer Satisfaction

We monitor customer perceptions of the company and our performance through several tools. The two most notable are the J.D. Power & Associates Electric Utility Customer Satisfaction studies and the customer transactional satisfaction studies that we implement with our partner, MaritzCX.

J.D. Power & Associates implements an industry-wide benchmark that provides details of our relationship with residential and small- to medium-sized business customers and how that compares to industry peers. For the residential electric study, we improved from low second quartile in our peer set in 2017 to high second quartile in 2018. Residential customers provided the most positive feedback in the areas of quality and reliable electricity service, efforts to develop energy supply plans for the future and total monthly cost of electric service. With business customers, Xcel Energy ranked in the second quartile in our peer set in 2018. Our highest satisfaction scores among business customers were for efforts to develop supply plans for the future and for actions to take care of the environment.

We also continue to demonstrate strong performance at our customer contact centers. Through regular transactional surveys in 2018, 85% of residential and business customers reported that they were satisfied with their transaction involving an agent at our contact centers. Similarly, more than 86% of customers reported their problem or issue was resolved on the first call to Xcel Energy. Our Customer Care organization sets annual goals with satisfaction and first call resolution, and we met or exceeded both of these in 2018.

Customers in Need

We work with state and local agencies and advocates for low-income customers to provide energy assistance to those in need. Our Personal Accounts department helps to monitor and assist customers who have medical needs or who are struggling to make their monthly energy payments. They can assist and make energy bills more affordable to income-qualified individuals and families by promoting special energy efficiency programs, arranging payment plans and providing energy assistance resources.

Our support of energy assistance includes:

- Public policy and advocacy supporting efforts on the state and federal level for funding of Low-income Home Energy Assistance Programs (LIHEAP)
- Funding for state and local energy assistance agencies and energy weatherization programs
- Encouraging our customers to contribute to statewide fuel funds via their Xcel Energy bills
- In-kind marketing and public relations to support energy assistance organizations and advocates for low-income customers

We encourage customers who are having trouble paying their bills to contact us to develop a payment plan and determine if additional assistance is available. In Minnesota and Colorado, we have medical exemption or affordability programs for low-income customers with special medical needs to help them with their utility bills.

We only disconnect service as a last resort if we are unable to resolve the issue or arrange a payment plan. For customers behind on their payments, we typically send a reminder notice 33 days after the unpaid bill is due and a disconnection notice 64 days after the original due date. In 2018, we disconnected service to a total of 64,635 customers. The majority of these customers were reconnected within 72 hours of the disconnect after they arranged payment plans or paid their bills in full. Heat-affected disconnections are not performed in our five Upper Midwest states during the heating season. In each of our states, our Customer Care leadership has the authority to suspend disconnections during extreme weather or other emergency situations.

Scam Awareness

Nationwide and internationally scammers continue to target utility customers, trying to take their money. Utility scam activity first spiked in 2014, and since then, we have combatted the problem by making technology changes and raising awareness to expose the tactics of scammers and help customers protect themselves.

Customer losses were down 8% in 2018 compared to the previous year, while the reported number of scam attempts was up, indicating customers may be increasingly informed around the danger scammers present. Since we formally began to address the issue, customer losses are down by more than half.

We are able to track both in-person and phone-based scam attempts thanks to the reports of customers. When we learn of heightened scam activity in specific locations, we promptly contact local media and use our social media channels to release information and alert customers. The data we collect is also used in partnership with law enforcement to investigate possible larger scam efforts and trends across our territory, with the ultimate goal of shutting down scammers. Xcel Energy security alone has shut down more than 250 phone numbers used by scammers to target our customers.

In addition, we joined Utilities United Against Scams in 2016, a collaborative of more than 100 utilities across the United States. Members share leading practices and updates about how scams are affecting their customers, as well as ideas and updates on what they are doing to spread awareness. The group was instrumental in establishing an annual awareness day — National Utilities United Against Scams Day — which takes place on the third Wednesday each November.

Data Privacy

Xcel Energy takes seriously our responsibility to protect company information, including the confidential information that we generate and receive about our operations, customers, employees, contractors and vendors. Our corporate policies and standards regarding information management and protection are designed to maintain the trust of the individuals and organizations we do business with.

We operate in a highly regulated industry that requires the continued operation of sophisticated information technology systems and network infrastructure. In the ordinary course of business, we use our systems and infrastructure to create, collect, use, disclose, store, dispose of and otherwise process information. Our employees and contractors are trained on information management and protection requirements.

Our Enterprise Security Services group helps ensure the protection of company information across all business units. This organization includes four main branches: Cyber Security, Enterprise Resilience, Physical Security and Security Governance and Risk Services. In addition, we have established a Cyber Defense Center and an Enterprise Command Center designed to investigate, respond, mitigate and remediate incidents and vulnerabilities that may involve company information.

Serving our customers involves working to keep them safe. We continuously promote public safety campaigns to raise awareness around the hazards associated with natural gas and electricity.

Public safety

Raising safety awareness

Our goal is for everyone who lives, works or gathers near our facilities to be aware of possible hazards and how to respond safely to them.

Ensuring the safety of our employees, customers and the public is a responsibility we take very seriously. To do this, we have comprehensive outreach programs that promote safe behavior among our customers, communities, emergency responders and third-party workers.

Ultimately, we aim to prevent accidents that can result in serious injury or death, property damage, costly repairs or fines and decreased service reliability. Most serious accidents involving the energy we deliver happen because someone directly or indirectly makes contact with an overhead electric line, digs into an electric or natural gas line, or fails to respond safely to the warning signs of a natural gas or electric emergency.

2018 Results

- Our company delivered its best-ever public safety performance during the year. We surpassed our annual target of 1.30 or fewer excavation damages per 1,000 locate requests by more than 8% as the number of third-party dig-ins to underground pipes and wires continued to decline and responded within an hour or less to 87% of customer calls associated with a suspected natural gas leak or other emergency.
- We opened new training villages in Minnesota and Colorado that will provide 600 to 800 employees and community emergency responders with the opportunity to train in a realistic setting. The villages can simulate more than 40 different types of natural gas leaks and recreate incidents that have occurred across the country.
- Customer recall of our safety advertising and perception of our commitment to public safety continue to steadily increase, as measured by customer survey responses.

- An advertising partnership among utilities to promote calling 811 before digging resulted in nearly 1.1 million total message impressions in April 2018 — national safe digging month.
- Xcel Energy linemen Kellen Schmidt and Scott Knight were instrumental in changing Minnesota's Move Over law, which now requires drivers to slow down or move over when approaching utility, construction and emergency vehicles stopped along two-lane roads.

Public Safety Awareness Efforts

Raising awareness about the dangers associated with activities near overhead and underground electric and natural gas lines is no easy task. We send direct mail to thousands of customers each year and offer free safety materials through fulfillment programs and partner organizations. We also offer online safety resources for emergency responders, public officials, elementary educators, students and their parents, and third-party workers.

We employ the following tactics to raise public safety awareness:

- Advertising
- Broadcast media appearances and outreach
- Email communications
- Event appearances
- Mailings
- Social Media
- Sponsorships
- Trainings and meetings
- Websites

Advertising

Xcel Energy's Always Delivering campaign launched in mid-2016 and continued to carry public safety messages throughout 2018. While the campaign uses simple language and consistent, entertaining visuals, as well as subtle humor and a friendly approach, we adjusted safety language to be a bit more serious and even more direct to make a quicker connection to our critical safety messages.

Advertising continues to be one of our most successful tactics for raising safety awareness. With an objective to reach as many customers as possible, we extended our campaigns to run year-round in 2018 and concentrated on high-impact media, such as television, radio and digital advertising. As a result, we increased total number of impressions by approximately 50%.

Outreach to Specialty Audiences

Throughout the year, we also focus awareness efforts on audiences that are influential or play an important role in supporting public safety. These audiences include:

- Emergency responders, such as firefighters and law enforcement, who may be first to respond to electric and natural gas emergencies
- Third-party contractors who may come into contact with power lines or natural pipelines as part of their jobs, including construction, roofing and tree care professionals, as well as agricultural workers and those who do excavation work
- Educators, including principals and superintendents, and teachers and students in second through sixth grades

We have fulfillment programs that annually distribute tens of thousands of brochures, booklets, DVDs, videos, posters, activity sheets, visor cards or other materials tailored to educate and inform these audiences of safety practices and hazards. Many of these communications are provided in both English and Spanish. We also direct these groups to use our e-SMART worker and e-SMART kids websites, as well as the Responding to Utility Emergencies online training that we sponsor.

In addition to materials and online resources, we provide in-person trainings and conduct numerous emergency drills for local emergency responders, and offer school and community safety presentations. There is an online course to encourage and train Xcel Energy employees who want to volunteer as Public Safety Ambassadors and conduct public safety presentations or participate in community events.

Public Safety Campaigns

Our public safety campaigns are targeted at communicating outreach messages in four key areas, including:

- Calling 811 before digging
- Staying at least 10 feet away from overhead lines to be safe
- Recognizing and responding to a possible natural gas leak
- Keeping natural gas meters clear of snow and ice

Call 811 Before You Dig

Accidental third-party excavation damage to underground electric and natural gas facilities not only interrupts service for our customers unnecessarily, it is a significant safety concern and remains the biggest threat to our natural gas distribution systems. Xcel Energy is a member of the Common Ground Alliance, a member-driven association committed to saving lives and preventing damage to underground infrastructure by promoting effective damage prevention practices. The association's most prominent initiative is the national 811 phone number that people can call to have underground utility lines marked before they dig.

Some of our outreach efforts to promote 811 in 2018 included:

- Launching an advertising partnership in Colorado and Minnesota. Together with Colorado 811, Centerpoint Energy and Gopher State One Call, we created a cohesive, separately branded message for calling 811 before digging.
- Sending semi-annual bill inserts with details about the importance of maintaining customer-owned service lines, and updating the semi-annual natural gas safety bill insert to include this information, so that this message will now be delivered quarterly.
- Participating in the National Excavator Initiative video as a subject matter expert for calling 811 and safe digging practices. Xcel Energy was joined by peer utilities, locate and excavation companies along with heavy equipment providers and operators.
- Collaborating in lighting the Lowry Bridge in Minneapolis green for National 811 Day, as well as Xcel Energy's Hiawatha and Midtown substations in Minneapolis.
- Participating in the third annual Colorado 811 5K run, which included a post-run safety event with electric safety demonstrations and bucket truck rides, local emergency responders, Red Cross information and games. The number of registration spaces was increased again in 2018 and registration was full before race day.
- Sponsoring JJ Harrison, the 811 Rodeo Clown, with over 1 million FaceBook followers.
- Participating in and sponsoring the Colorado Mock Line-strike Drill attended by more than 300 excavators and emergency responders.
- Sponsoring the Cold Zone Hazmat Conference in Minnesota for 200 attendees from seven states.

Electric Safety

Contact with electricity can result in serious injury or even death. We continually work to engage and educate the public, urging them to stay away from equipment, such as overhead lines, underground lines, downed power lines and damaged electrical equipment.

Some of our outreach efforts in 2018 included:

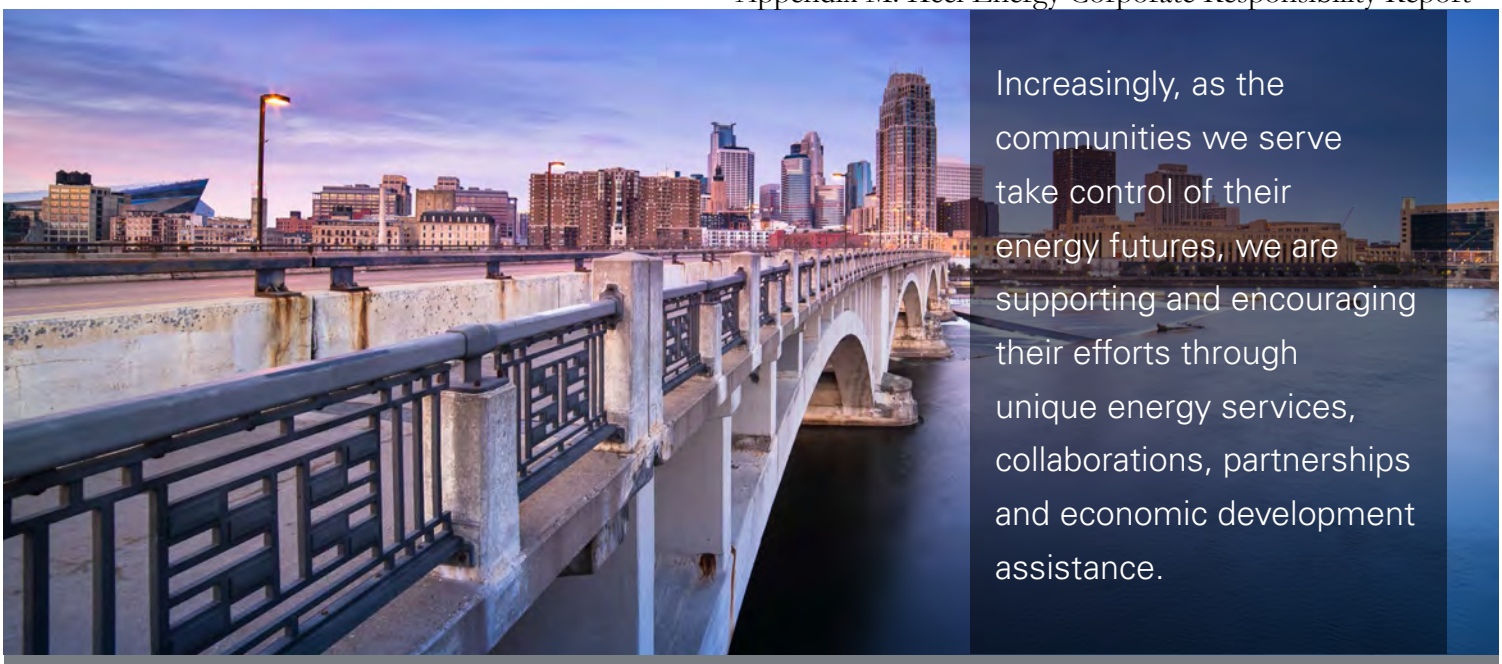
- Conducting dozens of public electric safety demonstrations featuring the Power Town arcing display.
- Conducting electric safety demonstrations at the Minnesota State Fair for our 29th year. We had 72 employees volunteer nearly 200 hours to educate approximately 30,000 fair attendees about electric and natural gas safety and calling 811 before you dig.
- Including safety messaging with our press releases and social media during severe weather.
- Providing thousands of electric and natural gas safety pamphlets at public safety events throughout our service territory.

Natural Gas and Pipeline Safety

While keeping the public safe is a core value for Xcel Energy, it is also a requirement when it comes to natural gas pipeline safety. We must meet the American Petroleum Institute Public Awareness Programs for Pipeline Operators Recommended Practice 1162. This involves taking steps to increase awareness about the safety of our facilities and energy service that build trust among stakeholders, including customers, communities, investors, employees, public officials, at-risk workers, educators and the industry.

We annually distribute materials through our membership with the national nonprofit Pipeline Association for Public Awareness and our participation in state-specific pipeline associations, as well as Minnesota's Community Awareness Emergency Response association. Through these organizations in 2018, we helped distribute more than 111,000 safety guides, books and newsletters to excavators and to public and emergency officials in states where we have natural gas distribution and transmission pipelines. We also participated in and helped sponsor many pipeline emergency responder meetings in our states and provided additional, in person pipeline safety trainings to hundreds more emergency responders.

Twice a year, we send safety information designed to share details about staying safe around natural gas to all of our natural gas customers with their bills. The bill inserts include a special mercaptan scratch-and-sniff badge that helps to educate customers on how a natural gas leak smells. Customers that receive electronic bills can request the insert with the mercaptan scratch-and-sniff badge.



Economic development and jobs

Partnering with communities

We play a valuable role in supporting local economies as an energy provider through our electric and natural gas service and our partnership.

With our ongoing investment in infrastructure — the plants, pipes, poles and wires that make up our business — we generate tax revenue, purchase goods and services and employ local workers. But, our connection and contribution to local economies goes much deeper than this.

By working side-by-side with local chambers of commerce and economic development organizations, we provide energy expertise and a valuable service that can help attract and retain area business. After all, for many businesses, energy is an important consideration for where they locate — it may be their largest expense or the focus of corporate sustainability goals. By offering a complete package of energy solutions, including a comprehensive portfolio of renewable and energy-saving options, along with competitive prices and outstanding service reliability, we are helping our communities successfully compete for business, something that supports all of our bottom lines.

2018 Results

- Through our focus on economic development, we generated and supported over 85 new business prospects for our communities in 2018. Of those, nine located and began doing business within our service area, supporting nearly 1,950 jobs and $750 million in capital investment.
- We filed a plan with regulators in early 2019 to provide renewable energy to a proposed Google data center to be located on Xcel Energy property adjacent to our Sherco Generating Plant in Becker, Minnesota. Consistent with transition plans developed in partnership by the company, Becker and Sherburne County, the project will add tax base and generate jobs for the community affected by the planned retirement of the plant's two oldest coal units. If approved, the Minnesota Department of Employment and Economic Development estimates the project will result in nearly 2,000 construction jobs, 50 full-time jobs and general economic growth of almost $150 million.

- Xcel Energy supported legislation in Colorado that was adopted to support economic development and new customer growth in the state. It allows utilities to offer negotiated, economic development rates to customers that require a new minimum electric load of three megawatts. The legislation also allows utilities to expand already authorized renewable programs to provide up to 20 megawatts of renewable energy for a customer that meets the criteria under the economic development rate program.
- Since 2014, Partners in Energy has worked with 37 communities to develop energy action plans — 20 in Minnesota and 17 in Colorado. Working with these communities to provide outreach delivered strong results for the year, including more than 49,000 participants in Xcel Energy efficiency programs and 15,500 participants in renewable energy offerings.
- We signed Memorandums of Understanding to establish Energy Future Collaborations with eight communities in Colorado. Customers in these communities represent approximately 32% of our retail load in the state, and the communities reflect a cross-section of the varied municipalities we serve — from rural to urban and mountain locations.

Xcel Energy Direct Economic Impacts

2018 Economic Value Generated (in millions)

Total revenues	$11,537
Electric utility revenues	$9,719
Natural gas revenues	$1,739
Other operating revenues	$79

2018 Economic Value Distributed (in millions)

Electric fuel and purchased power costs	$3,854
Cost of natural gas sold and transported	$843
Employee compensation, including wages and benefits	$1,983
Property tax payments	$442.9
Franchise fees	$190.8
Community investment	$63.1
Interest charges and financing costs	$652
Dividends paid	$730

Energy Future Collaborations: A Proactive Partnership Approach

Through Energy Future Collaborations, Xcel Energy is taking a new approach and uniting the specific energy goals of communities with our company's services and expertise to achieve shared objectives. The proactive collaborations are aimed at addressing a wide range of priorities, including how best to:

- Advance specific reduction carbon and renewable energy targets
- Reduce a city's carbon footprint
- Maximize energy efficiency programs
- Support economic development
- Integrate emerging energy-related technologies into area homes and businesses

The relationship-driven approach taps into many existing Xcel Energy programs and offerings but also focuses on uncovering creative solutions to new ideas and needs. From Xcel Energy's standpoint, not only do we develop a more meaningful relationship with some of our largest customers — our communities — but the collaborations provide an opportunity to inform key leaders and community members about our business and significant initiatives. Ultimately, the collaborations can help increase support for company initiatives that support community goals, such as the Colorado Energy Plan and the company's carbon reduction vision.

We have signed Memorandum of Understandings (MOU) for Energy Future Collaborations with eight diverse communities including: Alamosa, Breckenridge, Denver, Lakewood, Louisville, Lone Tree, Nederland and Westminster. We also believe the collaborations can be replicated with other cities and towns throughout Colorado, as well as in other jurisdictions.

With the MOUs in place, the company and the communities develop work plans involving a number of projects, along with objectives, timelines, resources required, funding needed, metrics for success, reporting measures and ultimate deliverables. We have finalized work plans with six of the eight communities and are on track to complete the other plans this year. An important point about the new framework is that the MOU guiding principles allow flexibility, but also protect nonparticipants from things like cost shifts.

Partners in Energy

Xcel Energy has a program and special team to support communities in achieving clean energy, economic development and energy conservation goals. The effort, known as Partners in Energy, started in fall of 2014 and is targeted at communities with the objective of helping them identify their future energy goals and develop strategic plans to drive activity. We then provide the resources to put the plan into action, supporting communities as they implement projects designed to achieve their goals.

Local governments play a larger role in choices around energy, and through the program, we can work with communities to support development and implementation of energy action plans that they own. Partners in Energy is unique in that it provides the opportunity to connect directly with community officials and organizations to help them meet their goals, leveraging our entire portfolio of energy solutions including efficiency, renewable and even payment programs. Typically, a community brings ideas and resources, while Xcel Energy offers direction, guidance and project management. We learn what communities prioritize and identify potential gaps where we can provide products to meet their needs and help them reach their goals. In return, the partnerships help to raise awareness and increase participation in Xcel Energy's current conservation and renewable energy offerings.

An energy action team is a group of local residents, business owners or energy stakeholders who work to develop the community's energy action plan and oversee its implementation. They are often the local leaders who work with Partners in Energy while connecting with their community. Action plans are based on community needs, resources, leadership commitment and the local vision for energy use in the future. Strategies to gain local support may include educational workshops, outreach at local events and promotional outreach including newsletters or personal canvasing — all approaches designed to gain recognition, participation and spread awareness to local residents.

Each community determines its goals, and we work together to drive success. We also help communities to track and report progress. In 2018, we expanded to reach and support even more communities through the following improvements:

- Planning services broadened to assist communities that did not have the need or resources to develop a full energy action plan.
- In-person programming was introduced to deliver educational resources to community leaders while providing opportunities to network and learn from the experience of others.
- The program's online presence was expanded to give participants a place to access their individual community documents, plus other resources critical to making informed choices around energy in today's rapidly changing energy landscape

Focus on Economic Development

Xcel Energy is leading local economic development activities in the communities it serves. We start by providing a competitive solution that meets customer needs. This includes offering outstanding reliability and customer service, combined with favorable pricing on our nationally recognized renewable energy and efficiency options.

We have developed strong partnerships with local, state and regional economic development organizations to support opportunities for customer and economic growth. In 2018, our Corporate Economic Development team attended more than 35 national conferences and industry events to promote economic development opportunities across our service area. This work focused on developing relationships to expand business development in all eight states where we operate.

We continue to focus on serving top industry clusters that represent the leading employers and capital investors within our service area.

These include:

- Aerospace and defense contractors
- Data centers
- Refrigerated storage warehouse and distribution
- Food and beverage processors
- Industrial manufacturing
- Medical device, instrument and supply manufacturing
- Oil and gas

Our team tracks trends that affect the growth of these industries to identify new service options and programs that can facilitate continued growth of these key industries. We develop deep-dive customer analytic reports to better understand individual customer needs and create individualized action plans that can enhance our relationship we these customers. We host Business Expansion and Retention meetings with key accounts to strengthen our existing relationships and explore matters that are of mutual interest that go beyond energy. Through these efforts, we can explore new product offerings and promote policies that anticipate customers' future needs.

Our Certified Site program provides business prospects with real estate options to increase their speed to market in locating their operations. In 2018, an inventory of 41 certified sites was identified throughout our eight states. These sites have undergone rigorous review of more than 120 data points to attract business development. We work directly with site representatives including landowners, developers, municipalities and economic development organizations to develop the data and complete the certification process. A nationally recognized site selection expert reviews the reports and validates the data and its significance for identifying prominent real estate options for potential users. Information on Xcel Energy's Certified Sites is available on xcelenergy.com.

Minneapolis Clean Energy Partnership

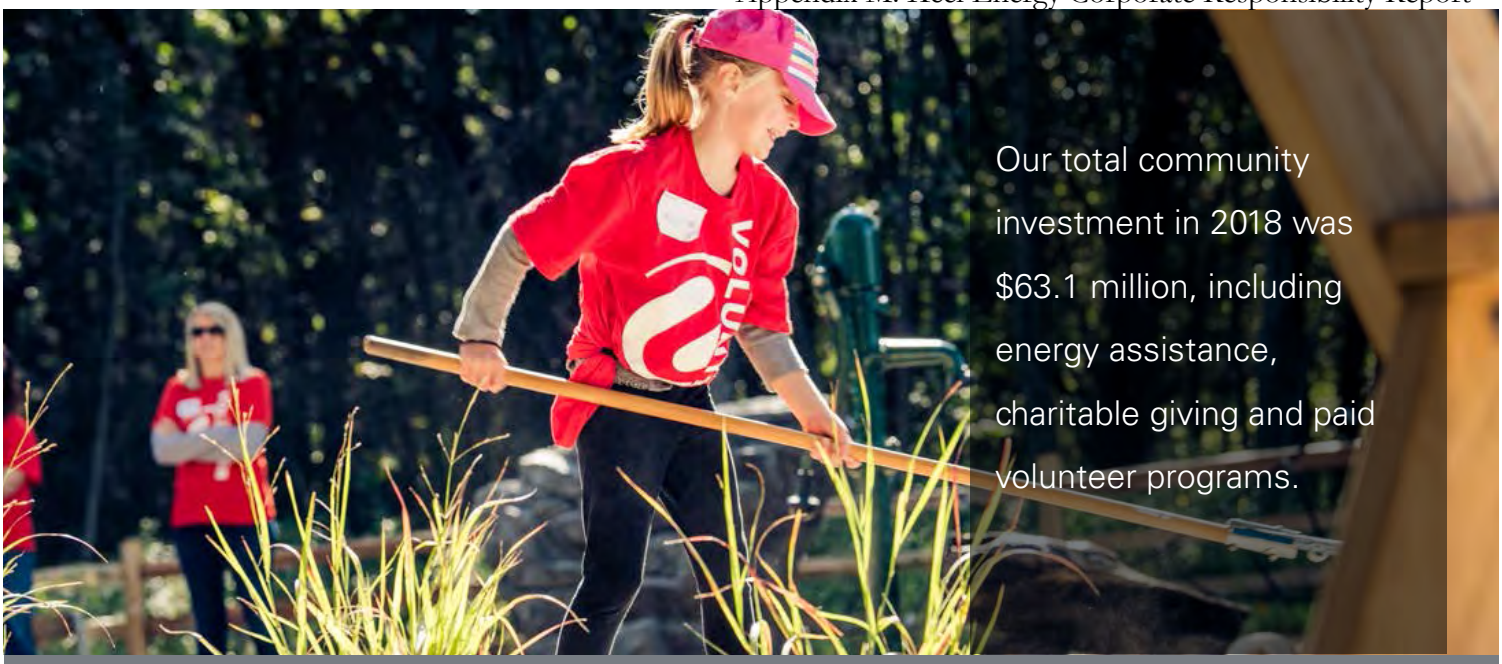
The city of Minneapolis, Xcel Energy and CenterPoint Energy teamed up to form a novel Clean Energy Partnership (CEP) in 2014 in support of the city's Climate Action Plan and 2040 Energy Vision. Now in its fifth year, the partnership continues to build on a long history of collaboration to explore innovative approaches and enhanced outcomes in energy efficiency and the use of renewable energy in Minneapolis and create longstanding community impacts. The partnership provides a leadership framework through which the city and utilities can work together to prioritize, plan, coordinate, implement, market, track and report progress on clean energy activities in the city.

The Clean Energy Partnership has approved the following priorities:

- Achieve energy efficiency in the industrial, commercial and residential sectors
- Make clean energy accessible through financing tools
- Make the city more sustainable or resilient through increased local renewable energy

The 2019-2021 work plan was approved by the board in late 2018. Xcel Energy partnered with the city on pilot projects including, developing a plan to decrease city enterprise energy consumption 10%, installing electric vehicle infrastructure to enable earlier transition of city fleet, and a focused effort to work with our business customers. We are also working with the city to build a community solar garden with a focus on low-income subscribers where we will target energy efficiency efforts to decrease the energy usage of the solar garden subscribers. The partnership continues to explore equitable access to clean energy jobs through study and project implementation, and we are working on energy disclosure tools to help the city implement new energy requirements.

We continue to help the city progress towards its clean energy goals through our precedent setting transition to a cleaner generation mix as well as by helping city residents and businesses save energy and increase options in our renewable choice programs. According to the partnership's latest annual report, released in mid-2018, citywide greenhouse gas emissions are down 20.4% from 2006 levels, exceeding the city's 2015 reduction goal of 15%.



Community giving and volunteerism

Corporate citizenship

We are committed to making a positive impact — as an energy provider, environmental steward, good neighbor and community advocate.

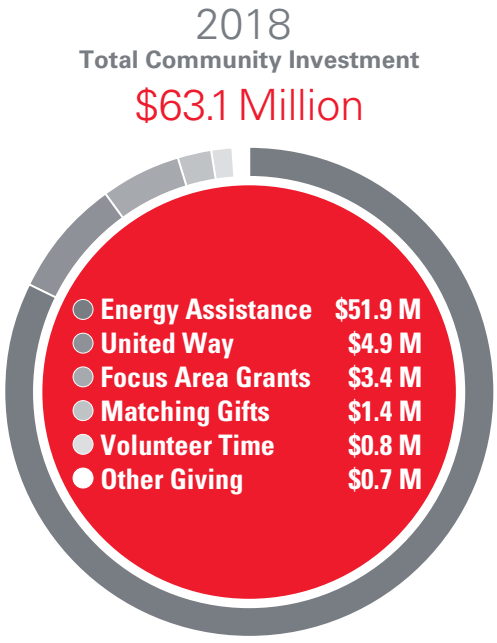
Xcel Energy serves hundreds of cities and towns across eight states. Through our active investment in their infrastructures and the energy we provide, we are literally connected to and serve as an integral member of those communities.

We understand our company's success is directly tied to the success of our communities. That is why investing in them through charitable giving and sharing our time and talents is fundamental to how we do business.

2018 Results

- Xcel Energy employees volunteered more than 90,000 hours and served on over 400 community, chamber and nonprofit boards. During the past year, we improved our tracking of volunteer and board participation because we use the information to measure community engagement.
- Through programs funded by our focus area grants, more than 450,000 students benefitted from science, technology, engineering and math education — an essential field of study for our future workforce and for the economy as a whole.
- The Xcel Energy Foundation contributed $60,000 to relief efforts following the Lake Christine, Spring Creek and other wildfires that burned almost 120,000 acres in Colorado in early summer. The funds helped to replace damaged equipment for the fire departments and other emergency responders who managed the wildfires.

- For National Philanthropy Day, the Association of Fundraising Professionals recognized the Xcel Energy Foundation as an Outstanding Foundation that is demonstrating an exceptional commitment through its strategic financial support and its encouragement and motivation of others to take leadership roles in philanthropy and community involvement.
- The Amarillo Branch of the National Association for the Advancement of Colored People (NAACP) honored Xcel Energy with its Diamond Jubilee for the company's support of its efforts. In this Texas community, we have funded and presented scholarships as part of the NAACP's spring scholarship luncheon for more than a decade and have consistently sponsored the group's educational and fundraising programs.
- Junior Achievement of Northwest Wisconsin recognized Xcel Energy as its Outstanding Community Partner of the Year for the company's commitment to helping area youth with financial literacy, work readiness and entrepreneurship. The organization serves a district of approximately 18,000 students in classrooms across 20 Wisconsin counties, most of which Xcel Energy serves.
- Xcel Energy was nominated as Corporate Supporter of the Year by the Black Data Processing Associates (BDPA) Twin Cities chapter. The award recognizes the efforts of corporations that support BDPA's mission to increase participation of people of color in the information technology field. For a number of years, we have provided the organization with financial support, volunteers and internship opportunities.
- Xcel Energy was a recipient of a Colorado Business Committee for the Arts Award, a statewide recognition that honors companies and individuals for their outstanding partnerships and engagement with the arts. We were nominated by several of our arts and culture grant partners including Cleo Parker Robinson, Dairy Arts Center, 40 West Arts and the Alamosa Live Music Association, among others.



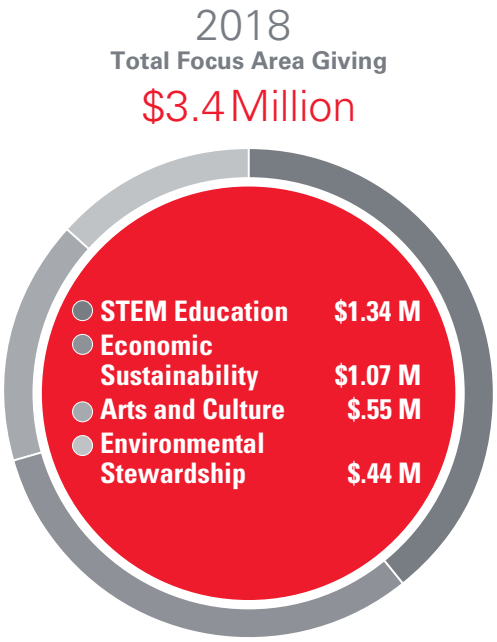
Xcel Energy Foundation

The Xcel Energy Foundation is our company's charitable arm that oversees giving and volunteer programs. Its mission is to use the collective knowledge, resources and skills of our staff and colleagues to make a positive impact in communities throughout our service territory.

The foundation generally focuses its support in four areas:

- **STEM Education (science, technology, engineering and math):** The economic growth and future of the communities we serve relies on the educational systems and programs that produce a quality workforce for tomorrow. Just like other businesses in the community, Xcel Energy's future success relies on having a workforce that is educated and well trained.
- **Economic Sustainability:** Employment levels directly impact a community's economic prosperity, and ultimately, quality of life. We believe that all of our customers should have the skills and opportunity to be successfully employed so we support organizations that promote workforce development and economic self-sufficiency.
- **Environmental Stewardship:** Our communities count on us to produce energy responsibly and to conserve natural resources. While we do all we can in our operations to meet these expectations, we can do more by supporting organizations and programs that work to protect and enhance the natural environment.
- **Arts and Culture:** Thriving arts and cultural activities are a key component to vibrant and strong communities. With a mission to help create desirable communities in which to live, we support programs that increase the opportunities and accessibility of arts and cultural programs to all.

In 2018, the Xcel Energy Foundation contributed over $3.4 million in grants to promote our primary focus areas of STEM education, economic sustainability, environmental stewardship and access to arts and culture. Altogether, 380 nonprofit organizations received grants averaging about $9,000 each.



Employee Involvement

Our employees are active members of their communities, where they live and work. We support this commitment by offering a number of programs that encourage their involvement, including:

- **Volunteer Paid Time Off (VPTO):** Full-time employees are eligible for up to 40 hours per year to volunteer for nonprofit organizations in our service area to help strengthen the communities we serve.
- **Dollars for Doing:** The Xcel Energy Foundation matches each hour an employee volunteers with a $10-per-hour contribution to the nonprofit, up to 100 hours annually per employee.
- **Volunteer Energy:** Groups of employees and retirees that volunteer together on a project are eligible for Volunteer Energy funding of up to $1,000 annually, which goes to the associated nonprofit from the Xcel Energy Foundation, in appreciation for the volunteer effort.
- **Matching Gifts:** The Xcel Energy Foundation matches dollar for dollar any employee and retiree charitable donations of $50 or more, up to $750 for nonprofit organizations and up to $2,000 for higher education institutions.
- **United Way:** the Xcel Energy Foundation sponsors an annual United Way campaign and matches the pledges of employees, retirees and contractors.
- **Day of Service:** Xcel Energy hosts a special volunteer day where employees demonstrate collectively their community spirit.
- **Board Service:** Throughout our service territory, we currently have hundreds of employees serving on nonprofit boards, with some employees serving on multiple boards.

United Way Campaign

Xcel Energy has a long-standing tradition of supporting United Way and the community organizations it assists. Each year, we sponsor an employee campaign that for seven consecutive years has raised well over $2.5 million annually in employee and retiree pledges, which the company matches.

The campaign is a fun and rewarding part of working at Xcel Energy, with a number of special fundraising events — from chili cook-offs to sport tournaments. This includes a popular "dress down" badge that employees can purchase which gives them a pass to wear jeans to work and significantly boosts fundraising.

Combined with the company match, the campaign in 2018 raised more than $4.9 million to support United Way programs and hundreds of nonprofit organizations throughout Xcel Energy's service territory. More than 4,000 employees and retirees contributed about $2.72 million in pledges, surpassing the campaign goal by 7%.

In addition, employees in our Texas and New Mexico service area support United Way's Day of Caring each spring. More than 70 employees volunteered in 2018 to lend a hand to complete improvement projects at several local nonprofit agencies.

2018 Day of Service

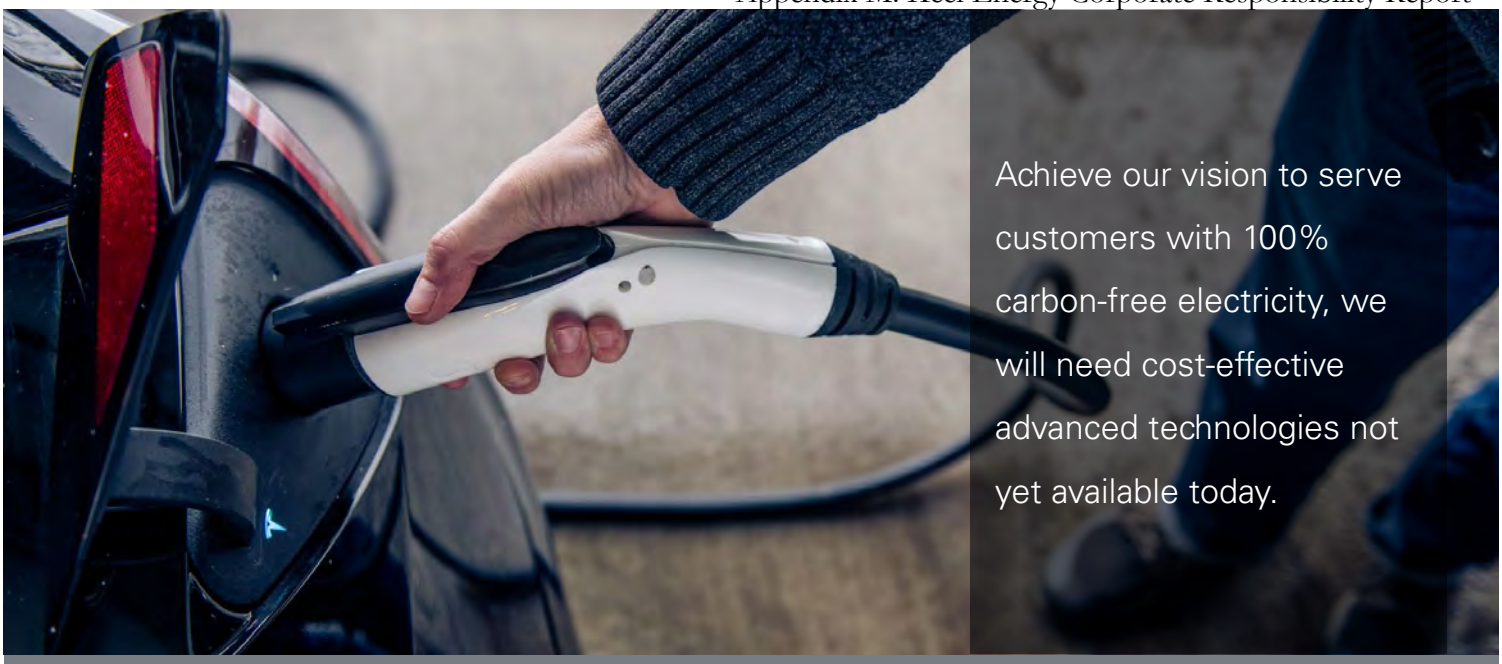
More than 4,600 employees, retirees and family members, along with some friends and customers, came together in September to volunteer to better their communities by participating in Xcel Energy's eighth annual Day of Service. The volunteers joined together at 116 project sites across Colorado, Minnesota, South Dakota, North Dakota, Michigan and Wisconsin to dig, plant, paint, cut, sort, organize and much more on behalf of a variety of community nonprofit partners.

In total, the effort contributed approximately 13,800 volunteer hours to support our local communities, valued at more than $429,000.

Energy Education

We want our customers to know how their energy is produced and delivered. To help achieve this objective, we support energy education in a number of ways. Most of our major non-nuclear power plants provide public tours for their neighboring communities, and through our online Energy Classroom, we offer educational resources for teachers and students.

Through a special community program in New Mexico, we support solar energy education for customers and schools. Our solar education center in Roswell demonstrates different technologies for collecting sunlight to generate electricity. We own four photovoltaic systems located on partner sites that are available to help teachers with energy curriculum specifically developed for New Mexico classrooms.



Innovative energy programs and technology research and demonstration

Energy innovation

Rapidly evolving technology is changing customer preferences for more sophisticated products and services, and those customer preferences are driving change in how we serve our customers.

Within the next decade and beyond, we will have more change in our industry than we have experienced in the last half century, driven largely by technology. Through collaborations with researchers, technology developers, venture investors and others in our industry, we actively monitor and stay abreast of developments in emerging and advanced energy technology. We also have underway a number of pilot and demonstration projects that are testing the real-world application of cutting-edge technologies and are serving our customers today.

This work has become increasingly important because of our ambitious carbon reduction goals. To realize our vision for a carbon-free future, we will need clean 24/7 technologies to integrate high levels of renewable energy, as well as other advanced technologies.

Advanced technologies also make our operations more efficient, safer and cost effective. As powerful tools emerge to transform our work, they can reduce our costs, improve productivity and enhance the service we provide, benefitting our customers through their overall experience and the costs they pay.

2018 Results

- We launched our first set of voice actions using the Google Assistant as a seamless way for customers to access information to improve energy efficiency in their homes. It is part of a new collaboration with Google to deliver tools that customers can use to manage energy use.
- In Minnesota, we announced plans to build on our clean energy leadership by investing more than $25 million to increase access to electric vehicles (EVs), and help drivers and fleet operators start driving electric.

- In Colorado, we proposed and received approval for a residential demand response battery pilot. It will study the integration of batteries into utility systems, battery performance and customer preferences. We are seeking to work with two to four battery vendors and engage up to 500 customers during the pilot term, which will begin in late 2019 and continue for up to two years.
- We continue to gain valuable insights from our investment in Energy Impact Partners, which has now invested $325 million in 25 companies that support a number of advancements from distributed energy resources to storage, electric vehicles, advanced data analytics, microgrid applications, cybersecurity and other clean energy technologies.
- Xcel Energy became the first public utility to receive permission from the Federal Aviation Administration to inspect transmission lines using drones flown beyond the operator's visual line of sight.
- We began piloting the use of bots to drive speed and accuracy in performing routine tasks within our Finance department, enabling employees to shift time to higher-value work.

Advanced Grid Intelligence and Security

Through our Advanced Grid Intelligence and Security (Advanced Grid) strategic initiative, we plan to transform the grid into an intelligent, integrated network that securely, efficiently, reliably and safely integrates distributed energy resources.

We have started building Advanced Grid technology infrastructure in Colorado where regulators have approved the initiative. This includes:

- Upgrading to advanced meters for 1.5 million Colorado electric customers from 2019 to 2024.
- Installing Integrated Volt-VAR Optimization technology (IVVO) from 2017 to 2022 which allows customers' appliances to run more efficiently, and in turn, use less energy and potentially reduce monthly bills.
- Implementing the Field Area Network (FAN), a new communications network that provides the infrastructure necessary to enable two-way communications between intelligent devices on the grid — such as advanced meters — and the control center. These communications include automatically notifying us when customers lose or regain power, improving our ability to identify outages and more efficiently deploying repair crews. The FAN continues to be installed in the Denver metro area and the entire network will be complete by 2023.

We began deploying FAN advanced field devices in 2018 and implemented a secure, two-way private network that will function as the foundation for the technology in Colorado, as well as Minnesota, where we have regulatory approval for a time-of-use pilot that will launch in 2020. The network enables the secure flow of information between control centers, new advanced devices in the field and our customers.

The FAN infrastructure is critical for when we begin deploying advanced meters to Colorado and Minnesota customers in 2019. We plan to begin rolling out advanced meters to 13,000 Denver metro area customers in late 2019. Through the pilot in Minnesota, 17,500 meters will be deployed giving 10,000 customers from the Hiawatha West and Midtown area of Minneapolis and customers in the Westgate area of Eden Prairie the opportunity to save money by using electricity when it is less expensive to generate and deliver.

Electric Vehicles

The future of transportation is dramatically changing, and as more electric vehicle options become available, a growing number of customers want to reduce their carbon footprint through the cars they drive. We are uniquely positioned to support our customers and communities and to work with electric vehicle (EV) stakeholders to make this change and ensure it truly benefits customers, the environment and the power grid we all rely upon.

Through our EV strategy, we are focused on:

- Raising awareness and increasing access to information on the benefits of EVs
- Helping reduce the upfront costs of infrastructure needed to charge EVs
- Establishing time-varying rates and smart charging technologies to ensure that EVs can charge as much as possible on low-cost, low-carbon energy

While EVs create a significant opportunity for drivers and fleet operators to save on fuel and other costs, barriers exist to wider-scale adoption, such as customer awareness, high up-front costs and the availability of charging infrastructure. We can help overcome these barriers by developing new services, piloting them and then rolling out our most successful ideas to customers on a broader scale.

We developed a portfolio of innovative pilots in Minnesota that will benefit drivers, customers and the environment. The initiatives and pilot programs focus in three main areas: home charging, public charging and fleet operations. This includes a two-year pilot in Minnesota to 100 residential customers that offers a turn-key approach to charger installations by reducing the upfront costs for equipment and providing off-peak pricing benefits. Future options could include a new subscription service that would provide drivers with a set bill for EV charging and equipment each month, and we are exploring dynamic digital tools to help customers understand all their options when it comes to vehicle choices, pricing options and charging solutions.

For public charging, our fast-charging-corridor pilot will seek to leverage public and private funds to increase the availability of fast-charging stations on highways and other major corridors. We are also working with the cities of Saint Paul and Minneapolis on a pilot to support a charging network for everyone, including those who may not own vehicles. Through a partnership with HOURCAR, a local, independent, nonprofit car-sharing service, Xcel Energy will support a new, all-electric, one-way car-sharing service and other innovative mobility services in the Twin Cities. This project is intended to increase access to the benefits of electric transportation, including those in low-income, under-served communities.

We also plan to make it easier and more affordable for large fleet operators like Metro Transit, the Minnesota Department of Administration and the City of Minneapolis to integrate electric vehicles into their fleets. We will provide the electrical infrastructure needed to charge the first eight of Metro Transit's electric buses and are looking to provide charging infrastructure for the State of Minnesota and the City of Minneapolis EV fleets and other customers over time.

We expect to expand our EV efforts to other states, and as we pursue our EV Plan, we are focused on these objectives:

- Empower customers with information, tools and options
- Increase access to electricity as a transportation fuel in an equitable manner
- Encourage efficient use of the power grid and integrate renewable energy
- Improve air quality and decrease carbon emissions
- Ensure reliability, interoperability and safety of equipment
- Leverage public and private funding opportunities
- Provide benefits to all customers, both EV drivers and non-EV drivers
- Ensure transparency and measure results

Colorado Innovative Clean Technology Projects: Battery Demonstration Projects

Our Colorado Innovative Clean Technology program was first approved in 2009 to test emerging technologies intended to lower emissions. We have and continue to test several new technologies and evaluate their cost, reliability and environmental performance on a small, demonstration scale before determining whether to deploy them more widely for our customers.

We have two battery-storage demonstration projects currently under the program:

- As demand for solar energy at our customers' homes and businesses increases, we are examining how battery storage can help integrate higher concentrations of customer solar energy on our system. Through a project in Denver's Stapleton neighborhood, six homeowners have received Sunverge customer battery systems to test with their rooftop solar installations. We also have installed six larger grid battery systems, supplied by Northern Reliability, Inc., in right-of-ways or easements.
- Through a public-private partnership, Xcel Energy, Panasonic and Denver International Airport are collaborating to test a battery storage system that can both serve as a microgrid to provide backup power to Panasonic's Denver headquarters and to support Xcel Energy's grid at other times. As part of the project, Xcel Energy owns a 1.3 MW-AC solar carport installation and a 1 MW/2MWh lithium ion battery. Panasonic also owns a 0.20 MW-AC solar array located atop its building, which is tied into the system.

With both projects, we are testing various ways to operate the battery systems, and are evaluating and analyzing performance. Testing will be completed in 2020. We are finding that the battery systems perform well and are learning many things that will influence future battery system design and associated integration with our system.

Drones

We are using unmanned aircraft systems or drones in a number of applications. From inspecting power lines to wind turbine blades and evaluating substations for equipment upgrades, drones are making these tasks easier, safer and helping to reduce costs.

We were the first in the nation to enter into a partnership for safety with the Federal Aviation Administration (FAA), and now hold one of five of the partnerships, along with GE, Amazon, Google, and Florida, Light and Power. In 2018, we increased the use of drones as we became the first public utility in the country to receive FAA permission to fly drones beyond the operator's visual line of sight and without a visual observer to inspect transmission lines. The flights, which began last summer and continued monthly through the year, are part of a program to prove the value of using unmanned aircraft to inspect critical infrastructure in the power industry.

As a regulated utility we are required to inspect electric transmission lines on a routine basis. Traditionally, we have conducted these inspections with helicopters and foot patrols. Using drones to inspect our 24,000 miles of electric transmission lines delivers value on many fronts, starting with ensuring reliability for our customers thanks to better data. It is also safer for employees, especially in remote mountainous areas, and less costly. As technology improves, the cost to operate drones continues to fall, which will save even more money for customers.

The program started in Colorado, and pending FAA approval, we plan to expand the transmission inspection program in other states in 2019.

Energy Impact Partners

With the pace and scale of emerging technologies and changing customer interests, the energy industry is evolving in ways it never has before. Xcel Energy joined Energy Impact Partners in 2015 as an opportunity to better understand technology's impact on our business and to drive greater efficiency and innovation as we meet customer needs.

EIP is a collaborative, strategic investment platform that provides capital primarily to clean-tech companies that seek to optimize energy consumption and improve sustainable energy generation. Our planned $50 million investment over five years represents a new era for us, where we move beyond clean energy implementation for our customers and into the clean-tech investment space.

Xcel Energy was an original participant in the collaboration that now includes more than 15 utility and industrial participants. By joining with peer companies, we gain greater visibility into the business models and technologies of promising companies and have the opportunity to influence emerging business models so that energy companies and third parties can collaborate and grow together. Also EIP brings together energy companies from around the world to share diverse, global perspectives and insights into policy and regulations, helping position us for new trends, rules and other requirements in the states we serve.

We are gaining insights that are helping inform our strategic decisions and how we conduct our business across the organization from energy supply to distribution, customer solutions and cybersecurity.

Electric Power Research Institute (EPRI)

Through our long-time membership with EPRI, we gain insights into the challenges and opportunities for using advanced clean energy technologies and reducing carbon emissions. This includes EPRI's work on electric system resiliency, climate scenario analysis and greenhouse gas reduction goals, as well as integrating renewables, electric vehicles, combined heat and power, customer demand response and energy efficiency.

EPRI also informs our regulators and customers on technical and economic issues, opportunities and challenges related to the use of new grid technologies, including large-scale and customer-sited distributed energy resources, such as energy storage and distributed generation. In this collaborative research environment, we can engage with the industry, technology developers and other stakeholders who test and evaluate new technologies and products, develop tools and methodologies to analyze the effects of distributed energy resources on the power delivery network and optimize their use.

GridNXT at SolarTAC

The Solar Technology Acceleration Center (SolarTAC) in Aurora, Colorado, is a world-class facility for demonstrating and validating advanced solar and distribution grid technologies in a real-world, grid-connected environment. Even before the project's grand opening in 2011, Xcel Energy recognized the potential benefit of the facility and signed on as an original founding member.

Our investment has paid off for customers. Not only have we tested important battery projects at the site, solar technologies fine-tuned at SolarTAC serve our customers in Colorado and New Mexico with more cost-effective, efficient solar energy. Through testing, solar developers were able to make adjustments for adverse weather conditions before installing the technology in our service areas.

To continue evolving with technology and developer needs, the 74-acre site has transitioned to become a test-bed for solar, storage and other distributed energy enabling products and components. GridNXT at SolarTAC now supports the demonstration of advanced technologies for integrating distributed generation and storage, including microgrid capabilities at the edge or end of the electric distribution system.

Renewable and advanced clean technologies

Renewable energy

Xcel Energy operates in some of the country's best regions for producing wind and solar power, and we are putting these resources to work for customers.

Increasingly, the customers and communities we serve want their energy from clean, renewable sources, and we are delivering. Renewable energy plays a vital and growing role in our energy supply and future plans for meeting customer needs.

As wind and solar technologies continue to improve, prices decline, making it possible to operate a reliable, affordable power grid with significant levels of renewable generation. When it comes to managing cost and reliability, scale matters. We are focused on increasing the use of large-scale, universal wind and solar energy because these resources are significantly more economical and can provide energy for all customers at half the cost compared to smaller, distributed resources.

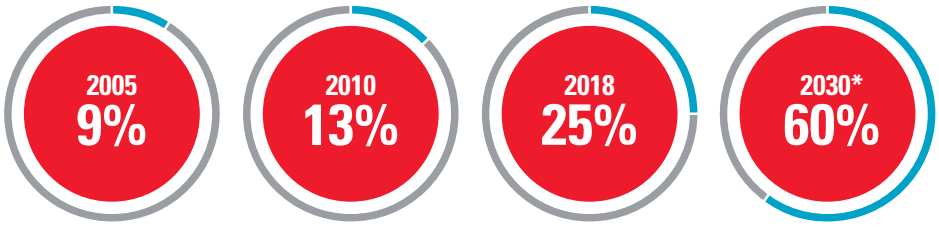
We also recognize that some customers want more renewable energy, beyond what is currently in our energy supply, including some of our business customers and communities that have set goals for up to 100% renewable energy. To meet this need, we continue to expand and improve our voluntary renewable choices, enabling customers to achieve their goals.

2018 Results

- Since 2005, we have been a national leader in wind energy, and according to the American Wind Energy Association, are ranked the No. 2 utility wind provider with nearly 8% of the country's wind capacity on our system.
- Our new, 600-megawatt Rush Creek wind project was completed and is estimated to produce enough electricity to power approximately 325,000 homes annually. It is the largest project we have built and is among the largest in Colorado, with 300 Vestas wind turbines manufactured in the state. The project injected $1 billion into Colorado's economy and is projected to help avoid 1 million tons of carbon per year.

- At year-end, we had 762 megawatts of large-scale, universal solar capacity and 7,288 megawatts of wind capacity — enough to power approximately 3.8 million homes. This includes 1,440 megawatts at wind farms we own.
- After its 2017 debut in Minnesota, our Renewable*Connect® program quickly sold out during its 2018 launch in Colorado. Early in 2019, we successfully transitioned 100% of Windsource® subscribers in Wisconsin to Renewable Connect, demonstrating high engagement and satisfaction with this new option. As customer demand for Renewable*Connect grows, we have proposed expanding the program in Minnesota and expect to propose an expansion in Colorado.
- Nearly 190,000 customers participate in renewable choice programs. Plus, we achieved a milestone of more than 1 gigawatt of distributed solar installed on our system since the programs began.
- The City of Eau Claire, Wisconsin, recognized Xcel Energy for making a difference and helping the city to become more sustainable through the company's efforts to increase renewable energy, efficiency and conservation.

Renewable energy is a vital and growing part of our energy supply.



*Results are estimated and reflect potential scenarios that achieve 80% reduction in carbon emissions by 2030; actual system depends on various factors, including regulatory approval of future plans.

Ramping Up Renewables: Steel for Fuel

Xcel Energy's Steel for Fuel strategy resonates with all types of stakeholders because it expands the company's renewable portfolio and delivers carbon-free energy without raising customer bills. Under the effort, we are adding renewable resources — the steel — at a net savings because the capital costs of the projects are more than offset by future avoided fuel costs.

Delivering on the nation's largest multi-state wind investment

Several years ago, we announced the addition of 12 new wind farms across seven states, totaling 3,680 megawatts of new wind capacity, enough clean wind capacity to power about 1.7 million homes annually. All the projects have now moved from the approval to execution phase. When complete, we will own about 70% of the new capacity, more than quadrupling our company-owned wind portfolio.

Our Rush Creek wind project was the first to be completed in fall 2018, and we are now building three wind farms to be completed in 2019: Hale (478 megawatts) in Texas, Foxtail (150 megawatts) in North Dakota and Blazing Star I (200 megawatts) in Minnesota. Nearly all 12 projects will be online by year-end 2020 to take advantage of the full production tax credit. Only the Dakota Range wind project will be complete in 2021 and is still low cost despite qualifying for a partial tax credit.

All of these projects must be built from the ground up, except for one. For about 20 years we purchased power from the Lake Benton wind project in southern Minnesota. Now we plan to buy and operate the project as part of our wind fleet once it is rebuilt in 2019 with new, more efficient turbines. By repowering an existing wind farm such as this, we are able to take advantage of existing transmission and other infrastructure. It is one of the reasons Lake Benton could successfully compete in the bidding process against other wind projects.

The Colorado Energy Plan

Under the Colorado Energy Plan approved by regulators in 2018, we will add 1,100 megawatts of wind energy from three new wind farms and the repowering of a fourth, existing wind farm. The projects include the 500-megawatt Cheyenne Ridge wind farm that we will construct and own. We will also add a 72-megawatt solar farm and three solar and battery storage projects, which combined incorporate 560 megawatts of large-scale solar and 275 megawatts of battery storage.

The solar-battery projects are located in different parts of Colorado, with one project in Adams County near the Denver metropolitan area and the other two in southern Colorado. The two projects in Pueblo County are the largest, with capacities of 100 to 125 megawatts and four hours of battery storage. They will help provide reliable generation capacity to replace coal power from nearby Comanche units 1 and 2, slated for retirement by 2026.

Economic benefits

In addition to providing affordable, carbon-free electricity for customers, all of these projects support economic development. Our 12 new wind projects are expected to create 2,700 construction jobs, 150 full-time jobs and generate $800 million in landowner lease and property tax payments over the lives of the projects. The Colorado Energy Plan is anticipated to inject $2.5 billion into the state's economy, including $1 billion from Xcel Energy.

Repowering plans

We continue to seek new, economic opportunities to expand our wind portfolio and have asked regulators for approval to buy two older wind farms in southern Minnesota, which are currently being repowered with the latest wind technology. We have purchased power from the Jeffers and Community Wind North projects over the past decade under long-term agreements. Adding the refurbished wind farms with a capacity of 44 and 26 megawatts, respectively to our own energy portfolio further supports our clean energy transition and will save customers money compared to long-term purchases. If approved, we would close on the completed projects by year-end 2019. We plan to pursue similar opportunities in the future.

Renewable Choice Programs

Just as customers want more control over their energy use, they also want more choice in how they engage with energy options. Our goal is to offer innovative solutions that enable our customers to meet their priorities around clean energy and the environment, while balancing these choices with the cost that all customers pay to support them.

We were an early adopter of voluntary green power back in 1998 with the introduction of our flagship program, Windsource. Since then, our program offerings have expanded to include options for community solar gardens, on-site solar and Renewable*Connect — our newest offering.

Through Renewable*Connect, customers can choose to make their energy up to 100% renewable through different contract options, such as month-to-month, five-year and 10-year terms. There is no equipment to install and customers can remain on the program if they move to a different home or business location within our service area.

Renewable*Connect exemplifies innovation. We have combined our program and regulatory experience and customer input to design the program so customers retain the renewable energy credits and rights to renewable energy claims. Renewable*Connect also keeps bills low for participating customers, while not increasing costs for nonparticipants. It is self-supporting through subscription fees, so nonparticipants don't pay more.

In Colorado, the program's energy is delivered from the new 50-megawatt Titan Solar facility, near Deer Trail, Colorado. The energy sources for the Minnesota and Wisconsin programs include the Odell Wind Farm and North Star Solar.

Participation in our other renewable choice programs continues to grow as well. In Minnesota, there were approximately 7,700 subscribers participating in our Solar*Rewards Community® program at the end of 2018. With more than 500 megawatts of capacity from 170 participating solar gardens, the program is easily the largest community solar garden program in the country, although the purchase rate for this Minnesota solar energy is two to four times higher than what we would pay from more cost-efficient energy sources. Our Colorado community solar garden program was one of the first in the nation and also continues to grow, quadrupling in size between 2017 and 2019.

In Wisconsin, our Solar*Connect Community® program is fully subscribed and continues to expand. A second community solar garden located in La Crosse began generating power for subscribers in March 2019 and a third project is expected to be built later during the year in Ashland. Once that project is complete, local gardens will be available to customers throughout our Wisconsin service territory. Similar to Renewable*Connect, the incremental program costs are covered through subscription fees so that non-participating customers do not pay extra to make the program available.

Customers also continue to install more on-site solar, with our Colorado customers increasingly choosing to install solar panels without incentives through Solar*Rewards®. Across all states, more than 7,600 solar systems were installed during 2018, adding 66 megawatts of additional on-site distributed solar. To reduce the impact of energy bills for customers struggling to make ends meet, we recently launched incentive options to test solar installations for income-qualified households in Colorado and Minnesota.

We offer the following renewable choice programs that reflect our company's commitment to meeting the clean energy interests of customers.

Program	Description	REC Attribution	MN	WI	ND	SD	CO	NM	TX	MI
Renewable*Connect	A flexible and affordable way to subscribe for up to 100% renewable energy	Participant	■	■			■			
Windsource	An easy, low risk way to subscribe to clean wind energy	Participant	■				■	■		■
Solar*Connect Community	Subscribe to a solar garden and get full rights to the solar claims, plus a bill credit for choosing solar energy	Participant		■				■*		
Solar*Rewards Community	Subscribe to third-party solar gardens and receive electric bill credit payments for solar energy produced	All Customers	■				■			
Solar*Rewards	Install your private on-site solar system and earn an incentive for transferring the RECs to Xcel Energy	All Customers	■				■	■**		
Net Metering	When you produce wind or solar energy through on-site equipment, you're able to retain RECs and sell any excess energy back to the grid	Participant	■	■	■		■	■	■	■

*Solar*Connect Community has been filed but not yet approved in New Mexico.

**New Mexico Solar*Rewards availability varies from year to year and is not currently available.

In addition to renewable choices, we started offering customers in Wisconsin a Certified Renewable Percentage as a way to let them claim the full benefit of our increasingly clean energy mix. We now retire Renewable Energy Credits (RECs) to cover the entire renewable energy portion of the electricity we deliver to customers in Wisconsin, beyond what we retire to meet Wisconsin's Renewable Portfolio Standard. Certified Renewable Percentage is not something customers enroll in or subscribe to but is a benefit they automatically receive. This enables customers to make renewable energy claims. For example, our commercial customers can claim the portion of renewable energy included in the Certified Renewable Percentage just by being an Xcel Energy customer.

We plan to propose the approach for regulatory approval in Colorado and Minnesota this year to begin offering customers the same benefit in these states.

Integrating Wind and Solar Power

The significant wind and solar resources on our systems have fundamentally changed the way we operate. With each increase in renewable capacity, we have improved system operations, enabling our ability to incrementally grow the use of wind and solar power and achieve new system records.

Some of our operational improvements for accommodating more wind and solar energy include:

- **Adding more flexible backup generation.** As we retire aging coal plants, we are replacing some of the energy with more carbon-friendly natural gas generation, which can more efficiently and cost-effectively ramp up or down to accommodate variable, renewable generation.
- **Cycling coal offline and reducing minimum generation levels.** Once considered infeasible, we are turning off coal units to accommodate more wind generation and are reducing the time that units need to be offline before than can be restarted. Cycling off coal units and then turning them back on is much more challenging than with a natural gas unit because of all the systems involved, but our Operations team has studied the issues and is working to cycle coal units more efficiently and cost effectively, helping to reduce fuel use and emissions.
- **Negotiating greater flexibility from our natural gas suppliers.** These agreements allow us to efficiently use our gas generation resources to balance variable renewable generation, helping to increase system reliability and lowering customer costs.
- **Investing in transmission.** We are improving and building new transmission facilities that can deliver more wind and solar energy to customers.
- **Using control equipment.** We use set-point controls for wind farms in combination with automatic generation control of thermal units that lets wind farms operate at peak levels while fossil-fuel production is reduced.
- **Establishing a 30-minute flexibility reserve.** We previously carried one megawatt of reserve capacity for every megawatt of wind generation as backup in case winds suddenly dropped off. As our wind portfolio grew, we studied the maximum amount of wind energy typically lost within 30 minutes and were able to reduce this reserve, dramatically decreasing costs associated with carrying large wind reserves while maintaining system reliability.
- **Adjusting planned maintenance.** We now plan transmission and plant maintenance outages around times of the year when wind and solar production is lowest.

Generally, we find that wind and solar are very compatible resources for meeting customer needs. Our renewable generation works together fairly consistently to operate on average across all hours of the day.

While solar energy is relatively simple to forecast, wind generation has been notoriously difficult because of its variability. Most weather forecasting models are designed to generate information about winds near ground level rather than at 200 to 300 feet, where turbine hubs are located. Also, landscape features such as hills and trees can reshape wind speeds and directions, causing turbulence in ways that can greatly influence the amount of energy produced.

To improve on this, we began working in 2009 on a multi-year research and development project with the National Center for Atmospheric Research (NCAR) and its affiliate company Global Weather Corp. (GWC). Today the WindWX system helps utilities around the globe including Xcel Energy to make better commitment and dispatch decisions. It uses real-time, turbine-level operating data and applies sophisticated algorithms to forecast the amount of wind power that will be produced. Forecasts for a 168-hour period are provided every 15 minutes across Xcel Energy's entire service territory — from the hills of western Minnesota to the plains of eastern Colorado and the Texas Panhandle.

Compliance with State Renewable Energy and Portfolio Standards

Xcel Energy is on pace to surpass established renewable energy requirements in the states we serve through at least 2030. New Mexico recently adopted the Energy Transition Act to set one of the most ambitious renewable portfolio standards in the nation. We are currently evaluating our compliance strategy with the increased targets that will be set by the law once it takes effect in June of 2019.

Renewable Energy Requirements in Xcel Energy States

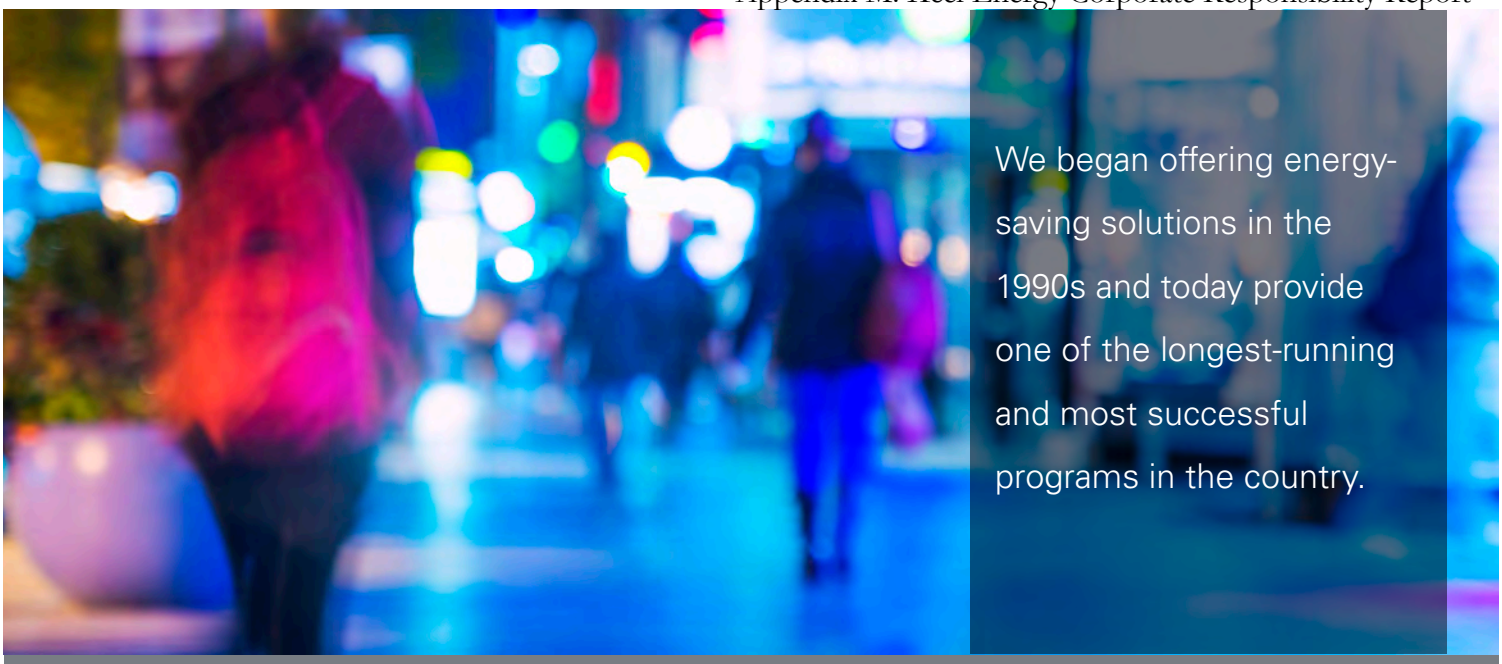
State	2018	Next Increase	Notes
Colorado Renewable Energy Standard	20%	30% by 2020	30% of retail sales by 2020, with 3% from distributed generation (DG), including at least 1.5% from retail net-metered DG resources and up to 1.5% from wholesale DG resources (defined as resources ≤30 megawatts located in Colorado that are not customer sited)
Michigan Renewable Portfolio Standard	10%	12.5% by 2019; 15% by 2021	Goal of 35% by 2025
Minnesota Renewable Portfolio Standard	25%	31.5% by 2020	30% of retail sales by 2020, with at least 24% from wind, plus 1.5% of retail sales from solar by 2020, with at least 10% from on-site solar 40kW or less
New Mexico Renewable Portfolio Standard	15%	20% by 2020	The New Mexico Energy Transition Act increases future goals of the RPS; in addition to the immediate goals, it sets a standard of 40% by 2025, 50% by 2030, 80% by 2040 and then 100% carbon-free electricity by 2045 Note: the Public Regulation Commission must consider the safe and reliable operations of the system and the prevention of unreasonable costs
North Dakota Renewable and Recycled Energy Objective		Voluntary	No RPS Requirement for North Dakota
South Dakota Renewable, Recycled and Conserved Energy Objective	10%	Voluntary	No RPS Requirement for South Dakota
Texas Renewable Generation Requirement	Statewide Goal	10,000 MW statewide by 2025 (goal achieved) & (non-wind goal: 500MW)	Xcel Energy's portion is approximately 3.3% of the statewide goal (the 3.3% is based on Xcel Energy Texas electric retail sales as a percentage of the total state electric retail sales)
Wisconsin Renewable Portfolio Standard	12.89%		

Renewable Energy Credits

A renewable energy certificate or credit (REC) is created for every megawatt-hour of renewable electricity generated (1 REC = 1 MWh). RECS provide a mechanism to commoditize renewable energy attributes and are tracked in national commission-approved REC tracking registries. RECs can be disaggregated or separated from the underlying renewable energy and sold separately. Typically, RECs are traded to companies looking to claim green energy or transferred to other utilities to reduce compliance costs.

Xcel Energy uses RECs to satisfy compliance with state renewable energy standards throughout our service territory. Our company carefully tracks its REC ownership and works to comply with the rules and best practices around renewable energy claims. Only parties that own and retire RECs can claim to use the renewable energy, according to the Federal Trade Commission's Green Guides. However, renewable energy separated from or without the associated REC can retain its value and be used for compliance with environmental regulations.

In 2018, we continued to look for ways to increase the value of the renewable energy on our systems through the sale of RECs. In several states, Xcel Energy has more renewable energy on its system than is needed for compliance with renewable energy standards. Based on market opportunities and the projected shelf life of RECs, we sold more than 3.7 million RECs in 2018, about 3 million less than in 2017. The renewable energy that generated these RECs came from Colorado, New Mexico, Texas and the Upper Midwest. Our customers benefit by sharing portions of these profits associated with the sales. REC sales make up a minor portion of our REC holdings.



Energy efficiency

Encouraging Efficient Energy Use

Our comprehensive portfolio of energy solutions meets the individual needs and preferences of customers and gives everyone an opportunity participate — from large industrials to small businesses and customers living on fixed incomes.

Customers rely on the energy we provide for their comfort, security and convenience, but increasingly they want more control and new options for managing and using energy. We are paying attention to the market, listening to our customers and responding with new and improved solutions.

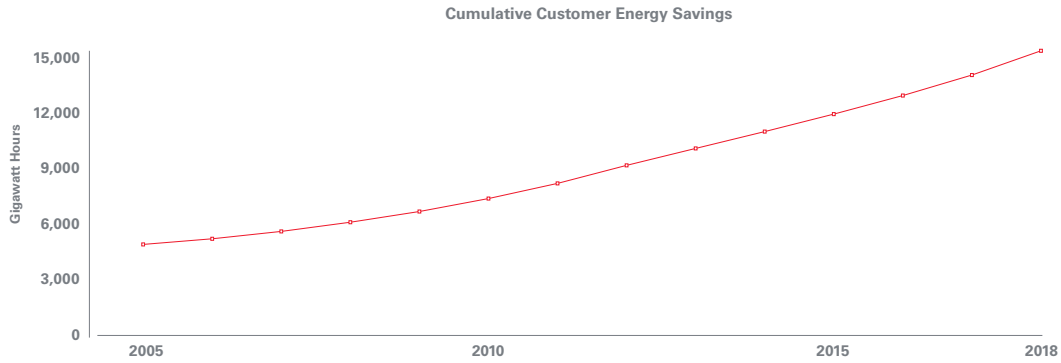
We continuously evaluate emerging technologies and program models, looking for opportunities to expand our portfolio of energy solutions and anticipate evolving customer needs and interests. Beyond our customer offerings, we continue to demonstrate leadership by incorporating energy efficient technologies and practices at Xcel Energy office buildings and service centers.

2018 Results

- Five of Xcel Energy's energy efficiency programs are recognized as being among the country's best, according to the American Council for an Energy-Efficient Economy (ACEEE). The following programs received the organization's Exemplary Program Award in early 2019: the Low-Income Program and Energy Design Assistance in Colorado, Home Energy Squad and One-Stop Efficiency Shop in Minnesota, and Partners in Energy in both Colorado and Minnesota.
- Our customers completed nearly 3.5 million electric and 1.4 million natural gas efficiency projects and received $141million in rebates through our conservation programs. We had more than 42,000 customers participate in our load management or demand response programs.

- We launched five new demand response programs, which helped participating customers save money and provided flexibility in how we manage the power grid. Under the programs, customers reduce or shift their energy use during peak periods, helping balance the supply and demand of electricity. We have around 25 new programs set to launch between 2018 and 2021 and have installed a new system to track demand response use and effectiveness.
- Altogether, customers saved about 1,240 gigawatt hours of electricity for the year, equivalent to powering 160,000 average homes, and 1.6 million dekatherms of natural gas, enough to fuel 20,000 average homes. The annual energy savings through efficiency measures was enough to avoid about 780,000 tons of carbon emissions, equivalent to the annual carbon emissions from approximately 150,000 cars.
- Some of the states we serve provide incentives for achieving energy efficiency goals. Thanks to strong program performance, we earned more than $41 million in incentives, exceeding our expectations.
- In early spring 2019, we hosted our annual Energy Expo for Colorado industrial, commercial and small-business customers. It featured teams of energy experts from Xcel Energy and outside organizations providing energy-saving ideas and opportunities for rebates and energy efficiency study funding. During the event, 13 businesses were recognized for outstanding efforts to save energy. These companies greatly lowered energy costs and reduced their impact on the environment. Altogether, they saved more than 33 million kilowatt hours of electricity in a 12-month period.
- Xcel Energy's Education and Outreach program promotes and encourages customer participation in our energy efficiency and renewable choice programs. During the year, we successfully expanded our efforts in Colorado, Minnesota and New Mexico. We reached more than 4.2 million people and generated over 19,800 targeted customer leads and 5,900 direct program sign-ups through event participation and community sponsorships. Some of our more notable partners include the Como Zoo in Minnesota, Denver Botanic Gardens, and sports teams — the Saint Paul Saints and Denver Outlaws.

Since we began consistently tracking results in 1992, we estimate that the energy savings through our efficiency programs has avoided the need for 21 average-size power plants.



State-by-State Efficiency Programs and Performance

Xcel Energy's portfolio of over 150 electric and natural gas conservation programs continues to experience strong customer engagement and growth. We continued to help our customers achieve significant energy savings in 2018, meeting and exceeding savings goals in several key states. The following is a summary by state of overall performance and program offerings.

Minnesota

2018 Approved Savings Goals of 433,694,480 kWh and 769,720 Dth	
Electric Projects	1,920,207
Natural Gas Projects	765,805
Total Spending	$122,958,724
Electric Savings	680,448,447 kWh
Natural Gas Savings	913,240 Dth

In Minnesota, we offer residential programs that range from prescriptive rebates to in-home services providing energy-efficient materials and labor for installation. Consumer education is included with most of the residential programs to increase conservation awareness and encourage energy-wise choices and behavior in the home. We also offer services and products to help income-qualified customers reduce their energy use and ultimately lower their bills.

The business segment includes electric and natural gas commercial, industrial and small business customers. We offer a variety of programs that encourage business customers to save energy, lower their energy bills, reduce peak demand and minimize environmental impacts. The portfolio has three primary components, including prescriptive products focused on common equipment, custom products to encourage savings from unique situations, and study and educational products that help customers identify energy efficiency opportunities.

North Dakota

Electric Projects	149
Natural Gas Projects	880
Total Spending	$257,670
Electric Savings	16,426 kWh
Natural Gas Savings	12,697 Dth

We provide savings opportunities for North Dakota business customers through load management programs, as well as residential natural gas rebate programs and home energy audits.

South Dakota

2018 Approved Savings Goal of 5,761,199 kWh	
Electric Projects	62,953
Total Spending	$775,604
Electric Savings	6,057,290 kWh

Our energy efficiency portfolio for South Dakota customers is a mix of electric programs designed to encourage both residential and business customers to save energy and lower their energy bills in a variety of ways. We offer programs for lighting, load management and educational outreach for business and residential customers and continue to work with trade partners to promote our programs.

Wisconsin

Electric Projects	153,135
Natural Gas Projects	152,758
Total Spending	$9,872,298
Electric Savings	119,139,835 kWh
Natural Gas Savings	98,169 Dth

In Wisconsin, Xcel Energy participates in a statewide program called Focus on Energy that provides incentives to eligible residents and businesses for installing cost-effective energy efficiency and renewable energy projects. We retain a portion of the approved annual funding for our voluntary customer programs and to promote the Focus on Energy programs. We also use the funds for general conservation activities, advertising and energy efficiency education for residential customers, commercial customers and trade allies in our service territory.

Michigan

Electric Projects	15,634
Natural Gas Projects	321
Total Spending	$384,663
Electric Savings	1,292,727 kWh
Natural Gas Savings	6,170 Dth

We participate in a statewide program in Michigan called Efficiency United that educates residential and commercial customers about energy efficiency and offers cost-effective solutions and rebates for reducing energy use.

Colorado

2018 Goals/Targets of 400 GWh and 573,136 Dth	
Electric Projects	793,208
Natural Gas Projects	449,006
Total Spending	$107,385,072
Electric Savings	453,894,496 kWh
Natural Gas Savings	604,928 Dth

Our Colorado residential energy efficiency programs focus on cost-effective, direct impact products that target household appliances, HVAC and lighting. This effort is supplemented with educational services intended to further increase customer understanding and interest in conservation and energy efficiency. We also offer income-qualified customers products to analyze natural gas and electric consumption, and provide products, services and education designed to help lower energy bills.

Our business program — for commercial and industrial customers of all sizes — offers a broad portfolio of demand side management products designed to meet the needs of this varied segment. The portfolio has three primary components, including prescriptive products focused on common equipment, custom products to encourage savings from unique situations, and study and educational products that help customers identify energy efficiency opportunities.

New Mexico

Electric Projects	371,298
Total Spending	$10,685,496
Electric Savings	51,698,426 kWh

We offer a broad portfolio of programs to meet the needs of business, residential and low-income customers in our eastern New Mexico service territory.

Texas

Electric Projects	145,992
Total Spending	$3,610,230
Electric Savings	20,524,107 kWh

We offer our Texas customers energy efficiency programs through Standard Offer Programs and third-party Market Transformation programs. These programs are provided to residential, low-income, commercial and industrial customers.

Conservation at Xcel Energy Facilities

Our building management practices support our commitment to the environment and the communities we serve. We own or lease more than 150 office building and service centers throughout our eight-state territory and strive to set an example with conservation. Similar to how we encourage customers to use energy more efficiently in their homes and businesses, we look for ways to save energy and water in our own facilities, especially when those opportunities reduce our costs and conserve resources.

We also go beyond conservation to incorporate a number of environmentally sound practices into our daily building management, including steps that ensure indoor air and water quality, green cleaning and the use of GREENGUARD Certified products and materials.

We proactively began managing our facilities to reduce environmental impact in 2008, and by the end of 2018, have accomplished the following:

- Saving more than 8 million kilowatt hours
- Conserving more than 173,600 therms of natural gas
- Reducing water usage by 4.7 million gallons

Through our energy management initiative, we plan to continue trying to identify and implement projects that reduce energy use and costs at our facilities while helping to reduce overall maintenance needs. Projects will consist of individual, standalone opportunities, as well as efforts to support and improve new construction, remodeling and HVAC replacement projects that are planned and approved. To do this, we review past facility energy audits with the company's annual capital budget to identify energy improvement opportunities to support.

LEED Certified Facilities

Xcel Energy continues to seek LEED (Leadership in Energy and Environmental Design) certification for our facilities. We currently have 15 facilities that are LEED certified throughout the eight states where we operate. LEED is a U.S. Green Building Council certification program that recognizes sustainable building strategies and practices. To receive LEED certification, building projects satisfy prerequisites and earn points to achieve different levels of certification. LEED certification has four levels — Certified, Silver, Gold and Platinum — based on achievement in five areas: sustainable site development, water savings, energy efficiency, materials selection and indoor environment quality.

Company and workplace

Governance, ethics and compliance

Corporate compliance and business conduct

For decades we have fostered a culture of compliance and ethical business conduct, striving to earn and maintain the trust of our stakeholders.

For more than 100 years, we have had the privilege of serving our customers and doing so with honesty and integrity. Because trust is so essential to our ongoing success, it is included in our corporate vision to be the preferred and trusted provider of the energy our customers need. To help deliver on this vision, we hold our employees, contractors and board of directors to the highest ethical standards and ensure their decisions are consistent with our values.

Every day we deliver safe, clean, reliable and affordable energy while holding ourselves accountable and acting responsibly. Through our commitment to doing what is right, we have established a reputation that our employees can be proud of and gives customers confidence in doing business with us.

2018 Results

- We revised our corporate values, putting new focus on who we are as a company today and who we want to be in the future. Through conversations across the organization, we asked ourselves what values will guide us for the years to come as we continue to evolve. Employees have responded positively to our renewed values of Connected, Committed, Safe and Trustworthy.
- We updated policy content in response to new or changing regulations and business practices. An example is our new, stand-alone anti-retaliation policy. While our Code of Conduct has always prohibited retaliation and protected employees who report concerns, we created a dedicated anti-retaliation policy to increase visibility of the company's expectations.

- We focused on educating leaders on how to respond to employee concerns and prevent, recognize and report retaliation. We held in-person compliance and ethics training, created a micro-learning training module and launched an e-learning course titled Compliance for Leaders.
- We completed a system refresh of Xcel Energy's allegation of wrongdoing case management system. This initiative included streamlining the hotline phone- and online-reporting intake form to make it easier for employees to report concerns, as well as simplifying the process of recording and monitoring progress on the investigations. These improvements drive consistency in reporting and enhance the employee experience.

Ethical Foundation: Code of Conduct

Our Code of Conduct serves as the foundation for our Corporate Compliance and Business Conduct program. It guides everything we do — how we work together, make business decisions and interact with stakeholders. Our Code of Conduct also provides guidance for handling difficult judgement calls and reporting concerns.

The board of directors reviews and approves the Code of Conduct annually, ensuring top-level ownership for this foundational resource.

Employees at all levels, as well as contract workers and our board of directors, are expected to apply the Code of Conduct to their work with Xcel Energy. Code of Conduct training occurs annually and included in the training course is a statement of commitment. While contract workers are not required to take Code of Conduct training, they are required to perform services in accordance with the Code of Conduct as specified in the terms of their agreements with Xcel Energy.

Corporate Compliance and Business Conduct Program

The focus of Xcel Energy's Corporate Compliance and Business Conduct program is to:

Do What's Right: Report What *Seems* Wrong.

Sound Governance Practices

Xcel Energy's Board of Directors has overall authority for the Corporate Compliance and Business Conduct program, with key elements of oversight delegated to the Audit and Governance, Compensation and Nominating committees. Our Corporate Compliance and Business Conduct Council is comprised of leaders from across the company and ensures engagement with all employees.

The company's CEO sets a strong tone at the top and supports that tone in many ways including championing the values refresh and highlighting the company's commitment to compliance on webcasts and in-person at various team meetings. The chief ethics and compliance officer reports to the CEO, and also oversees the company strategy and corporate governance functions, enabling her to effectively drive company culture and values. The integration of these activities and responsibilities ensures that compliance is part of how we make decisions across the company.

Policies, Training and Communications

Company policies, training and communications help employees understand expectations in order to make good decisions every day. Information about policies and expectations are shared through multiple channels and in multiple ways to ensure that they are a regular part of all employees' work experience.

Employees are responsible for knowing and following not only the Code of Conduct but also multiple other corporate policies associated with Corporate Compliance and Business Conduct. Training courses include content from corporate policies and other information that demonstrate how our values guide the way we do business. Employees use training information to ensure their actions protect and enhance the company's brand and reputation by working safely and effectively and complying with the many policies, laws, regulations and expectations governing our work.

Regular, consistent communications are designed to help employees do what's right. We use a variety of channels to reach employees across teams, such as emails, posters, videos, intranet news articles and in person discussions.

Issues, Investigations and Actions

When things don't seem right, employees are encouraged to discuss concerns with their leaders. We know reporting a potential issue can be difficult, so we offer multiple reporting options that include contacting:

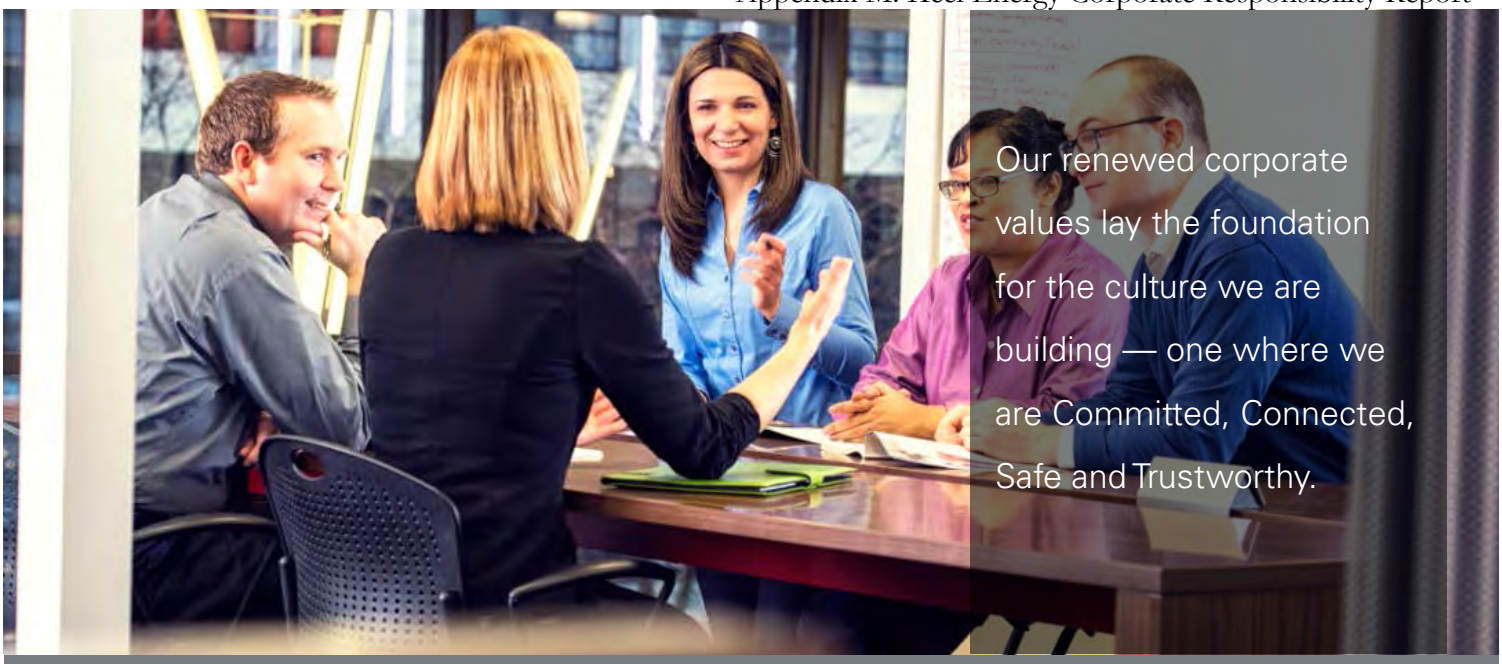
- Equal Employment Opportunity, Employee Relations or Workforce Relations
- The employee's next level of management
- The Compliance Hotline, available 24 hours a day and with the option to remain anonymous
- The Corporate Compliance and Business Conduct Office
- Legal Services
- The Xcel Energy Board of Directors

Employees working at our nuclear generating plants have additional reporting options that include completing a Nuclear Corrective Action Request form, reporting issues to the Employee Concerns program or contacting the Nuclear Regulatory Commission.

Our Compliance Hotline also offers employees the opportunity to ask questions about decisions they are unsure about.

As we follow up on reports, we conduct effective and timely investigations, take appropriate action and ensure employees are safe from retaliation. The Investigations Governance Committee oversees the investigation process and is comprised of the chief ethics and compliance officer, general counsel, chief financial officer and chief human resources officer.

When concerns are reported through the Compliance Hotline, the Corporate Compliance and Business Conduct Office assigns them to the appropriate business function to investigate based on allegation type. Business functions include Equal Employment Opportunity and Employee Relations, Workforce Relations, Legal, Security or Audit. These business functions also receive and investigate concerns reported through other channels. All reports are tracked and processed through a case management system that provides the company with a comprehensive view of allegations.



Workforce development

Our people and culture

At Xcel Energy, our business and workforce are changing while customer expectations are rising — a dynamic that is driving us to become more innovative, competitive and customer focused.

Our workforce strategy begins with a mission to proactively attract, retain and develop the highest quality talent. We take a proactive approach to workforce planning and are identifying the skills we need to prepare and meet our future energy objectives, aligning our talent strategies to build diverse pipelines and identifying opportunities to retrain or develop our workforce.

We know our people are our greatest strength. That is why once employees are part of our team, we offer extensive training and engagement opportunities to develop their skills and talents and help them grow professionally, in addition to recognizing their achievements. We are also improving our leadership development programs, tools and resources to help ensure our leaders are effective in our changing environment. Through these efforts, our objective is to develop inspirational and courageous leaders that hold employees accountable for achieving results.

2018 Results

- More than 96% of employees participating in Connect 4 Performance met with their leaders for Quarterly Connections to discuss job performance, professional development and alignment with company goals and priorities.
- Internal candidates successfully filled 41% of our 2,318 job postings, and of employees newly hired to the company, 56% came from within the states we serve and nearly 24% had ethnically diverse backgrounds.

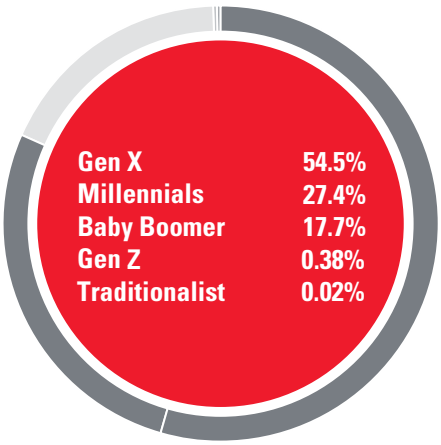
- Xcel Energy was named a Top Veteran-friendly Company by U.S. Veteran's Magazine for the fifth consecutive year, a Best for Vets employer by Military Times for the fourth consecutive year, and a Top-10 Military Friendly Employer by GI Jobs for the ninth consecutive year. We are included in Military Times' Best for Vets Index, and are honored to be a Most Valuable Employer for Military, according to Recruit Military. More than 10% of our new hires were veterans.
- For the third consecutive year, we received a perfect score on the Human Rights Campaign Corporate Equality Index and the designation as one of the Best Places to Work for LGBTQ Equality.
- Through a collaborative process that included feedback from employees throughout the organization, we renewed and streamlined our corporate values to reflect our core beliefs — who we are, how we conduct our business and the importance of our customers. We are Committed, Connected, Safe and Trustworthy.

Workforce Profile

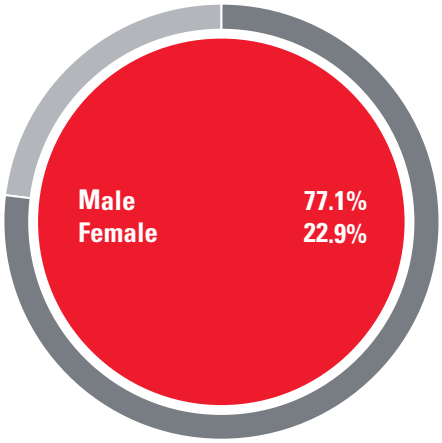
Bargaining		Non-bargaining		
43% Bargaining	5% Temporary Craft	2% Temporary	38% Nonmanagement Professional	12% Management

As of year-end 2018, Xcel Energy had 11,691 full-time, part-time and temporary employees.

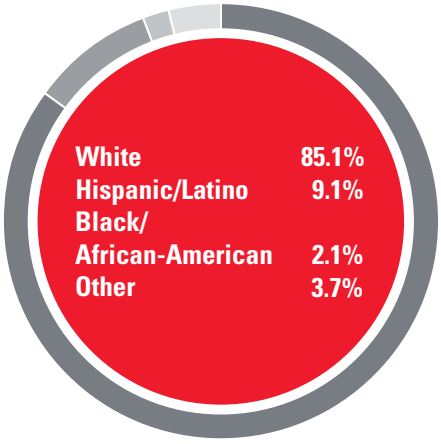
Generational Age



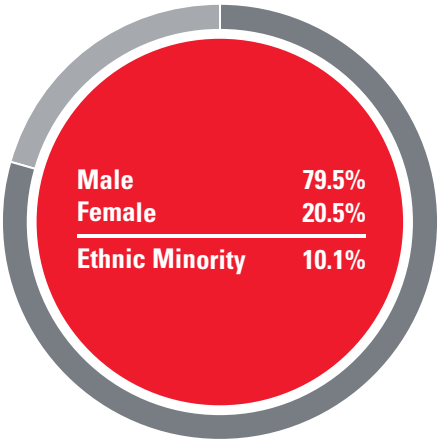
Gender



Ethnicity



Management Gender and Ethnicity



The average employee turnover in 2018 was 9.9%. About 29.7% of turnover was the result of retirements, about 56.1% were resignations and the remaining 14.2% includes turnover for other reasons, such as unsatisfactory performance, misconduct, severance or death.

Our projections show that 27.9% of our workforce will be eligible for retirement over the next five years and 41% over the next 10 years. However, we do not expect all employees to retire once they become eligible.

Workforce Planning and Analytics

Our strategic workforce planning models and process support leaders in using the opportunities that arise as a result of changes in our business objectives, including the workers required to complete budgeted work and turnover. By leveraging data and analytics, we are able to more accurately determine what the organization will need in terms of size and skill sets to achieve its objectives. The strategic workforce plan supports a more intentional approach to deploying solutions that will address our changing workforce.

In conjunction with this effort, we provide a Human Capital Report that helps leaders make data-based decisions. It is a dashboard that includes standard measures related to employee cost, performance management, and headcount and attrition trends. This information, combined with consultation with business partners, informs our leaders about their current workforce and predictive and statistical analysis provides insights into future impacts.

Attracting Top Talent

To ensure a steady stream of qualified candidates for Xcel Energy's available jobs, we proactively engage with community and educational organizations to prepare a future workforce. We are focused on helping military veterans make the transition to civilian jobs through targeted recruitment and participation in the Hiring our Heroes program. To ensure we can best support our customers' needs, we are committed to having a diverse workforce that reflects the communities we serve.

Some of our targeted recruitment activities include:

Educational Relationships

We work with a number of colleges, universities and technical schools to provide an avenue to educate students on the opportunities for stable, well-paid jobs with energy providers like Xcel Energy. As a member of the Center for Energy Workforce Development (CEWD), we also help develop training and curriculum that prepares students for skilled jobs in the energy industry. Through our partnership with CEWD, we implemented the Legacy I-3 program for high school students in the Twin Cities to build a pipeline of diverse candidates.

Internships

Through internships we ensure a pipeline for our future workforce needs. We hired 26 college interns into full-time positions with the company in 2018. We work with high schools throughout our Texas and New Mexico service areas, where we have the greatest needs. In Colorado, we have four programs in partnership with Denver Public Schools and Jefferson County high schools. In Minnesota, we continue our partnership with Step-Up Achieve and Right Track to hire high school summer interns. Through these programs, we had 60 high school interns in 2018.

Targeted Job Fairs

We seek out employment events that help us successfully identify and hire qualified employees who are customer focused, curious and innovative. We maintain relationships with several schools and local organizations within our service territory that hold job fairs for diverse populations. Partnerships like this allow us to reach prospective employees to continuously improve our candidate pool.

Search Engines

Xcel Energy markets its jobs on several key sites, including Indeed, LinkedIn and other social media platforms. In partnership with Professional Diversity Network and other industry and skill-specific boards, we target diverse, local talent and individuals that have specialized skills. We also work with local, community-based organizations to reach candidates throughout our service areas, reducing the need for candidate relocation and supporting our local economies.

Military and Veteran Outreach

We remain focused on strengthening our strategic partnerships with military veteran organizations and engaging in activities that maintain our visibility as a preferred employer for veterans. Through military-specific marketing and communications efforts and participation in more than 35 job fairs that specifically target military veterans throughout our service territory, our commitment to hiring veterans and active duty reservists remains strong.

Diversity Outreach

Through our partnerships with workforce centers in Minnesota, Colorado, Texas and New Mexico, Local Job Network and Diversity Minnesota, we are able to reach diverse job seekers in the places where they live and work. We also engage with diverse student groups such as National Society of Black Engineers, Society of Women Engineers, Society of Hispanic Professional Engineers and Society of Asian Scientists and Engineers to attract diverse entry-level employees.

Diversity and Inclusion

We believe that a diverse and inclusive workforce makes our company stronger. Our commitment to diversity and inclusion goes beyond human resource policies and practices — it is an integral part of who we are, how we operate and how we see our future.

Our inclusive work culture embraces all employees and provides them with equal access to employment opportunities and development. To us, diversity is more than ethnicity, gender, age, race, national origin, disability, religion and sexual orientation. It includes differences in thought processes, educational backgrounds, work experiences, personalities, lifestyles and cultural backgrounds.

Each Xcel Energy employee is empowered to make a difference when it comes to creating an inclusive environment. We encourage our employees to remember that:

Diversity Exists: Inclusion is My Responsibility.

Diversity and Inclusion Education

Xcel Energy's commitment to diversity and inclusion is instilled in employees from their first day on the job, as part of our new employee orientation program. Employees receive ongoing education in these areas, and in 2018, 813 employees and leaders throughout our service territory participated in a new half-day diversity and inclusion education session. The classes are designed to provide knowledge, insight and skills to manage diverse teams and create an inclusive culture. The company goal is to have 100% of employees through the program within three years.

Business Resource Groups and the Council for Diversity and Inclusion

Our 11 Business Resource Groups give Xcel Energy employees an inclusive and supportive venue to unite for personal and professional growth. They offer opportunities for cultural exchange and community outreach and helping solve business challenges. Additionally, through the Council for Diversity and Inclusion, leaders of our Business Resource Groups collaborate with leaders from our business areas to help address key challenges and achieve goals.

- **ECN (Employee Connection Network):** Connects new and existing employees and helps broaden all employees' understanding of Xcel Energy through networking opportunities, meet ups and community service events.
- **GCEEE (General Counsel Employee Excellence and Equality Committee):** Aids the general counsel in fostering a spirit of inclusiveness throughout the company.
- **GenNext:** Aims to support employees through employee education, collaboration and development.
- **GROW:** Identifies and implements innovative ideas and strategies for recruiting, developing, promoting and retaining women in non-traditional work roles in our Energy Supply business area.
- **MOVE (Military Ombudsmen for Veterans and Employees):** Sustains awareness on issues of interest to veterans and active military employees in our workforce and programs and policies that support the welfare of veterans and their families.
- **SAGE (Supportive Association for Gay/Lesbian/Bisexual/Transgender Employees):** Works to help the company become and remain a leader in this area of workforce diversity by addressing issues relating to sexual orientation and gender identification.
- **SOURCE (Strategic Organization Utilizing Resources for Career Enhancement):** Promotes career development, continued education, training and cultural awareness with a focus on African Americans.
- **Tribal Wind:** Supports diverse workforce initiatives and the Native American population through business initiatives such as recruiting, retention, professional development and cultural awareness.
- **WIN (Women's Interest Network):** Focuses on issues of interest to women, such as professional development and work/life balance.
- **!Xcelente¡:** Increases visibility of Latino employees within the company and community while also promoting professional development and sharing Latino culture through awareness, inclusion and celebration.

- **XE WiN (Women in Nuclear):** Explores and develops programs that help all employees working within our nuclear organization to expand their leadership skills, network and create positive visibility for the nuclear industry within the communities we serve.

Performance Management

Last year was the third year for Connect 4 Performance, our performance management approach for non-bargaining employees who make up over half of our workforce. Connect 4 Performance enables employees to align their individual goals with the priorities of Xcel Energy through simple, meaningful and frequent conversations with their leaders. Throughout the year, employees and leaders work together to identify opportunities that support employee professional development while helping achieve the company's strategic priorities. Employees are encouraged to record their development goals and regularly update and discuss progress and ideas with their leaders.

Employee Engagement

After pausing from our traditional approach to measuring engagement through an annual survey, Xcel Energy spent 2018 developing a comprehensive plan to measure our employee engagement and sentiment. In 2019, we are introducing a new platform that allows employees to provide feedback digitally giving leaders real-time results. This new approach will provide us the flexibility to gather employee feedback at different career points and conduct pulse surveys on engagement.

We help employees stay engaged through a number of channels, including regular webcasts with our senior leadership team, an intranet site that is updated daily, a regular company news magazine for employees and retirees, rewards and recognition programs, company-sponsored volunteer opportunities and our annual Day of Service.

Employees are continuously encouraged to offer feedback to Xcel Energy leadership through a variety of methods. They can submit anonymous comments and questions during regular leadership webcasts and face-to-face meetings, and respond to blogs and articles that our leaders publish throughout the year.

Workforce Relations

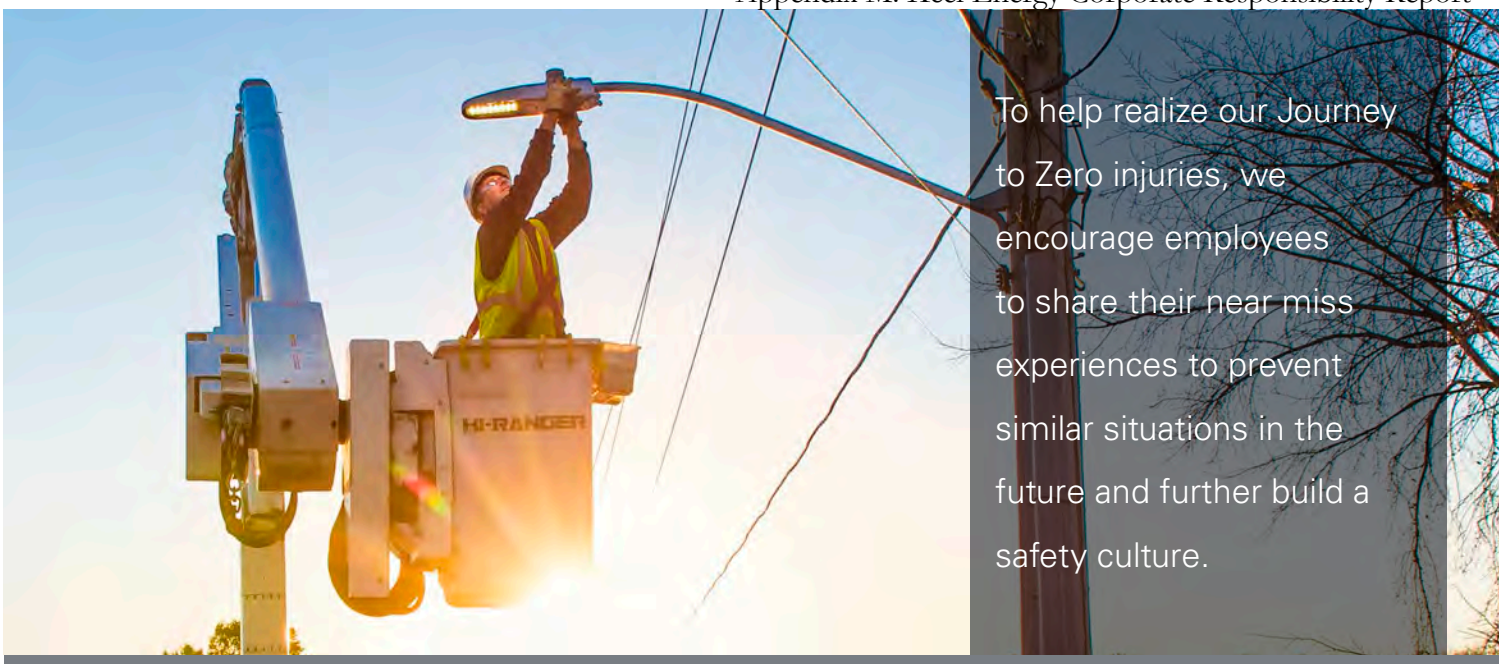
Xcel Energy is committed to providing all employees with a safe, rewarding workplace that values their contributions and ensures fair treatment. We respect our employees' right to organize if desired, and approximately half of our workforce is currently represented by unions.

While each collective bargaining agreement is negotiated with a specific local union, we include equal opportunity clauses in all our bargaining contracts. We also operate in compliance with the policies and regulations established by the National Labor Relations Board, the statutes of the National Labor Relations Act and the guidance of the federal Department of Labor.

Xcel Energy recognizes that all parties benefit by coming together to achieve mutual goals, so we meet frequently with our unions to discuss new and ongoing issues. Employee safety is a mutual focus for both bargaining units and the company. Bargaining unit employees fully support and participate in the company's safety advisory councils, committees, training and other programs.

Interim bargaining has been used for the past 18 years to improve union relations and promote collaboration on business challenges that impact our operations and workforce. We also hold regular meetings between management and labor unions to address grievances with the goal of resolving issues between the parties.

In early 2018, Xcel Energy (Public Service of Colorado) reached an agreement with the International Brotherhood of Electrical Workers (IBEW), Local 111 the Union representing our employees in Colorado.



To help realize our Journey to Zero injuries, we encourage employees to share their near miss experiences to prevent similar situations in the future and further build a safety culture.

Employee safety

Our journey to zero

When we refreshed our corporate values in 2018 to reflect our core beliefs, there was never a doubt that staying safe would remain a top priority.

Given the nature of our business, our employees face numerous hazards while performing their jobs. That is why we continue to instill a culture that values safety through the work of our safety committees, company policies, and training and ongoing awareness campaigns.

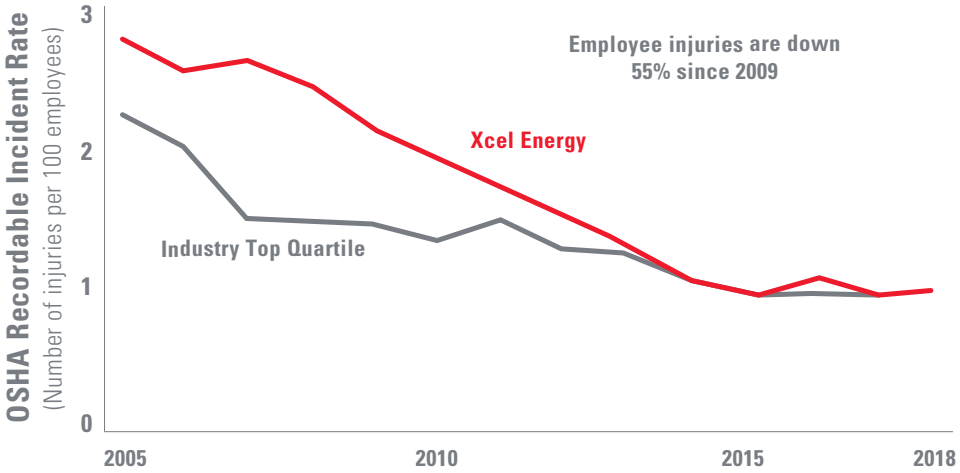
Our Journey to Zero is not just a slogan or program but is a commitment that all employees will return home from work injury free every day. It is about building a safer work environment by putting safety at the forefront of everything we do. Starting with top leadership, we continue to actively demonstrate support for safety throughout the organization. We strive to advance a safety culture through strategic behavioral safety programs and initiatives that encourage employees to take personal responsibility for their safety and the safety of others.

2018 Results

- Our employee safety performance ranks in the top-quartile for our industry. We have reduced OSHA recordable injuries by 55% and injuries classified as Days Away, Restricted and Transferred by 59% since embarking on our Journey to Zero.
- All contract employees receive safety training from their employers as a requirement of working with Xcel Energy. Plus, job briefings and job-site safety reviews occur daily. The total safety incident rate for contract workers in 2018 was down by almost 30%, even though the number of hours that contractors worked nearly doubled.
- We conducted Safety Leadership Training for all employees who are most at risk because they work directly with the delivery of electricity and natural gas.

- We continued to encourage employees to share their safety experiences and to learn from one another. Through a special campaign, we increased our near-miss sharing by 150% over 2017.
- The American Gas Association recognized our annual performance with the 2018 AGA Safety Achievement Award for excellence in employee safety.

Our Journey to Zero commitment entered into its ninth year in 2018 and continued to make significant progress in keeping employees safe. Although, as the name of this effort implies, we won't be satisfied until 100% of employees go home injury free.



Managing Employee Safety

Xcel Energy has 21 corporate safety policies in place to address occupational safety and health issues. These policies apply to all company bargaining and non-bargaining unit employees, as well as contractors. Our policies cover a wide range of topics — from working in confined and enclosed spaces to preparing for and responding to emergency situations.

As part of our corporate values, and to protect our employees and the public, working safely is the first consideration while planning or performing work. It is the role of Xcel Energy management to foster, develop, implement and provide training and communication about safety programs that will help reduce occupational injuries and illnesses at work. We expect employees to report unsafe acts, behaviors or conditions to management in a timely manner so that we may address these safety concerns. Any retaliation against an employee who, in good faith, reports a safety violation or suspected violation is strictly prohibited. All employees are empowered to stop work if they see unsafe practices

Our corporate safety organization manages implementation of regulatory compliance, provides technical consultation to business areas, tracks and communicates the company's safety performance, and fosters our safety philosophy and core value. The vice president of Safety and Workforce Relations leads this organization and reports to the chief human resources officer, who reports directly to the president, chairman and CEO. Xcel Energy's Operations, Nuclear, Environmental and Safety committee for the board of directors oversees the company's safety strategy and performance.

There are three key components to our safety and health culture that include:

- **Communication:** Within each business area, we verify that OSHA-required written programs are current and maintained at our facilities. Employees must be thoroughly briefed on site-specific hazards and protective measures prior to starting any job at an Xcel Energy operating facility or on electric and natural gas transmission and distribution lines and equipment. Finally, we establish a system of hazard analysis, which includes hazard identification and control in each business area, and we communicate this system to all affected employees.
- **Safety Committees:** Our safety committees are organized and represented by bargaining unit and non-bargaining unit employees and management. The expectations for these committees are outlined by management and periodically audited to track progress and effectiveness. Managers in each business area provide support for safety committee findings and recommendations that align with our corporate values.
- **Training:** Each business area and Corporate Safety develop training plans annually to include OSHA-required training and required elements of our Corporate Safety and Industrial Hygiene programs. We maintain thorough records of all training, including recording the names and dates of employees who complete required safety training.

We provide effective safety and health communications in various formats, including verbal instructions, written documents and posters, safety committee meetings and multimedia presentations, such as video and computer-based training. Through these various media, all employees have access to required safety and health training, policies, programs and safety manuals, as well as federal or state required communications. All Xcel Energy employees are expected to actively participate in the company's safety and health training and communications program.

Safety Initiatives

We continued a number of important safety initiatives in 2018, while also launching new initiatives to help keep employees safe.

24/7 Safety

Our 24/7 Safety campaigns focus on maintaining a safety mindset around the clock, helping employees to be safe both on and off the job. The 2018 campaign focused on intervening when you see something unsafe and some of the common household and public hazards to watch out for.

Ergonomics

Musculoskeletal Disorders (MSDs or strains and sprains and cumulative trauma disorders) are the leading type of injury at Xcel Energy, with sprains and strains representing more than 41% of our injuries. Several ergonomics training modules were initiated in 2018 to help improve this, including the Eyes on Ergo training module, Ergo Tips pocket guides and videos, prevention exercises and a Five-week Workplace Athlete Challenge.

Near Miss Sharing

Sharing near misses with coworkers provides a learning opportunity that can prevent similar situations in the future. To encourage employees to share their stories, we do not pursue discipline for employees who report near misses, and we carried out a campaign in 2018 that included video testimonials, posters and articles.

Safety Blitzes

After recognizing certain injury trends, company leaders set out to connect with employees to hear their views and suggestions about safety. Three safety blitzes were held in 2018 and a commitment was made by leaders to spend more time visiting with employees in 2019, as well.

Safety Leadership Training

To help reduce serious life-changing incidents, the Safety Leadership Training program was conducted in 2018 for all at-risk employees. The program was designed to transform how employees view their role in safety because everyone is a leader when it comes to safety.

Safety Promise

Xcel Energy's Safety department hosted a series of events in 2018 offering employees' families an opportunity to ask their loved ones to work safely on camera. The employees were then given the opportunity to make a safety promise on camera. These requests and promises were shared in various formats, encouraging everyone to make a personal commitment to their safety and the safety of those around them.

Slips, Trips and Falls

Slips, trips and falls are avoidable, yet each year they make up a significant number of Xcel Energy's OSHA recordable injuries. We enhanced our Slips, Trips and Falls Toolkit in 2018 to include even more videos, training and guides detailing strategies for these incidents and minimizing the chance of injury when falling.

Labor practices

Total Rewards for employees

As our industry becomes more competitive, it is vital that we continue to offer current and prospective employees an attractive package of pay, benefits and professional development.

Xcel Energy is committed to providing employees with market-competitive compensation and benefits. We use best practices and benchmarking to ensure the programs we offer are aligned with the market and attractive to our workforce, while also finding ways to manage costs to keep our compensation and benefits programs financially viable.

We have reviewed and made changes to our contracts with benefit providers to help manage costs at their source rather than change plan design or increase cost to our employees.

2018 Results

- Forbes recognized Xcel Energy as one of the World's Top Regarded Companies and World's Best Employers, as rated by employees.
- We developed a new parental leave policy that allows non-bargaining employees up to an additional four weeks paid time off to care for a new addition — whether it is through birth, adoption or foster care.
- Employees participated in 440,000 internal learning opportunities as recorded through our Learning Management System.
- Our tuition reimbursement program supported 256 employees with their continuing education, with annual reimbursements totaling $806,755.
- We identified 286 "ready now" successors to key positions around the company — potential successors that possess the necessary skills to make a seamless transition if needed into a role for which they have been identified.

Employee Total Rewards

Xcel Energy's Total Rewards package includes base and variable compensation, along with benefits like health and well-being, retirement and pension, paid time off, recognition and talent development. We have a pay-for-performance philosophy, recognizing and providing larger rewards to our best performers. Base pay is influenced by job descriptions and external market pay data, as well as the employee's skills, experience and job performance. Bargaining unit employees are paid in accordance with their collective bargaining agreements.

Our annual incentive plan includes three award opportunities:

- Annual Incentive Program (AIP) Year-end
- I Deliver
- Innovator awards

These awards are given to exempt, non-bargaining employees who went above and beyond and who achieved results that were aligned with Xcel Energy's corporate goals. Our non-exempt employees are eligible for Spot-On bonus awards in recognition of above-and-beyond results in their responsibilities. Employees and leaders can also recognize one another through an online system, and when appropriate, give points-based awards that can be redeemed for merchandise and gift cards.

We provide a Total Rewards Statement that shows our employees the full value of the pay and benefits they receive. It offers a personalized snapshot of pay and benefits information, as well as links to additional program and service information. Employees can access their individual statements online.

Benefits

A significant portion of our investment in employees is made through a benefits package that remains competitive in the marketplace. Offering a comprehensive approach to well-being, Xcel Energy provides programs that address the physical, emotional and financial welfare of employees.

We are committed to supporting the health of employees and offer a medical plan that provides comprehensive coverage, encouraging preventive care so health issues can be identified.

Our Employee Assistance Program connects employees with free, confidential support to resolve a variety of issues including mental health counseling, elder care, financial and legal advice.

Xcel Energy continues to offer defined benefit pension plan along with a 401(k) savings plan, which demonstrates our commitment to partnering with employees to meet their long-term financial goals. Unlike many employers who have frozen pension plans or reduced contributions to 401(k) accounts, we continue to contribute to these plans at market-appropriate levels to indicate our commitment to help employees save for the future.

Xcel Energy Benefits Package for Eligible Non-bargaining Unit Employees*

Health Benefit Plans

- High Deductible Healthcare Plan (HDHP)
  - Reasonable and affordable premiums
  - Includes a Health Savings Account (HSA) employees can contribute pre-tax dollars
  - In aggregate, Xcel Energy pays approximately 75% of medical costs
- Dental plan
  - Xcel Energy offers a basic and enhanced dental plan
- Vision plan
  - Xcel Energy offers access to a vision plan
- Wellness Program
  - Financial incentives to encourage healthy lifestyles
  - Wellness coaching including tobacco cessation, weight management, diabetes management, onsite yoga and flu shots
  - Fitness center reimbursements

Retirement Plans

- Pension plan
  - 5% cash balance plan for new employees and legacy formulas for other employees
  - 100% paid by Xcel Energy
- 401(k) savings plan
  - Savings Plan allows employees to save for their future through automatic payroll deductions (pre-tax, Roth 401(k) after-tax or a combination of both)
  - Variety of investment options (cash, bond and stock investments)
  - Company matching contributions

Income Protection

- Life Insurance
  - Xcel Energy covers the full cost of basic life insurance
  - Offers voluntary supplemental and dependent life insurance coverage
- Paid Time Off
  - Xcel Energy covers the full cost of short-term and long-term disability for eligible employees

Work/Life Balance Programs

- Employee Assistance Program (EAP)
- Paid Time Off
  - Vacation/PTO
  - Sick leave

- Transit pass subsidies
- Adoption assistance
- Parental leave allows employees up to an additional four weeks paid time off
- Flexible Spending Accounts
  - Dependent care
  - Medical
  - Transportation

Professional Development Programs

- Tuition reimbursement
- Variety of internal and external development opportunities

*Xcel Energy employees are eligible for benefits based on employee group and status (regular full-time and regular part-time non-bargaining). Bargaining unit benefits are based on the contract negotiated with the specific local union.

Professional Development

Total Rewards is more than pay and benefits. It also includes providing employees opportunities for professional development. Xcel Energy is committed to professional development and maintaining an environment where learning and growth can occur. Employees are ultimately responsible for owning and managing their own professional development. However, we expect managers to encourage development through feedback, coaching and support.

With this in mind, we offer employees resources and tools to support their personal and professional development, including a Learning Management System (LMS), which provides e-learning, virtual and traditional training options. We also provide employees with development planning tools, assessments and suggestions for practicing new skills and behaviors.

2018 Professional Development Opportunities

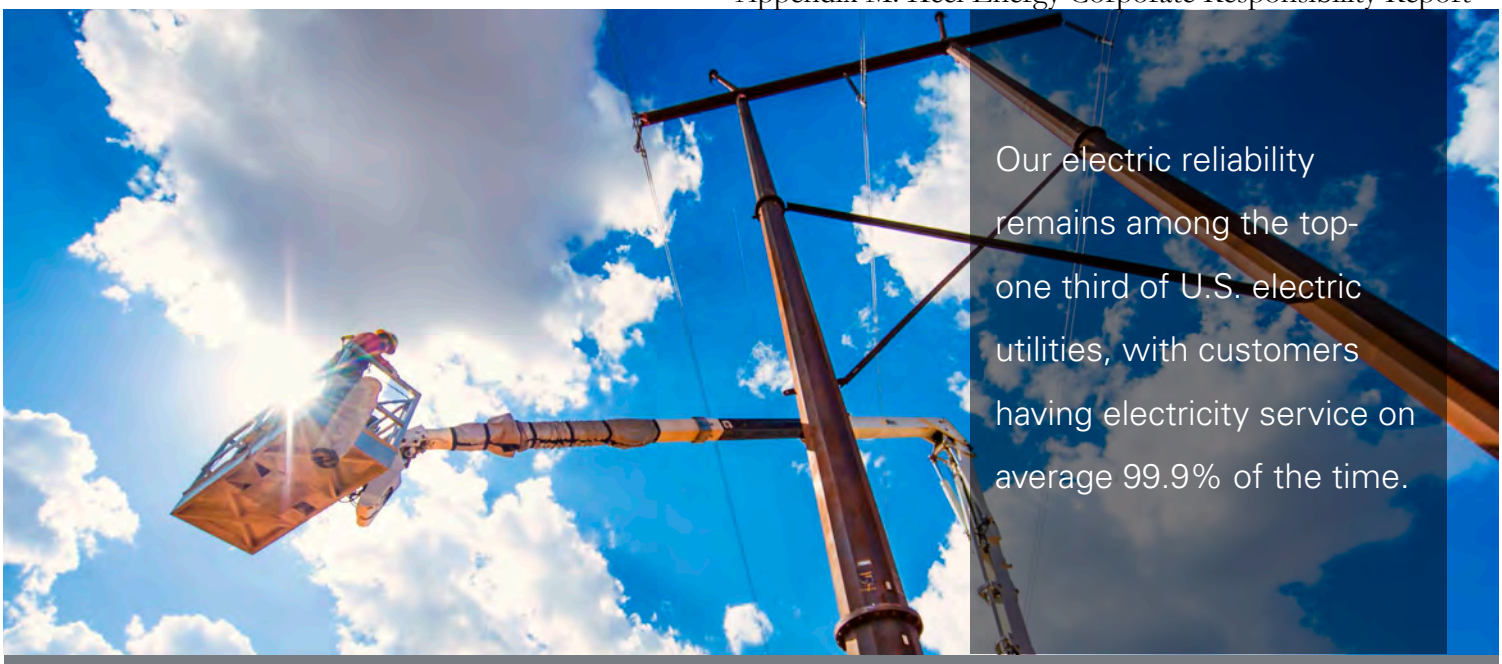
Learning Programs	Opportunities
Online Courses	We offer an extensive catalog of online courses for employees to complete, ranging from technical and computer application training to professional and management training to compliance-related education and more. Some of these training programs are mandatory.
Classroom Courses	Employees can choose to attend a number of different training programs that are taught in person, ranging from safety and compliance-related classes to professional development classes to technical trainings. Depending on job responsibilities, some of these courses are mandatory.
Career Development Assignment Program	The Career Development Assignment Program is an intentional effort to support the development of high-performing employees through cross-functional experience aligned to business needs. Employees may be pre-identified through succession planning or, in some cases, the opportunity may be posted.

2018 Leadership Development Opportunities

Programs	Opportunities
Succession Planning	Talent Review identifies individuals who might be successors for critical positions at Xcel Energy. Through this systematic process, executives and managers discuss assessments regarding the long-term performance, leadership potential and career aspirations of their employees. Working in teams, they determine the developmental readiness of each employee, create customized development plans and identify talent gaps. Potential "ready now" successors are identified for key positions around the company. This ensures there are successors that possess the necessary skills to make a seamless transition into the role for which they have been identified. In 2018, about 202 key positions were identified and nearly 2,300 leaders and individual contributors were assessed during Talent Review.
Coaching in the Moment	Coaching in the Moment is a course that teaches leaders how to coach employees by using insightful observations, shifting their worldviews and empowering them to take meaningful action. Offered both in a classroom and online setting, this training is transforming how our leaders interact with their team members by helping them learn to resolve their own dilemmas.
Leadership Essentials	Leadership Essentials is an online portal accessible to all employees that features over 25 learning topics, such as managing relationships, influencing and development planning. Each topic contains informational content, practice activities, and links to curated internal and external resources such as helpful articles and videos.
Leading the Call	Leading the Call is a small cohort-based executive development program for high potential, senior leaders. A cohort will meet regularly over several months to engage on topics such as culture, leading change, self-awareness, cross-functional and enterprise thinking, and to prepare for the highest levels of leadership. To put learning into action, they also divide into small groups to address real business challenges. In 2018, a cohort of 17 leaders went through the program.

Equal Employment Opportunity and Non-discrimination Policies

Our corporate Code of Conduct prohibits all forms of discrimination and promotes equal employment opportunities. We have Equal Employment Opportunity and Non-Discrimination policies in place that apply to all Xcel Energy operating companies and subsidiary companies. Xcel Energy provides equal opportunity in hiring, training, compensation, promotion, termination, transfer and all other terms and conditions of employment, without regard to race, color, religion, creed, national origin, gender, age, disability, veteran status, sexual orientation or any other protected class status in accordance with applicable federal, state and local laws.



Energy reliability, fuel diversity, nuclear generation, security, emergency preparedness and advanced grid

Reliable and secure energy

We provide 24/7 convenience for millions of customers who depend on us for the fundamentals — reliable, affordable and safe energy from an increasingly cleaner mix of resources.

Above all else, our fundamental purpose is to provide customers with safe, clean, reliable and affordable energy. We continually invest to strengthen and upgrade our infrastructure — the generating plants, power lines, pipelines and other systems that serve customers. This includes diversifying our energy supply to provide energy from a reliable mix of resources while managing cost, environmental impact and making sure we don't depend too heavily on any one energy source. As we decide where to invest, we naturally consider projects that address all these considerations while providing the best overall value for all stakeholders — addressing the interests of regulators, policy makers, communities, customers and investors.

To run and maintain our system, we must also invest in our people to cultivate a culture of continuous improvement where we strive to work better and smarter for our customers. Among our operations employees, we have a mantra of getting better every day.

2018 Results

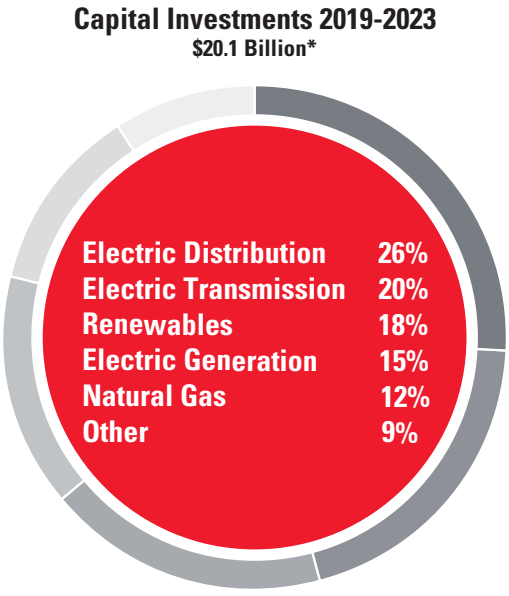
- Regulators approved our Colorado Energy Plan that is supported by a diverse coalition of stakeholders, including environmental groups, consumer advocates, municipalities and customers. Under the plan, we will retire 660 megawatts of coal-fueled generation and add 1,100 megawatts of wind, 700 megawatts of solar, 275 megawatts of battery storage and 380 megawatts of existing natural gas resources. We will own 500 megawatts of the new wind and all of the natural gas resources.

- We reached a $650 million agreement to purchase the Mankato Energy Center, a 760-megawatt natural gas power plant. The plant currently provides power to our customers under a purchased power agreement with Southern Power, a subsidiary of Atlanta-based Southern Company. Purchasing the plant is a great value for customers because of the cost savings and operating flexibility it can provide as we transition to clean energy and reduce reliance on coal.
- We delivered the Rush Creek wind project on time and within budget. The 600-megawatt project is our largest constructed to date. We also made progress advancing eight other wind projects across seven states to different stages of development. Xcel Energy is building and will own the projects, totaling 2,550 megawatts of capacity. In addition, we expect to own an additional 470 megawatts of wind capacity from four projects that others are building or repowering.
- Under our Advanced Grid Intelligence and Security initiative, we deployed 100 network and more than 200 advanced distribution devices, and implemented a secure, two-way private network that will function as the foundation for advanced technology in Colorado and Minnesota. This work is just the beginning of the initiative that will upgrade the power grid to better serve customers and enhance our ability to efficiently restore power and improve reliability. The initiative will create a platform that provides enhanced visibility and control of the energy grid through the integration of modern information system technology and traditional distribution systems.
- Xcel Energy was one of several companies recognized with a special 2018 Emergency Assistance Award by the Edison Electric Institute. Approximately 200 of our line workers and support personnel traveled to Puerto Rico to help restore power following the devastation of Hurricane Maria.

Investing for the Future

Over the next five years, we plan to invest $20.1 billion in projects that, in addition to ongoing maintenance and repair, will improve energy production, strengthen the energy grid, ensure security and offer customers more options.

We are investing in projects that offer the most value for customers.



*Includes the purchase of the Mankato Energy Center and the Jeffers and Community Wind North repowering projects, which are awaiting regulatory approval in 2019.

System Resource Planning

We are required by some state regulatory commissions to regularly conduct a system resource planning process. The process varies by state, but generally begins with Xcel Energy filing a proposed long-term resource plan with the public utilities commission, which is then evaluated by regulators, as well as customer, environmental and community stakeholders. The plans assess the overall resources we need to serve the energy needs of our customers. The plans also discuss many other factors associated with our generation portfolio including transmission needs and our total load obligations, which are influenced by items like energy efficiency program goals.

Once the plan is approved, it may result in the need to add resources to serve our customers. We then typically release one or more requests for proposals, which may be general or targeted toward specific resources, such as natural gas or renewable energy. As the regulatory commissions decide on the resources to be acquired, our stakeholders have the opportunity to provide input.

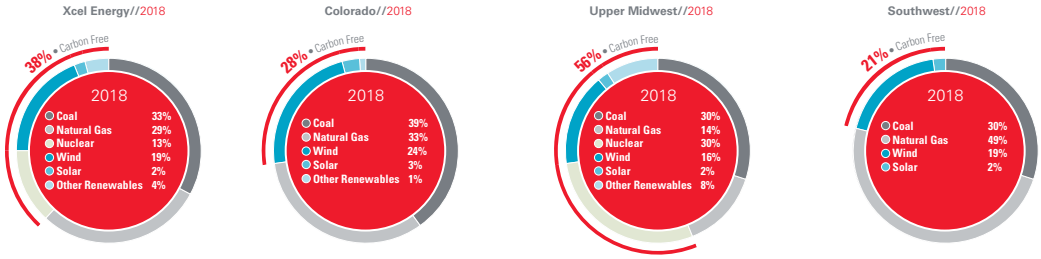
In Colorado, regulators approved the Colorado Energy Plan in August 2018, which completed phase two of our 2016 resource plan. We are now acquiring the new renewable, battery and natural gas resources that are part of the plan.

In the Upper Midwest, we are preparing to file a new resource plan in July 2019. We have announced our 2030 goal to reduce carbon emissions from the electricity that serves our customers 80% while maintaining reliability and keeping customer bills affordable. We are currently working with stakeholders on the upcoming proposal to achieve this goal.

In our southwestern states, we are only required to file a resource plan in New Mexico. In early 2018, regulators in New Mexico and Texas approved our plans to add 1,230 megawatts of new wind generation for the region in 2020. We are now implementing the wind projects, which are expected to meet customer energy needs while saving money long term through lower fuel and other costs. We anticipate filing updated resource plans in New Mexico as our system load requirements and generation portfolio continues to evolve.

Our Energy Supply

Xcel Energy provides electricity from a diverse mix of energy sources, including coal, natural gas, nuclear and renewables. We delivered more than 102 million megawatt hours of electricity to customers in 2018 produced at Xcel Energy generating plants and purchased from third-party suppliers.



Utility Operations

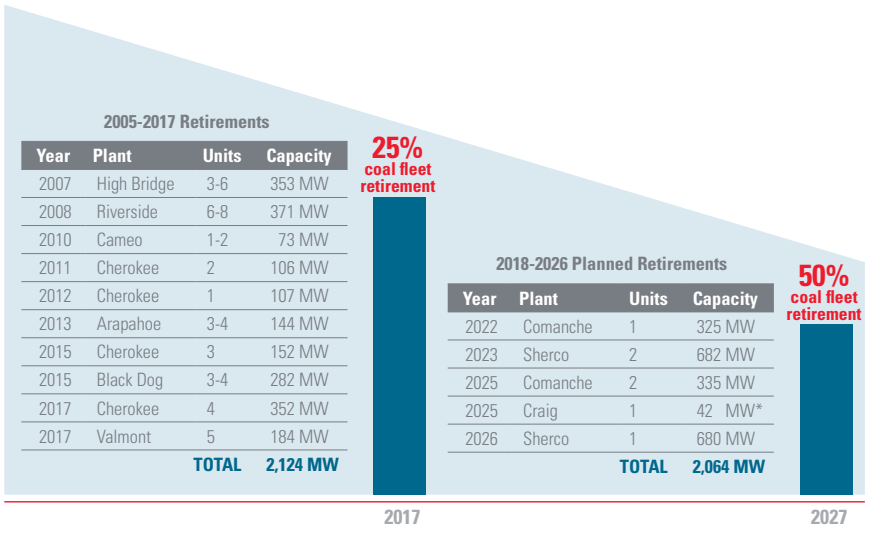
Generating Electricity

We currently own 79 generating plants that operate across our eight-state service territory with more than 18,000 megawatts of capacity. Traditionally, our generation portfolio has depended on coal, but we are transitioning our energy supply away from coal to rely more on renewable energy and energy sources that enable renewable integration, such as flexible natural gas generation. We need technologies that can be dispatched to balance the peaks when customer use exceeds renewable generation and valleys when renewable generation exceeds customer use.

By 2026, we will retire 23 coal units under approved plans, representing approximately 50% of the coal-fueled capacity we own. When we file our proposed Upper Midwest Energy Plan in July 2019 for consideration with the Minnesota Public Utilities Commission, it will include additional coal retirements. We will propose closing the Allen S. King Generating Plant in 2028 and Sherco Unit 3 in 2030 — our last remaining coal plants in the region.

As we retire resources and replace them with new ones, we are making the transition responsibly and thoughtfully for the communities and employees who are impacted. To date, we have managed plant closures through attrition and employee transfers to different company work locations. For our communities, we continue to partner on economic development opportunities, and we expect the transition will also create new jobs and economic development opportunities throughout our service area.

Xcel Energy's declining reliance on coal enables significant reductions in carbon and other emissions.



*Based on Xcel Energy's 10% ownership interest in Craig Unit 1.

We continue to invest in wind energy under our Steel for Fuel strategy, capitalizing on historic-low wind prices and available tax credits to install new wind farms — where the cost to build the projects is offset by future fuel savings. Xcel Energy is recognized as a national leader in wind energy. Currently, most of the wind power on our systems is contracted under long-term agreements with third parties, but that is changing under our Steel for Fuel strategy.

Our two nuclear generating plants in Minnesota play an essential role in our energy future, providing 1,657 megawatts of reliable, carbon-free capacity, enough to power 2.3 million homes. The plants delivered exceptional performance in 2018, generating more than 14.6 million megawatt hours of energy. It is a record for the plants, which produced power 96% of the time while reducing operating and maintenance costs by nearly 3%. Both plants also received the top rating under the Nuclear Regulatory Commission's Reactor Oversight Process that classifies the nation's nuclear reactors into categories based on safety. Our Monticello Nuclear Generating Plant was honored with the Institute of Nuclear Power Operations' Excellence Award for achieving an excellent rating on the plant's annual evaluation.

Delivering Power

Xcel Energy operates nearly 21,000 miles of power lines and more than 1,200 substations and other equipment to safely and reliably deliver electricity to customers.

Transmission lines are a vital link to bring electricity over long distances from power sources to substations closer to homes and businesses. Xcel Energy is one of the fastest growing, investor-owned transmission systems in the country.

The following are notable projects in 2018:

- As part of the Power for the Plains initiative in New Mexico and Texas, we completed nearly 250 miles of new transmission. The largest effort was the new 90-mile 345-kV Hobbs-China Draw project in New Mexico that provides a new source of bulk power to meet growing electricity demand in Eddy and Lea Counties.
- We completed the 83-mile, 345-kV transmission line between Missile Site Substation and the new Pronghorn and Rush Creek II Substations. The new line carries power from the Rush Creek wind project to Colorado business and residential customers.
- In Minot, North Dakota the 20-mile Magic City-McHenry 230-kV transmission line and new substation went into service, providing another source of electricity and improving reliability for the area. Xcel Energy crews partnered with the U.S. Fish and Wildlife Partners for Wildlife program to plant 40 acres of pollinator habitat around the new substation.
- The La Crosse-Madison Transmission Line Project, also known as the Badger Coulee Project, was completed and energized in December 2018. The approximately 180-mile, 345-kV line provides electric system reliability to benefit western Wisconsin communities, the state of Wisconsin and the entire Upper Midwest region and provides access to lower-cost power and renewable energy.

In addition to these projects, we successfully started a critical rebuild project near Boulder in difficult terrain. In three days, we hauled and set 19 steel transmission structures by helicopter to rebuild a 110-year-old 115-kV line that runs between the El Dorado Substation and the NCAR Substation in Colorado. The line is located in Boulder Open Space in an area largely inaccessible to vehicles.

Fueling Homes and Businesses

Xcel Energy is the tenth largest provider of natural gas service in the country, based on number of customers. We fuel the homes and businesses of approximately 2 million customers in Colorado, Michigan, Minnesota, North Dakota and Wisconsin, and also operate some gas transmission in South Dakota and Texas. Natural gas is an extremely safe and efficient way to heat homes, from both a cost and environmental perspective, especially in our cold weather service areas. With more than 2,200 miles of transmission and 35,000 miles of distribution pipelines already in service, we plan to add approximately 750 miles of new pipeline over the next five years.

To maintain safe and reliable gas service for everyone, we continue to upgrade and renew our natural gas pipelines and other equipment. We finished replacing all cast-iron pipes on our system in 2014. Low natural gas prices have made it possible to invest in our system and accelerate upgrades with minimal impact to customer bills.

Xcel Energy purchases natural gas from third-party producers to generate electricity and distribute to customers for use in their homes and businesses. Natural gas production is governed by federal, state and local regulations, with additional regulations under consideration. We expect all our suppliers to conduct their operations responsibly and in compliance with all regulatory requirements.

We can play an important role in ensuring natural gas is produced responsibly and as sustainably as possible. To help promote sustainable production upstream of our operations, we joined the Natural Gas Supply Collaborative — a group of the nation's large natural gas purchasers. Collaborative members have called for and are encouraging enhanced transparency from natural gas producers across 14 social and environmental metrics.

Vegetation Management

Xcel Energy's Vegetation Management department manages millions of trees across more than 47,000 miles of distribution right-of-way and nearly 21,000 miles of transmission right-of-way throughout our service territory. For 24 years, the Arbor Day Foundation has recognized our company as a Tree Line USA utility for our commitment to proper tree pruning, planting and care.

We use industry best practices such as Integrated Vegetation Management, which encompasses a progressive system of information gathering and helps us develop compliant solutions for controlling vegetation near electric and natural gas facilities. The practice helps us achieve our vegetation management goals in an environmentally sensitive, socially responsible and cost-effective manner.

In addition, pruning methods comply with standards set by the American National Standards Institute and the Tree Care Industry Association, which are endorsed by the International Society of Arboriculture.

For our distribution and transmission lines, work is generally performed on a four- to five-year cycle. In Colorado, we have established a Mountain Hazard Tree Program that helps us stay ahead of the tree mortality caused by the Mountain Pine Beetle. Our practices seek to balance our customers' need for reliable energy while respecting the natural environment that surrounds our facilities. For example, we work with landowners to determine if trees and other vegetation can be deemed compatible with safe operation of our electric lines.

In our efforts to comply with governmental regulation and to better ensure electric system reliability, our transmission line vegetation management program emphasizes the removal of incompatible vegetation to promote long-term vegetation control. In many cases, this means removing trees in areas where trees had been pruned in the past.

We employ manual and mechanized clearing techniques, as well as responsible herbicide applications. All herbicides used are products registered by the EPA and the appropriate state regulatory agency. The herbicides are applied by licensed applicators.

Safety: Grid Resilience and Security

As the use of technology and interconnected systems expands, the grid is increasingly subject to attack by those who might choose to do us harm, whether for criminal purposes or as part of an effort to undercut our national security. Ensuring our energy grid is secure from cyber and physical threats is an ever-evolving responsibility that demands our constant vigilance and is a top priority for Xcel Energy.

We continue to implement an array of efforts to increase preparedness and decrease vulnerability. Our Enterprise Security Services organization oversees coordination of all security efforts, including employee training and awareness, compliance with federal regulations and corporate security governance.

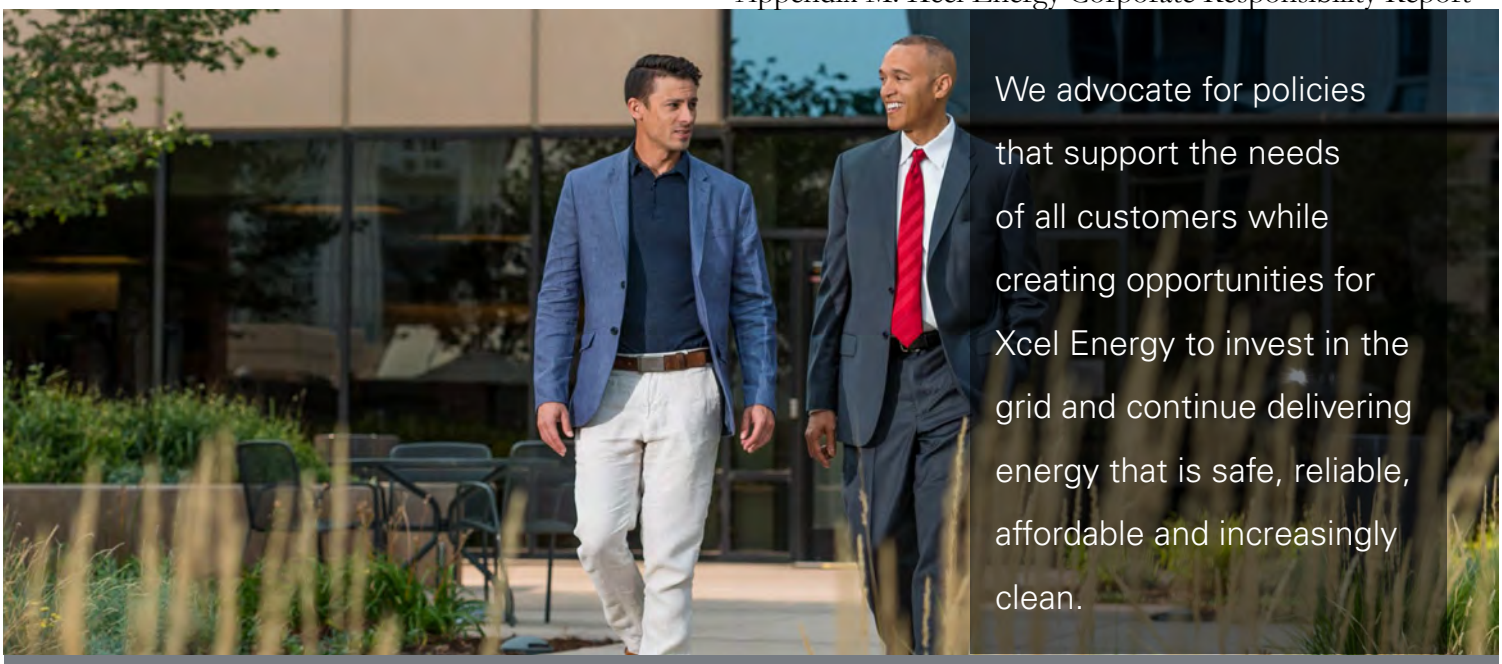
Through our state-of-the-art Cyber Defense Center, we monitor and protect our networks 24 hours a day, seven days a week. Our cyber security program is risk-based and uses known standards and best practices which encompass security controls that provide adherence to government and regulatory requirements. It includes "Defense-in-Depth" methodology that provides multi-layered safeguards to reduce or eliminate single points of failure and weakness.

While it is impossible to protect our systems and grid against every malicious attack, we are taking reasonable and prudent steps to prevent, detect and mitigate the impacts of an intrusion. We are hardening systems to limit opportunities for attack and deploying enhanced monitoring and detection systems to help us promptly identify any successful intrusion.

In 2018, we introduced the Enterprise Command Center, which provides constant monitoring for natural and man-made events that could be disruptive to Xcel Energy's ability to serve our customers, protect our assets and keep our employees safe.

We engage with other members of our industry, other segments of the economy and the government to engage in threat information sharing and test our combined capabilities to respond to an attack. Individually and in collaboration with other energy providers, we are working to prepare our employees and systems for responding to a successful attack by developing inventories of spare equipment and processes for preserving reliability in the unlikely event our key operational systems were to be compromised.

As part of our commitment to security, Ben Fowke, Xcel Energy chairman, president and CEO, is a member of the National Infrastructure Advisory Council, which advises the President on ways the nation can protect its critical infrastructure. He also participates in the Electric Sector Coordinating Council, which serves as the principle liaison between the federal government and the electric power sector on these issues.



Public policy engagement

Public policy

Xcel Energy engages in policy and regulatory issues important to ensuring our ability to provide all customers with the energy service and products they want and value.

As the energy industry continues to undergo a significant transformation, it is essential that we participate in the policy developments that will determine our future, representing the interests of our company and its many diverse stakeholders. With more than a century of experience in meeting the energy and financial needs of customers, communities and investors, we aim to share our expertise with policy makers and elected officials to better inform and guide decisions that impact the service we provide.

While we may not always share the same positions, we participate in industry, trade, business and other associations to provide our perspectives and to learn from the perspectives and experiences of others. We discuss issues and solutions with policy makers on all levels — local, state and federal. We also provide informal input and formal testimony and comments on proposed legislation and regulation.

Our policy priorities focus on advancing research of new clean energy technologies and developing the right conditions that allow technologies to be seamlessly adopted by our existing system, once they are ready. To help facilitate or accelerate our industry transformation, we are exploring targeted incentives and the right mandates that will not increase customer costs.

2018 Results

- When we announced the company's industry-leading carbon vision in late 2018, policy makers, community leaders and environmental advocates from around the country expressed their support for our new goals. We worked extensively with stakeholders on this commitment to help confirm our goals and advocate for the policy objectives for achieving them.

- We worked with public utilities commissions in all of our states to determine how cost savings associated with major tax reforms passed by the U.S. Congress in late 2017 will be shared with our customers. Overall, our average electricity rates were 0.2% lower in 2018 due to customer refunds associated with the Tax Cuts and Jobs Act.
- The President's National Infrastructure Advisory Council released its report on how the nation can best prepare for and recover from a catastrophic power outage. Xcel Energy's chairman, president and CEO Ben Fowke participates on the council, and we were significant contributors to the report, which examines how our nation can strengthen its long-term power outage prevention and recovery capabilities.
- The 2018 Farm Bill signed into law at the end of the year includes a provision that we supported to authorize the U.S. Forest Service to work with utilities to manage vegetation adjacent to transmission rights-of-way on federal lands. The program supports overall forest health and can help protect utility infrastructure from wildfires.
- The U.S. House of Representatives passed a bill in spring 2018 that allows for consolidated interim storage facilities and encourages the finalization of a permanent repository for radioactive waste from the nation's nuclear generating plants. We supported the bill and continue to work on a solution to this long-standing issue. In May 2019, our Chief Nuclear Officer testified in support of similar legislative proposals in the U.S. Senate.

Public Policy Principles

Our energy landscape is evolving, driven by new technologies and customers demanding new energy options and a reduced carbon footprint. In this new landscape, we are striving to meet the interests of individual customers while continuing to deliver safe, clean, reliable energy at an affordable cost and creating opportunities for our company to invest in the grid. To meet the challenges ahead, we follow these four core principles as we support the transformation of our energy landscape.

- **Utilities are engines for innovation and deployment at scale.** The vertically integrated utility model with regulatory oversight is well-positioned to adapt to changing energy markets, new technologies, new customer preferences and community goals. This model provides inherent system value through efficiency, optimization and economies of scale that benefit all customers and balances the allocation of risks and benefits between the utility and its customers. As such, we are well-positioned to grow the market for value-added services — such as energy storage, microgrids, electric vehicles, and solar power — and to do so at scale and in a manner that benefits all customers.
- **We can enable greater customer choice without eroding fundamental rate design principles.** Ideally, rates should reflect the cost of service provided to a customer and continue to prioritize affordability because reliable, affordable energy is essential to a strong economy and protecting low-income customers. Matching rates to price signals moves the system to a more efficient state of operation and options like time-of-use pricing can incentivize customers to shift energy use to more desirable times.
- **The grid is our economy's greatest physical asset and utilities are its stewards.** More than a collection of wires, the grid is an integrated system of plants, wires, transformers, substations, control systems, and other equipment that is foundational to our economy. In our jurisdictions, the vertically integrated utility model — from supply to delivery — is the most effective way to economically maintain a reliable and secure grid and make the investments necessary to meet customer needs and achieve environmental goals.
- **Our economy will continue to electrify and utilities should be the architects of that transition.** There are clear signs that our economy is undergoing a transformation to greater and cleaner electricity usage, and through lower-carbon electricity and electrification, we can further reduce greenhouse gas emissions. The transition must be done as part of a thoughtful, deliberate, policy process — one that builds upon past utility successes and engages customers and communities who wish to actively participate.

Our society does not need a new business model for utilities in order to meet modern day challenges. We need a modernized version of the model that has been delivering for decades. The utility industry, and Xcel Energy as a leader in the industry, is well poised to meet these challenges in direct partnership with our regulators and our customers.

Advocacy for Innovation and Developing Advanced Energy Technologies

We continue to engage in and work to address policy issues at all levels of government. One of those issues, and a significant objective for us going forward, is establishing a path for the development of advanced, carbon-free 24/7 technologies that we will need to fulfill our aspiration to serve customers with 100% carbon-free electricity by 2050.

Federal and state policies must support the development of new, carbon-free, 24/7 resources to complement our existing and growing portfolio of renewable energy, energy efficiency and demand response resources. We can also send clear signals to the market around price, capabilities and timing for when these technologies will be needed. In this way, utility resource plans provide the market signal — the state-level "technology pull" — from which the private sector and national laboratories and federal agencies can align their investments. This investment in further research and demonstration will help develop the carbon-free solutions we need at the cost and scale at which our sector will need them.

We are advocating for policies that help take advanced clean energy technologies from demonstration stage to commercialization by creating programs to manage cost and spread risk. In order for this to happen most effectively, it is important that developers leverage existing infrastructure and current market conditions. There is also opportunity to provide incentives for clean energy innovation and reducing barriers to new development. These incentives can be powerful mechanisms for deploying these technologies in the marketplace, but they require careful design. For that reason, we are working on policies that allow the efficient use of existing and new tax incentives.

Political Contributions and Lobbying

Xcel Energy has a corporate policy that sets guidelines and rules for political contributions and to ensure all contacts with government officials meet legal and ethical standards.

Our board of directors, leadership and employees must comply with all federal laws restricting the making of political contributions or expenditure using corporate funds in connection with elections for federal offices. When communicating about matters involving Xcel Energy, the board of directors, leadership and employees must accurately convey corporate messages and support the Xcel Energy brand. Xcel Energy's Political Contributions Report provides corporate contributions and dues paid to trade associations.

Employee Policy Engagement

Grassroots advocacy is important to Xcel Energy because our industry is so complex. Xcel Energy employees can help educate their friends, neighbors and community leaders by participating in:

- **Legislative Days:** We offer a special day at the capitol in each of our jurisdictions for employees to meet their elected officials and learn more about the legislative process.
- **Local events and meetings:** Employees can represent the company at community meetings and special events.
- **Political Action Committees:** Employees can voluntarily participate in seven different groups that are organized and run by employees.

Political Action Committees

Xcel Energy sponsors seven Political Action Committees or PACs organized and run by employees, six at the state level and one at the federal level. Participation in the company's PACs is completely voluntary and is part of the engagement opportunities that we offer employees.

Each of the company-sponsored PACs has its own board of directors elected by its members that make contribution decisions. All of our PACs are strictly voluntary, and there are no employment benefits based upon participation. Each complies with all applicable local, state and federal laws.

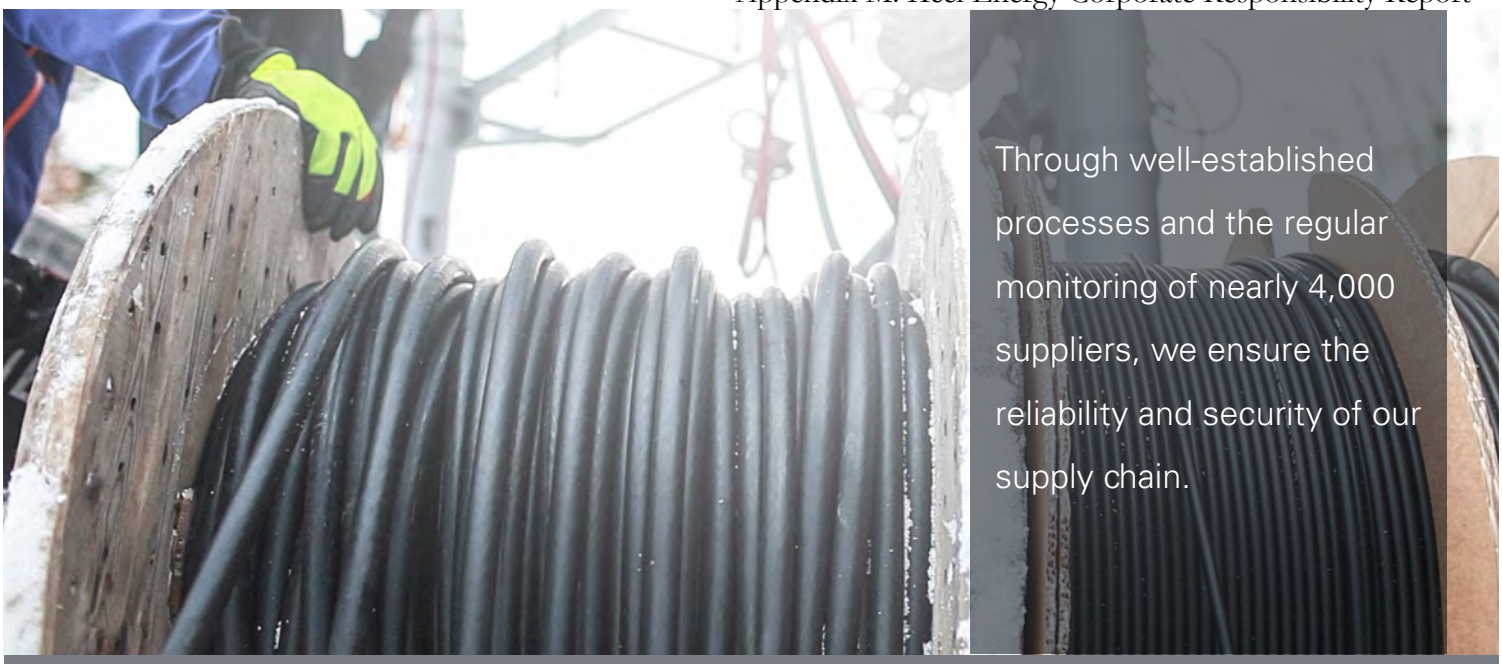
2018 Xcel Energy Political Action Committee Activity

PAC	Employees Participating	Total Employee Contributions to PAC	Total Contributions Made to Candidates*
Colorado (Western PAC)	327	$28,927	$38,375
Minnesota**	329	$48,705	$44,700
North Dakota	24	$1,945	***$6,200
South Dakota	0	$0	***$3,900
Texas/New Mexico (SCOPE)	368	$35,787	$59,050
Wisconsin	342	$36,614	$27,488
XPAC (federal PAC)	389	$246,220	$253,000

*Funds contributed by employees can accrue over multiple years and are not necessarily distributed in the same year they were contributed. Contributions vary by year and are typically lower in nonelection years or years when state legislatures are in session.

**The state PAC in Minnesota is operated outside of Xcel Energy in accordance with state law that prohibits the use of corporate resources to support the PAC; although, payroll deduction is specifically permitted in Minnesota. Activity for the Minnesota PAC is only included in this report for transparency and informational purposes.

***With the exception of 24 North Dakota state PAC-only contributors, all contributions made to both the North Dakota and South Dakota state PACs were made via funds transferred from the Minnesota state PAC in compliance with all federal, state and local campaign finance laws.



Procurement practices

Supply chain management

Suppliers play a vital role in our company's ability to manage costs, operate efficiently and provide the ongoing service that our customers value.

We continuously look for ways to improve efficiency and reduce the cost of doing business through our supply chain processes. As we negotiate favorable prices or find ways to reduce waste, we pass the savings on to customers, helping to manage their energy costs.

Much of our spending on materials and services is with local businesses, which supports economic prosperity in the communities we serve. We also look for business partners that share our priorities around safety, diversity and environmental protection and that will adhere to our Code of Conduct.

2018 Results

- We spent $533 million, directly and indirectly, with businesses owned by women, minorities or veterans, achieving our goal to spend 12.4% of total annual spending with diverse suppliers.
- Nearly 70% of our supply chain spending was with local businesses, totaling more than $2.9 billion. While not all materials and services can be sourced locally, we build relationships and set targets to support our area economies.
- Through our supply chain, we saved approximately $307 million, which was first-quartile performance in a benchmarking of peer utilities.
- The Hispanic Chamber of Commerce of Metro Denver named Xcel Energy its Corporate Advocate of the Year in early 2019 for the company's ongoing support and work with member companies. Three of our largest contractors in Colorado are chamber members, including Alvarado Construction, Campos EPC and Redeker Excavating.

Supply Chain Process

Our central Supply Chain organization is responsible for the sourcing and procurement of goods and services, materials management, fleet management and accounts payable for all of Xcel Energy's operations. The group negotiates contracts for everything from day-to-day business necessities, such as office supplies and furniture, to capital items used to construct, operate and maintain our generation and transmission assets, including transmission poles and transformers. They develop supplier and contractor management strategies and policies, handle accounts payable and execute company-wide sourcing and procurement strategies.

We employ a systematic sourcing method to deliver needed materials and services to the right place at the right time for the right price. To select suppliers, we use a five-step sourcing process that includes: preparation, request for information, request for proposal, contract evaluation and negotiation, and implementation.

Four key business objectives — each associated with specific initiatives — drive our supply chain strategy. These include:

- Maximizing investment yield
- Achieving operational excellence
- Managing risks and opportunities
- Supporting community and environmental leadership

In 2019, we expect to spend approximately $4.58 billion on materials and services that fall into 35 categories with more than 800 subcategories. These categories are used to determine risk, opportunity and negotiation leverage with suppliers. We have developed guidelines for bid analysis for all categories. Within these guidelines, up to 20% of the bid analysis weight can be allocated to social and environmental factors such as diversity, safety and environmental performance.

2018 Supply Chain Spending Categories

Battery	Engineering Services	Meters	Steel Structures
Boiler Systems	Environmental	MRO Materials	Transformers
Cable and Wire	Fleet	Other Plant Systems	Transportation Services
Chemicals Gases and Lubes	Gas Materials	Property Services	Travel Services
Circuit Breakers	HR and Benefits	Radiation Protection	Turbine and Generator Systems
Construction	IT and Telecom	Revenue Cycle	Vegetation Management
Consulting Services	Logistics Integrator	Safety	Wind
Dry Fuel Storage	Maintenance Services	Solar	Wood Poles
Electrical Materials and Equipment	Marketing and DSM	Staff Augmentation	

Risk Management

Through our Supplier Qualification program, we use services such as Dunn & Bradstreet to regularly monitor all active suppliers for Office of Foreign Assets Control, Excluded Parties List System, OSHA and EPA violations, as well as criminal proceedings and disaster events. We assess suppliers' financial health, safety and use of diverse subcontractors before contracting with them, and suppliers who will have access to our confidential data must undergo a data security review.

Periodically, we conduct key risk assessments, looking at categories such as commodity price risk, supply continuity, quality and governance processes. We also design sourcing strategies that take into account multiple fulfillment locations and supply channels that can minimize potential supply disruptions in case of extreme weather or disaster-related events.

Our company works with a broad range of suppliers. The majority of our spending is with American suppliers, but we also do significant work with American-based affiliates of foreign suppliers and a small amount of work with foreign suppliers.

We have recently implemented a program for Security Vendor Risk Assessment that focuses on exposure to cyber, information and other security risks to Xcel Energy that could result from suppliers' access to our systems, confidential information and critical infrastructure. The requirement for this additional level of scrutiny is established in sourcing and contracting processes and involves a comprehensive testing of the supplier's security environment by our Enterprise Security Services team.

All contractors that provide services or materials at our sites are required to complete a contractor health and safety questionnaire and submit five years of safety-related performance data. Our contractor safety department reviews this data and may reject a contractor or require a safety improvement plan. We continue to monitor safety performance once a contract is implemented.

Tier	Annual Spending	No. of Suppliers	% of Annual Spend
Tier 1	More than $10 million	77	73%
Tier 2	Between $4-10 million	59	8%
Tier 3	Between $1-4 million	211	10%
Tier 4	Less than $1 million	3,382	8%

In addition, all contracts include a clause requiring suppliers to abide by equal employment opportunity and affirmative action mandates prohibiting discrimination on the basis of race, color, religion, sex, national origin, actual or perceived sexual orientation or gender identity of an individual, or physical or mental disability. All suppliers are expected to comply with our Code of Conduct, which is referenced in our standard agreement language and is made available to them upon request.

Supplier Classifications

We classify our suppliers in four tiers based on a combination of overall supplier spend and their importance or risk to our operations. Critical suppliers provide essential materials and services required to support daily operations. Tier one suppliers, including those who are critical to our operations, are part of our Supplier Relationship Management program. The program enables us to build longer-term contracts with these strategic suppliers and implement continuous improvement initiatives to benefit both the supplier and Xcel Energy in terms of costs and operations. Suppliers are also tiered, based on their total spend.

We support suppliers in non-tier one spend classifications through collaborative initiatives and programs. For example, we are a founding member of the ITASCA-Project in the Twin Cities, which is dedicated to helping smaller local suppliers grow through procurement opportunities. The ITASCA-Project group is made up of chief supply chain personnel from large corporations, such as Xcel Energy, U.S. Bank, Target, United Health and General Mills, who meet monthly to discuss ideas for supporting the local economy by growing the capacity of small- and medium-sized businesses.

Supplier Diversity Program

Our corporate policies underscore our commitment to supplier diversity by recognizing that it is in our best interest to encourage a broad base of supplier relationships. Using diverse suppliers contributes to the economic growth and expansion of the communities we serve. Our policy is to offer these businesses the opportunity to compete in our procurement for products and services. We develop and strengthen business relationships with diverse suppliers by:

- Conducting outreach efforts to seek, identify and encourage supplier diversity in our procurement processes
- Facilitating alliances and partnerships
- Educating businesses about our procurement and business processes
- Identifying and encouraging subcontracting (tier two) opportunities with major suppliers when direct participation is not possible

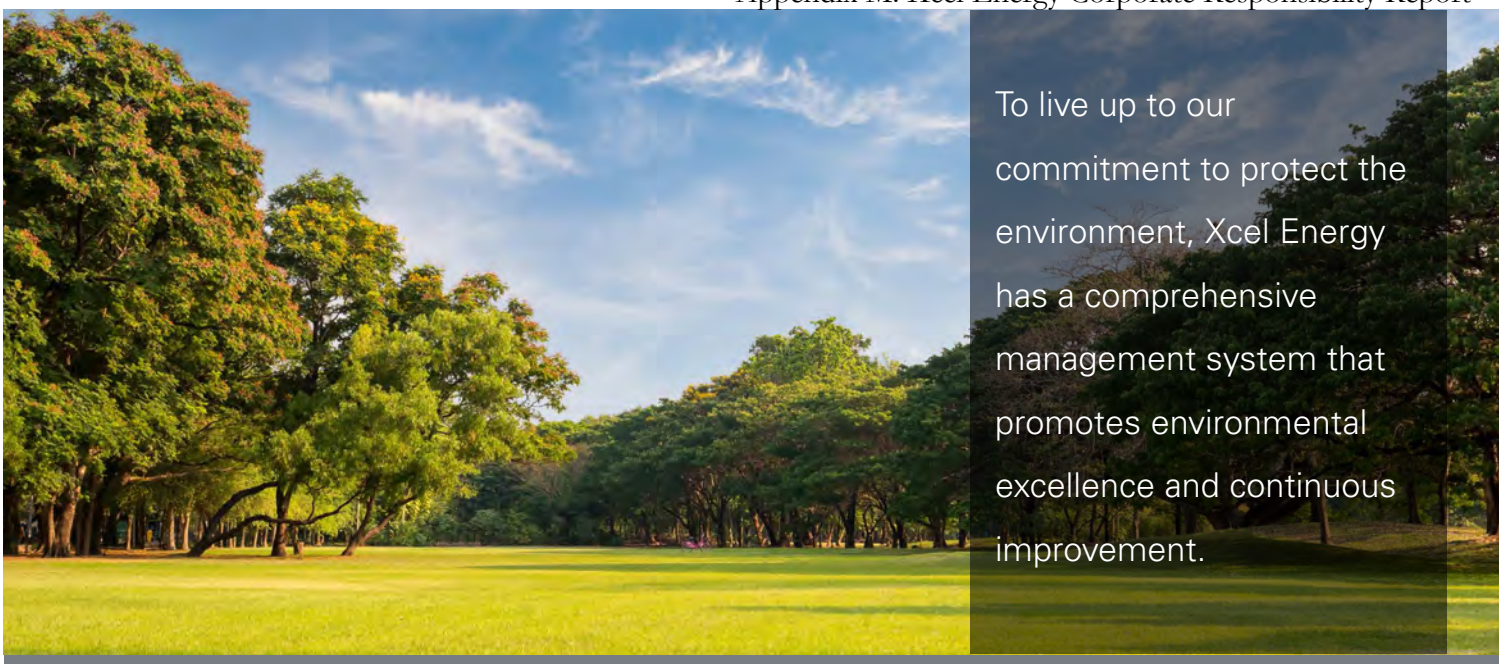
For 2019, we have set a goal of approximately $575 million, or roughly 12.5% of total spending, to spend with diverse suppliers. Most of the recent increases in our goal have been associated with Xcel Energy's continued investment in renewable energy, especially in constructing new wind farms. Wanzek, one of our diverse suppliers, is constructing multiple new wind projects on our system.

We are an active member of the Edison Electric Institute's Supplier Diversity Best Practices Group, as well as the Mountain Plains and North Central Minority Supplier Development Councils, the Women's Business Enterprise National Council, the National Association of Women Business Owners, the National Veteran Business Development Council, National Gay and Lesbian Chamber of Commerce and most local chambers of commerce in our service territory.

Annual Spending with Diverse Supplier

	2016	2017	2018
Dollars Spent	$401 million	$378 million	$533 million
% of Total Purchases	11.2%	10.5%	12.4%

Environment



Our policy and management approach

Environmental management

At Xcel Energy, protecting the environment is a priority and expectation for all employees and contractors as part of their jobs.

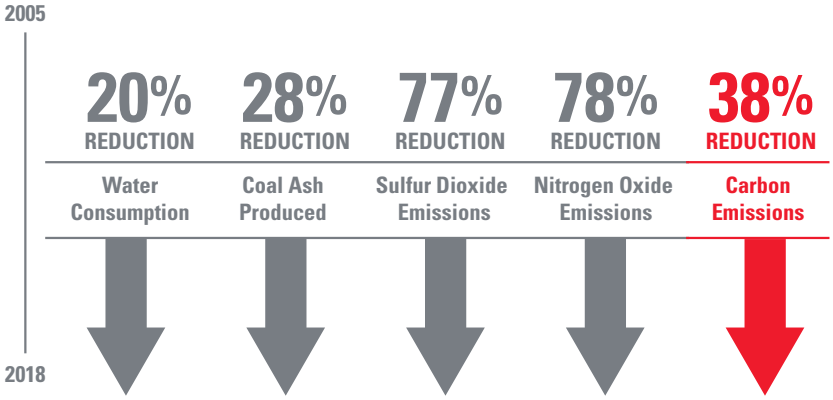
Every year we produce millions of megawatt hours of electricity and deliver millions of cubic feet of natural gas to serve our customers, fueling their homes and businesses. Our operations depend on natural resources — from fossil fuels to water and wind and solar — and they have an impact on the environment. It is an important relationship, and one that we are committed to managing carefully.

The customers and communities we serve depend on us and expect that through our daily operations we will protect our air and water, reduce waste and conserve natural resources.

2018 Results

- The Colorado Department of Public Health and Environment through its Environmental Leadership Program recognized Xcel Energy as a Gold Leader for the company's comprehensive Environmental Management System as well as its clean energy leadership and environmental stewardship.

We have significantly reduced our environmental impact since 2005.



Environmental Policy

Xcel Energy's environmental policy lays the foundation for the company's commitment and approach to protecting the environment and sets expectations for aligning our business practices with this commitment.

Our policy is to pursue environmental excellence through our corporate strategy and daily operations, striving to demonstrate leadership by doing what is right and advancing initiatives that will benefit the environment. At the same time, it is important that we balance our environmental commitment with the ability to provide customers with reliable and affordable energy.

Examples of our environmental leadership include:

- Significantly reducing carbon emissions through our proactive clean energy strategy
- Reducing other air emissions beyond what is required by regulations
- Surpassing state-level renewable standards by adding more cost-effective wind and solar
- Offering customers a robust portfolio of energy efficiency and renewable choice programs to meet unique needs and interests
- Conserving and reducing water consumption through electric generation
- Establishing more than 2,000 acres of pollinator habitat on the land we manage

As part of our decision making, we consider opportunities to reduce emissions, eliminate waste and conserve resources, including taking additional steps to protect wildlife. We also regularly monitor our operations to ensure we are acting in an environmentally responsible manner, and if appropriate, take steps to improve our efforts. We support environmental research and development, as well as environmental projects and partnerships in our communities.

To fulfill the responsibilities of our corporate environmental policy, we have more than 40 policies and procedures that ensure our ongoing environmental performance and that help to foster our commitment to environmental excellence.

All Xcel Energy employees, as well as contractors and vendors, are expected to follow these policies, and our employees are trained and empowered to take responsibility for protecting the environment through their jobs.

Environmental Principles

Engaging with stakeholders is essential to our work in addressing policy issues involving energy and the environment. As we engage on these matters with our regulators, elected officials, community leaders and others, we keep the following principles in mind:

- **Proactive solutions.** On behalf of customers, we have invested substantially in clean energy and environmental improvements. We continue to look for ways to proactively address environmental issues, especially when we can improve efficiency and reduce costs.
- **Rewarding leadership.** We believe that environmental and clean energy policy should appropriately recognize the environmental benefits of our proactive efforts made on behalf of our customers and communities.
- **Supporting technology.** Environmental and clean energy policy should drive forward the development of new, cost-effective technologies. As a national leader in wind, as well as energy efficiency and renewable choice programs, we are optimistic about the future opportunities that clean energy technologies present. Additionally, we are committed to owning these resources to improve the overall value and cost savings to our customers and stakeholders.
- **Efficiency and cost effectiveness.** The most efficient and effective response to environmental mandates is not always stack-by-stack or emission-specific compliance requirements. In some cases, compliance should be coordinated on a system-wide basis to maximize cost effectiveness and environmental benefits.
- **Flexibility.** Flexibility mechanisms, such as alternative compliance options and market-based environmental programs, should be incorporated into environmental rules. Flexibility yields real cost benefits to customers while maintaining environmental benefits.

Environmental Management System

We have a comprehensive environmental management system designed to promote environmental excellence and ensure continuous improvement and compliance with all applicable environmental requirements. Although we have not used formal certification under ISO 14001, our environmental management system aligns with and enables the nine elements of the ISO 14001 standard, including: policies, responsibilities, environmental interaction, impacts, compliance, objectives and targets, monitoring and measurement, performance review and continuous improvement.

Our management system provides:

Oversight	Board of Directors — Operations, Nuclear, Environmental and Safety Committee
	Chairman, president and CEO
	Executive Committee
	Environmental Policy department
	Environmental Services department
Risk analysis	Goals and performance indicators at corporate and operating levels
	Multidisciplinary teams for developing new compliance programs
	Environmental Audit program
	Regular risk assessments
Policies & procedures	Corporate environmental policy
	Formal, documented processes, procedures and standards
	Routine monitoring of new, evolving regulatory activity

Monitoring	Centralized and automated compliance tracking system that uses real-time data
	Monthly performance reporting
	Routine facility audits
Follow-up for compliance gaps	Tracking for corrective action and internal audit findings
Training and communication	New employee orientation
	Site and topic specific employee training and tracking
	Updates and information communicated through internal channels

Compliance Results

We strive to operate in compliance with all federal, state and local rules and regulations. However, there are occasions when regulatory agencies issue notices of violation (NOVs) or other types of notifications of potential noncompliance for alleged exceedances of permit limits or regulatory requirements. These NOVs can result in fines or penalties. Often there can be disputes about the alleged noncompliance, and even when it is our view that we remained in compliance, settlements are often reached to avoid the transaction costs of litigation and to cooperate with the regulatory agencies.

Every year as part of our internal and ongoing efforts to self-identify and self-correct any potential noncompliance issues, we conduct our own facility audits.

2018 Compliance Activity

Activity*	2016	2017	2018
Notices of Violation or Compliance Advisories	4	7	5
Penalties Paid	$25,000	$14,949	$0
External Agency Audits or Inspections	83	64	71
Internal Audits Conducted to Ensure Compliance	99	95	94

*Because of the regulatory process and timing, penalties are not typically paid in the same year that Notices of Violation or Compliance Advisories are issued.

We received five notices of violation or compliance advisories in 2018 involving activities at our facilities. All were considered minor infractions and no penalties or fines have been assessed. Of the five incidents, two involved wastewater discharges and the others related to air emissions testing, drinking water sampling and regulated waste storage.

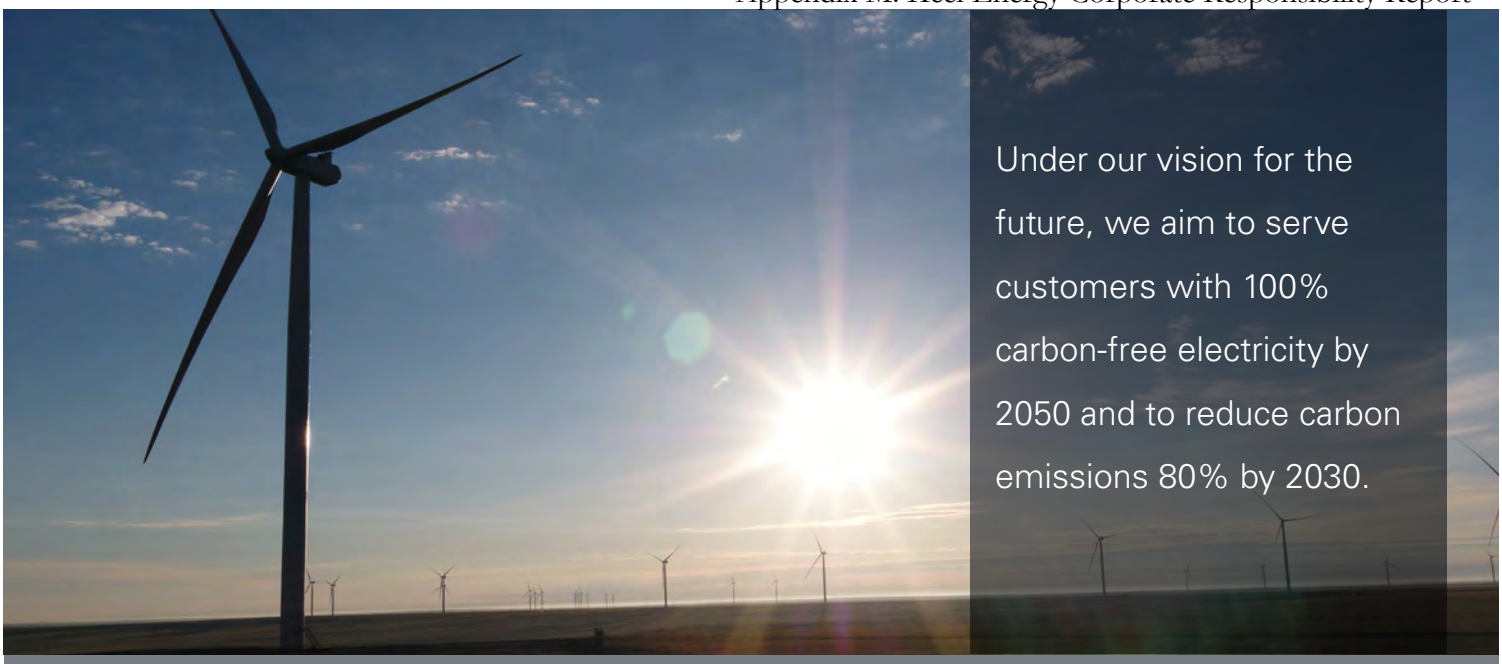
Environmental Expenditures

Environmental costs include payments for nuclear plant decommissioning, storage and ultimate disposal of spent nuclear fuel, disposal of hazardous materials and waste, remediation of contaminated sites and monitoring of discharges to the environment. As we have reduced emissions through the addition of environmental controls, the total costs of investing in and operating the controls has risen somewhat over time.

Environmental Expenditures

Expenditure Type	2016	2017	2018
Operating and Maintenance	$304	$303	$309
Capital	$93	$61	$50

More detailed information regarding nuclear decommissioning and spent nuclear fuel disposal expenses is provided in our 2018 Form 10-K.



Climate change and greenhouse gas emissions

A carbon-free future

Energy is an essential service that powers the economy and provides comfort and security. As we lead the clean energy transition, we will ensure that customers have energy when they need it, at an affordable price.

We know that climate change is an urgent issue for many of our policy makers and investors and is a growing concern of our customers who want to help make a difference. It is a priority for us as well, and is the reason we were the first major energy company in the nation to announce a vision to serve customers with 100% carbon-free electricity.

Planning for this transition to a clean energy future today will allow us to deliver the products our customers want and achieve reductions that our policy makers and investors are increasingly demanding. By acting now, we increase our ability to achieve our goals while assuring that our system remains reliable and our energy service affordable.

2018 Results

- We established our bold, new vision to provide customers with 100% carbon-free electricity by 2050 and to reduce carbon emissions 80% by 2030 from the electricity that serves our customers. To successfully make this transition, we must also maintain the reliable, affordable energy that customers expect.
- Climate modeling experts from the University of Denver, led by a lead author for the Intergovernmental Panel on Climate Change, analyzed our carbon goals and concluded they are consistent with electric sector emissions in scenarios likely to achieve the temperature targets of the Paris climate agreement.

- Our carbon emissions continue to decline. Since 2005, we have decreased carbon emissions 38% from electricity that serves our customers — an additional 3% reduction compared to 2017 levels. Our reduction levels surpass the U.S. commitment under the Paris climate agreement, which called for a 26% to 28% reduction in carbon emissions by 2025, and the EPA Clean Power Plan, which would have reduced carbon emissions 32% by 2030.
- For 13 consecutive years, our carbon reporting has been third-party verified in accordance with The Climate Registry — we are the only electric utility with this length of consecutive verified data.
- Since Xcel Energy became a member of EPA's Natural Gas STAR program in 2008, we have reduced methane emissions by more than 350 million cubic feet while expanding our miles of pipe 6%.

Our Pathway to a Carbon-free Future

As we produce energy to serve our customers, we emit greenhouse gases. Our primary source of these emissions is from the combustion of fossil fuels to generate electricity, which makes up 99% of our total greenhouse gas emissions. Nearly all of our generation-related emissions are carbon dioxide. Because of this, it makes sense that our clean energy strategy focus primarily on reducing carbon emissions from electricity.

To achieve our carbon vision, we will continue working with our states and stakeholders. Our interim goal to reduce carbon emissions 80% by 2030 is based on absolute, company-wide emissions from the electricity that serves our retail and wholesale customers, measured from a 2005 baseline. Likewise, our aspiration to serve customers with carbon-free electricity by 2050 is company-wide.

Currently, we are implementing plans to achieve our previous goal to reduce carbon emissions 60% by 2030, from 2005 levels. Our state regulatory commissions have already approved the following efforts underway:

- The Colorado Energy Plan, which calls for the early retirement of 660 megawatts of coal-fueled generation by 2026 and the addition of 1,100 megawatts wind, 700 megawatts solar, 380 megawatts existing natural gas and 275 megawatts large-scale battery storage.
- Our current 2016 to 2030 Minnesota Resource Plan, which increases renewables in the Upper Midwest and retires nearly 1,400 megawatts of coal-fueled generation by 2026. A new resource plan for the region will be proposed in summer 2019.
- Our multi-state wind expansion announced in 2017 that will add nearly 3,700 megawatts of wind energy from 12 new projects across seven states.

We also are working on plans that take us all the way to reduce carbon emissions 80%. This is not a single plan, but will happen through a series of resource plans to be approved through our state regulatory processes.

In setting our goals, we did sensitivity analysis to identify key elements and variables that could affect our plans for reaching the interim goal. There are a variety of cost-effective pathways to reduce carbon emissions 80% by 2030, and we know the following common elements will be part of the plans:

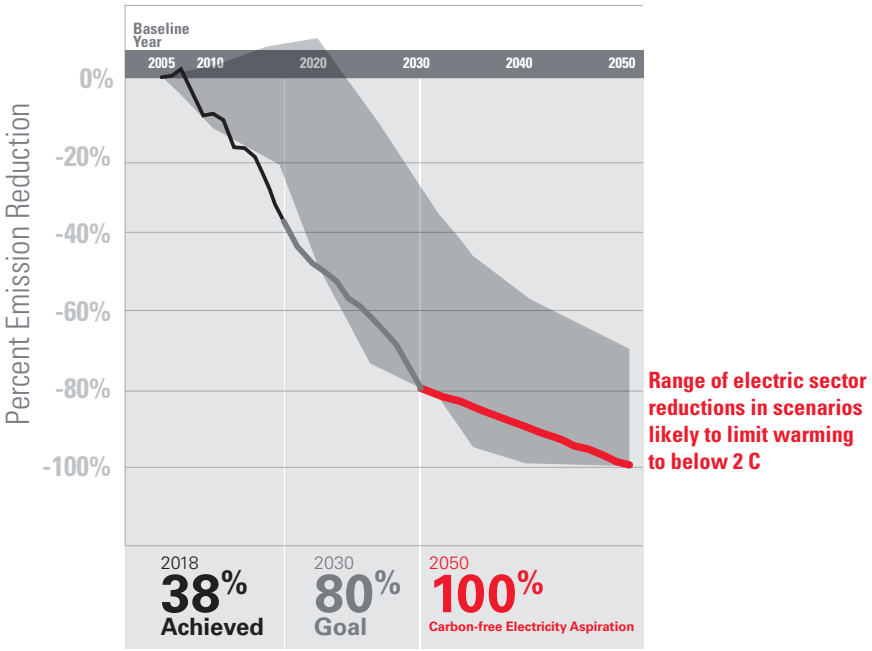
- Adding thousands of megawatts of wind and solar power to our system
- Incorporating both natural gas and storage resources to help balance high levels of renewable energy
- Deploying strategic electrification of certain end uses to help create flexible demand
- Continuing to implement industry-leading energy efficiency programs
- Seeking to operate our nuclear plants through at least the remainder of their licenses
- Retiring additional coal units or changing their operations to minimize emissions affordably and reliably
- Investing in supportive infrastructure to modernize the power grid

Looking beyond 2030 to our 2050 carbon-free aspiration, we will need new, 24/7 carbon-free technologies that are not yet commercially available at the cost and scale needed. These are technologies that can integrate high levels of renewables, balancing the peaks when customer use exceeds renewable generation and valleys when renewable generation exceeds customer use. To ensure these technologies are ready when we need them at an affordable price, there must be more research, innovation and development. Technology advancement is key to the long-term success of our strategy, and it has a long lead time for development.

Scientific Analysis

The most recent climate science informed our carbon vision, which is designed to minimize the long-term risks associated with climate change. After reviewing international and national climate reports released in 2018, we hired an IPCC lead author and other climate modeling experts with the University of Denver to understand how our vision relates to global temperature goals. They consulted the newest International Panel on Climate Change emission scenarios database and analyzed carbon emissions for the electric sector in industrialized countries, within the scenarios that have a high (66% or greater) probability of achieving the 2 C goal and those more likely than not (50% or greater) to achieve the 1.5 C goal.

Xcel Energy's carbon goals align with scenarios likely to limit warming to 2 C.



The dark gray shaded area in the chart above represents the range from the highest to the lowest of these emission scenarios. The climate modeling experts then compared Xcel Energy's carbon emission reduction trajectory, including carbon reductions to date and the 2030 and 2050 goals. Based on their analysis, our reduction targets are clearly consistent with — even on the low end of — the electric sector reductions in scenarios that achieve the international 2 C goal. Even more encouraging, this analysis shows that our emission trajectory is also consistent with the more aggressive 1.5 C goal.

Driving Change

We believe reducing carbon emissions reliably and affordably must be the top priority of our clean energy transition. To achieve this, we need to be disciplined and focus on efforts that will produce the greatest carbon reductions at the lowest cost to customers.

We have identified the following drivers that will make the change possible:

- **Protect energy reliability and affordability.** Our goals rely on maintaining these service fundamentals and cannot be achieved without them.
- **Support from our states and stakeholders.** We will need the support of stakeholders and state regulators to implement the resource plans that will achieve our goals.
- **A constructive policy environment and framework.** Reducing carbon emissions at the lowest cost should be the policy objective. To that end, we are advocating for policies that encourage economical large-scale clean energy development and utility ownership of resources.
- **Availability of cost-effective, carbon-free, 24/7 technologies.** There must be research and development to advance clean energy technologies, beyond renewables. We will need these technologies to eliminate the last 20% of carbon from the electricity serving our customers.

While our vision is ambitious, we believe these drivers implemented together will make it possible to transform our operations and the industry overall. Our plan is to continue working proactively and collaboratively in all these areas and to advance the solutions that emerge.

Energy and Carbon Emissions Reporting

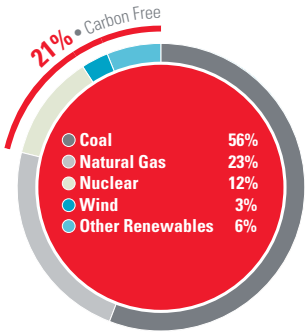
Xcel Energy supports timely, transparent public reporting of carbon dioxide and other greenhouse gas emissions. Our comprehensive greenhouse gas reporting, from all parts of our business, is based on The Climate Registry and its Electric Power Sector Protocol, which aligns with the World Resources Institute and ISO 14000 series standards.

We joined The Climate Registry as a founding member in 2007 to help establish a consistent and transparent standard for calculating, verifying and reporting greenhouse gases. Through The Climate Registry, we annually third-party verify, register and publicly disclose our greenhouse gas emissions.

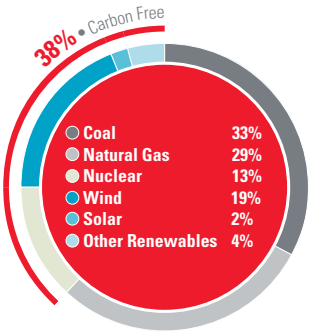
We report carbon emissions from electric generating plants that we own and from electricity that we purchase from others. We sell a small portion of the electricity we generate into the market to retailers outside our service territory. The carbon emissions from these off-system sales are excluded from our goal and associated carbon reporting because the energy does not serve our customers. Also, it is likely that companies purchasing the energy account for the emissions in their reporting, so excluding the carbon emissions associated with off-system sales from our reporting avoids double counting.

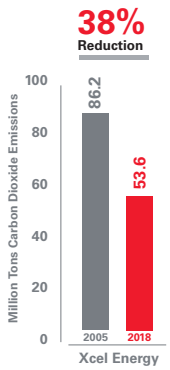
Our progress toward a carbon-free future.

Xcel Energy//2005

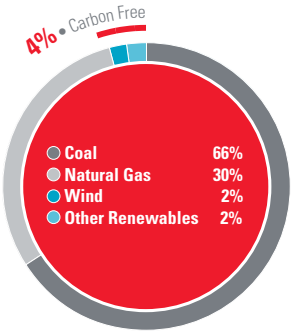


Xcel Energy//2018

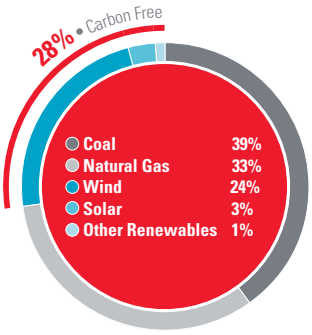


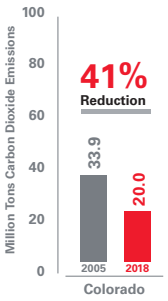


Colorado//2005

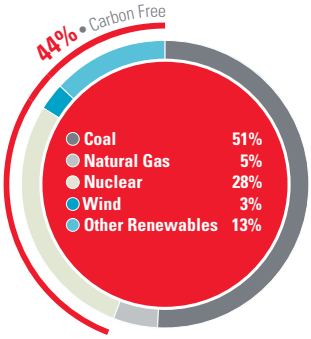


Colorado//2018

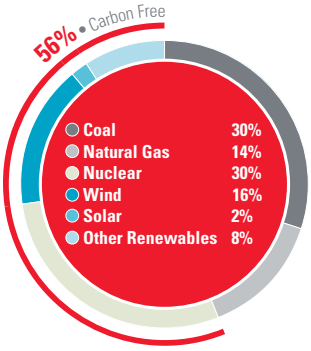


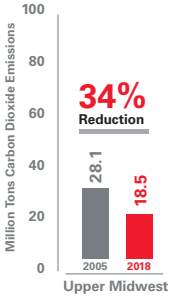


Upper Midwest//2005

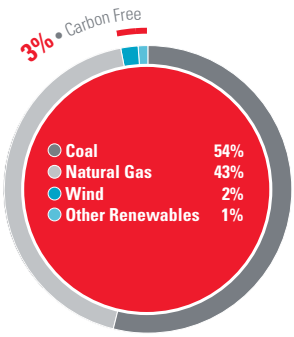


Upper Midwest//2018

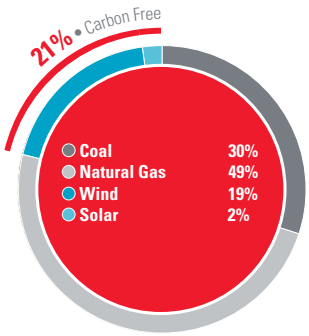


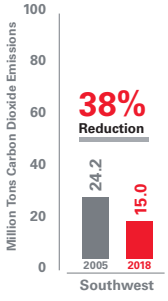


Southwest//2005



Southwest//2018





Methane Emissions

Our efforts to reduce greenhouse gas emissions also include methane emissions — a primary concern for the natural gas value chain. We are actively involved in programs that work to address the supply, midstream, distribution and consumer use of natural gas that are important to maintaining the industry's ability to operate. Xcel Energy serves about 2 million customers with natural gas for heating and other energy uses critical to the colder parts of our territory, Colorado and Minnesota, and does so with minimal methane emissions.

Methane emissions make up a small part of our total greenhouse emissions — less than 1% of our total greenhouse gas emissions (190,249 metric tons CO_2e) in 2018. Nevertheless, we strive to operate the cleanest distribution system possible and minimize our methane emissions through cost-effective improvements to our natural gas system.

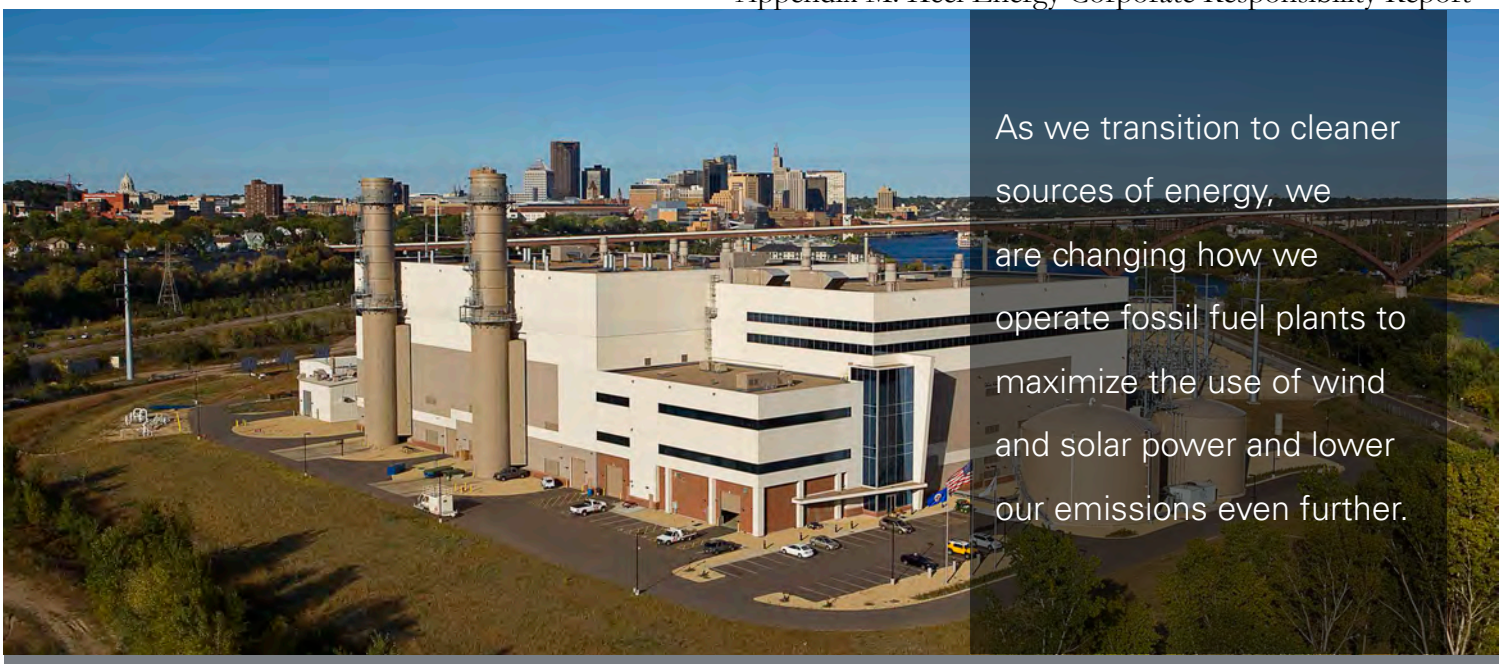
We have achieved these reductions through voluntary efforts. Since 2008, we have participated in EPA's Natural Gas STAR program, and we are a founding member of the program's Methane Challenge launched in 2016. Through the Methane Challenge, we plan to reduce methane releases more than 50% from the venting of pipelines during scheduled construction. We are also investing in operational improvements that not only reduce methane emissions but improve the overall safety and efficiency of the natural gas system for customers. These improvements include:

- **Replacing the cast iron pipe and unprotected steel pipe on our system, originally installed 50 to 100 years ago.** We replaced all 880 miles of cast iron pipe and have regulatory approval to continue removing bare-steel pipe from our system over the next five years.
- **Using pressure reductions and other methods to reduce methane emissions during pipeline maintenance and repairs.** We reduced our emissions from blowdowns on systems operating at excess of 60 psig by 89%, therefore, avoiding the release of 24 million cubic feet of gas into the atmosphere.
- **Replacing high-bleed controllers on our distribution and high-pressure pipelines.** We are currently working to replace the high-bleed controllers in our processing plants and are considering new programs to modernize the high-bleed controllers at our storage fields and compressor stations to reduce emissions at these facilities.

In addition to these programs, we are collaborating within the natural gas industry on initiatives that support our own proactive approach to operating and maintaining a natural gas system. For example, we are members of the Natural Gas Downstream Initiative, a collaborative effort with other major gas utilities, facilitated by MJ Bradley & Associates, focused on addressing the regulatory and technical issues related to the role of natural gas in a low-carbon future.

Beyond our direct distribution operations, we also recognize that the majority of greenhouse gas emissions associated with natural gas is in other parts of the value chain. This includes methane emissions from upstream sources through the production, compression and long-distance transmission of natural gas, and carbon emissions from downstream, end-use consumers. We participate in the Natural Gas Supply Collaborative, a group of natural gas producers calling for transparency and sustainability from upstream suppliers. Our industry associations, the American Gas Association and the Edison Electric Institute, are also partnering to understand methane emissions and enhance disclosures across the value chain.

For our customers who use natural gas, we are exploring opportunities to offer low-carbon solutions. We already provide a comprehensive portfolio of natural gas efficiency programs, but are exploring new technologies and methods to help our customers further reduce their carbon footprints. We see great potential for renewable natural gas to provide a lower carbon alternative and the potential for targeted, strategic electrification, such as water heaters, that could be powered with clean, renewable energy. As always, we are monitoring long-term technologies, such as hydrogen or power-to-gas, which could fundamentally shift natural gas supply and related carbon emissions.



Air quality

Reducing air and other emissions

With support from stakeholders and regulators, we are voluntarily retiring half of our coal-fueled capacity by 2026 — a step that will significantly reduce emissions.

Our largest source of air and other emissions is the combustion of fossil fuels to generate electricity, primarily from coal. For well over half a century, coal has been a steady source of low-cost, dependable electricity for our customers that we have carefully controlled and operated in an environmentally responsible manner.

Since the 1990s, we have worked with our states and other local stakeholders on proactive environmental projects that serve as a national model for addressing state air quality needs while providing operational flexibility and ensuring reliable, affordable energy for customers. We know that clean air and cleaner energy are priorities for the customers and communities we serve, and as a leader in this field, they continue to be our priorities too.

As the cost to generate electricity with natural gas and renewable sources declines and these technologies improve, the way we generate electricity is becoming progressively cleaner. We are moving away from coal to lead the transition to clean energy, especially now as we work to achieve our vision to serve customers with 100% carbon-free electricity by 2050. To fulfill this commitment, we plan to rely on the relationships we have built and our successful model for engaging stakeholders to find new solutions — solutions that will not only cut carbon, but have the added benefit of reducing other emissions and improving the environment overall.

2018 Results

- Since 2005, we have reduced carbon emissions 38% from the electricity that serves customers.
- We continued to decrease emissions of sulfur dioxide, nitrogen oxides, mercury and particulate matter to levels that were 77%, 78%, 91% and 73% lower, compared to 2005.
- Under the EPA's Toxic Release Inventory program, we have reduced releases by nearly 30%, compared to 2005 levels.

- The Colorado Department of Public Health and Environment through its Environmental Leadership Program recognized Xcel Energy as a Gold Leader for the company's comprehensive Environmental Management System as well as its clean energy leadership and environmental stewardship.
- Within our vehicle fleet, we essentially replace all sedans scheduled for retirement with electric vehicles. We estimate that our 43 plug-in hybrid electric vehicles (PHEVs) helped to avoid emission of nearly 92 metric tons of carbon emissions for the year.

Maximizing System Operations to Reduce Emissions

There is a significant shift in how we operate our power grid now compared to several decades ago. Not only are we changing the way we produce electricity, but the dispatch and operation of our generating resources is different too.

Through major clean energy initiatives in Colorado and Minnesota, we have retired coal units and replaced the power with cleaner, more flexible natural gas and wind and solar generation, and we have plans to do more. Last year, regulators approved our new Colorado Energy Plan that will retire two coal units and add thousands of megawatts of new wind, solar and battery storage, as well as existing natural gas. We also have approval to retire two coal units in Minnesota by 2026, and are moving forward with our multi-state wind initiative with 12 new wind farms to be completed in 2021.

As renewable energy gradually becomes the majority energy source on our system, we are focusing our operations to follow the wind and sun to maximize clean electricity production and do so reliably and cost effectively.

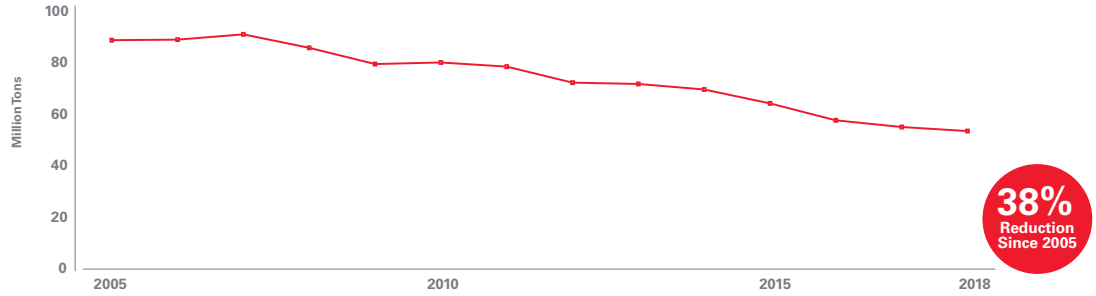
Advanced forecasting tools have dramatically improved the predictability of wind energy, making a variable energy source much more dependable. With reliable wind forecasts now available seven days in advance, we are able to make more accurate commitment and dispatch decisions associated with wind energy. Cleaner natural gas generation is an excellent companion to renewable generation. It has long managed the variability of wind-power production, with natural gas units cycling up and down as needed to help meet electric loads as wind speeds rise and fall.

Several years ago, an Xcel Energy operations team began exploring how coal units could do the same, although ramping up and down coal units is much more challenging. Traditionally, coal units have provided baseload power for our system, with the capability to run dependably 24/7. The company's coal plants began testing and learning their limitations, working around problems at lower load points and figuring out how to overcome them.

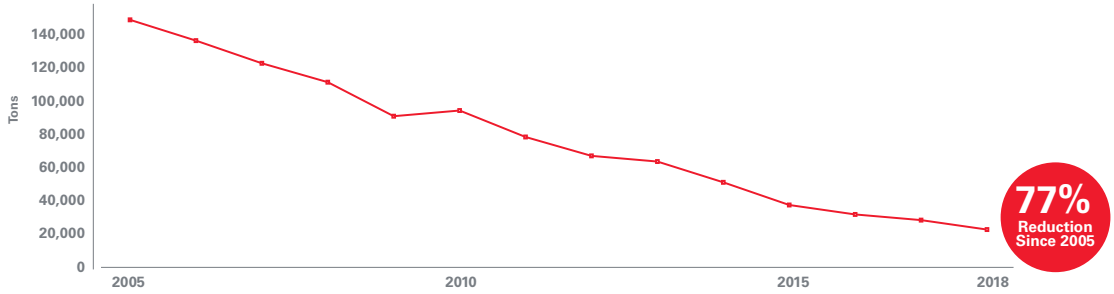
Today, this reduction in coal operations is creating additional system flexibility and helping to advance our transition to clean energy while reducing emissions and saving customers money. In 2018, our efforts to turn down and cycle off these units reduced coal generation by more than 788,000 megawatt hours, saving an estimated $1.6 million and avoiding approximately 886,000 tons of carbon dioxide, as well as other emissions.

Air Emissions Reporting

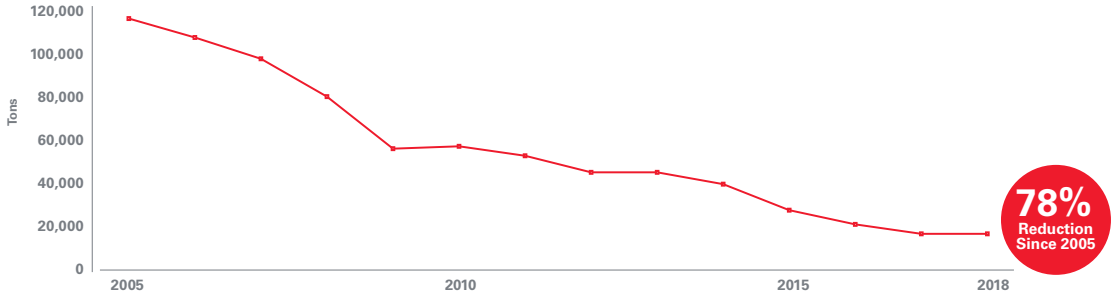
Carbon Dioxide



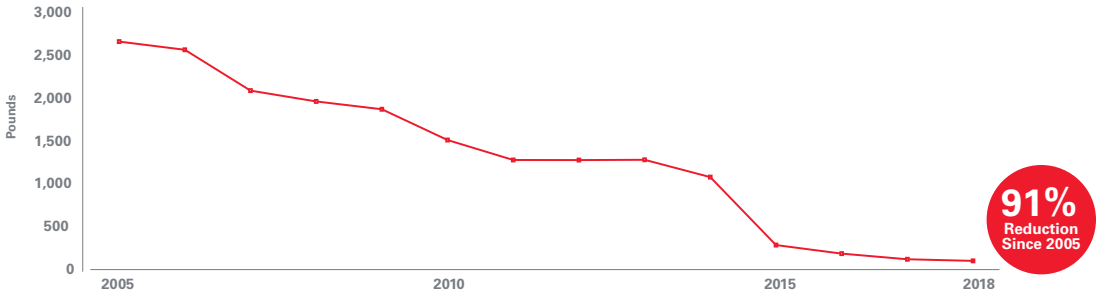
Sulfur Dioxide



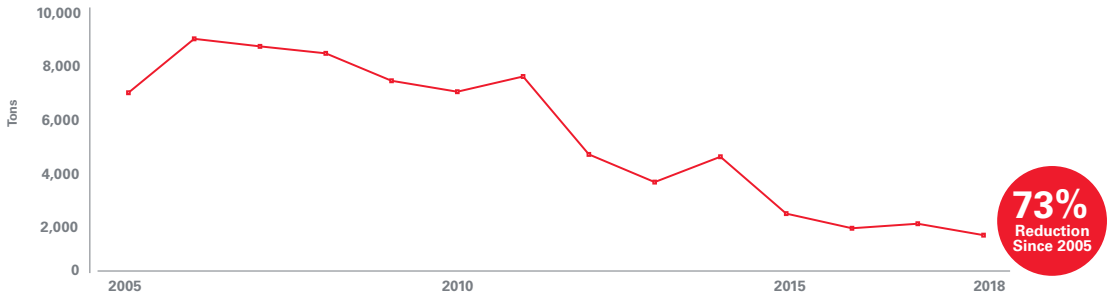
Nitrogen Oxides



Mercury



Particulate Matter



Reducing Fleet Vehicle Emissions

Our fleet of about 7,000 vehicles includes everything from small cars to light trucks, bucket trucks, excavators and trailers. In 2014, our vehicles were equipped with telematics to reduce fuel costs and improve driver safety. Using the technology has reduced idling and fuel consumption, wear and tear on vehicles, and emissions. In 2018, we estimate that the use of telematics saved approximately 150,000 gallons of fuel at a value of more than $350,000.

Community Right to Know and the Toxic Release Inventory Program

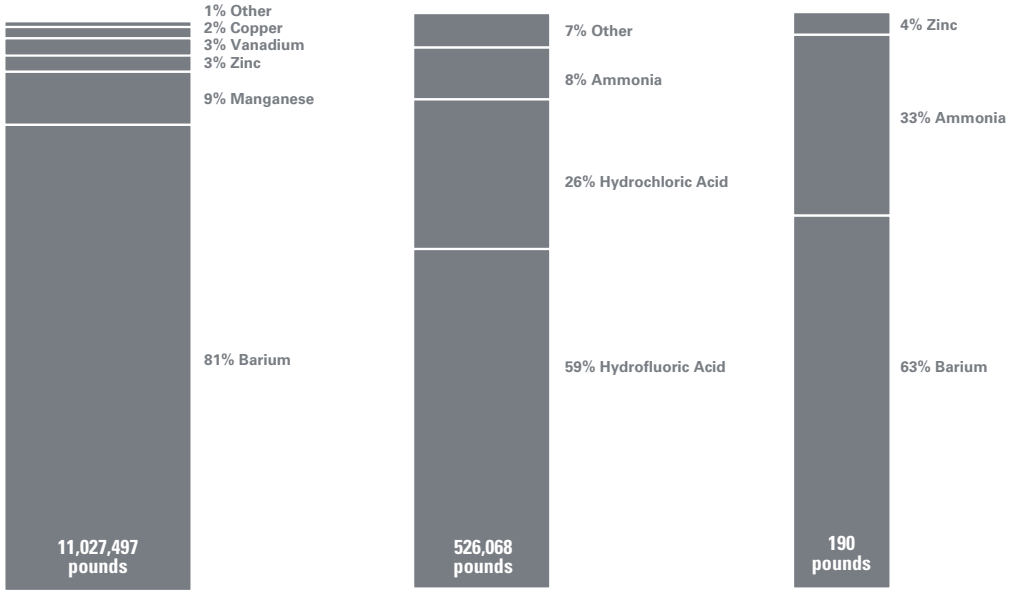
The EPA has administered the Emergency Planning and Community-Right-to-Know Act or EPCRA since 1986. The program is intended to help communities protect residents from potential chemical hazards. Under EPCRA, residents have the "right-to-know" about chemicals in their communities. Each year facilities in specific industries that manufacture, process or use the nearly 650 substances identified under the program must report their releases to air, land and water. The EPA manages the information in a publicly available database under the Toxic Release Inventory (TRI) program.

Xcel Energy supports this type of reporting and has participated since 1999 when the program was expanded to include electric utilities. We annually report to EPA our releases, which are the result of using coal, oil and refuse-derived fuel (processed municipal solid waste) to produce electricity. When these fuels are combusted, they release trace amounts of TRI reportable substances, including barium, chromium, copper, lead, manganese, mercury, nickel and zinc.

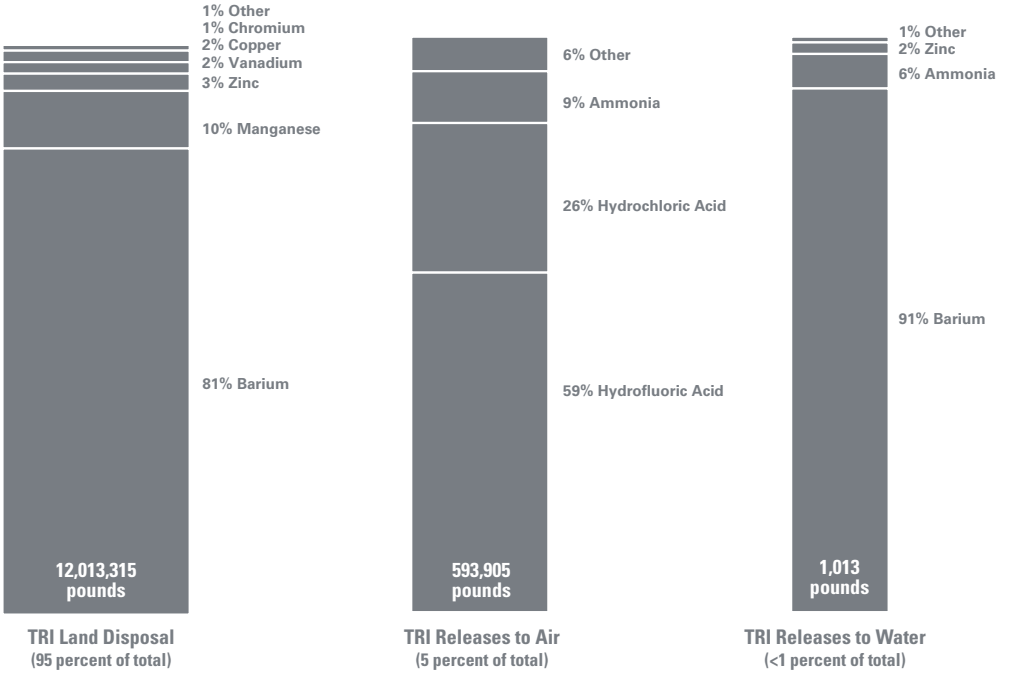
TRI reportable substances are reported by facility and release type — land, air and water. A facility's releases may change slightly from year to year based on the amount of electricity produced and the associated fuel that is consumed, as well as the fuel composition and mineralogy.

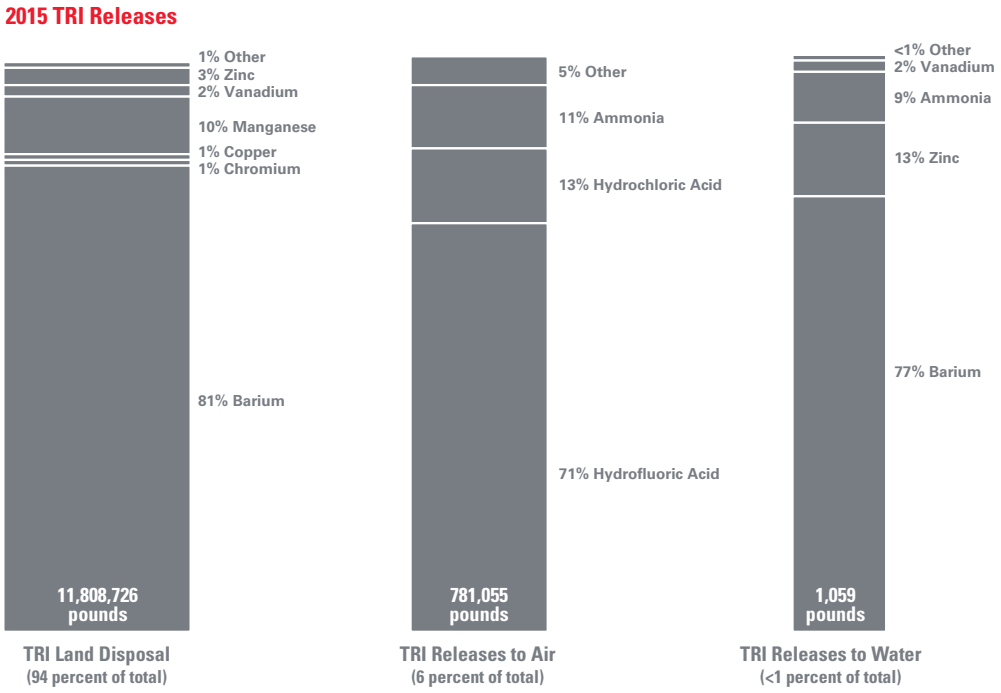
The vast majority of our TRI reportable substances are controlled at our facilities as part of the coal ash where they are contained, preventing them from entering the air. We capture about 95% of these substances and safely dispose of them in managed landfills.

2017 TRI Releases

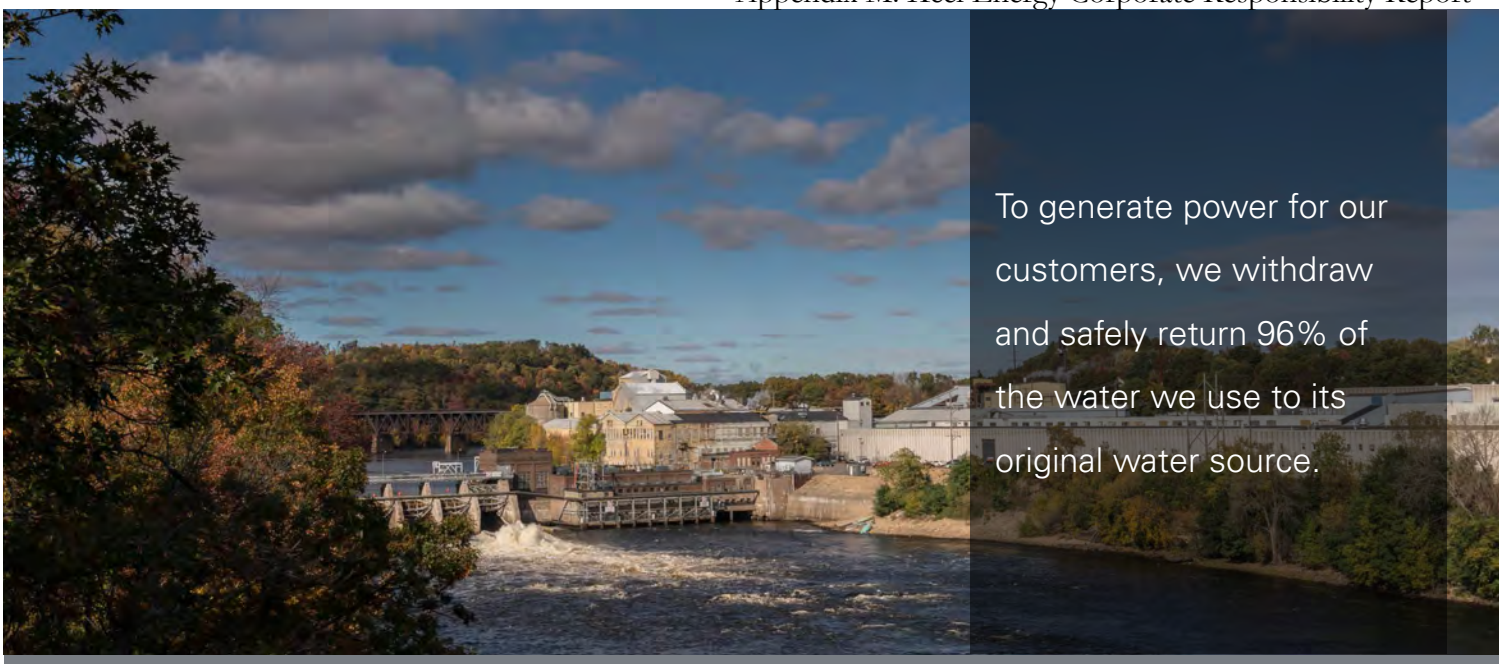


2016 TRI Releases





Releases provided here are from 11 generating plants in locations throughout our service territory. For individual plant information visit the EPA's TRI Explorer website or contact corporateresponsibility@xcelenergy.com.



Water quality, availability and management

Managing water use

We regularly collaborate with local stakeholders and water managers on innovative partnerships and agreements to ensure reliable, cost-effective water supplies for our operations while also addressing different community needs.

Water conservation and protecting water quality are priorities for us. In the more arid Western and Southwestern regions where we operate, conserving and managing our water supply is especially important given challenges we face in dry years and concerns over drought. In all regions, we continually evaluate and monitor our systems and processes to ensure the water we return to local waterways is safe and meets the discharge limits contained in our Clean Water Act permits.

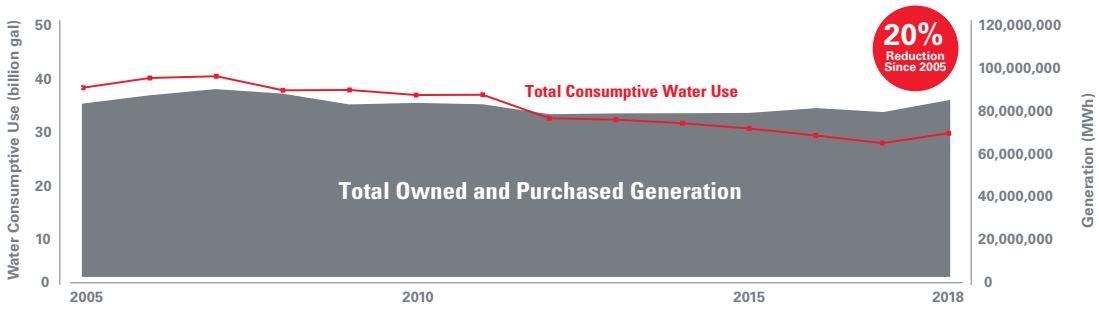
We understand that water is a fundamental, shared resource and is vital to the growth and development of our communities and to other industries, agriculture and ecosystems. As competition for water increases and weather patterns change, our water resources will become more stressed. That is why we continue to work cooperatively with our communities and states to secure responsible supply options and to save fresh water where we can.

2018 Results

- Water powers steam turbines and cools equipment at thermal electric generating plants. Our thermal plants in Colorado, Texas and New Mexico use closed-loop cooling which requires less water to operate efficiently and minimizes fresh water withdrawals by recirculating water multiple times within the system — up to 25 times at some plants.
- From 2005 to 2018, we reduced water consumption approximately 20% from the electricity we generate and purchase, while total electricity production remained generally the same over that period. We expect water consumption to continue to decrease as we retire additional coal units and rely more on wind and solar resources that require no water to produce electricity.

- We withdrew approximately 638 billion gallons of water during the year, including municipal wastewater or effluent, to generate electricity at our thermal electric and hydroelectric generating plants. From these withdrawals, our facilities consumed approximately 24 billion gallons of water and returned approximately 614 billion gallons (96%) to the original water source.
- Our Upper Midwest thermal plants use open-loop cooling where water is continuously withdrawn and directly returned. Although water withdrawals are higher with this type of cooling system, consumption is lower. Our plants with open-loop cooling systems return about 99% of the water they withdraw to its original source.
- Over the past 38 years, we have saved about 200 billion gallons of freshwater by pioneering the use of treated municipal effluent to cool the Nichols-Harrington and Jones generating plants in Texas — enough water to fill nearby Lake Meredith and then some.
- The Xcel Energy Foundation contributed more than $135,000 through its environmental stewardship focus area to nonprofit programs that support water quality, education and riparian restoration efforts. For several years, the foundation has supported the restoration work of RiversEdge West and its DesertRivers Collaborative. The program supports local land managers and efforts to restore riparian areas along the Colorado River in the Grand Valley region of Colorado and the lower Gunnison River. In Minnesota, we are a longstanding supporter of Friends of the Mississippi and currently fund its Community Stewards program. Working with agency staff, volunteers and local partners, the organization held 35 stewardship events for the year at different sites along the river.

Xcel Energy water consumption compared to electricity supply from owned and purchased generation.



Managing Water Supply

Thermal Operations in the West and Southwest

In the semi-arid and arid states where we operate — Colorado, New Mexico and Texas — we have strategic water resource plans that are updated annually to reflect our current operational requirements, local climate conditions and water use. Throughout the year we conduct a variety of activities to accurately predict and plan for future water supplies, which include:

- Forecasting plant water requirements based on anticipated electric generation
- Accounting for the water we need and use
- Monitoring snowpack reports
- Studying stream flow forecasts, seasonal climate projections and changes to the Ogallala aquifer — the primary aquifer that underlies much of the region in Texas and New Mexico that we serve

We acquire water for our thermal and hydroelectric plants through water rights and other agreements Our integrated portfolio of water supply resources includes owned or self-supplied water rights, reservoir storage, groundwater rights and a number of other supplies, such as municipal and recycled water supplies. We own water supplies dedicated for our own use, and in Colorado, these water rights are available depending on regional water supply conditions in accordance with the state's prior appropriation system. Our portfolio also includes water from geographically diverse areas, including trans-basin water imported from other basins. This diversity is critical for maintaining a resilient, reliable water supply in the arid, climatically variable western United States.

We have expended significant resources to improve our water supply and the resiliency of our systems. Other suppliers that we do business with have responded similarly, taking steps to improve their water supplies and adopt drought response plans for ensuring they meet their municipal and industrial water supply obligations. Further, they pursued the acquisition of geographically diverse water supplies originating in other river basins, enhancing the resiliency of their systems.

Finally, we use recycled water or treated municipal effluent where available and feasible, which minimizes the competition between water needs for power generation and needs for environmental, recreational, municipal or other industrial uses. Recycled water use has the added benefit of increasing the reliability of our water supply because it is virtually drought proof and preserves billions of gallons of fresh water.

Thermal Operations in the Upper Midwest

In Minnesota and Wisconsin where we operate thermal plants, water is more abundant and these facilities are permitted to withdraw and return water to nearby rivers and other waterways. While this helps to minimize water consumption, we still take a strategic approach to water use in these areas by monitoring weather patterns and using meteorological forecasting models to predict and ensure an adequate water supply during times when unusually dry conditions are likely to persist.

During these rare dry periods or drought years, we evaluate the use of alternative cooling options for each facility and implement prudent, temporary measures to provide supplemental thermal cooling. In times of energy emergencies, our permits have provisions that allow some plant operating flexibility, along with additional environmental monitoring requirements to ensure the protection of fish and other aquatic life.

2018 Water Use by Source (Billions of Gallons)

Source	Withdrawn	Consumed	Returned
South Platte River Basin	*5.18	4.48	0.70
Arkansas River Basin	*4.56	3.72	0.84
Yampa River Basin	1.32	1.32	0.00
Colorado Total	**11.06**	**9.52**	**1.54**
Ogallala Aquifer	3.63	3.33	0.30
Treated Municipal Effluent (Lubbock, Amarillo)	5.19	3.99	1.20
Southwest Total	**8.82**	**7.32**	**1.50**
St. Croix River	112.31	0.0	112.31
Lake Superior	9.83	0.0	9.83
Mississippi River	459.87	7.18	452.69
Minnesota River	36.47	0.0	36.47
Upper Midwest Total	****618.48**	**7.18**	**611.30**
XCEL ENERGY TOTAL	**638.36**	**24.02**	**614.34**

*Includes transbasin diversions

**Does not include groundwater from these locations

Hydroelectric Operations

Xcel Energy operates 26 hydroelectric plants, including six in Colorado, one in Minnesota and 19 in Wisconsin, with enough capacity to power more than 280,000 homes. Although these plants use water to produce electricity, the only water loss is through natural evaporation from reservoirs. We work with environmental and wildlife agencies to ensure plans are in place for monitoring watering quality, protecting aquatic life, ensuring minimum stream flow, preventing erosion, and controlling noxious weeds and other invasive plants. Many of our hydroelectric plants offer public recreational opportunities and some are stocked with fish.

Xcel Energy's hydroelectric plants operate on the following waterways; many of these are open to public recreation:

2018 Water Use by Source (billions of gallons)

Colorado	Minnesota	Wisconsin
Lower Clear Creek	Mississippi River	Chippewa River
South Fork Arkansas River		Apple River
South Clear Creek		Red Cedar River
Colorado River		Namekagon River
Animas River and tributaries		Montreal River
San Miguel River and tributaries		White River
		Flambeau River
		St. Croix River

Meeting Mutual Water Needs

Planning for and managing future water supply is essential for the states and communities we serve. We actively participate in these efforts to provide our expertise and solutions, as well as to plan for our own water needs. The following are examples of our engagement and some of the innovative partnerships and agreements we have in place.

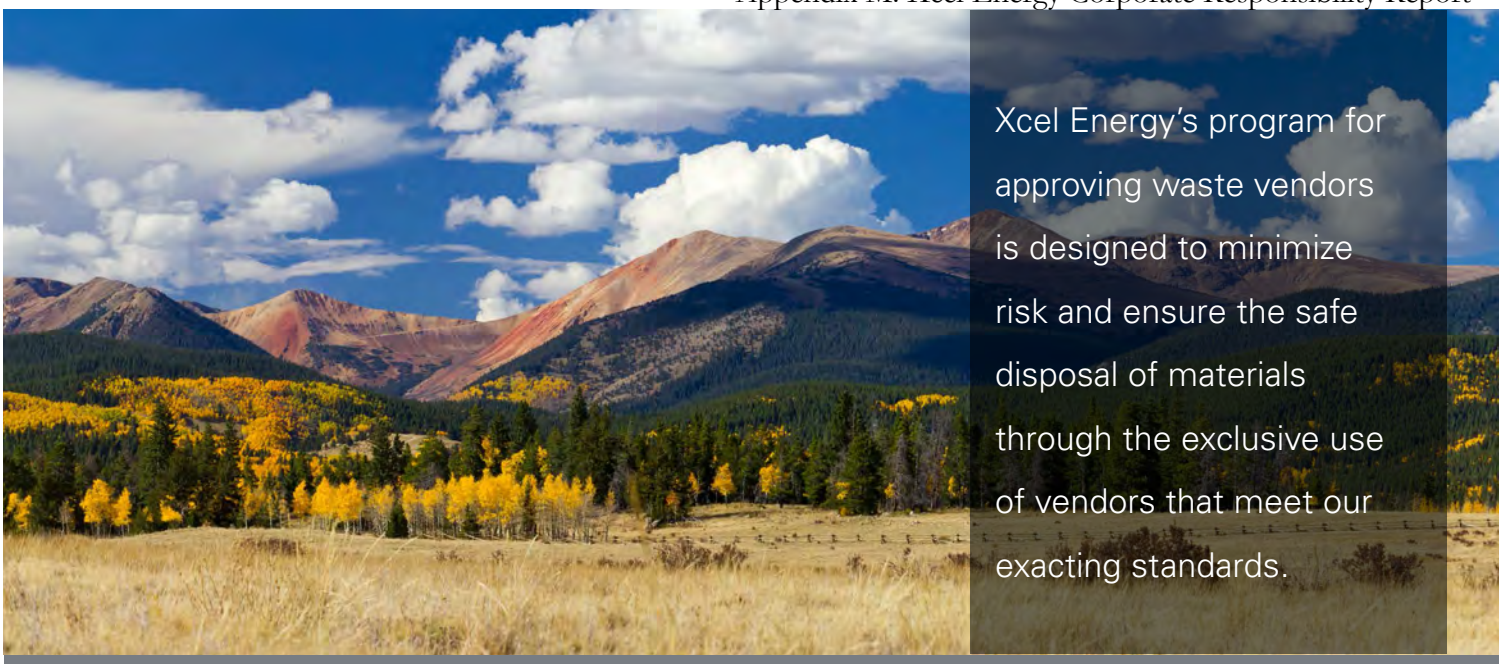
- Our Water Resources staff is actively engaged in the ongoing Colorado Water Plan process. They participate on volunteer boards and technical working groups, serve on the board of water user groups working to meet Colorado's obligations under Endangered Species Recovery programs, and participate in other water user groups working to craft policy and legislation to better adapt Colorado's water supplies to changing conditions. For decades, they have served on boards and as officers overseeing nine ditch companies in Colorado where the company owns significant water rights. Through these organizations, conflicts involving water are often identified and amicably resolved.
- We own very senior water rights on the Colorado River that are used to operate the Shoshone Hydroelectric Generating Plant. To help meet water needs within the city of Denver, along the Front Range and for some users on the Western slope, we established an agreement in 2006 to "relax" a portion of our water requirements for Shoshone during dry years. Colorado experienced below-average moisture in 2013, which is the most recent year that we executed on the agreement. We reduced Shoshone's water use by more than half and allowed water to be stored for critical uses, benefitting users throughout the state.

- We have agreements with the cities of Longmont and Westminster in Colorado to exchange high quality water under our water rights with their lowest quality water or effluent, which we use at our area power plants. It's similar to a practice we pioneered in Texas where we use recycled municipal effluent for cooling at our power plants.
- In dry years, Colorado farmers typically lack the full water supply needed to produce marketable crops. Through a mutually beneficial agreement, we buy limited quantities of water that farmers have available and use it in our power plants. Under this arrangement, farmers are compensated, helping them financially during dry years.
- In the Southwest, our Water Resources staff serves on regional groundwater planning committees to better manage critical resources like the Ogallala Aquifer which is the region's primary water supply and underlies much of our service area.
- Xcel Energy is a member of the Minnesota Sustainable Growth Coalition, a business-led partnership of 33 businesses and organizations working to promote a circular economy in the state. The coalition focuses on energy, water and waste issues to optimize use of resources, minimize waste and conserve resources. In the water area, the coalition is working on "greening gray infrastructure" or promoting infrastructure and practices designed to mimic the natural water cycle.

Maintaining Water Quality

All of our large plants in Texas and New Mexico, as well as several plants in Colorado, are zero-discharge facilities — no process water is discharged from the plant site. Instead, it can be reused for growing crops or disposed through evaporation ponds.

Other plants, especially those in Minnesota and Wisconsin, use once-through cooling where water is taken from a river or other waterway and returned to the environment. At all our plants where we return or discharge water, we systematically treat, monitor and analyze the water to ensure we are meeting discharge requirements and to protect fish and other aquatic life.



Waste management

Preventing and managing waste

We follow the same high standards outlined in our corporate environmental policy to responsibly reduce, reuse or dispose of our waste.

Our primary waste streams result from producing and delivering energy. This includes the coal ash that is left from burning coal to generate electricity, and the materials and equipment that come from the maintenance and repair of our transmission and distribution systems, as well as our natural gas system.

The best way to manage waste is to prevent it, and we have programs in place to help with this. We also look for opportunities to recycle or reuse waste as appropriate. When we must dispose of waste, we take steps to ensure that it is safely and properly disposed, which requires that our employees have the right training and follow the proper guidelines and procedures and that we use licensed facilities where applicable.

2018 Results

- We continue to reduce coal ash production as we transition to cleaner energy sources. Our generating plants produced 28% less coal ash for the year, compared to 2005.
- Approximately 19% of the coal ash our plants produced was reused. At our Texas generating plants, 100% of the coal ash is beneficially used, replacing products that would normally be produced from natural resources.
- We recycled nearly 23,000 tons of material from our operations, including more than 18,000 tons of wire and scrap metal.
- Altogether, we disposed of almost 10,000 tons of regulated waste from our operations, including 47 tons of hazardous waste.

Coal Ash Management

Coal-fueled generating plants produce coal combustion residuals or byproducts commonly referred to as coal ash. Xcel Energy's generating plants consumed about 23.2 million tons of coal in 2018, supplied from mines in Colorado and the Powder River Basin of Wyoming.

Our plants operate in states that have regulated coal ash for many years. We store and dispose of ash in impoundments or ponds and landfills in accordance with these regulations, which specify construction standards and operating requirements including routine inspections and groundwater monitoring.

The following are important facts about our coal ash management:

- More than half of our coal operations are in arid regions where groundwater is scarce or at a greater depth, a favorable geologic condition that mitigates the risks of impacts from ash storage or disposal.
- We reduced our number of coal ash repositories in 2018 by about 30%, from 13 to nine. We now manage three impoundments and six landfills. This is the result of shutting down coal units and actively removing ash impoundments that are no longer needed.
- Only 18% of the total ash our plants produced in 2018 was permanently disposed in impoundments.
- Our three active impoundments include a three-acre incised pond, a 17-acre bottom ash pond, and a 100-acre ash disposal impoundment. This larger impoundment is built to state-of-the-art standards and meets stringent safety requirements, according to an EPA inspection.

Throughout our system, we try to recycle coal ash whenever possible for beneficial use, such as in concrete products, roadbed material, soil stabilization, engineered-fill material and more. As we install and operate new emission controls at our plants, such as scrubbers and activated carbon for controlling mercury emissions, the ash composition changes, making it potentially less desirable for beneficial use.

Coal Ash Summary (estimated in tons)

	2016		2017		2018	
	Produced	Reused	Produced	Reused	Produced	Reused
Colorado	934,063	127,657	731,740	91,996	987,652	37,510
Southwest	274,785	274,785	289,391	289,391	207,092	207,092
Upper Midwest	699,401	55,982	649,662	43,531	775,237	121,675
TOTAL	1,908,249	458,424	1,670,793	424,918	1,969,981	366,277

EPA's Final Rule for Managing and Disposing Coal Ash

The final Coal Combustion Residuals Rule became effective in October 2015 and regulates coal ash as a non-hazardous waste under Subtitle D of the Resource Conservation and Recovery Act (RCRA-D). It establishes minimum national standards for the design, operation and closure of landfills and surface impoundments. Beneficial use of coal ash as defined under the regulation is exempted. Although it has undergone a number of changes since being enacted, Xcel Energy's facilities are well positioned to meet the rule's requirements without significant impact to operations and cost.

Our company completed our second annual groundwater monitoring reports required by the rule in January of 2019. We identified two sites in Colorado where there are impoundments or landfills present and where a statistically significant increase of certain constituents exists in the groundwater. However, at one of these locations, we have already removed the coal ash from the impoundment. Furthermore, the groundwater monitored at those two sites is directly adjacent to the impoundments or landfills and does not indicate any impact to local drinking water. We have

kept county officials informed of the situation, and are currently conducting additional groundwater sampling and initiating an assessment of corrective measures as prescribed by the rule to evaluate whether corrective action is required at these facilities. If applicable, we will be informing stakeholders on that process.

Waste Management

Xcel Energy's central Environmental Services department facilitates the company's waste management program, which is supported by facilities that generate regulated wastes. Environmental Services staff routinely visits these facilities and provides training and job aides to ensure facility personnel understand their waste management responsibilities. Our largest facilities have specific personnel trained to properly manage waste.

We have a program for approving waste vendors that is designed to minimize risk and ensure the safe disposal of materials through the exclusive use of vendors that meet our exacting standards. A team comprised of Environmental Services, Supply Chain, Legal, Risk Management and Investment Recovery employees meets quarterly to discuss the program and any relevant vendor issues. Vendors contracted to manage the higher risk wastes, such as hazardous waste, are audited on a routine basis.

Material Recycling and Reuse

We are committed to preventing pollution and reducing waste as part of our business planning and decision making processes. Some of our waste materials can be recycled, reused or may consist of parts and materials that can be reclaimed. Not only is the recovery of these materials good for the environment, but it also can help manage the cost of generating and delivering energy.

We began a major effort in 2016 to recycle "cobra head" style streetlights after launching a five-year project to replace these older lights with new energy-efficient LED fixtures throughout our territory. We are investing in the new technology to support the energy goals of the communities we serve and to reduce operating costs. The new LED fixtures use about 40% to 60% less electricity than high pressure sodium lights and have a longer operating life, which means fewer replacements and less maintenance.

We could have potentially sold the fixtures for reuse, but we agreed not to put these older, less efficient lights back on the street. Instead, we are recycling the lights after removing and properly disposing of environmentally sensitive components.

We will begin a multi-year project in 2019 to replace gas and electric meters as part of our Advanced Grid Intelligence and Security strategic initiative. Depending on regulatory and planning considerations, we could replace up to 5.5 million meters. We are developing a plan for managing and recycling the old meters as part of the sourcing effort for this project.

Global market conditions have negatively impacted the recyclables market, and in 2019, we saw a sharp decline in the market for recycled cardboard and plastic. We constantly look for viable and environmentally responsible recycling opportunities. The vendors that we choose to recycle these materials are selected by a competitive bid process. Waste recycling vendors that handle sensitive materials, such as oil and batteries, are reviewed using the same approved vendor process that is used for the disposal of wastes.

Material Recycling Summary (in Tons)

	2016	2017	2018
Cardboard		72	21
Batteries[1]		49	76
Plastic	53	72	2
Scrap metal	20,841	13,390	18,334
Used oil	3,609	3,635	4,320

1 Large lead-acid batteries recycled for reclaiming lead.

Waste Disposal

The waste we generate must be disposed at properly licensed facilities based on the waste type. All of the vendors that we contract to manage regulated wastes are part of our approved vendor program and are required to have a valid contract established in accordance with Xcel Energy's Supply Chain. The regulated wastes identified below are disposed at licensed facilities that have been vetted for financial viability, a positive compliance record and proper insurance.

The waste summary below generally represents normal operating conditions in 2018. In addition, we completed two significant environmental projects that resulted in the one-time generation of special wastes that are excluded from the totals below. We closed a water treatment pond at the Black Dog Generating Plant, which resulted in the disposal of 4,992 tons of coal and coal ash tainted sediments. We also completed remediation of a legacy manufactured gas plant site in Fargo, North Dakota that resulted in 46,000 tons of nonhazardous contaminated soils.

Waste Disposition Summary (in Tons)

	2016	2017	2018
Hazardous	31	50	47
Universal[1]	78	112	163
PCB related[2]	517	415	670
Asbestos	546	448	326
Special[3]	16,978	8,363	8,716

1 Universal waste includes regulated waste such as fluorescent light bulbs, rechargeable batteries and mercury switches.

2 PCBs (polychlorinated biphenyls) are chemicals controlled under the Toxic Substances Control Act. PCBs were historically used in transformer oil.

3 Special waste includes oily materials recovered from our operations, such as rags, filters, soil and water.

PCB Phase-out Effort

We have been phasing out PCB-containing equipment from our transmission and distribution system for many years. The Toxic Substances Control Act of 1979 defines PCB equipment as equipment containing oil having a PCB concentration of 500 parts per million (ppm) or more, while PCB-contaminated equipment has oil with a PCB concentration of 50 to 499 ppm.

Xcel Energy has made dedicated efforts to remove all known PCB equipment from its system, including transformers, capacitors and other regulated categories of equipment. This equipment was targeted, removed and replaced with non-PCB equipment.

Other phase-out efforts include the replacement of regulated equipment with non-PCB equipment as systems are upgraded. Any regulated equipment removed from the field is disposed of and replaced with non-PCB equipment unless there are extenuating circumstances associated with the design or procurement of the equipment. Xcel Energy personnel are trained on PCB regulations and the proper identification, handling, removal and disposal of this equipment to facilitate phase-out efforts. Aside from PCBs that are occasionally discovered during facility upgrade projects in small sealed or previously untested specialized equipment, most of the PCB and PCB-contaminated equipment left on our system is the result of cross-contamination occurring during manufacturing or maintenance activities prior to or shortly after the adoption of the Toxic Substances Control Act.

PCB Contaminated Equipment and Oil Removed from the Xcel Energy System

	2016	2017	2018
PCB and PCB-contaminated oil (gallons disposed)	21,378	36,632	33,311
PCB and PCB-contaminated equipment (units removed from service)	632	815	1,235

Legacy Manufactured Gas Plant Projects

In the late1800s until the mid-1900s, gas was manufactured using coal, oil and petroleum. It was used as natural gas is today, primarily for heating, cooking and street lighting. EPA estimates that thousands of manufactured gas plants or MGP facilities operated in the United States between 1815 and 1960. They were owned by municipalities and corporations, including predecessor companies to today's electric utilities. MGPs produced a variety of wastes and byproducts, including coal tar. Some of the waste and byproducts were sold for reuse or disposed off-site, and some were left at plant sites.

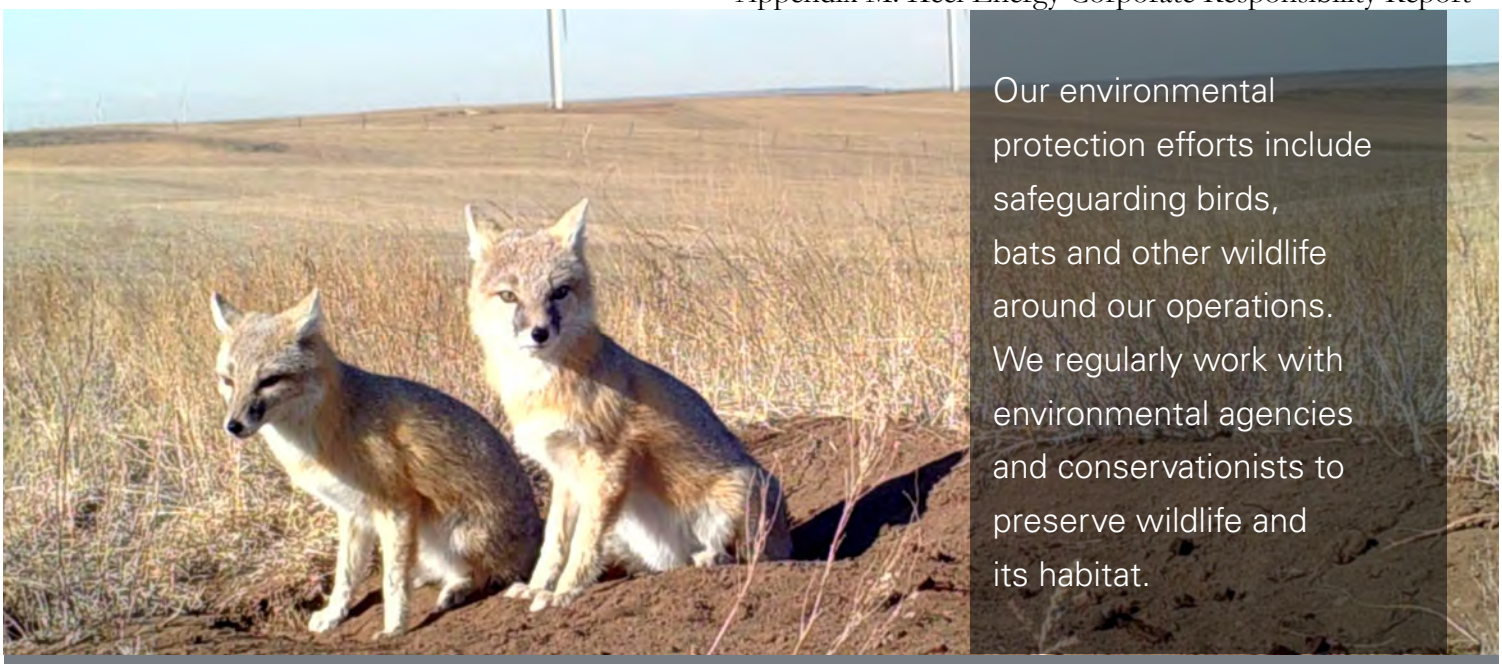
Given the extensive history of our operating companies — going back more than 100 years — Xcel Energy has inherited legacy MGP sites. All the plant facilities were closed and dismantled many years ago, and some of the properties where MGPs once operated have been sold. Over the years, Xcel Energy has worked cooperatively with environmental agencies and communities to successfully investigate and remediate former MGP sites when necessary.

Ashland

We successfully completed the remedial phase of an eight-year cleanup project along the lakefront of Lake Superior in Ashland, Wisconsin, which was one of the busiest industrial ports in the country during the late 1800s and early 1900s. A final site cap, as prescribed by the Record of Decision (ROD), will be installed at the site in 2019. It was the site not only of a legacy MGP, but other industrial operations. The MGP was operated at the site from 1885 to 1947 and provided gas for street lighting and businesses. Later, the site was used for a city-owned landfill and waste water treatment plant. We have owned a portion of the Ashland site since 1986.

The $200 million project was done under the supervision of EPA and the Wisconsin Department of Natural Resources. It involved more than 460,000 hours of work and employed best-in-class techniques, innovative technologies and a first-of-its-kind strategy to safely remove impacted lake sediments from the lakefront.

The effort included a unique agreement for cost recovery that effectively managed customer impact. In addition, numerous issues were successfully negotiated and litigated, including the recovery of more than $50 million in insurance and third-party settlements to reduce overall cost. Working closely with state and federal agencies, the project was environmentally sound and economically balanced. Throughout the effort, we maintained strong community relations with the city, customers, elected officials and local Native American tribes. With the project completed, the Ashland community can now move forward with waterfront-redevelopment plans.



Our environmental protection efforts include safeguarding birds, bats and other wildlife around our operations. We regularly work with environmental agencies and conservationists to preserve wildlife and its habitat.

Wildlife protection and biodiversity

Managing wildlife and habitat

We have a long history of working proactively with wildlife agencies and conservationists on special programs, research studies and regulatory efforts designed to protect wildlife and its habitat.

Our operations cover thousands of miles of transmission and power line right-of-ways, as well as the lakes, rivers and acres of land that surround our generating plants and wind farms. Given our footprint, we must take care and coexist responsibly with wildlife and the natural habitat that surrounds our facilities.

We consider our impact on wildlife as we upgrade, design and build facilities. For power line and plant construction projects, we evaluate our projects to determine possible impacts and take appropriate steps to help avoid and minimize potential risks. If we do have impacts, we have programs in place to document and report incidents to regulatory agencies, and then determine what actions we can take to prevent future issues.

2018 Results

- Under our Avian Protection Plans, 2,700 electric transmission and distribution power-line locations have been retrofitted with equipment to protect birds.
- We continued to support pollinator habitat on Xcel Energy property, especially in the Upper Midwest where we planted 47 acres of new habitat through three volunteer projects with agency and nonprofit partners. We even completed a demonstration garden at our downtown Amarillo headquarters by filling planters that surround the building with plants that are visually appealing and pollinator friendly.

- Our popular Bird Cam website had more than 1.3 million views with visitors tuning in to watch bald eagles, great horned owls and peregrine falcons. As early as 1989, we began working with the nonprofit Raptor Resource Project to install nest boxes at several of our Minnesota generating plants to help restore the peregrine falcon to the Mississippi River Valley. With the program's success, we began installing web-based cameras to share live video of the birds and their nesting habits. Our Bird Cam program grew from there.
- Through the Xcel Energy Foundation, we contributed nearly $436,000 in environmental stewardship grants to support organizations and programs that work to protect and enhance our natural environment.
- Former Vice President Walter Mondale, representatives from the National Park Service, and elected officials and community leaders from Minnesota and Wisconsin honored Xcel Energy for the company's donation of more than 24,000 acres of land along the St. Croix and Namekagon Rivers, which led to the creation of the Wild and Scenic Rivers Act of 1968. Events were held throughout Minnesota and Wisconsin in 2018 to recognize the 50th anniversary of the Act.

Avian Protection Plans

Xcel Energy was the first utility in the country to enter into a historic agreement with the U.S. Fish and Wildlife Service to proactively address potential issues involving birds and power-line structures, while helping the company comply with federal avian protection laws. Our utility operating companies entered into separate voluntary memorandums of understanding with USFWS in 2002 to collaborate on developing Avian Protection Plans.

Transmission and distribution lines and equipment can be attractive to birds for roosting and building nests and can pose a collision and electrocution hazard that may result in death or injury of the birds. In addition, threatened and endangered avian species and eagles are protected by the federal Endangered Species Act and the Bald and Golden Eagle Protection Act, respectively. Our Avian Protection Plans are a critical initiative for protecting birds and complying with these federal wildlife protection laws.

As part of its plan, each operating company developed a schedule for retrofitting facilities determined to pose a higher risk for bird injuries or deaths. Since then, we've had great success completing the retrofits in a timely manner, as called for under the plans. All of the initially identified retrofits have been completed in our Colorado, Texas and New Mexico service territories. In our Upper Midwest service territory, we have finished the highest priority lines and poles and are working through the next level of retrofit projects. Additionally, all of our facility design standards have been revised so that new or modified construction meets industry standards to prevent or mitigate avian incidents.

Xcel Energy employees are required under the plans to report injured or dead birds using the company's online reporting form. We then analyze whether reasonable retrofits or the installation of additional avian controls can minimize the risk of avian incidents at the location in the future. This reporting and evaluation process is another step in complying with federal avian protection laws and demonstrating our commitment to taking responsible actions for avian protection.

Helping Pollinators

Xcel Energy has been supporting the development and maintenance of pollinator habitats for over 30 years. With our Upper Midwest service territory coinciding with the Monarch Migration Corridor from Minnesota to Texas, we see tremendous potential to be a leader in helping pollinators.

The company currently has over 2,100 acres of pollinator habitat in Minnesota, North Dakota and Wisconsin. We have 44 active sites ranging from 0.25 to 800 acres on various company property including under transmission lines, around substations, power plants, community solar gardens, a wind project and company office sites. We are supporting and initiating projects that make a difference in the lives of pollinators, restoring native prairie ecosystems and targeting pollinator species of concern including the monarch butterfly, rusty patched bumblebee, and karner blue butterfly.

We can't achieve success on our own. We have many partners including state and federal agencies, communities and non-profit organizations. In 2018, we planted 40 acres of pollinator habitat around our Magic City Substation in Minot, North Dakota in collaboration with the U.S. Fish & Wildlife Service Partners for Wildlife. We partnered with Great River Greening and Xcel Energy employee volunteers to seed four acres of milk weed outside our Blue Lake Power Plant in Shakopee, Minnesota. An additional 16 acres will be planted in 2019 with the goal of creating a seed bank. We also partnered with the city of Burnsville, Minnesota in 2018 to plant three acres of pollinator habitat under transmission lines in an area where a new natural gas pipeline was installed leading to the Black Dog Generating Plant.

In Colorado, employee volunteer groups are partnering with nonprofit organizations to educate our employees on the importance of pollinator species and supporting projects for the development and maintenance of pollinator habitats in our communities. Partner organizations include the Butterfly Pavilion, Volunteers for Outdoor Colorado and the Colorado Pollinator Network.

Xcel Energy and the contractors we employ do not use chemicals that are harmful to beneficial insects in our vegetation management practices to control brush, trees and weeds on our rights-of-way and properties. This includes not using neonicotinoids, which is of special concern to people working to improve bee populations.

As we move forward with the pollinator initiative, we are focusing on developing habitat that can be sustained, allowing time for the sites to develop. Our primary goal is to continue to educate the communities we serve on the importance of the pollinators in their daily lives while utilizing company property to make a difference.

Responsible Wind Development

Wind energy is an important and growing part of our energy mix, especially as we look to build and operate more company-owned wind farms. Through wind, we are reducing carbon and other emissions and improving the environment in ways that ultimately support and protect wildlife. But, wind farms must be properly located, constructed, operated and monitored to minimize impacts to wildlife and protected species.

Project Siting and Development

Before construction, we carefully select wind farm sites to ensure impacts to birds, bats and other wildlife are minimized to the fullest extent practicable. This includes following the USFWS's Land-based Wind Energy Guidelines, conducting wildlife and habitat surveys and following other best practices. As part of this, we work with wind project developers, the USFWS and appropriate state wildlife and natural resource agencies during siting and permitting to ensure turbine locations are not in critical habitat for threatened and endangered species. If issues are identified, we work with the appropriate agencies to avoid or minimize impacts.

Our Sagamore Wind project in New Mexico is an example of our commitment to responsible wind development. The project developer sited turbines in locations that avoid and minimize impacts, and we are voluntarily entering into a conservation agreement. We have signed a letter of intent with the Lost Draw Conservation Bank to purchase preservation and restoration credits for the Lesser Prairie-Chicken (LPC) pending project approval and transfer of ownership.

Our participation in the Lost Draw Conservation Bank will help support LPC conservation by expanding, improving, and protecting high-quality LPC habitat. The bank is expected to restore thousands of acres of habitat by reconverting agricultural fields and removing tall woody species such as mesquite. It will eliminate existing fragmentation, such as pivot irrigation, wind mills, and other tall structures, and provide permanent protection of this high-quality habitat using easements held by a New Mexico land trust.

Construction

Pre-construction surveys are conducted prior to excavation for road or foundation construction, cable installation or crane relocation. This helps ensure that potential wildlife impacts can be minimized during wind farm construction. During construction of the Rush Creek wind project in Colorado, pre-construction surveys located burrowing owl nests in prairie dog colonies. Buffer zones were identified and marked to allow construction to continue while protecting the owls.

These surveys provide opportunities to identify other potential wildlife impacts due to indirect construction activity. At Rush Creek, for example, construction activity along a section of access road was restricted to protect an active swift fox den. We will also try to maintain existing trees and abandoned buildings on these sites when possible to avoid disturbing bat roosting habitat.

Wind Farm Operations

Once a wind farm is built, we continue to perform studies and monitor wind turbine operations. Our wind farms have detailed Bird and Bat Conservation Plans, which provide a framework for how we study, monitor and minimize impacts over the life a project — from wind farm planning to construction to the operation and maintenance and decommissioning.

Despite all these efforts, wildlife can be unpredictable, and there are no guarantees. We report injuries or fatalities to USFWS and appropriate state agencies. If protected avian species build nests in close proximity to existing wind turbines, we will evaluate what actions are needed to avoid and minimize impacts and engage our state and federal wildlife experts to ensure we take the right steps.

In addition to the wind farms we own, we also purchase a significant amount of wind capacity. We expect our third-party wind suppliers to perform similar permitting, reporting, reviews and studies of their wind farm operations.

Preserving Native American Cultural Resources

Protecting significant tribal cultural resources during the siting, construction and operation of our wind facilities is a priority. We voluntarily work with interested tribes to identify tribal cultural resources in areas where there are potentially important resources and may modify the final wind facility design to avoid impacts as much as possible. During construction, tribal cultural resource monitors may be used to help with the unexpected discovery of artifacts, ensuring they are evaluated and managed in a culturally appropriate manner.

During development and construction of the Foxtail wind project, we worked closely with the Standing Rock Sioux Tribe and others because the facility is sited near the Whitestone Hill State Historic Site in North Dakota, which was identified early in the development process as a historical site with major significance to a number of Tribes.

Enticing Ospreys to Alternative Nest Sites

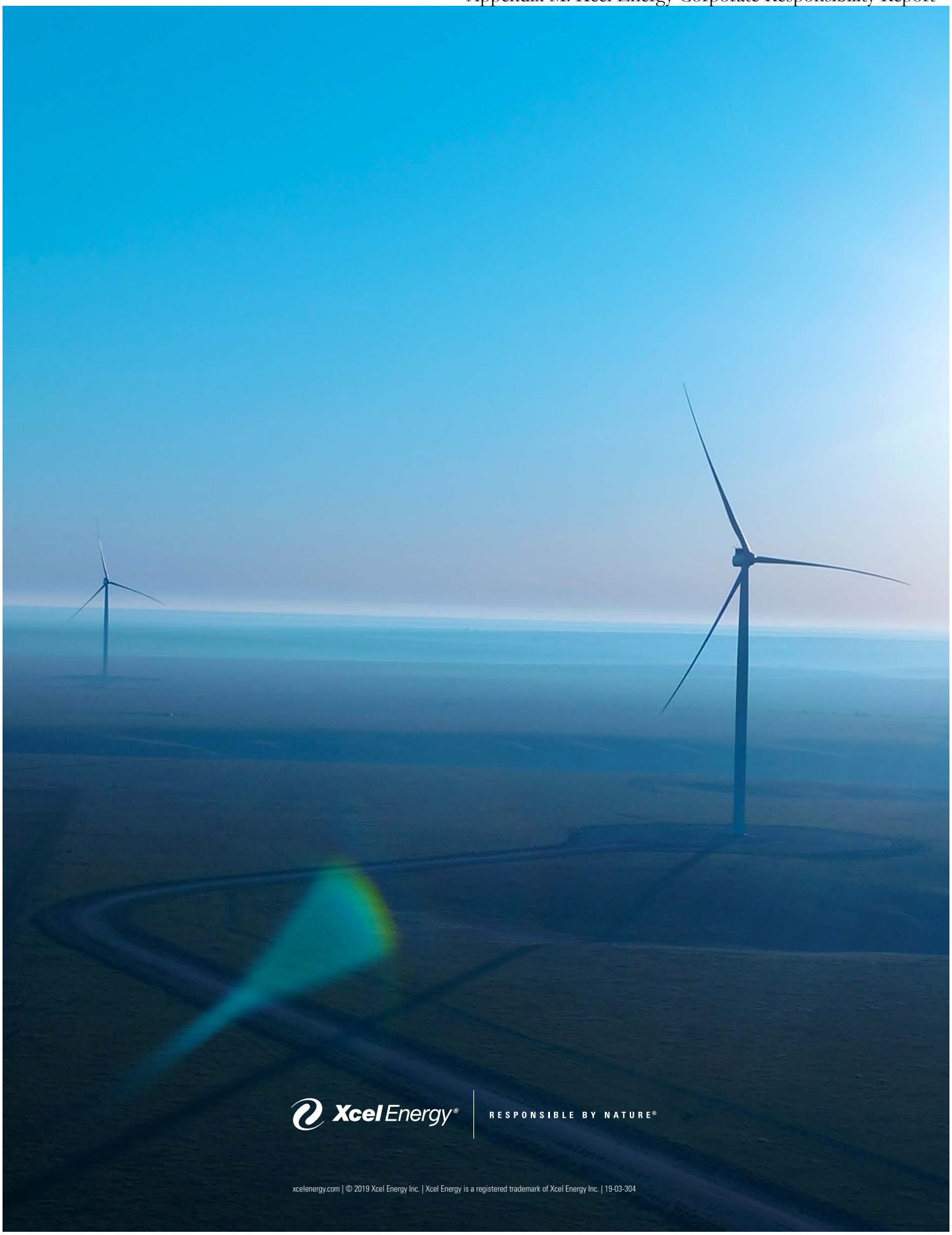
Ospreys are federally protected raptors that have been successfully reintroduced in the Midwest, following decades of restoration and conservation efforts. Ospreys like distribution poles and transmission structures for nesting, but nests built on utility poles can pose a threat to the birds and may cause outages and damage to electrical equipment. Xcel Energy frequently erects alternative nest platforms that are taller than nearby lines in known osprey nesting areas to provide more attractive and safer nesting sites, while protecting system reliability. We also work closely with communities and civic groups to help them evaluate utility poles near high-quality osprey habitat, to identify alternative sites and assist with building and installing safe osprey nest platforms.

Lesser Prairie-Chicken Conservation Agreement

We voluntarily entered into a conservation agreement with the Western Association of Fish and Wildlife Agencies (WAFWA) pursuant to the Lesser Prairie-Chicken Range-Wide Conservation Plan to help protect this species of prairie grouse.

Rangelands in our Colorado, New Mexico and Texas service areas provide important habitat for the LPC. To participate in the conservation agreement, we pay enrollment and mitigation fees based on our anticipated development activity. We also take conservation measures, following avoidance, minimization and mitigation practices during operation, maintenance and new construction activities. As an example, we may bury distribution lines within the buffers of active breeding areas and use special types of pole construction in certain LPC habitat areas.

The goal of the WAFWA conservation plan is to increase the population of the species from about 17,000 birds in 2013 to 67,000 birds across Colorado, Kansas, New Mexico, Oklahoma and Texas. These efforts appear to be working — in 2018, WAFWA reported that there has been a steadily increasing LPC population trend over the last years.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414 Nicollet Mall
Minneapolis, MN 55401

PUBLIC DOCUMENT – NOT PUBLIC (OR PRIVILEGED) DATA HAS BEEN EXCISED

July 1, 2019

—Via Electronic Filing—

Anne Sell
Minnesota Department of Commerce
85 Seventh Place East, Suite 280
St. Paul, MN 55101

RE: ANNUAL ELECTRIC UTILITY REPORT
DOCKET NO. E999/M-19-11

Dear Ms. Sell:

Northern States Power Company, doing business as Xcel Energy, submits the enclosed 2018 Electric Utility Annual Report required under Minn. Rule 7610.0130. Our Annual Report consists of the enclosed pages as well as individually uploaded live spreadsheets.

Private and Trade Secret Data Justification
This report contains private data on individuals such as the names, addresses, and usage of our largest electric customers. This information is maintained by the Company as private customer data, and for this reason, pursuant to Minn. Stat. §13.679, we have removed this data from the public version of our filing.

Please note that this report also contains Trade Secret information protected by the Minnesota Data Practices Act. That information has economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by other persons and is subject to efforts by the Company to protect the information from public disclosure. Xcel Energy maintains this information as a trade secret based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. For this reason, we ask that the data be treated as non-public data pursuant to Minn. Stat. § 13.37, subd. 1(b).

The forecast purchase and resale energy information has economic value to Xcel Energy, its customers, suppliers, and competitors. Because Xcel Energy competes for purchased energy, fuel and transportation services in a competitive marketplace, disclosure would directly harm Xcel Energy by making its delivered supply costs less competitive. For this reason, pursuant to Minn. Stat. § 13.37, subd. 2, we have removed this data from the public version of our filing.

We have electronically filed this document with the Minnesota Public Utilities Commission. Please feel free to contact me at (612) 330-6935 or gail.baranko@xcelenergy.com if you have any questions regarding this report.

Sincerely,

/s/

GAIL A. BARANKO
MANAGER, REGULATORY PROJECT MANAGEMENT

Enclosures

7610.0320 - Forecast Methodology

NSP Electric – Minnesota Annual Report
Peak Demand and Annual Electric Consumption Forecast

OVERALL METHODOLOGICAL FRAMEWORK

Xcel Energy prepared its forecast by major customer class and jurisdiction, using a variety of statistical and econometric techniques. The NSP System serves five jurisdictions. Minnesota, North Dakota and South Dakota are served by Northern States Power Company, a Minnesota corporation (NSP). Wisconsin and Michigan are served by Northern States Power Company, a Wisconsin corporation (NSPW). The overall methodological framework is "model oriented". The NSP and NSPW Systems operate as an integrated system. The forecast is referred to as the 2018v2.1 Forecast.

SPECIFIC ANALYTICAL TECHNIQUES

1. Econometric Analysis. Xcel Energy used econometric analysis to develop jurisdictional MWh sales forecasts at the customer meter for the following sectors (exceptions to this are noted in bullet 2):
    a. Residential without Space Heating;
    b. Residential with Space Heating;
    c. Small Commercial and Industrial;
    d. Large Commercial and Industrial (Minnesota only);
    e. Public Street and Highway Lighting (Minnesota only);
    f. Sales to Public Authorities (Minnesota only).

    Xcel Energy also used econometric analysis to develop the total system MW peak demand forecast.
2. Trend analysis was used for all other sectors, which includes North Dakota, South Dakota, Wisconsin and Michigan Large Commercial and Industrial; North Dakota, South Dakota, Wisconsin and Michigan Public Street and Highway Lighting; North, Dakota, South Dakota, Wisconsin and Michigan Other Sales to Public Authorities; and Interdepartmental sales (all jurisdictions).
3. Loss Factor Methodology. Loss factors by jurisdiction were used to convert the sales forecasts into system energy requirements (at the generator).
4. Judgment. Judgment is inherent to the development of any forecast. Whenever possible, Xcel Energy used quantitative models to structure its judgment in the forecasting process.

The sales forecasts are estimates of MWh levels measured at the customer meter. They do not include line or other losses. The various jurisdictional class forecasts are summed to yield the total system sales forecast. Native energy requirements are measured at the generator and include line and other losses. Xcel Energy creates native energy requirements based on the sales forecasts. A system loss factor for each jurisdiction, developed based on average historical losses, is applied to the sales forecast to calculate total losses. The sum of the MWh sales and the MWh losses equals the native energy requirements. The native energy requirements, along with peak producing weather and binary variables, then are used as independent variables within an econometric model to forecast MW peak demand for the

Xcel Energy North System.

MODELS USED

1. ***Residential Econometric Models.*** Sales to the residential sectors represent 29.7% of total NSP System electric sales in 2018. Residential sales are divided into with space heating and without space heating customer classes for Minnesota, North Dakota, and South Dakota. Econometric regression models using historical data are developed for each residential sector. A variety of independent variables are used in the models, including:
    - Number of customers;
    - Real Personal Income or Real Personal Income per Capita for respective jurisdiction;
    - Gross State Product;
    - Total Employment for respective jurisdiction;
    - Price of oil (WTI crude);
    - Actual heating and temperature humidity index (THI) degree days;
    - Number of monthly billing days;
    - Price of electricity ($/kWh).
2. ***Small Commercial and Industrial Econometric Models.*** The small commercial and industrial sector represents 43.7% of NSP System electric sales in 2018. The models are econometric regressions using historical data. The models include a combination of variables, including the following:
    - Number of small commercial and industrial customers;
    - Gross Metro Product for respective jurisdiction;
    - Gross State Product (North Dakota only);
    - Employment for respective jurisdiction;
    - Real Personal Income per Capita for respective jurisdiction;
    - Actual heating and temperature humidity index (THI) degree days;
    - Number of monthly billing days.
3. ***Large Commercial and Industrial Econometric Model.*** Sales to the large commercial and industrial sector represent 26.0% of NSP System electric sales in 2018. The regression model uses historical data and the following explanatory variables:
    - U.S. Industrial Production Index;
    - Number of monthly billing days.
4. ***Others.*** Sales to the "Others" sector represent 0.6% of NSP System electric sales in 2018. This sector includes Public Street and Highway Lighting (PSHL), Sales to Public Authorities (OSPA) and Interdepartmental (IDS) sales. Regression models are used to estimate sales for the PSHL and OSPA classes (Minnesota only), using historical data and a combination of variables, including the following:
    - Number of customers;
    - Population for Minneapolis St. Paul MSA;
    - Number of monthly billing days.
5. ***Municipals.*** As of 2014 there are no longer any municipal customers for whom NSP or NSPW provides firm service.

6. ***Peak Demand Model.*** An econometric model is developed to forecast base peak demand for the entire planning period. The model includes a combination of variables, including the following:
    - Weather normalized native energy requirements;
    - Peak producing weather by month.

METHODOLOGY STRENGTHS AND WEAKNESSES

The strength of the process Xcel Energy used for this forecast is the richness of the information obtained during the analysis. Xcel Energy's econometric forecasting models are based on sound economic and statistical theory. Historical modeling and forecast drivers are based on economic and demographic variables that are easily measured and analyzed. The use of models by class and jurisdiction gives greater insight into how the NSP System is growing, thereby providing better information for decisions to be made in the areas of generation, transmission, marketing, conservation, and load management.

With respect to accuracy, forecasts of this duration are inherently uncertain. Planners and decision makers must be keenly aware of the inherent risk that accompanies long-term forecasts. They must also develop plans that are robust over a wide range of future outcomes.

DATA FOR FORECASTS

Data Definitions

The following is a list of definitions of the variables used in Xcel Energy's econometric models.

Jurisdiction Abbreviations

M or MN	State of Minnesota
N or ND	State of North Dakota
S or SD	State of South Dakota
W or WI	State of Wisconsin
Mi or MI	State of Michigan

Monthly MWh Sales Series

SLS_Reswo(Juris)	Residential without space heating for given jurisdiction
SLS_ResSH(Juris)	Residential with space heating for given jurisdiction
SLS_SmCI(Juris)	Small commercial and industrial for given jurisdiction
SLS_LgCI(Juris)	Large commercial and industrial for given jurisdiction

Monthly Customer Series

Cust_Reswo(Juris)	Residential without space heating for given jurisdiction
Cust_ResSH(Juris)	Residential with space heating for given jurisdiction
Cust_SmCI(Juris)	Small commercial and industrial for given jurisdiction
Cust_LgCI(Juris)	Large commercial and industrial for given jurisdiction

Monthly Economic and Demographic Series

HH_(Juris)	Number of Households in given jurisdiction
NR_(Juris)	Total Population in given jurisdiction
CGMP_(MSA)	Real Gross Metro Product for given metropolitan statistical area
CGSP_(State)	Real Gross State Product for given state
EE_(Juris)	Total employment in given jurisdiction
EEMFG_(Juris)	Manufacturing employment in given jurisdiction
CYP_(Juris)	Real Personal Income in given jurisdiction
CYPNR_(Juris)	Real per capita Personal Income in given jurisdiction
(Juris)TotRes_RAP	Real Average Price for electric sales to residential customers

Monthly Data Variables used in Demand Model

THI12(Month)Cust	Temperature Humidity Index @12:00 noon multiplied by total retail customers
THI15(Month)Cust	Temperature Humidity Index @15:00 (3:00 PM) on the peak day multiplied by total retail customers
HDD(Season)	Normal Heating Degree Days on the day of the Peak multiplied by a binary variable for the season (winter – Wtr, shoulder month – sh)
WNActEnergy_LpYrAdj_12MoSum	12 month rolling sum of the weather normalized net energy requirements adjusted to remove the effect of leap years

Monthly Weather Variables

H65_bill (Juris) (Month)	HDD base 65 for given jurisdiction and month
T65_bill (Juris) (Month)	THI DD base 65 for given jurisdiction and month

Other Monthly Variables

BillDaysCellnet21	Billing Month Days

Monthly Binary Variables

Jan	Binary variable for the month of January
Feb	Binary variable for the month of February
Mar	Binary variable for the month of March
Apr	Binary variable for the month of April
May	Binary variable for the month of May
Jun	Binary variable for the month of June
Jul	Binary variable for the month of July
Aug	Binary variable for the month of August
Sep	Binary variable for the month of September
Oct	Binary variable for the month of October
Nov	Binary variable for the month of November
Dec	Binary variable for the month of December

Xcel Energy used internal and external data sources to create its MWh sales and MW peak demand forecast.

Historical MWh sales are taken from Xcel Energy's internal company records, fed by its billing system. Historical coincident net peak demand data is obtained through company records. The load management estimate is added to the net peak demand to derive the base peak demand.

Weather data (dry bulb temperature and dew points) were collected from the National Oceanic and Atmospheric Administration for the Minneapolis/St. Paul, Fargo, Sioux Falls, and Eau Claire areas. The heating degree-days and THI degree-days were calculated internally based on this weather data.

Economic and demographic data was obtained from the Bureau of Labor Statistics, U.S. Department of Commerce, and the Bureau of Economic Analysis. Typically they are accessed from IHS Global Insight, Inc. data banks, and reflect the most recent values of those series at the time of modeling.

DEMAND-SIDE MANAGEMENT PROGRAMS

The regression model results for the residential and commercial and industrial classes were reduced to account for the expected impacts of demand-side management (DSM) programs. The DSM methodology implemented for both the State of Minnesota and the State of South Dakota utilizes a transparent method for projecting the impacts of energy efficiency and load management on sales forecasts. There are three distinct steps to this process:

- Collect and calculate historical and current effects of DSM on observed sales
- Project the forecast using observed data with the impact of DSM removed (i.e. increase historical sales to show hypothetical case without DSM)
- Adjust the forecast to show the impact of all current and planned DSM in future years.

The Company's Saver's Switch program results in short-term interruptions of service designed to reduce system capacity requirements rather than permanent reductions in energy use, so it is not considered here.

Adjustments equivalent to those made to sales have also been made to the historical monthly energy and peak demand used in the peak demand regression model and to the resulting peak demand forecast.

BEHIND-THE-METER DISTRIBUTED SOLAR GENERATION

In response to the establishment of a Solar Energy Standard (SES) by the Minnesota Legislature an increased emphasis has been placed on distributed solar generation. A forecast of the expected impact on demand and energy has been developed based on new programs designed to meet goals established for the SES. The Minnesota class-level sales forecasts and the system peak demand forecast were adjusted to account for the impacts of customer sited behind-the-meter solar installations on the NSP System. This process of adjusting the sales and peak demand forecasts for behind-the-meter solar generation is similar to the adjustments made for DSM programs. There are three distinct steps to this process:

- Collect and calculate historical and current effects of behind-the-meter solar generation on observed sales and peak demand

- Project the forecast using observed data with the impact of behind-the-meter removed (i.e. increase historical sales to show hypothetical case without behind-the-meter solar generation)
- Adjust the forecast to show the impact of all current and planned behind-the-meter solar generation in future years.

PLUG-IN ELECTRIC VEHICLE CHARGING

The residential sales and peak demand forecasts also are adjusted to account for the increasing use of plug-in electric vehicle charging. The forecast adjustment for the monthly consumption of electricity for electric vehicle charging is based on a model that incorporates the stock of electric vehicles, electricity consumption per vehicle, an adoption rate for this technology, and financial incentives. The peak demand forecast adjustment is based on monthly electric vehicle energy consumption, daily consumption profile, and the time of day the monthly peak hour occurs.

DATA ADJUSTMENTS AND ASSUMPTIONS

1. Weather Adjustments. Xcel Energy adjusted its monthly weather data to reflect billing schedules. Therefore, the monthly weather data corresponds exactly with the billing month schedule.

2. Economic Adjustments. All price data and related economic series were deflated to 2009 constant dollars.

3. Large Customer Adjustments. The large commercial and industrial sales model results have been adjusted to account for announced changes in operations for large customers.

ASSUMPTIONS AND SPECIAL INFORMATION

Xcel Energy believes that its process is a reasonable and workable one to use as a guide for its future energy and load requirements. The underlying assumptions used to prepare Xcel Energy's median forecast are as follows:

1. Demographic Assumption. Population or household projections are essential in the development of the long-range forecast. The forecasts of customers are derived from population and household projections provided by IHS Global Insight, Inc., and reviewed by Xcel Energy staff. Xcel Energy customer growth mirrors demographic growth over the forecast period.

2. Weather Assumption. Xcel Energy assumed "normal" weather in the forecast horizon. Normal weather is defined as the average weather pattern over the 20-year period from 1998-2017. The variability of weather is an important source of uncertainty. Xcel Energy's energy forecasts are based on the assumption that the normal weather conditions will prevail in the forecast horizon. Weather-related demand uncertainties are not treated explicitly in this forecast.

3. Loss Factor Assumptions. The loss factors are important to convert the sales forecast to energy requirements. Xcel Energy uses a historical average loss factor for each jurisdiction, and assumes it will not change in the future.

FORECAST COORDINATION

Xcel Energy reports its energy and peak demand forecasts to the Midwest ISO (MISO). MISO then combines the forecasts of all its member utilities. Xcel Energy also reports its forecast to the Public Service Commission of Wisconsin as part of its Strategic Energy Assessment (SEA) process. In this process, the Wisconsin portion of the total Xcel Energy System load is combined with other Wisconsin electric utilities to form a statewide Wisconsin forecast.

7610.0410 – Future Facility Additions
7610.0420 – Future Facility Retirements

The Company's most recent, completed, Resource Plan (Docket No. E002/RP-15-21) was approved by Minnesota Public Utilities Commission (MPUC or the Commission) through an Order issued January 11, 2017. The next Resource Plan will be filed on July 1, 2019.

The Order to close the 2016-2030 Upper Midwest Resource Plan docket identified it reasonable to acquire 1000 MW of wind resources, manage solar acquisition to 650 MW between 2016-2021 through Community Solar Gardens and other acquisitions, retire Sherco units 1 & 2 in 2026 and 2023, respectively, identified a need for an additional 750 MW of intermediate capacity in 2026, and acquire an additional 400 MW of demand response by 2023.

The Company fulfilled the Ordered wind with the acquisition of resources through ownership and power purchase agreements. On September 22, 2016, the Company issued a Request For Proposals (RFP) for 1000 MW wind resources. The Company filed petitions (Docket No. E002/M-16-777, E002/M-17-694) to build, own, and operate an additional 1850 MW wind. These resources will achieve Commercial Operation between 4th quarter of 2019 and 4th quarter of 2021. Orders granting approval were received from the Minnesota Commission in September 2017 and May 2018, respectively.

Project	Fuel	Size	COD	Location	Type
Blazing Star 1	Wind	200 MW	2019	Lincoln County, MN	Self-Build
Blazing Star II	Wind	200 MW	2020	Lincoln County, MN	Self-Build
Foxtail	Wind	150 MW	2019	Dickey County, ND	Self-Build
Freeborn	Wind	200 MW	2020	Freeborn County, MN and Worth & Mitchell Counties, IA	Self-Build
Crowned Ridge	Wind	300 MW	2019	Codington County, SD	PPA
Crowned Ridge	Wind	300 MW	2019	Codington County, SD	BOT
Lake Benton	Wind	100 MW	2019	Pipestone County, MN	BOT
Clean Energy #1	Wind	100 MW	2019	Mercer & Morton Counties, ND	PPA
Dakota Range	Wind	300 MW	2021	Watertown, SD	Self-Build

Note: The Wind Petitions (Docket Nos. E002/M-16-777 and E002/M-17-694) provide additional information regarding these resources, including accredited capacity value, accredited capacities and production, and estimated costs.

The Company is on track to fulfill the Ordered solar acquisition through the Community Gardens (CSG) program. As of June 3, 2019, 559 MW of CSG

resources are connected. The program forecasts exceed 650 MW by 2019 year end.

The 2019 Review of Remaining Lives (Docket No. E,G002/D-19-161) – an annual review of the remaining lives depreciation of its electric and gas production and gas storage facilities service lives and salvage rates – updated the Remaining Life forecast for all Northern States Power Company – Minnesota (NSPM) units. This remaining life is associated with Financial End of Life for rate making purposes. Projections for the 2019-2029 timeframe are listed below. This is a tentative schedule, subject to change, pending the outcome of future Annual Review of Remaining Lives filings and the next Resource Plan filing.

Projected Plant Retirements*			
Year	**Unit/Site**	**Size (MW)****	**Fuel Type**
2019	Granite City	47	Natural Gas
2019	Bayfront 4	20	Natural Gas
2023	Blue Lake Units 1 thru 4	160	Oil
2024	Sherco Unit 2	765	Coal
2026	Wheaton	250	Oil/Natural Gas
2027	Sherco Unit 1	765	Coal
2027	Inver Hills	281	Natural Gas
2028	Red Wing	23	Refused Derived Fuel (RDF)
2028	Wilmarth	25	Refused Derived Fuel (RDF)

Notes:
* Years indicated represent the financial end-of-life as identified in the above referenced Remaining Lives docket. Financial end-of-life dates may be adjusted to coincide with the MISO Planning Year, ending May 31st.
** Size represents nameplate or contracted value of the resource.

The following list outlines current Power Purchase Agreements (PPA) and their scheduled termination dates.

Projected PPA Retirements			
Year	**Unit/Site**	**Size (MW)****	**Fuel Type**
2019	Koda/Rahr	12	Biomass
2019	Renewable PPAs	24	Renewable
2020	Manitoba Hydro	73	Hydro
2020	Renewable PPAs	1	Renewable
2021	Renewable PPAs	1	Renewable
2022	Renewable PPAs	7	Renewable
2023	Renewable PPAs	22	Renewable

2023	St. Paul CoGen	25	Biomass
2024	Renewable PPAs	13	Renewable
2025	Renewable PPAs	21	Renewable
2025	Manitoba Hydro	827	Hydro
2025	Invenergy	312	Natural Gas
2026	Mankato 1*	277	Natural Gas
2026	Renewable PPAs	10	Renewable
2027	Renewable PPAs	44	Renewable
2028	LS Power	235	Natural Gas
2028	Renewable PPAs	7	Renewable
2029	Renewable PPAs	17	Renewable

*Termination year may change pending a decision in MPUC Docket No. IP6949,E002/PA-18-702 regarding the proposed acquisition.

Xcel Energy proposes to fulfill future electric generating resource needs through our resource planning process and subsequent resource acquisition processes. The specific generation technology, location of future generation facilities, and mix of utility-owned, PPAs, and other resources are subject to approval by the Commission.

Xcel Energy -- Minnesota

Transmission Assets

MANITOBA

ONTARIO

NORTH DAKOTA

SOUTH DAKOTA

WISCONSIN

IOWA

Kittson County
Roseau County
Lake of the Woods County
Marshall County
Koochiching County
Pennington County
Beltrami County
Red Lake County
Polk County
Clearwater County
St. Louis County
Cook County
Lake County
Itasca County
Norman County
Mahnomen County
Hubbard County
Clay County
Becker County
Cass County
Wadena County
Aitkin County
Carlton County
Crow Wing County
Wilkin County
Otter Tail County
Todd County
Pine County
Morrison County
Mille Lacs County
Kanabec County
Grant County
Douglas County
Traverse County
Benton County
Granite City
Stevens County
Pope County
Stearns County
Isanti County
Chisago County
Big Stone County
Sherburne County
Sherburne County
Monticello (MN)
Swift County
Anoka County
Kandiyohi County
Meeker County
Wright County
Lac Qui Parle County
Chippewa County
Washington County
Allen S King Plant
Hennepin County
Lower Dam
United Hospital
Hennepin Island
High Bridge
Alliant Techsystems
Minnesota Valley
McLeod County
Carver County
Black Dog
Inver Hills
Blue Lake (MN)
Yellow Medicine County
Renville County
Scott County
Dakota County
Prairie Island
Red Wing
Sibley County
Lincoln County
Lyon County
Redwood County
Goodhue County
Nicollet County
Rice County
Le Sueur County
Faribault
West Faribault
Wilmarth
Key City
Brown County
Wabasha County
Holland Wind
Pipestone County
Murray County
Cottonwood County
St James
Blue Earth County
Waseca County
Steele County
Dodge County
Olmsted County
Winona County
Watonwan County
Rock County
Nobles County
Jackson County
Martin County
Faribault County
Freeborn County
Mower County
Fillmore County
Houston County

LEGEND

Existing Transmission

- 230 kV
- 345 kV
- 500 kV

Proposed NewTransmission

- Huntley - Wilmarth Notice Area

Substation, Generation, and Service Territory

- Substation
- Generation Plant
- Xcel Energy Service Area

N

0 10 20 40 Miles

DISCLAIMER: This information is believed to be correct but is subject to change and is not warranteed.

Map Produced By:
Siting and Land Rights
Minneapolis -- jwf
Map Updated: June -- 2019

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Information Sheet

Minnesota

2019 Minnesota Communities Served by Xcel Energy

U = Unincorporated E = Electricity only G = Gas only EG = Electricity and Gas W = Wholesale

A
Ada W
Afton EG
Albany E
Albany Township E
Albertville E
Alma City UE
Almelund UEG
Alton Township E
Altura E
Amador Township EG
Annandale E
Anoka County EG
Apple Valley E
Arden Hills EG
Arlington Township E
Ashland Township E
Atwater E
Averill UE
Avon E
Avon Township E

B
Baker UE
Balaton E
Baldwin Township G
Bancroft Township E
Barclay Township G
Barnesville Township*** G
Bath Township E
Baxter G
Bayport EG
Baytown Township EG
Beauford UE
Beauford Township E
Becker EG
Becker Township E
Belgrade E
Belle Creek Township E
Belle Plaine E
Belle Plaine Township E
Bellechester E
Bellevue Township G
Belvidere Township E
Belview E
Benton County EG
Benton Township E
Bergen Township E
Bernadotte Township E
Big Lake EG
Big Lake Township E
Birch Cooley Township E
Birchwood EG
Bird Island E
Bird Island Township E
Blaine EG
Blakely Township E
Blomkest E
Blooming Grove Township E
Bloomington E
Blue Earth County EGW
Blue Hill Township EG
Bombay UE
Bongards UE
Borup E
Brainerd G
Breezy Point G
Bridgewater Township E
Briggs Lake G
Brighton Township E
Brockway Township EG
Brooklyn Center E
Brooklyn Park E
Brooten E
Brownton E
Brown County E
Buffalo EGW
Buffalo Lake E
Buffalo Township EG
Burnsville E
Butterfield E
Byron E

C
Camden Township E
Canisteo Township E
Cannon City UE
Cannon City Township E
Cannon Falls E
Cannon Falls Township E
Carver E
Carver County EG
Cass County G
Castle Rock Township E
Center City EG
Centerville EG
Champlin E
Chandler E
Chanhassen E
Chaska E
Cherry Grove Township E
Chester Township E
Chickamaw Beach G
Chippewa County E
Chisago City EG
Chisago County EG
Chisago Lake Township EG
Circle Pines E
Clara City E
Claremont E
Claremont Township E
Clarkfield E
Clarks Grove E
Clay County EG
Clear Lake EG
Clear Lake Township E
Clearwater EG
Clements E
Cleveland EG
Cleveland Township G
Clinton Falls UE
Clinton Falls Township E
Coates E
Cobden E
Cokato E
Cokato Township E
Cold Spring E
Collegeville EG
Collins Township E
Collinwood Township EG
Cologne E
Columbia Heights E
Columbus Township EG
Comstock E
Concord UE
Concord Township E
Coon Rapids E
Corcoran E
Cordova Township EG
Corinna Township E
Cornish Township E
Cosmos EG
Cosmos Township EG
Cottage Grove EG
Cottonwood E
Courtland E
Courtland Township E
Credit River Township E
Crosslake G
Crow Lake Township E
Crow Wing County UG
Crystal E
Currie E

D
Dahlgren E
Dakota E
Dakota County EG
Danube E
Danville Township E
Darwin G
Darwin Township G
Dassel EG
Dassel Township EG
Dayton E
Deephaven E
Deerfield Township E
Delano EGW
Delavan Township E
Delhi E
Dellwood EG
Denmark Township EG
Dennison E
Dilworth EG
Dodge Center E
Dodge County E
Douglas County E
Dresbach UE
Dresbach Township E
Dryden Township E
Dundas EG

2019 Minnesota Communities Served by Xcel Energy — Information Sheet

Minnesota

U = Unincorporated E = Electricity only G = Gas only EG = Electricity and Gas W = Wholesale

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- Eagan G
- Eagle Lake E
- East Bethel EG
- East Grand Forks* GW
- East Gull Lake G
- Echo E
- Echo Township E
- Eden Lake Township E
- Eden Prairie E
- Eden Valley E
- Edgerton E
- Edina E
- Edwards Township E
- Elba E
- Elko New Market E
- Ellington Township E
- Ellsworth Township G
- Elmwood Township E
- Elysian EG
- Elysian Township EG
- Empire E
- Essig UE
- Evan E
- Excelsior E

F
- Fairfield G
- Fairview Township G
- Falcon Heights EG
- Faribault EG
- Faribault County E
- Farmington EG
- Faxon Township E
- Featherstone Township E
- Felton E
- Fifty Lakes G
- Fletcher E
- Florence E
- Florence Township E
- Foley EG
- Forest Lake EG
- Forest Lake Township EG
- Fort Snelling E
- Franconia Township EG
- Franklin E
- Franklin Township EG
- Freeborn County E
- Freedom Township E
- Freeport E
- Fridley E
- Frontenac UE

G
- Garden City Township E
- Garvin E
- Gaylord E
- Gem Lake EG
- Gibbon E
- Gillford Township E
- Gilmanton Township E
- Glasgow Township E
- Glencoe EW
- Glencoe Township E
- Glenwood E
- Glenwood Township E
- Glyndon EG
- Glyndon Township E
- Golden Valley E
- Good Thunder E
- Goodhue E
- Goodhue County EG
- Goodhue Township E
- Goodview* EG
- Gordon Township E
- Grafton Township E
- Granite Falls Township EW
- Grant EG
- Grant Township G
- Green Isle EG
- Green Isle Township EG
- Green Lake UEG
- Greenfield E
- Greenfield Township E
- Greenvale Township E
- Greenwald EG
- Greenwood E
- Grey Cloud Island Township EG
- Grove Township E

H
- Hadley E
- Hale Township E
- Ham Lake G
- Hamburg EG
- Hamel UE
- Hammond E
- Hampton E
- Hampton Township E
- Hancock E
- Hanley Falls E
- Hanover E
- Hartland E
- Harris E
- Hartland Township E
- Hassan Township E
- Hastings E
- Hatfield E
- Haven Township EG
- Hawk Creek Township E
- Hay Creek Township EG
- Hayfield E
- Hector E
- Helen Township E
- Helena Township E
- Henderson E
- Hennepin County EG
- Hillsdale Township E
- Hilltop E
- Hitterdal G
- Hokah E
- Holding Township E
- Holdingford EG
- Holland E
- Holland Township E
- Hollywood Township E
- Holy Cross Township E
- Homer Township EG
- Hopkins E
- Houston County E
- Howard Lake E
- Hugo EG
- Hyde Park Township E

I
- Ideal Township G
- Ihlen E
- Independence EG
- Inver Grove Heights EG
- Iona E
- Iosco Township E
- Irving Township EG
- Isanti G
- Isanti County G

J
- Jackson Township EG
- Jamestown Township E
- Janesville EW
- Janesville Township E
- Jasper E
- Jenkins G
- Jenkins Township G
- Jessenland Township E
- Jordan E

K
- Kalmar Township E
- Kandiyohi County EG
- Kandiyohi Township G
- Kandiyohi G
- Kasota Township EW
- Kasson W
- Kellogg E
- Kenyon Township EW
- Kilkenny E
- Kilkenny Township E
- Kimball E
- Kingston E
- Kingston Township E
- Krain Township E

L
- La Crescent E
- La Crescent Township E
- Lac Qui Parle County E
- Lafayette E
- Lake City EGW
- Lake Crystal W
- Lake Edward Township G
- Lake Elmo EG
- Lake Henry E
- Lake Henry Township E
- Lake Lillian E
- Lake Lillian Township E
- Lake Shore G
- Lake St. Croix Beach E
- Lake Township EG
- Lake Washington G
- Lake Wilson E
- Lakeland EG
- Lakeland Shores EG
- Laketown Township E
- Lakeville E
- Landfall EG
- Lanesburgh Township E
- Lauderdale EG
- Le Sauk Township EG
- Le Sueur County EG
- LeHillier E
- Lemond Township E
- Lent Township EG
- LeRay Township E
- Lester Prairie E
- Leven Township E
- Lexington E
- Lilydale EG
- Lime Township E
- Lincoln Township E
- Lindstrom EG
- Lino Lakes EG
- Linwood Township EG
- Little Canada EG
- Long Beach E
- Long Lake E
- Lonsdale E

2019 Minnesota Communities Served by Xcel Energy

Information Sheet

Minnesota

U = Unincorporated E = Electricity only G = Gas only EG = Electricity and Gas W = Wholesale

Loon Lake Township G
Loretto E
Louisville Township G
Lowry E
Lura Township E
Luxemburg Township E
Lydia UE
Lynden Township EG
Lyon County E
Lyra Township E

M
Madelia W
Madison Lake EG
Mahtomedi EG
Maine Prairie Township E
Manchester E
Manhattan Beach G
Mankato E
Mankato Township E
Mantorville E
Mantorville Township E
Maple Grove E
Maple Lake E
Maple Plain E
Mapleton E
Mapleton Township E
Maplewood EG
Marine on St. Croix EG
Marshall W
Marysville Township EG
May Township EG
Mayer E
Mazeppa E
Mazeppa Township E
McLeod County E
McPherson Township EG
Medford E
Medford Township E
Medicine Lake E
Medina E
Medo Township E
Meeker County EG
Meire Grove E
Melrose W
Mendota EG
Mendota Heights EG
Meriden UE
Meriden Township E
Middleville Township G
Mille Lacs County G
Millville E
Milton Township E
Minden Township EG
Minneapolis E
Minneapolis–St. Paul International Airport E
Minneiska E
Minneola Township E
Minnesota City EG
Minnesota Falls Township E
Minnesota Lake E
Minnetonka E
Minnetonka Beach E
Minnetrista EG
Minnewaska Township E
Moltke Township E
Montevideo E
Monticello E
Monticello Township E
Montrose EG
Moorhead EG
Moorhead Township G
Morgan E
Morgan Township E
Morrison County G
Morristown E
Morristown Township E
Morton E
Mound E
Mounds View EG
Mountain Lake W
Mount Pleasant Township EG
Mount Vernon Township E
Mower County E
Munson Township E
Murray County E

N
Navarre E
Nerstrand E
New Auburn E
New Brighton EG
New Germany E
New Hartford Township E
New Haven Township E
New Hope E
New London EG
New London Township EG
New Market Township E
New Munich E
New Prague E
New Richland E
New Richland Township E
New Scandia Township EG
New Sweden Township E
New Ulm W
Newport EG
Nicollet E
Nicollet County E
Nicollet Township E
Nininger Township E
Nisswa G
Nobles County G
Nodine UE
Norman County E
North Branch EG
North Branch Township G
North Mankato E
North Oaks EG
North St. Paul G
Northfield EG
Northfield Township E
Norwood Young America E

O
Oak Center UE
Oak Park Heights EG
Oak Township E
Oakdale EG
Oaklawn Township G
Oakport Township EG
Oakwood Township E
Olmsted County E
Orono E
Orrock Township G
Osakis E
Oshawa Township E
Osseo E
Otisco UE
Otsego E
Ottawa Township E
Otter Tail County G
Owatonna E
Oxford Township G

P
Palmer Township G
Paxton Township E
Paynesville E
Paynesville Township E
Pelican Township G
Pemberton E
Pepin Township E
Pequot Lakes G
Pillager** G
Pine Island E
Pine Island Township E
Pine River G
Pine River Township G
Pine Springs EG
Pipestone E
Pipestone County E
Plato E
Pleasant Hill Township EG
Pleasant Lake G
Plymouth E
Point Douglas Park E
Polk County G
Pope County E
Princeton G
Prinsburg E
Prior Lake E

R
Ramsey County EG
Randolph E
Randolph Township E
Rapidan UE
Raymond E
Reads Landing UE
Red Wing EG
Redwood County E
Redwood Falls W
Regal E
Renville E
Renville County E
Rheiderland Township E
Rice EG
Rice County EG
Rich Valley E
Richfield E
Richmond E
Ridgeway UE
Robbinsdale E
Rock County E
Rockford E
Rockford Township EG
Rockville EG
Rogers E
Rollingstone EG
Rollingstone Township E
Roscoe E
Roscoe Township E
Roseland UE
Rosemount EG
Roseville EG
Royalton G
Ruthton E

S
Sabin E
Sacred Heart E
Sacred Heart Township E
Salem Township E

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2019 Minnesota Communities Served by Xcel Energy — Information Sheet

Minnesota

U = Unincorporated E = Electricity only G = Gas only EG = Electricity and Gas W = Wholesale

San Francisco Township E
Sand Creek Township E
Santiago G
Sartell EG
Sauk Center W
Sauk Rapids EG
Sauk Rapids Township E
Savage E
Scandia UEG
Scott County EG
Sedan E
Severence Township E
Shafer EG
Shafer Township EG
Shakopee EG
Sherburne County EG
Sherman Township E
Shieldsville Township E
Shoreview EG
Shorewood E
Sibley County EG
Sibley Township EG
Silver Lake E
Skyberg UE
Skyline E
Slayton E
Sleepy Eye W
Smiths Mill UE
South Bend UE
South Bend Township E
South Haven E
South St. Paul EG
Southside Township E
Sparta Township E
Spencer Brook Township G
Spicer EG
Spring Hill E
Spring Lake Park E
Spring Lake Township E
Spring Park E
Springfield W
St. Anthony Village E
St. Augusta EG
St. Bonifacius E
St. Clair EG
St. Cloud EG
St. James W
St. Joseph EG
St. Joseph Township E
St. Lawrence Township E
St. Louis Park E
St. Martin E
St. Mary Township E
St. Mary's Point E
St. Michael EG
St. Paul EG
St. Paul Park EG
St. Peter W
St. Stephen G
St. Wendell Township G
Stacy EG
Stanton UE
Stanton Township E
Starbuck E
Stearns County EG
Steele County E
Sterling Township E
Stewart E
Stillwater EG
Stillwater Township EG
Stockholm Township E
Stoneham Township E
Stony Run Township E
Sumter Township E
Sunfish Lake EG
Sunrise UEG
Sunrise Township EG
Swedes Forest Township E
Sylvan Township** G

T
Taylors Falls EG
Timothy Township G
Todd County E
Tonka Bay E
Tracy E
Trosky E
Tunsberg Township E
Tyrone Township E

U
Ulen G
Union Grove Township E

V
Vadnais Heights EG
Vermillion E
Vermillion Township E
Veseli UE
Victor Township EG
Victoria E
Villard E

W
Wabasha EG
Wabasha County EG
Waconia E
Waconia Township E
Wacouta Beach UE
Wacouta Township EG
Waite Park EG
Wakefield Township E
Walcott Township E
Walden G
Waldorf E
Waltham E
Waltham Township E
Wanamingo E
Wanamingo Township E
Warsaw UEG
Warsaw Township EG
Waseca EW
Waseca County E
Washington County EG
Washington Lake Township EG
Washington Township G
Wasioja UE
Wasioja Township E
Watab Township EG
Waterford UEG
Watertown EG
Watertown Township EG
Waterville E
Waterville Township E
Watkins E
Watonwan County E
Watopa Township E
Watson E
Waverly EG
Wayzata E
Weaver UE
Webster UE
Webster Township E
Wegdahl UE
Welch Township E
Wells Township E
West Concord E
West Lakeland Township EG
West St. Paul EG
West Union E
Westport E
Westport Township E
Wheatland Township E
Wheeling Township E
White Bear Lake EG
White Bear Lake Township E
White Bear Township EG
Wilken County E
Willernie EG
Wilson UEG
Wilton Township E
Windom W
Winona EG
Winona County EG
Winona Township E
Winsted E
Winsted Township E
Witoka UE
Wolverton E
Wood Lake E
Wood Lake Township E
Woodbury EG
Woodland E
Woodland Township EG
Woodstock E
Woodville Township E
Wright County EG
Wyanett Township G
Wyoming EG
Wyoming Township EG

Y
Yellow Medicine County E
Young America Township E

Z
Zimmerman G
Zion Township E
Zumbro Falls E
Zumbrota E
Zumbrota Township E

Communities served based on tariff sheets on file with the Minnesota Public Utilities Commission. Minnesota Electric Rate Book, MPUC No. 2, Sheet Nos. 3-1 through 3-8, effective 11-01-15, and Minnesota Gas Rate Book, MPUC No. 2, Proposed Sheet Nos. 3-1 through 3-3, effective 11-01-14.

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Electric Rate Schedules

Electric Rate Schedules
June 1, 2018 – June 1, 2019

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK – MPUC NO. 2

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Date Filed: 11-01-17 By: Christopher B. Clark Effective Date: 08-07-18
President, Northern States Power Company, a Minnesota corporation
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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK – MPUC NO. 2

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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK – MPUC NO. 2

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Date Filed: 11-02-15 By: Christopher B. Clark Effective Date: 10-01-17
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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK – MPUC NO. 2

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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
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Date Filed: 11-17-17 By: Christopher B. Clark Effective Date: 06-25-18
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Docket No. E002/M-17-817 Order Date: 05-09-18

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK – MPUC NO. 2

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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

RESIDENTIAL SERVICE Section No. 5
RATE CODE A00, A01, A03 31st Revised Sheet No. 1

AVAILABILITY
Available to any residential customer for domestic purposes only in a single private residence and qualifying farm customers.

DETERMINATION OF CUSTOMER BILLS
Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and / or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

RATE

	Standard	Electric Space Heating	
Customer Charge per Month – Water Heating (A00)	$0.00	N/A	
– Overhead (A01)	$8.00	$10.00	
– Underground (A03)	$10.00	$12.00	
Energy Charge per kWh			
June - September	$0.10301	$0.10301	R
Other Months	$0.08803	$0.05988	R

In addition, customer bills under this rate are subject to the following adjustments and/or charges.

FUEL CLAUSE
Bills are subject to the adjustments provided for in the Fuel Clause Rider.

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider, the Renewable Development Fund Rider, the Transmission Cost Recovery Rider, the Renewable Energy Standard Rider and the Mercury Cost Recovery Rider.

ENVIRONMENTAL IMPROVEMENT RIDER
Bills are subject to the adjustments provided for in the Environmental Improvement Rider.

MONTHLY MINIMUM CHARGE
Customer Charge.

(Continued on Sheet No. 5-1.1)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

RESIDENTIAL SERVICE Section No. 5
RATE CODE A00, A01, A03 30th Revised Sheet No. 1

AVAILABILITY
Available to any residential customer for domestic purposes only in a single private residence and qualifying farm customers.

DETERMINATION OF CUSTOMER BILLS
Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and / or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

RATE

	Standard	Electric Space Heating	
Customer Charge per Month – Water Heating (A00)	$0.00	N/A	
– Overhead (A01)	$8.00	$10.00	
– Underground (A03)	$10.00	$12.00	
Energy Charge per kWh			
June - September	$0.10815	$0.10815	R
Other Months	$0.09241	$0.06287	R

In addition, customer bills under this rate are subject to the following adjustments and/or charges.

FUEL CLAUSE
Bills are subject to the adjustments provided for in the Fuel Clause Rider.

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider, the Renewable Development Fund Rider, the Transmission Cost Recovery Rider, the Renewable Energy Standard Rider and the Mercury Cost Recovery Rider.

ENVIRONMENTAL IMPROVEMENT RIDER
Bills are subject to the adjustments provided for in the Environmental Improvement Rider.

MONTHLY MINIMUM CHARGE
Customer Charge.

(Continued on Sheet No. 5-1.1)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

RESIDENTIAL SERVICE Section No. 5
RATE CODE A00, A01, A03 29th Revised Sheet No. 1

AVAILABILITY
Available to any residential customer for domestic purposes only in a single private residence and qualifying farm customers.

DETERMINATION OF CUSTOMER BILLS
Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and / or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

RATE

	Standard	Electric Space Heating	
Customer Charge per Month – Water Heating (A00)	$0.00	N/A	
– Overhead (A01)	$8.00	$10.00	
– Underground (A03)	$10.00	$12.00	
Energy Charge per kWh			
June - September	$0.10582	$0.10582	R
Other Months	$0.09032	$0.06082	R
			D

In addition, customer bills under this rate are subject to the following adjustments and/or charges.

FUEL CLAUSE
Bills are subject to the adjustments provided for in the Fuel Clause Rider.

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider, the Renewable Development Fund Rider, the Transmission Cost Recovery Rider, the Renewable Energy Standard Rider and the Mercury Cost Recovery Rider.

ENVIRONMENTAL IMPROVEMENT RIDER
Bills are subject to the adjustments provided for in the Environmental Improvement Rider.

MONTHLY MINIMUM CHARGE
Customer Charge.

(Continued on Sheet No. 5-1.1)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

RESIDENTIAL SERVICE (Continued) Section No. 5
RATE CODE A00, A01, A03 9th Revised Sheet No. 1.1

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

LOW INCOME ENERGY DISCOUNT RIDER
Bills are subject to the adjustment provided for in the Low Income Energy Discount Rider.

REVENUE DECOUPLING MECHANISM RIDER
Bills are subject to the adjustments provided for in the Revenue Decoupling Mechanism Rider.

The following are terms and conditions for service under this tariff.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

LOW INCOME ENERGY DISCOUNT
Energy discount is available to qualified low income customers under this schedule subject to the provisions contained in the Low Income Energy Discount Rider.

OTHER PROVISIONS
This schedule is also subject to provisions contained in Rules for Application of Residential Rates.

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

RESIDENTIAL TIME OF DAY SERVICE Section No. 5
RATE CODE A02, A04 31st Revised Sheet No. 2

AVAILABILITY
Available to any residential customer for domestic purposes only in a single private residence and qualifying farm customers.

DETERMINATION OF CUSTOMER BILLS
Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and / or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

RATE

	Standard	Electric Space Heating	
Customer Charge per Month			
Overhead (A02)	$10.00	$12.00	
Underground (A04)	$12.00	$14.00	
On Peak Period Energy Charge per kWh			
June - September	$0.20497	$0.20497	R
Other Months	$0.16508	$0.09284	R
Off Peak Period Energy Charge per kWh			
June - September	$0.04170	$0.04170	R
Other Months	$0.04170	$0.04170	R

In addition, customer bills under this rate are subject to the following adjustments and/or charges.

FUEL CLAUSE
Bills are subject to the adjustments provided for in the Fuel Clause Rider.

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider, the Renewable Development Fund Rider, the Transmission Cost Recovery Rider, the Renewable Energy Standard Rider and the Mercury Cost Recovery Rider.

ENVIRONMENTAL IMPROVEMENT RIDER
Bills are subject to the adjustments provided for in the Environmental Improvement Rider.

(Continued on Sheet No. 5-3)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

RESIDENTIAL TIME OF DAY SERVICE Section No. 5
RATE CODE A02, A04 30th Revised Sheet No. 2

AVAILABILITY
Available to any residential customer for domestic purposes only in a single private residence and qualifying farm customers.

DETERMINATION OF CUSTOMER BILLS
Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and / or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

RATE

	Standard	Electric Space Heating	
Customer Charge per Month			
Overhead (A02)	$10.00	$12.00	
Underground (A04)	$12.00	$14.00	
On Peak Period Energy Charge per kWh			
June - September	$0.21520	$0.21520	R
Other Months	$0.17328	$0.09748	R
Off Peak Period Energy Charge per kWh			
June - September	$0.04378	$0.04378	R
Other Months	$0.04378	$0.04378	R

In addition, customer bills under this rate are subject to the following adjustments and/or charges.

FUEL CLAUSE
Bills are subject to the adjustments provided for in the Fuel Clause Rider.

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider, the Renewable Development Fund Rider, the Transmission Cost Recovery Rider, the Renewable Energy Standard Rider and the Mercury Cost Recovery Rider.

ENVIRONMENTAL IMPROVEMENT RIDER
Bills are subject to the adjustments provided for in the Environmental Improvement Rider.

(Continued on Sheet No. 5-3)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

RESIDENTIAL TIME OF DAY SERVICE Section No. 5
RATE CODE A02, A04 29th Revised Sheet No. 2

AVAILABILITY
Available to any residential customer for domestic purposes only in a single private residence and qualifying farm customers.

DETERMINATION OF CUSTOMER BILLS
Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and / or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

RATE

	Standard	Electric Space Heating	
Customer Charge per Month			
Overhead (A02)	$10.00	$12.00	
Underground (A04)	$12.00	$14.00	
On Peak Period Energy Charge per kWh			
June - September	$0.21096	$0.21096	R
Other Months	$0.16968	$0.09385	R
Off Peak Period Energy Charge per kWh			
June - September	$0.04260	$0.04260	R
Other Months	$0.04260	$0.04260	R

In addition, customer bills under this rate are subject to the following adjustments and/or charges. D

FUEL CLAUSE
Bills are subject to the adjustments provided for in the Fuel Clause Rider.

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider, the Renewable Development Fund Rider, the Transmission Cost Recovery Rider, the Renewable Energy Standard Rider and the Mercury Cost Recovery Rider.

ENVIRONMENTAL IMPROVEMENT RIDER
Bills are subject to the adjustments provided for in the Environmental Improvement Rider.

(Continued on Sheet No. 5-3)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

RESIDENTIAL TIME OF DAY SERVICE (Continued) Section No. 5
RATE CODE A02, A04 12th Revised Sheet No. 3

MONTHLY MINIMUM CHARGE
Customer Charge.

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

LOW INCOME ENERGY DISCOUNT RIDER
Bills are subject to the adjustment provided for in the Low Income Energy Discount Rider.

REVENUE DECOUPLING MECHANISM RIDER
Bills are subject to the adjustments provided for in the Revenue Decoupling Mechanism Rider.

The following are terms and conditions for service under this tariff.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

LOW INCOME ENERGY DISCOUNT
Energy discount is available to qualified low income customers under this schedule subject to the provisions contained in the Low Income Energy Discount Rider.

DEFINITION OF PEAK PERIODS
The on peak period is defined as those hours between 9:00 a.m. and 9:00 p.m. Monday through Friday, except the following holidays: New Year's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. When a designated holiday occurs on Saturday, the preceding Friday will be designated a holiday. When a designated holiday occurs on Sunday, the following Monday will be designated a holiday. The off peak period is defined as all other hours. Definition of on peak and off peak period is subject to change with change in Company's system operating characteristics.

OPTIONAL TRIAL SERVICE
Customers may elect time of day service for a trial period of three months. If a customer chooses to return to non-time of day service after the trial period, the customer will pay a charge of $20.00 for removal of time of day metering equipment.

(Continued on Sheet No. 5-4)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

RESIDENTIAL TIME OF DAY SERVICE (Continued) Section No. 5
RATE CODE A02, A04 6th Revised Sheet No. 4

TERMS AND CONDITIONS OF SERVICE

1. Customer selecting the above time of day rate schedule will remain on this rate for a period of not less than 12 months, except as provided under Optional Trial Service. While served under this schedule, the Residential Service rate is not available.

2. This schedule is also subject to provisions contained in Rules for Application of Residential Rates.

3. Time of Day Metering Charge per Month Option (Closed): For any customer who prior to November 1, 1988, elected to pay a non-refundable payment of $310.00 in lieu of the time of day metering charge, the monthly customer charge is reduced by $2.00.

Date Filed: 11-02-15 By: Christopher B. Clark Effective Date: 10-01-17
President, Northern States Power Company, a Minnesota corporation
Docket No. E002/GR-15-826 Order Date: 06-12-17

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

RESIDENTIAL TIME OF USE PILOT PROGRAM Section No. 5
SERVICE 1st Revised Sheet No. 4.1
RATE CODE A72, A74

PILOT PROGRAM DESIGN
This is an experimental rate design for the residential Time of Use Pilot Program to be applied for two years from the effective date of this rate schedule. Participating customers will have received Residential Service without electric space heating prior to the Pilot, and may elect a return to the Residential Service rate schedule following the Pilot.

AVAILABILITY
A maximum of 10,000 customers will be selected to receive service with this rate schedule. The Company will determine pilot participants that receive service through the Hiawatha West, Midtown, or Westgate substations. Pilot participants will not include customers that are on net metering service or have other interconnected distributed generation on their premise, or customers that also receive Energy Controlled (Non-Demand Metered) Service, Residential Electric Vehicle Service, Limited Off-Peak Service, or customers that are medical equipment-dependent. Pilot participants may elect to opt out of participation in this Pilot for a specific premise.

DETERMINATION OF CUSTOMER BILLS
Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and / or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Bill Protection may also apply. Details regarding the specific charges applicable to this service and Bill Protection are listed below.

RATE

Customer Charge per Month		
Overhead (A72)	$8.00	
Underground (A74)	$10.00	
Energy Charge per kWh		
June – September		
On-Peak Period	$0.22576	R
Mid-Peak Period	$0.09013	R
Off-Peak Period	$0.02784	R
Other Months		
On-Peak Period	$0.19266	R
Mid-Peak Period	$0.07515	R
Off-Peak Period	$0.02784	R

In addition, customer bills under this rate are subject to the following adjustments and/or charges.

FUEL CLAUSE
Bills are subject to the adjustments provided for in the Fuel Clause Rider.

(Continued on Sheet No. 5-4.2)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

RESIDENTIAL TIME OF USE PILOT PROGRAM Section No. 5
SERVICE Original Sheet No. 4.1
RATE CODE A72, A74

PILOT PROGRAM DESIGN
This is an experimental rate design for the residential Time of Use Pilot Program to be applied for two years from the effective date of this rate schedule. Participating customers will have received Residential Service without electric space heating prior to the Pilot, and may elect a return to the Residential Service rate schedule following the Pilot.

AVAILABILITY
A maximum of 10,000 customers will be selected to receive service with this rate schedule. The Company will determine pilot participants that receive service through the Hiawatha West, Midtown, or Westgate substations. Pilot participants will not include customers that are on net metering service or have other interconnected distributed generation on their premise, or customers that also receive Energy Controlled (Non-Demand Metered) Service, Residential Electric Vehicle Service, Limited Off-Peak Service, or customers that are medical equipment-dependent. Pilot participants may elect to opt out of participation in this Pilot for a specific premise.

DETERMINATION OF CUSTOMER BILLS
Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and / or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Bill Protection may also apply. Details regarding the specific charges applicable to this service and Bill Protection are listed below.

RATE

Customer Charge per Month	
Overhead (A72)	$8.00
Underground (A74)	$10.00
Energy Charge per kWh	
June – September	
On-Peak Period	$0.23094
Mid-Peak Period	$0.09270
Off-Peak Period	$0.02913
Other Months	
On-Peak Period	$0.19675
Mid-Peak Period	$0.07720
Off-Peak Period	$0.02913

In addition, customer bills under this rate are subject to the following adjustments and/or charges.

FUEL CLAUSE
Bills are subject to the adjustments provided for in the Fuel Clause Rider.

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(Continued on Sheet No. 5-4.2)

Date Filed: 11-01-17 By: Christopher B. Clark Effective Date: 08-07-18
President, Northern States Power Company, a Minnesota corporation
Docket No. E002/M-17-775 Order Date: 08-07-18

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

RESIDENTIAL TIME OF USE PILOT PROGRAM Section No. 5
SERVICE (Continued) Original Sheet No. 4.2
RATE CODE A72, A74

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider, the Renewable Development Fund Rider, the Transmission Cost Recovery Rider, the Renewable Energy Standard Rider and the Mercury Cost Recovery Rider. N

ENVIRONMENTAL IMPROVEMENT RIDER
Bills are subject to the adjustments provided for in the Environmental Improvement Rider.

MONTHLY MINIMUM CHARGE
Customer Charge.

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

LOW INCOME ENERGY DISCOUNT RIDER
Bills are subject to the adjustment provided for in the Low Income Energy Discount Rider.

REVENUE DECOUPLING MECHANISM RIDER
Bills are subject to the adjustments provided for in the Revenue Decoupling Mechanism Rider.

The following are terms and conditions for service under this tariff.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

LOW INCOME ENERGY DISCOUNT
Energy discount is available to qualified low income customers under this schedule subject to the provisions contained in the Low Income Energy Discount Rider.

BILL PROTECTION
Billing charges considered for bill protection will include customer and energy charges, fuel cost charges and if applicable, the Residential Controlled Air Conditioning and Water Heating Rider discounts. Bill protection will be considered only for customers that have been pilot participants at the same residential location for 12 months from the effective date of this rate schedule, based on the first 12 months of participation in the pilot program. Any Pilot program billing charge in excess of 10 percent of the corresponding billing charge that would have been applied had the customer not been a pilot participant will be credited to the customer's account, including any applicable taxes. The bill protection in this paragraph will terminate after the first 12 months of participation in the pilot program.

Customers that have received LIHEAP assistance within the 12 months prior to participation in the pilot program will have bill protection determined monthly for the first 12 months of pilot participation for any billing charges in excess of the corresponding billing charge that would have been applied had the customer not been a pilot participant. This will be determined on a monthly basis for the first 12 months of pilot participation. For the second 12 months of pilot participation, the bill protection will continue to be provided for these LIHEAP assistance customers for billing charges in excess of 10 percent of the corresponding billing charge on an annual basis for the second 12 months of pilot participation. Customers that start to receive LIHEAP assistance after their participation in the pilot has begun will receive monthly bill protection up to the first 12 month anniversary of the pilot, and shall receive annual bill protection for the second 12 month period of the pilot. Customers who opt out or leave the pilot area will forego the annual protection otherwise offered for this second 12 month period. N

(Continued on Sheet No. 5-4.3)

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President, Northern States Power Company, a Minnesota corporation
Docket No. E002/M-17-775 Order Date: 08-07-18

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

RESIDENTIAL TIME OF USE PILOT PROGRAM Section No. 5
SERVICE (Continued) Original Sheet No. 4.3
RATE CODE A72, A74

DEFINITION OF PEAK PERIODS
The On-Peak period is defined as those hours between 3:00 p.m. and 8:00 p.m. Monday through Friday, except the following holidays: New Year's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. When a designated holiday occurs on Saturday, the preceding Friday will be designated a holiday. When a designated holiday occurs on Sunday, the following Monday will be designated a holiday. The Mid-Peak period is defined as all hours not defined as On-Peak or Off-Peak periods. The Off-Peak period is defined as those hours between midnight (12:00 a.m.) and 6:00 a.m. every day. N

RESIDENTIAL CONTROLLED AIR CONDITIONING AND WATER HEATING RIDER
Customers that received service with the Residential Controlled Air Conditioning and Water Heating Rider in combination with Residential Service prior to participation in the pilot will have a revised discount for Company controlled central air conditioning or electric water heating that is specific to the pilot program. The controlled air conditioning discount is a monthly $10 credit applied during the billing months of June through September. The controlled electric water heating discount is a monthly $2 credit during each billing month. Pilot customers will receive these revised credits in place of percent discounts and are subject to all other terms of the Residential Controlled Air Conditioning and Water Heating Rider.

TERMS AND CONDITIONS OF SERVICE

1. This schedule is also subject to provisions contained in Rules for Application of Residential Rates. N

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President, Northern States Power Company, a Minnesota corporation
Docket No. E002/M-17-775 Order Date: 08-07-18

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

RESIDENTIAL ELECTRIC VEHICLE SERVICE Section No. 5
RATE CODE A08 19th Revised Sheet No. 5

AVAILABILITY
Available to residential customers for service only to electric vehicle loads including battery charging and accessory usage. The customer must complete Company-approved documentation verifying possession, through ownership or lease, of an electric vehicle as defined in Section 169.011, subdivision 26a of Minnesota law.

CHARACTER OF SERVICE
Single-phase 60-Hertz service at approximately 120 or 120/240 volts will be provided hereunder. Three-phase service or other service upgrade requests will be provided in accordance with Company service regulations.

RENEWABLE ENERGY SUPPLY OPTION
Customers have the option to elect all or a portion of the supply of electricity under this schedule from renewable energy resources. The renewable energy supply option is available subject to the provisions contained in the Voluntary Renewable and High-Efficiency Energy Purchase (Windsource Program) Rider, or other available rate schedule for voluntary renewable energy supply that is applicable.

DETERMINATION OF CUSTOMER BILLS
Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and / or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

RATE

Customer Charge per Month	$4.95	
On-Peak Period Energy Charge per kWh		
June - September	$0.20497	R
Other Months	$0.16508	R
Off-Peak Period Energy Charge per kWh	$0.04170	R

In addition, customer bills under this rate are subject to the following adjustments and/or charges.

FUEL CLAUSE
Bills are subject to the adjustments provided for in the Fuel Clause Rider.

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider, the Renewable Development Fund Rider, the Transmission Cost Recovery Rider, the Renewable Energy Standard Rider and the Mercury Cost Recovery Rider.

(Continued on Sheet No. 5-6)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

RESIDENTIAL ELECTRIC VEHICLE SERVICE Section No. 5
RATE CODE A08 18th Revised Sheet No. 5

AVAILABILITY
Available to residential customers for service only to electric vehicle loads including battery charging and accessory usage. The customer must complete Company-approved documentation verifying possession, through ownership or lease, of an electric vehicle as defined in Section 169.011, subdivision 26a of Minnesota law.

CHARACTER OF SERVICE
Single-phase 60-Hertz service at approximately 120 or 120/240 volts will be provided hereunder. Three-phase service or other service upgrade requests will be provided in accordance with Company service regulations.

RENEWABLE ENERGY SUPPLY OPTION
Customers have the option to elect all or a portion of the supply of electricity under this schedule from renewable energy resources. The renewable energy supply option is available subject to the provisions contained in the Voluntary Renewable and High-Efficiency Energy Purchase (Windsource Program) Rider, or other available rate schedule for voluntary renewable energy supply that is applicable.

DETERMINATION OF CUSTOMER BILLS
Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and / or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

RATE

Customer Charge per Month	$4.95	
On-Peak Period Energy Charge per kWh		
June - September	$0.21520	R
Other Months	$0.17328	R
Off-Peak Period Energy Charge per kWh	$0.04378	R

In addition, customer bills under this rate are subject to the following adjustments and/or charges.

FUEL CLAUSE
Bills are subject to the adjustments provided for in the Fuel Clause Rider.

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider, the Renewable Development Fund Rider, the Transmission Cost Recovery Rider, the Renewable Energy Standard Rider and the Mercury Cost Recovery Rider.

(Continued on Sheet No. 5-6)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

RESIDENTIAL ELECTRIC VEHICLE SERVICE Section No. 5
RATE CODE A08 17th Revised Sheet No. 5

AVAILABILITY
Available to residential customers for service only to electric vehicle loads including battery charging and accessory usage. The customer must complete Company-approved documentation verifying possession, through ownership or lease, of an electric vehicle as defined in Section 169.011, subdivision 26a of Minnesota law.

CHARACTER OF SERVICE
Single-phase 60-Hertz service at approximately 120 or 120/240 volts will be provided hereunder. Three-phase service or other service upgrade requests will be provided in accordance with Company service regulations.

RENEWABLE ENERGY SUPPLY OPTION
Customers have the option to elect all or a portion of the supply of electricity under this schedule from renewable energy resources. The renewable energy supply option is available subject to the provisions contained in the Voluntary Renewable and High-Efficiency Energy Purchase (Windsource Program) Rider, or other available rate schedule for voluntary renewable energy supply that is applicable.

DETERMINATION OF CUSTOMER BILLS
Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and / or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

RATE

Customer Charge per Month	$4.95	
On-Peak Period Energy Charge per kWh		
June - September	$0.21096	R
Other Months	$0.16968	R
Off-Peak Period Energy Charge per kWh	$0.04260	R

In addition, customer bills under this rate are subject to the following adjustments and/or charges. D

FUEL CLAUSE
Bills are subject to the adjustments provided for in the Fuel Clause Rider.

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider, the Renewable Development Fund Rider, the Transmission Cost Recovery Rider, the Renewable Energy Standard Rider and the Mercury Cost Recovery Rider.

(Continued on Sheet No. 5-6)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

RESIDENTIAL ELECTRIC VEHICLE SERVICE Section No. 5
RATE CODE A08 16th Revised Sheet No. 6

MONTHLY MINIMUM CHARGE
Customer Charge.

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

DEFINITION OF PEAK PERIODS
The on-peak period is defined as those hours between 9:00 a.m. and 9:00 p.m. Monday through Friday, except the following holidays: New Year's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. When a designated holiday occurs on Saturday, the preceding Friday will be designated a holiday. When a designated holiday occurs on Sunday, the following Monday will be designated a holiday. The off-peak period is defined as all other hours. Definition of on-peak and off-peak period is subject to change with change in Company's system operating characteristics.

COMMUNICATION COSTS
The Company will maintain separate accounting of the information, education, advertising and promotion costs associated with electric vehicles as provided in Minn. Stat. §216B.1614, subd.2, paragraph (c) 2 by deferring the costs to a tracker account, and will petition the Minnesota Public Utilities Commission to recover the qualifying costs.

TERMS AND CONDITIONS OF SERVICE
1. Residential Electric Vehicle Service shall be separately served and metered and must at no time be connected to facilities serving customer's other loads. Metering may be installed as a sub-meter behind the customer’s main meter, in which case consumption under this rate schedule will be subtracted from the main meter for purposes of billing customer’s non-Electric Vehicle electricity usage.
2. The customer shall supply, at no expense to the Company, a suitable location for meters and associated equipment used for billing. Installations must conform to the Company’s specifications.
3. Company may require customer to provide access for Company-owned equipment for the recording and wireless communication of energy usage.
4. The rate contemplates that this service will utilize existing facilities with no additional major expenditures. Customer shall reimburse Company for any expenditure for facilities necessary to serve this load which would not otherwise be required to serve customer's load.
5. This schedule is also subject to provisions contained in Rules for Application of Residential Rates.
6. Customers that elect the Windsource program in calendar year 2015 for at least three (3) 100 kWh blocks or their entire usage on this schedule may receive a one-time $25 bill credit or gift card of the same value.

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

RESIDENTIAL ELECTRIC VEHICLE PILOT SERVICE Section No. 5
RATE CODE A80, A81 5th Revised Sheet No. 7

AVAILABILITY
Available while this Pilot Service is in effect to Residential Service customers for service only to electric vehicle loads including battery charging and accessory usage. Bundled service includes Company installed and provided charging equipment. Pre-Pay Option service is available to customers electing to pay Company for the installed cost of charging equipment prior to beginning service with this tariff. Customers electing Pre-Pay Option service are separately invoiced at the time of installation. The customer must complete Company-approved documentation verifying possession, through ownership or lease, of an electric vehicle as defined in Section 169.011, subdivision 26a of Minnesota law.

CONTRACT
Customers must contract for this service through an Electric Vehicle Pilot Electric Service Agreement with the Company. The initial contract period will normally be for 24 months.

CHARACTER OF SERVICE
Single-phase 60-Hertz service at approximately 120 or 120/240 volts will be provided hereunder. Three-phase service or other service upgrade requests will be provided in accordance with Company service regulations.

RENEWABLE ENERGY SUPPLY OPTION
Customers have the option to elect all or a portion of the supply of electricity under this schedule from renewable energy resources. The renewable energy supply option is available subject to the provisions contained in the Voluntary Renewable and High-Efficiency Energy Purchase (Windsource Program) Rider, or other available rate schedule for voluntary renewable energy supply that is applicable.

DETERMINATION OF CUSTOMER BILLS
Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and /or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

RATE

Customer Charge per Month		
Bundled (A80)	$17.47	
Pre-Pay Option (A81)	$7.10	
On-Peak Period Energy Charge per kWh		
June - September	$0.20497	R
Other Months	$0.16508	R
Off-Peak Period Energy Charge per kWh	$0.04170	R

PRE-PAY OPTION
The Pre-Pay Option Customer Charge per Month applies in place of the Bundled Customer Charge per Month to customers that have paid the installed cost of charging equipment to the Company.

In addition, customer bills under this rate are subject to the following adjustments and/or charges.

(Continued on Sheet No. 5-8)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

RESIDENTIAL ELECTRIC VEHICLE PILOT SERVICE Section No. 5
RATE CODE A80, A81 4th Revised Sheet No. 7

AVAILABILITY
Available while this Pilot Service is in effect to Residential Service customers for service only to electric vehicle loads including battery charging and accessory usage. Bundled service includes Company installed and provided charging equipment. Pre-Pay Option service is available to customers electing to pay Company for the installed cost of charging equipment prior to beginning service with this tariff. Customers electing Pre-Pay Option service are separately invoiced at the time of installation. The customer must complete Company-approved documentation verifying possession, through ownership or lease, of an electric vehicle as defined in Section 169.011, subdivision 26a of Minnesota law.

CONTRACT
Customers must contract for this service through an Electric Vehicle Pilot Electric Service Agreement with the Company. The initial contract period will normally be for 24 months.

CHARACTER OF SERVICE
Single-phase 60-Hertz service at approximately 120 or 120/240 volts will be provided hereunder. Three-phase service or other service upgrade requests will be provided in accordance with Company service regulations.

RENEWABLE ENERGY SUPPLY OPTION
Customers have the option to elect all or a portion of the supply of electricity under this schedule from renewable energy resources. The renewable energy supply option is available subject to the provisions contained in the Voluntary Renewable and High-Efficiency Energy Purchase (Windsource Program) Rider, or other available rate schedule for voluntary renewable energy supply that is applicable.

DETERMINATION OF CUSTOMER BILLS
Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and /or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

RATE

Customer Charge per Month		
Bundled (A80)	$17.47	
Pre-Pay Option (A81)	$7.10	
On-Peak Period Energy Charge per kWh		
June - September	$0.21520	R
Other Months	$0.17328	R
Off-Peak Period Energy Charge per kWh	$0.04378	R

PRE-PAY OPTION
The Pre-Pay Option Customer Charge per Month applies in place of the Bundled Customer Charge per Month to customers that have paid the installed cost of charging equipment to the Company.

In addition, customer bills under this rate are subject to the following adjustments and/or charges.

(Continued on Sheet No. 5-8)

Northern States Power Company , a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

RESIDENTIAL ELECTRIC VEHICLE PILOT SERVICE Section No. 5
RATE CODE A80, A81 3rd Revised Sheet No. 7

AVAILABILITY N
Available while this Pilot Service is in effect to Residential Service customers for service only to electric vehicle loads including battery charging and accessory usage. Bundled service includes Company installed and provided charging equipment. Pre-Pay Option service is available to customers electing to pay Company for the installed cost of charging equipment prior to beginning service with this tariff. Customers electing Pre-Pay Option service are separately invoiced at the time of installation. The customer must complete Company-approved documentation verifying possession, through ownership or lease, of an electric vehicle as defined in Section 169.011, subdivision 26a of Minnesota law.

CONTRACT
Customers must contract for this service through an Electric Vehicle Pilot Electric Service Agreement with the Company. The initial contract period will normally be for 24 months.

CHARACTER OF SERVICE
Single-phase 60-Hertz service at approximately 120 or 120/240 volts will be provided hereunder. Three-phase service or other service upgrade requests will be provided in accordance with Company service regulations.

RENEWABLE ENERGY SUPPLY OPTION
Customers have the option to elect all or a portion of the supply of electricity under this schedule from renewable energy resources. The renewable energy supply option is available subject to the provisions contained in the Voluntary Renewable and High-Efficiency Energy Purchase (Windsource Program) Rider, or other available rate schedule for voluntary renewable energy supply that is applicable.

DETERMINATION OF CUSTOMER BILLS
Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and /or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

RATE

Customer Charge per Month	
Bundled (A80)	$17.47
Pre-Pay Option (A81)	$7.10
On-Peak Period Energy Charge per kWh	
June - September	$0.21096
Other Months	$0.16968
Off-Peak Period Energy Charge per kWh	$0.04260

PRE-PAY OPTION
The Pre-Pay Option Customer Charge per Month applies in place of the Bundled Customer Charge per Month to customers that have paid the installed cost of charging equipment to the Company.

In addition, customer bills under this rate are subject to the following adjustments and/or charges. N

(Continued on Sheet No. 5-8)

Date Filed: 11-17-17 By: Christopher B. Clark Effective Date: 06-25-18
President, Northern States Power Company, a Minnesota Corporation
Docket No. E002/M-17-817 Order Date: 05-09-18

Northern States Power Company , a Minnesota corporation
and wholly owned subsidiary of Xcel Energy Inc.
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

RESIDENTIAL TIME OF DAY SERVICE - UNDERGROUND Section No. 5
(Continued) 2nd Revised Sheet No. 7
RATE CODE A04

CANCELED

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

RESIDENTIAL ELECTRIC VEHICLE PILOT SERVICE Section No. 5
(Continued) 3rd Revised Sheet No. 8
RATE CODE A80, A81

FUEL CLAUSE
Bills are subject to the adjustments provided for in the Fuel Clause Rider. N

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider, the Renewable Development Fund Rider, the Transmission Cost Recovery Rider, the Renewable Energy Standard Rider and the Mercury Cost Recovery Rider.

MONTHLY MINIMUM CHARGE
Customer Charge.

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

DEFINITION OF PEAK PERIODS
The on-peak period is defined as those hours between 9:00 a.m. and 9:00 p.m. Monday through Friday, except the following holidays: New Year's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. When a designated holiday occurs on Saturday, the preceding Friday will be designated a holiday. When a designated holiday occurs on Sunday, the following Monday will be designated a holiday. The off-peak period is defined as all other hours. Definition of on-peak and off-peak period is subject to change with change in Company's system operating characteristics.

COMMUNICATION COSTS
The Company will maintain separate accounting of the information, education, advertising and promotion costs associated with electric vehicles as provided in Minn. Stat. §216B.1614, subd.2, paragraph (c) 2 by deferring the costs to a tracker account, and will petition the Minnesota Public Utilities Commission to recover the qualifying costs.

TERMS AND CONDITIONS OF SERVICE
1. Residential Electric Vehicle Pilot Service shall be served through wiring connected to customer's single meter provided for Residential Service. Consumption under this rate schedule will be subtracted from the main meter for purposes of billing customer's non-Electric Vehicle electricity usage.
2. The customer shall supply, at no expense to the Company, premises wiring and a suitable location for connection of charging and associated equipment.
3. Company may require customer to provide access for Company-owned equipment for the recording and wireless communication of energy usage.
4. The rate contemplates that this service will utilize existing facilities with no additional major expenditures. Customer shall reimburse Company for any expenditure for facilities necessary to serve this load which would not otherwise be required to serve customer's load.
5. This schedule is also subject to provisions contained in Rules for Application of Residential Rates.
6. Customer must execute an Electric Vehicle Pilot Service Agreement with the Company. N

Date Filed: 11-17-17 By: Christopher B. Clark Effective Date: 06-25-18
President, Northern States Power Company, a Minnesota Corporation
Docket No. E002/M-17-817 Order Date: 05-09-18

Northern States Power Company, a Minnesota corporation
and wholly owned subsidiary of Xcel Energy Inc.
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

RESIDENTIAL TIME OF DAY SERVICE - UNDERGROUND (Continued)
RATE CODE A04

Section No. 5
2nd Revised Sheet No. 8

CANCELED

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

ENERGY CONTROLLED SERVICE Section No. 5
(NON-DEMAND METERED) 30th Revised Sheet No. 9
RATE CODE A05

AVAILABILITY
Available to residential and commercial customers with permanently connected interruptible loads of up to 50 kW that would be under Company control. The types of loads served would include dual fuel space heating, water heating, and other loads subject to Company approval.

DETERMINATION OF CUSTOMER BILLS
Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and / or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

RATE

	Residential	Commercial & Industrial	
Customer Charge	$4.95	$4.95	
Energy Charge per kWh	$0.04487	$0.04487	R
Optional			
June - September	$0.10301	$0.09256	R
Other Months	$0.04487	$0.04487	R

OPTIONAL ENERGY CHARGE
This option is available to customers with heat pump installations for non-interruptible service during June through September billing months.

In addition, customer bills under this rate are subject to the following adjustments and/or charges.

FUEL CLAUSE
Bills are subject to the adjustments provided for in the Fuel Clause Rider.

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider, the Renewable Development Fund Rider, the Transmission Cost Recovery Rider, the Renewable Energy Standard Rider and the Mercury Cost Recovery Rider.

ENVIRONMENTAL IMPROVEMENT RIDER
Bills are subject to the adjustments provided for in the Environmental Improvement Rider.

(Continued on Sheet No. 5-10)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

ENERGY CONTROLLED SERVICE
(NON-DEMAND METERED)
RATE CODE A05

Section No. 5
29th Revised Sheet No. 9

AVAILABILITY
Available to residential and commercial customers with permanently connected interruptible loads of up to 50 kW that would be under Company control. The types of loads served would include dual fuel space heating, water heating, and other loads subject to Company approval.

DETERMINATION OF CUSTOMER BILLS
Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and / or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

RATE

	Residential	Commercial & Industrial	
Customer Charge	$4.95	$4.95	
Energy Charge per kWh	$0.04711	$0.04711	R
Optional			
June - September	$0.10815	$0.09728	R
Other Months	$0.04711	$0.04711	R

OPTIONAL ENERGY CHARGE
This option is available to customers with heat pump installations for non-interruptible service during June through September billing months.

In addition, customer bills under this rate are subject to the following adjustments and/or charges.

FUEL CLAUSE
Bills are subject to the adjustments provided for in the Fuel Clause Rider.

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider, the Renewable Development Fund Rider, the Transmission Cost Recovery Rider, the Renewable Energy Standard Rider and the Mercury Cost Recovery Rider.

ENVIRONMENTAL IMPROVEMENT RIDER
Bills are subject to the adjustments provided for in the Environmental Improvement Rider.

(Continued on Sheet No. 5-10)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

ENERGY CONTROLLED SERVICE Section No. 5
(NON-DEMAND METERED) 28th Revised Sheet No. 9
RATE CODE A05

AVAILABILITY
Available to residential and commercial customers with permanently connected interruptible loads of up to 50 kW that would be under Company control. The types of loads served would include dual fuel space heating, water heating, and other loads subject to Company approval.

DETERMINATION OF CUSTOMER BILLS
Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and / or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

RATE

	Residential	Commercial & Industrial	
Customer Charge	$4.95	$4.95	
Energy Charge per kWh	$0.04506	$0.04506	R
Optional			
June - September	$0.10582	$0.09514	R
Other Months	$0.04506	$0.04506	R

OPTIONAL ENERGY CHARGE
This option is available to customers with heat pump installations for non-interruptible service during June through September billing months.

In addition, customer bills under this rate are subject to the following adjustments and/or charges. D

FUEL CLAUSE
Bills are subject to the adjustments provided for in the Fuel Clause Rider.

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider, the Renewable Development Fund Rider, the Transmission Cost Recovery Rider, the Renewable Energy Standard Rider and the Mercury Cost Recovery Rider.

ENVIRONMENTAL IMPROVEMENT RIDER
Bills are subject to the adjustments provided for in the Environmental Improvement Rider.

(Continued on Sheet No. 5-10)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

ENERGY CONTROLLED SERVICE (NON-DEMAND METERED) Section No. 5
(Continued) 8th Revised Sheet No. 10
RATE CODE A05

MONTHLY MINIMUM CHARGE
Customer Charge.

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

REVENUE DECOUPLING MECHANISM RIDER
Bills are subject to the adjustments provided for in the Revenue Decoupling Mechanism Rider.

The following are terms and conditions for service under this tariff.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

TERMS AND CONDITIONS OF SERVICE

1. The controllable load shall be permanently wired, separately served and metered, and at no time connected to facilities serving customer's firm load.

2. The duration and frequency of interruptions shall be at the discretion of Company. Interruption will normally occur at such times:
   a. When Company is required to use generation equipment or to purchase power that results in production costs in excess of $70 per MWh,
   b. When Company expects to establish an annual system peak demand, or
   c. At such times when, in Company's opinion, the reliability of the system is endangered.

3. Customer selecting Energy Controlled Service (Non-Demand Metered) must have a Company approved electric space heating system and must remain on this service for a minimum term of one year.

4. Customer selecting Energy Controlled Service (Non-Demand Metered) must be prepared for interruptions that will last longer than 12 hours per occurrence. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service.

5. Electricity must be the primary source of energy for dual fuel space heating installations. Customer must have available alternative energy sources capable of supplying up to 30% of the annual heating needs during any heating season.

6. Customer's water heating system served under this rate must be designed and sized to be capable of providing customer's hot water needs for the full duration of the potential interruption periods.

(Continued on Sheet No. 5-10.1)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

ENERGY CONTROLLED SERVICE (NON-DEMAND METERED) Section No. 5
(Continued) 5th Revised Sheet No. 10.1
RATE CODE A05

7. Customer must furnish and install an NSP approved electric meter socket to accept Energy Controlled Service (Non-Demand Metered). Company reserves the right to inspect and approve the installation.

8. The rate contemplates that this service will utilize existing facilities with no additional major expenditures. Customer shall reimburse Company for any expenditures for facilities necessary to serve this load which would not otherwise be required to serve customer's load.

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President, Northern States Power Company, a Minnesota corporation
Docket No. E002/GR-15-826 Order Date: 06-12-17

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

LIMITED OFF PEAK SERVICE Section No. 5
RATE CODE A06 33rd Revised Sheet No. 11

AVAILABILITY
Available to any customers for controlled loads that will be energized only for the time period between 10:00 p.m. to 6:30 a.m. daily.

DETERMINATION OF CUSTOMER BILLS
Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and / or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

RATE

	Residential	Commercial & Industrial	
Customer Charge per Month			
Secondary Voltage			
Single Phase	$4.95	$10.00	
Three Phase	--	$13.60	
Primary Voltage	--	$60.00	
Transmission Transformed	--	$60.00	
Transmission	--	$60.00	
Energy Charge per kWh			
Secondary Voltage	$0.03665	$0.03665	R
Primary Voltage	--	$0.03560	R
Transmission Transformed	--	$0.03398	R
Transmission	--	$0.03388	R

In addition, customer bills under this rate are subject to the following adjustments and/or charges.

FUEL CLAUSE
Bills are subject to the adjustments provided for in the Fuel Clause Rider.

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider, the Renewable Development Fund Rider, the Transmission Cost Recovery Rider, the Renewable Energy Standard Rider and the Mercury Cost Recovery Rider.

(Continued on Sheet No. 5-11.1)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

LIMITED OFF PEAK SERVICE Section No. 5
RATE CODE A06 32nd Revised Sheet No. 11

AVAILABILITY
Available to any customers for controlled loads that will be energized only for the time period between 10:00 p.m. to 6:30 a.m. daily.

DETERMINATION OF CUSTOMER BILLS
Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and / or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

RATE

	Residential	Commercial & Industrial	
Customer Charge per Month			
Secondary Voltage			
Single Phase	$4.95	$10.00	
Three Phase	--	$13.60	
Primary Voltage	--	$60.00	
Transmission Transformed	--	$60.00	
Transmission	--	$60.00	
Energy Charge per kWh			
Secondary Voltage	$0.03848	$0.03848	R
Primary Voltage	--	$0.03740	R
Transmission Transformed	--	$0.03574	R
Transmission	--	$0.03563	R

In addition, customer bills under this rate are subject to the following adjustments and/or charges.

FUEL CLAUSE
Bills are subject to the adjustments provided for in the Fuel Clause Rider.

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider, the Renewable Development Fund Rider, the Transmission Cost Recovery Rider, the Renewable Energy Standard Rider and the Mercury Cost Recovery Rider.

(Continued on Sheet No. 5-11.1)

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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

LIMITED OFF PEAK SERVICE Section No. 5
RATE CODE A06 31st Revised Sheet No. 11

AVAILABILITY
Available to any customers for controlled loads that will be energized only for the time period between 10:00 p.m. to 6:30 a.m. daily.

DETERMINATION OF CUSTOMER BILLS
Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and / or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

RATE

	Residential	Commercial & Industrial	
Customer Charge per Month			
Secondary Voltage			
Single Phase	$4.95	$10.00	
Three Phase	--	$13.60	
Primary Voltage	--	$60.00	
Transmission Transformed	--	$60.00	
Transmission	--	$60.00	
Energy Charge per kWh			
Secondary Voltage	$0.03660	$0.03660	R
Primary Voltage	--	$0.03554	R
Transmission Transformed	--	$0.03389	R
Transmission	--	$0.03379	R

In addition, customer bills under this rate are subject to the following adjustments and/or charges. D

FUEL CLAUSE
Bills are subject to the adjustments provided for in the Fuel Clause Rider.

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider, the Renewable Development Fund Rider, the Transmission Cost Recovery Rider, the Renewable Energy Standard Rider and the Mercury Cost Recovery Rider.

(Continued on Sheet No. 5-11.1)

Date Filed: 11-02-15 By: Christopher B. Clark Effective Date: 10-01-17
President, Northern States Power Company, a Minnesota corporation
Docket No. E002/GR-15-826 Order Date: 06-12-17

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK – MPUC NO. 2

LIMITED OFF PEAK SERVICE (Continued) Section No. 5
RATE CODE A06 8th Revised Sheet No. 11.1

ENVIRONMENTAL IMPROVEMENT RIDER
Bills are subject to the adjustments provided for in the Environmental Improvement Rider.

REVENUE DECOUPLING MECHANISM RIDER
Bills are subject to the adjustments provided for in the Revenue Decoupling Mechanism Rider.

(Continued on Sheet No. 5-12)

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President, Northern States Power Company, a Minnesota corporation
Docket No. E002/GR-15-826 Order Date: 06-12-17

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

LIMITED OFF PEAK SERVICE (Continued) Section No. 5
RATE CODE A06 8th Revised Sheet No. 12

MONTHLY MINIMUM CHARGE
For all customers, the minimum charge shall be the applicable customer charge.

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

TERMS AND CONDITIONS OF SERVICE

1. Limited Off Peak Service shall be separately served and metered and must at no time be connected to facilities serving customer's other loads.

2. Company will not be liable for any loss or damage caused by or resulting from any interruption of service.

3. Customer selecting Limited Off Peak Service must remain on this service for a minimum term of one year, unless customer transfers to another interruptible service rate.

4. Customer has the option of directly controlling own load or allowing Company load control. If customer chooses Company load control, customer must:
   a. Provide a load-break switch or circuit breaker equipped with electronic trip and close circuits allowing for remote operation of customer's switch or circuit breaker by Company,
   b. Wire the trip and close circuits into a connection point designated by Company to allow installation of remote control equipment by Company, and
   c. Provide a continuous 120 volt AC power source at the connection point for operation of Company's remote control equipment.

5. A charge of $0.360 per kWh shall be applied to non-authorized energy used outside of the energized time period specified in this tariff. If this energy use occurs during three or more billing months, the Company reserves the right to remove customer from Limited Off Peak Service. R

6. The rate contemplates that this service will utilize existing facilities with no additional major expenditures. Customer shall reimburse Company for any expenditures for facilities necessary to serve this load which would not otherwise be required to serve customer's load.

Date Filed: 10-01-18 By: Christopher B. Clark Effective Date: 01-01-19
President, Northern States Power Company, a Minnesota corporation
Docket No. E002/GR-15-826 Order Date: 06-12-17

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

LIMITED OFF PEAK SERVICE (Continued) Section No. 5
RATE CODE A06 7th Revised Sheet No. 12

MONTHLY MINIMUM CHARGE
For all customers, the minimum charge shall be the applicable customer charge.

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

TERMS AND CONDITIONS OF SERVICE

1. Limited Off Peak Service shall be separately served and metered and must at no time be connected to facilities serving customer's other loads.

2. Company will not be liable for any loss or damage caused by or resulting from any interruption of service.

3. Customer selecting Limited Off Peak Service must remain on this service for a minimum term of one year, unless customer transfers to another interruptible service rate.

4. Customer has the option of directly controlling own load or allowing Company load control. If customer chooses Company load control, customer must:
   a. Provide a load-break switch or circuit breaker equipped with electronic trip and close circuits allowing for remote operation of customer's switch or circuit breaker by Company,
   b. Wire the trip and close circuits into a connection point designated by Company to allow installation of remote control equipment by Company, and
   c. Provide a continuous 120 volt AC power source at the connection point for operation of Company's remote control equipment.

5. A charge of $0.340 per kWh shall be applied to non-authorized energy used outside of the energized time period specified in this tariff. If this energy use occurs during three or more billing months, the Company reserves the right to remove customer from Limited Off Peak Service. R

6. The rate contemplates that this service will utilize existing facilities with no additional major expenditures. Customer shall reimburse Company for any expenditures for facilities necessary to serve this load which would not otherwise be required to serve customer's load.

Date Filed: 11-02-15 By: Christopher B. Clark Effective Date: 10-01-17
President, Northern States Power Company, a Minnesota corporation
Docket No. E002/GR-15-826 Order Date: 06-12-17

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

RULES FOR APPLICATION OF RESIDENTIAL RATES

Section No. 5
7th Revised Sheet No. 13

1. The Residential Service, Residential Time of Day Service and Residential Time of Use Pilot Program are the only rates available to residential customers for domestic purposes in a single private residence. Energy Controlled Service (Non-Demand Metered), Limited Off Peak Service, Residential Electric Vehicle Service, Residential Electric Vehicle Pilot Service and Automatic Protective Lighting Service rate schedules are also available to qualifying residential customers. N

2. Normal service under the Residential Service, Residential Time of Day Service and Residential Time of Use Pilot Program rate schedules is single phase service rendered through one meter. Three phase service or service through more than one meter will be provided upon a one-time payment of an amount to reimburse Company for the additional investment. If customer is served through more than one meter, each meter will be separately billed. N N

3. Electric space heating charges are applicable only when customer's electric space heating equipment is used as customer's primary heating source.

4. Underground service charges will apply where the underground facilities are owned by Company, and Company has not been fully reimbursed for the added cost of such underground facilities.

5. Standby and Supplementary Service is available for any residential customer subject to the provisions in the General Rules and Regulations, Section 2.4. The Company's meter will be ratcheted to measure the flow of power and energy from Company to customer only.

6. A customer using electric service for domestic and non-domestic purposes jointly may combine such use through one meter on such rates as are available to general service customers.

7. The Residential Service and Residential Time of Day Service rate schedules are available to farm installations which were served on the separate Farm Service rate schedule prior to its cancellation on November 1, 1988. Residential Service and Residential Time of Day Service to these qualifying farm customers is limited to 120/240 volts single phase service rendered through one meter. Motors and other equipment which interfere with service to neighboring customers and all transformer type welding machines larger than 25 kilovolt-amperes are not permitted as part of this service.

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

RULES FOR APPLICATION OF RESIDENTIAL RATES Section No. 5
6th Revised Sheet No. 13

1. The Residential Service and Residential Time of Day Service are the only rates available to residential customers for domestic purposes in a single private residence. Energy Controlled Service (Non-Demand Metered), Limited Off Peak Service, Residential Electric Vehicle Service, Residential Electric Vehicle Pilot Service and Automatic Protective Lighting Service rate schedules are also available to qualifying residential customers. N N

2. Normal service under the Residential Service and Residential Time of Day Service rate schedules is single phase service rendered through one meter. Three phase service or service through more than one meter will be provided upon a one-time payment of an amount to reimburse Company for the additional investment. If customer is served through more than one meter, each meter will be separately billed.

3. Electric space heating charges are applicable only when customer's electric space heating equipment is used as customer's primary heating source.

4. Underground service charges will apply where the underground facilities are owned by Company, and Company has not been fully reimbursed for the added cost of such underground facilities.

5. Standby and Supplementary Service is available for any residential customer subject to the provisions in the General Rules and Regulations, Section 2.4. The Company's meter will be ratcheted to measure the flow of power and energy from Company to customer only.

6. A customer using electric service for domestic and non-domestic purposes jointly may combine such use through one meter on such rates as are available to general service customers.

7. The Residential Service and Residential Time of Day Service rate schedules are available to farm installations which were served on the separate Farm Service rate schedule prior to its cancellation on November 1, 1988. Residential Service and Residential Time of Day Service to these qualifying farm customers is limited to 120/240 volts single phase service rendered through one meter. Motors and other equipment which interfere with service to neighboring customers and all transformer type welding machines larger than 25 kilovolt-amperes are not permitted as part of this service.

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President, Northern States Power Company, a Minnesota corporation
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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

RULES FOR APPLICATION OF RESIDENTIAL RATES Section No. 5
5th Revised Sheet No. 13

1. The Residential Service and Residential Time of Day Service are the only rates available to residential customers for domestic purposes in a single private residence. Energy Controlled Service (Non-Demand Metered), Limited Off Peak Service, and Automatic Protective Lighting Service rate schedules are also available to qualifying residential customers.

2. Normal service under the Residential Service and Residential Time of Day Service rate schedules is single phase service rendered through one meter. Three phase service or service through more than one meter will be provided upon a one-time payment of an amount to reimburse Company for the additional investment. If customer is served through more than one meter, each meter will be separately billed.

3. Electric space heating charges are applicable only when customer's electric space heating equipment is used as customer's primary heating source.

4. Underground service charges will apply where the underground facilities are owned by Company, and Company has not been fully reimbursed for the added cost of such underground facilities.

5. Standby and Supplementary Service is available for any residential customer subject to the provisions in the General Rules and Regulations, Section 2.4. The Company's meter will be ratcheted to measure the flow of power and energy from Company to customer only.

6. A customer using electric service for domestic and non-domestic purposes jointly may combine such use through one meter on such rates as are available to general service customers.

7. The Residential Service and Residential Time of Day Service rate schedules are available to farm installations which were served on the separate Farm Service rate schedule prior to its cancellation on November 1, 1988. Residential Service and Residential Time of Day Service to these qualifying farm customers is limited to 120/240 volts single phase service rendered through one meter. Motors and other equipment which interfere with service to neighboring customers and all transformer type welding machines larger than 25 kilovolt-amperes are not permitted as part of this service.

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President, Northern States Power Company, a Minnesota corporation
Docket No. E002/GR-15-826 Order Date: 06-12-17

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

AUTOMATIC PROTECTIVE LIGHTING SERVICE Section No. 5
RATE CODE A07 23rd Revised Sheet No. 14

AVAILABILITY
Available to all types of customers except for municipal street lighting purposes.

DETERMINATION OF CUSTOMER BILLS
Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and / or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

RATE

Designation of Lamp	Monthly Rate Per Unit	
Area Units		
100W High Pressure Sodium	$7.41	R
175W Mercury (1)	$7.41	R
250W High Pressure Sodium	$11.83	R
400W Mercury (1)	$11.83	R
Directional Units		
250W High Pressure Sodium	$14.08	R
400W High Pressure Sodium	$17.62	R
1,000W Mercury (1)	$27.33	R

(1) Available to existing installations only.

In addition, customer bills under this rate are subject to the following adjustments and/or charges.

SERVICE INCLUDED IN RATE
Company shall own, operate, and maintain the lighting unit including the fixture, lamp, ballast, photoelectric control, mounting brackets, and all necessary wiring. Company shall furnish all electric energy required for operation of the unit.

FUEL CLAUSE
Bills are subject to the adjustments provided for in the Fuel Clause Rider.

(Continued on Sheet No. 5-15)

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President, Northern States Power Company, a Minnesota corporation
Docket No. E,G999/CI-17-895 Order Date: 05-10-19

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

AUTOMATIC PROTECTIVE LIGHTING SERVICE Section No. 5
RATE CODE A07 22nd Revised Sheet No. 14

AVAILABILITY
Available to all types of customers except for municipal street lighting purposes.

DETERMINATION OF CUSTOMER BILLS
Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and / or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

RATE

Designation of Lamp	Monthly Rate Per Unit	
Area Units		
100W High Pressure Sodium	$7.71	R
175W Mercury (1)	$7.71	R
250W High Pressure Sodium	$12.30	R
400W Mercury (1)	$12.30	R
Directional Units		
250W High Pressure Sodium	$14.65	R
400W High Pressure Sodium	$18.33	R
1,000W Mercury (1)	$28.43	R

(1) Available to existing installations only.

In addition, customer bills under this rate are subject to the following adjustments and/or charges.

SERVICE INCLUDED IN RATE
Company shall own, operate, and maintain the lighting unit including the fixture, lamp, ballast, photoelectric control, mounting brackets, and all necessary wiring. Company shall furnish all electric energy required for operation of the unit.

FUEL CLAUSE
Bills are subject to the adjustments provided for in the Fuel Clause Rider.

(Continued on Sheet No. 5-15)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

AUTOMATIC PROTECTIVE LIGHTING SERVICE Section No. 5
RATE CODE A07 21st Revised Sheet No. 14

AVAILABILITY
Available to all types of customers except for municipal street lighting purposes.

DETERMINATION OF CUSTOMER BILLS
Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and / or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

RATE

Designation of Lamp	Monthly Rate Per Unit	
Area Units		
100W High Pressure Sodium	$7.57	R
175W Mercury (1)	$7.57	R
250W High Pressure Sodium	$12.07	R
400W Mercury (1)	$12.07	R
Directional Units		
250W High Pressure Sodium	$14.37	R
400W High Pressure Sodium	$17.98	R
1,000W Mercury (1)	$27.82	R

(1) Available to existing installations only.

D

In addition, customer bills under this rate are subject to the following adjustments and/or charges.

SERVICE INCLUDED IN RATE
Company shall own, operate, and maintain the lighting unit including the fixture, lamp, ballast, photoelectric control, mounting brackets, and all necessary wiring. Company shall furnish all electric energy required for operation of the unit.

FUEL CLAUSE
Bills are subject to the adjustments provided for in the Fuel Clause Rider.

(Continued on Sheet No. 5-15)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

AUTOMATIC PROTECTIVE LIGHTING SERVICE (Continued) Section No. 5
RATE CODE A07 11th Revised Sheet No. 15

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider, the Renewable Development Fund Rider, the Transmission Cost Recovery Rider, the Renewable Energy Standard Rider and the Mercury Cost Recovery Rider.

ENVIRONMENTAL IMPROVEMENT RIDER
Bills are subject to the adjustments provided for in the Environmental Improvement Rider.

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

The following are terms and conditions for service under this tariff.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

TERM OF AGREEMENT
Agreement shall be for a term of three years. If not then terminated by at least 30 days' written notice by either party, the agreement shall continue until so terminated.

TERMS AND CONDITIONS OF SERVICE
1. Service available subject to the provisions for Automatic Protective Lighting Service of the General Rules and Regulations, Section 5.4.

2. The lamp shall be lighted and extinguished by a photoelectric control furnished by the Company. The hours of burning shall be from approximately one-half hour after sunset until one-half hour before sunrise, every night.

3. If illumination of a lamp is interrupted and said illumination is not resumed within 72 hours from the time Company receives notice thereof from customer, one-thirtieth of the monthly compensation for such unit shall be deducted for each night of non-illumination after such notice is received.

4. Company reserves the right to discontinue service if equipment is abused.

5. Company will convert mercury vapor lighting units to high pressure sodium upon failure of the mercury vapor ballast.

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

SMALL GENERAL SERVICE Section No. 5
RATE CODE A09, A10, A11, A13 31st Revised Sheet No. 21

AVAILABILITY
Standard service (i.e., alternating current) is available to any non-residential customer for single or three phase electric service. Direct Current service is only available in Minneapolis and St. Paul to the extent now used.

DETERMINATION OF CUSTOMER BILLS
Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and / or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

RATE

Customer Charge per Month – Unmetered (A09)	$8.00	
– Metered (A10)	$10.00	
– Water Heating (A11)	$0.00	
– Direct Current (A13)	$10.00	
Energy Charge per kWh		
June - September	$0.09256	R
Other Months	$0.07757	R
Demand Charge (Direct Current Only) per Month per kW of Connected Load	$3.61	R

In addition, customer bills under this rate are subject to the following adjustments and/or charges.

FUEL CLAUSE
Bills are subject to the adjustments provided for in the Fuel Clause Rider.

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider, the Renewable Development Fund Rider, the Transmission Cost Recovery Rider, the Renewable Energy Standard Rider and the Mercury Cost Recovery Rider.

(Continued on Sheet No. 5-22)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

SMALL GENERAL SERVICE Section No. 5
RATE CODE A09, A10, A11, A13 30th Revised Sheet No. 21

AVAILABILITY
Standard service (i.e., alternating current) is available to any non-residential customer for single or three phase electric service. Direct Current service is only available in Minneapolis and St. Paul to the extent now used.

DETERMINATION OF CUSTOMER BILLS
Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and / or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

RATE

Customer Charge per Month – Unmetered (A09)	$8.00	
– Metered (A10)	$10.00	
– Water Heating (A11)	$0.00	
– Direct Current (A13)	$10.00	
Energy Charge per kWh		
June - September	$0.09728	R
Other Months	$0.08156	R
Demand Charge (Direct Current Only) per Month per kW of Connected Load	$3.80	R

In addition, customer bills under this rate are subject to the following adjustments and/or charges.

FUEL CLAUSE
Bills are subject to the adjustments provided for in the Fuel Clause Rider.

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider, the Renewable Development Fund Rider, the Transmission Cost Recovery Rider, the Renewable Energy Standard Rider and the Mercury Cost Recovery Rider.

(Continued on Sheet No. 5-22)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

SMALL GENERAL SERVICE Section No. 5
RATE CODE A09, A10, A11, A13 29th Revised Sheet No. 21

AVAILABILITY
Standard service (i.e., alternating current) is available to any non-residential customer for single or three phase electric service. Direct Current service is only available in Minneapolis and St. Paul to the extent now used.

DETERMINATION OF CUSTOMER BILLS
Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and / or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

RATE

Customer Charge per Month – Unmetered (A09)	$8.00	
– Metered (A10)	$10.00	
– Water Heating (A11)	$0.00	
– Direct Current (A13)	$10.00	
Energy Charge per kWh		
June - September	$0.09514	R
Other Months	$0.07965	R
Demand Charge (Direct Current Only) per Month per kW of Connected Load	$3.75	R

In addition, customer bills under this rate are subject to the following adjustments and/or charges. D

FUEL CLAUSE
Bills are subject to the adjustments provided for in the Fuel Clause Rider.

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider, the Renewable Development Fund Rider, the Transmission Cost Recovery Rider, the Renewable Energy Standard Rider and the Mercury Cost Recovery Rider.

(Continued on Sheet No. 5-22)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

SMALL GENERAL SERVICE (Continued) Section No. 5
RATE CODE A9, A10, A11, A13 8th Revised Sheet No. 22

ENVIRONMENTAL IMPROVEMENT RIDER
Bills are subject to the adjustments provided for in the Environmental Improvement Rider.

MONTHLY MINIMUM CHARGE
Customer Charge, or Customer Charge plus Demand Charge if served at Direct Current.

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

LOW INCOME ENERGY DISCOUNT RIDER
Bills are subject to the adjustment provided for in the Low Income Energy Discount Rider.

REVENUE DECOUPLING MECHANISM RIDER
Bills in rate codes A09, A10, and A11 are subject to the adjustments provided for in the Revenue Decoupling Mechanism Rider.

The following are terms and conditions for service under this tariff.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

TERMS AND CONDITIONS OF SERVICE FOR ALTERNATING CURRENT CUSTOMERS
Company shall install a demand meter for a customer when:
1. Customer's connected load is estimated to be 20 kW or greater,
2. Customer is served single phase and has a service entrance capacity greater than 200 amperes,
3. Customer is served three phase at 120/208 or 120/240 volts and has a service entrance capacity greater than 200 amperes,
4. Customer is served three phase at 240/480 or 277/480 volts and has a service entrance capacity greater than 100 amperes, or
5. Customer's average monthly kWh use for four consecutive months exceeds 3,500 kWh.

If a demand meter is installed in accordance with the above, the customer may remain on the Small General Service schedule as long as customer's maximum demand is less than 25 kW. When the customer achieves an actual maximum demand of 25 kW or greater, the customer will be placed on the General Service schedule in the next billing month. A customer with a billing demand of less than 25 kW for 12 consecutive months will be given the option of returning to the Small General Service schedule.

DETERMINATION OF CONNECTED LOAD FOR DIRECT CURRENT SERVICE
The nameplate rating shall be the basis of determining the connected load and shall be assumed to be one kW for each hp of nameplate rating. In any case, where there is reasonable doubt as to correctness of manufacturer's rating or where insufficient or no rating exists, the Company may fix the rating by test. For billing purposes, the demand shall be rounded to the nearest 0.1 kW.

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

SMALL GENERAL TIME OF DAY SERVICE Section No. 5
RATE CODE A12, A16, A18, A22 31st Revised Sheet No. 23

AVAILABILITY
Available to any non-residential customer for single or three phase electric service supplied through one meter.

DETERMINATION OF CUSTOMER BILLS
Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and / or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

RATE

Customer Charge per Month – Time Of Day Metered (A12)	$12.00	
– kWh Metered (A16)	$10.00	
– Unmetered (A18)	$8.00	
– Low Wattage (A22)	(Please see page 5-24.1)	

Energy Charge per kWh	Oct-May	Jun-Sep	
On Peak Period (A12)	$0.11723	$0.14880	R
Off Peak Period (A12)	$0.04170	$0.04170	R
Constant Hourly (A16, A18, A22) (= 35% On, 65% Off)	$0.06814	$0.07919	R

In addition, customer bills under this rate are subject to the following adjustments and/or charges.

FUEL CLAUSE
Bills are subject to the adjustments provided for in the Fuel Clause Rider.

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider, the Renewable Development Fund Rider, the Transmission Cost Recovery Rider, the Renewable Energy Standard Rider and the Mercury Cost Recovery Rider.

ENVIRONMENTAL IMPROVEMENT RIDER
Bills are subject to the adjustments provided for in the Environmental Improvement Rider.

MONTHLY MINIMUM CHARGE
Customer Charge.

(Continued on Sheet No. 5-24)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

SMALL GENERAL TIME OF DAY SERVICE Section No. 5
RATE CODE A12, A16, A18, A22 30th Revised Sheet No. 23

AVAILABILITY
Available to any non-residential customer for single or three phase electric service supplied through one meter.

DETERMINATION OF CUSTOMER BILLS
Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and / or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

RATE

Customer Charge per Month – Time Of Day Metered (A12)	$12.00	
– kWh Metered (A16)	$10.00	
– Unmetered (A18)	$8.00	
– Low Wattage (A22)	(Please see page 5-24.1)	

Energy Charge per kWh	Oct-May	Jun-Sep	
On Peak Period (A12)	$0.12331	$0.15644	R
Off Peak Period (A12)	$0.04378	$0.04378	R
Constant Hourly (A16, A18, A22) (= 35% On, 65% Off)	$0.07162	$0.08321	R

In addition, customer bills under this rate are subject to the following adjustments and/or charges.

FUEL CLAUSE
Bills are subject to the adjustments provided for in the Fuel Clause Rider.

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider, the Renewable Development Fund Rider, the Transmission Cost Recovery Rider, the Renewable Energy Standard Rider and the Mercury Cost Recovery Rider.

ENVIRONMENTAL IMPROVEMENT RIDER
Bills are subject to the adjustments provided for in the Environmental Improvement Rider.

MONTHLY MINIMUM CHARGE
Customer Charge.

(Continued on Sheet No. 5-24)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

SMALL GENERAL TIME OF DAY SERVICE Section No. 5
RATE CODE A12, A16, A18, A22 29th Revised Sheet No. 23

AVAILABILITY
Available to any non-residential customer for single or three phase electric service supplied through one meter.

DETERMINATION OF CUSTOMER BILLS
Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and / or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

RATE

Customer Charge per Month – Time Of Day Metered (A12)	$12.00	
– kWh Metered (A16)	$10.00	
– Unmetered (A18)	$8.00	
– Low Wattage (A22)	(Please see page 5-24.1)	

Energy Charge per kWh	Oct-May	Jun-Sep	
On Peak Period (A12)	$0.12060	$0.15323	R
Off Peak Period (A12)	$0.04260	$0.04260	R
Constant Hourly (A16, A18, A22) (= 35% On, 65% Off)	$0.06990	$0.08132	R

In addition, customer bills under this rate are subject to the following adjustments and/or charges. D

FUEL CLAUSE
Bills are subject to the adjustments provided for in the Fuel Clause Rider.

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider, the Renewable Development Fund Rider, the Transmission Cost Recovery Rider, the Renewable Energy Standard Rider and the Mercury Cost Recovery Rider.

ENVIRONMENTAL IMPROVEMENT RIDER
Bills are subject to the adjustments provided for in the Environmental Improvement Rider.

MONTHLY MINIMUM CHARGE
Customer Charge.

(Continued on Sheet No. 5-24)

Date Filed: 11-02-15 By: Christopher B. Clark Effective Date: 10-01-17
President, Northern States Power Company, a Minnesota corporation
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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

SMALL GENERAL TIME OF DAY SERVICE (Continued) Section No. 5
RATE CODE A12, A16, A18, A22 14th Revised Sheet No. 24

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

LOW INCOME ENERGY DISCOUNT RIDER
Bills are subject to the adjustment provided for in the Low Income Energy Discount Rider.

REVENUE DECOUPLING MECHANISM RIDER
Bills are subject to the adjustments provided for in the Revenue Decoupling Mechanism Rider.

The following are terms and conditions for service under this tariff.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

DEFINITION OF PEAK PERIODS
The on peak period is defined as those hours between 9:00 a.m. and 9:00 p.m. Monday through Friday, except the following holidays: New Year's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. When a designated holiday occurs on Saturday, the preceding Friday will be designated a holiday. When a designated holiday occurs on Sunday, the following Monday will be designated a holiday. The off peak period is defined as all other hours. Definition of on peak and off peak period is subject to change with change in Company's system operating characteristics.

OPTIONAL TRIAL SERVICE
Customers may elect time of day service for a trial period of three months. If a customer chooses to return to non-time of day service after the trial period, the customer will pay a charge of $25.00 for removal of time of day metering equipment.

TERMS AND CONDITIONS OF SERVICE
1. Customer selecting the above time of day rate schedule will remain on this rate for a period of not less than 12 months. While served under this schedule, the Small General Service rate is unavailable.

2. Company shall install a demand meter for a customer when:
   a. Customer's connected load is estimated to be 20 kW or greater,
   b. Customer is served single phase and has a service entrance capacity greater than 200 amperes,
   c. Customer is served three phase at 120/208 or 120/240 volts and has a service entrance capacity greater than 200 amperes,
   d. Customer is served three phase at 240/480 or 277/480 volts and has a service entrance capacity greater than 100 amperes, or
   e. Customer's average monthly kWh use for four consecutive months exceeds 3,500 kWh.

   If a demand meter is installed in accordance with the above, the customer may remain on the Small General Time of Day Service schedule as long as customer's maximum demand is less than 25 kW. When the customer achieves an actual maximum demand of 25 kW or greater, the customer will be placed on the General Time of Day Service schedule in the next billing month. A customer with a billing

(Continued on Sheet No. 24.1)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

SMALL GENERAL TIME OF DAY SERVICE (Continued) Section No. 5
RATE CODE A12, A16, A18, A22 12th Revised Sheet No. 24.1

TERMS AND CONDITIONS OF SERVICE (Continued)

demand of less than 25 kW for 12 consecutive months will be given the option of returning to the Small General Time of Day Service schedule.

3. Optional Metering Service: Optional metering is available subject to the provisions in the General Rules and Regulations, Section 1.5, for the following applications:

   a. Kilowatt-hour Metered Service: For applications where a non-time of day meter is used, the time of day metering charge will be waived and the applicable lower monthly Customer Charge shall apply.

   b. Unmetered Service: For applications where no metering is installed, the applicable lower monthly Customer Charge shall apply. If requested by Company, the customer agrees to receive one or more combined bills for all their unmetered service locations. For purposes of applying the appropriate customer service charge, one customer service charge shall be applied for every point of delivery. A point of delivery shall be any location where a meter would otherwise be required under this schedule.

   c. Low Wattage Unmetered Service: For applications where customer owns and operates multiple electronic devices in at least 500 locations within Company's Minnesota electric service area. Such electronic devices are: 1) individually located at each point of delivery, 2) rated at less than 400 Watts, and 3) operated with a continuous and constant load level year round. Each individual electronic device must not in any way interfere with Company operations and service to adjacent customers. This optional metering service is not applicable to electric service for traffic signals, civil defense, or lighting. Company reserves the right to evaluate customer requests for this optional metering service to determine eligibility.

      The monthly fixed charge under this optional metering service shall be $0.30 per device for devices with a rating of 100 Watts or less. For devices with a rating over 100 Watts but less than 400 Watts, the monthly fixed charge shall be $1.20 per device. R

      In place of metered usage for each device, customer will be billed for the predetermined energy usage in kWh per device. The energy charge shall equal the sum of the predetermined energy usage for customer's low wattage devices in service for the billing month multiplied by the Constant Hourly Energy Charge applicable for the billing month.

      Customer shall contract for this optional metering service through an electric service agreement with Company.

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President, Northern States Power Company, a Minnesota corporation
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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

SMALL GENERAL TIME OF DAY SERVICE (Continued) Section No. 5
RATE CODE A12, A16, A18, A22 11th Revised Sheet No. 24.1

TERMS AND CONDITIONS OF SERVICE (Continued)

demand of less than 25 kW for 12 consecutive months will be given the option of returning to the Small General Time of Day Service schedule.

3. Optional Metering Service: Optional metering is available subject to the provisions in the General Rules and Regulations, Section 1.5, for the following applications:

   a. Kilowatt-hour Metered Service: For applications where a non-time of day meter is used, the time of day metering charge will be waived and the applicable lower monthly Customer Charge shall apply.

   b. Unmetered Service: For applications where no metering is installed, the applicable lower monthly Customer Charge shall apply. If requested by Company, the customer agrees to receive one or more combined bills for all their unmetered service locations. For purposes of applying the appropriate customer service charge, one customer service charge shall be applied for every point of delivery. A point of delivery shall be any location where a meter would otherwise be required under this schedule.

   c. Low Wattage Unmetered Service: For applications where customer owns and operates multiple electronic devices in at least 500 locations within Company's Minnesota electric service area. Such electronic devices are: 1) individually located at each point of delivery, 2) rated at less than 400 Watts, and 3) operated with a continuous and constant load level year round. Each individual electronic device must not in any way interfere with Company operations and service to adjacent customers. This optional metering service is not applicable to electric service for traffic signals, civil defense, or lighting. Company reserves the right to evaluate customer requests for this optional metering service to determine eligibility.

      The monthly fixed charge under this optional metering service shall be $0.29 per device for devices with a rating of 100 Watts or less. For devices with a rating over 100 Watts but less than 400 Watts, the monthly fixed charge shall be $1.20 per device. R

      In place of metered usage for each device, customer will be billed for the predetermined energy usage in kWh per device. The energy charge shall equal the sum of the predetermined energy usage for customer's low wattage devices in service for the billing month multiplied by the Constant Hourly Energy Charge applicable for the billing month.

      Customer shall contract for this optional metering service through an electric service agreement with Company.

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Northern States Power Company, a Minnesota corporation
and wholly owned subsidiary of Xcel Energy Inc.
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

DIRECT CURRENT SERVICE (CLOSED) Section No. 5
RATE CODE A13 13th Revised Sheet No. 25

CANCELED

Date Filed: 11-02-05 By: Cynthia L. Lesher Effective Date: 02-01-07
President and CEO of Northern States Power Company
Docket No. E002/GR-05-1428 Order Date: 09-01-06

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Northern States Power Company, a Minnesota corporation
and wholly owned subsidiary of Xcel Energy Inc.
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

DIRECT CURRENT SERVICE (CLOSED) (Continued) Section No. 5
RATE CODE A13 2nd Revised Sheet No. 25.1

CANCELED

Date Filed: 11-02-05 By: Cynthia L. Lesher Effective Date: 02-01-07
President and CEO of Northern States Power Company
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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

GENERAL SERVICE Section No. 5
RATE CODE A14 31st Revised Sheet No. 26

AVAILABILITY
Available to any non-residential customer for general service where customer is not required to be on a time-of-day rate schedule. Once the customer's 15-minute measured demands are equal to or greater than 1,000 kW for at least 4 of the past 12 consecutive months, the customer will be transferred to the General Time of Day service.

DETERMINATION OF CUSTOMER BILLS
Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and / or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

RATE

Customer Charge per Month	$25.64		
Service at Secondary Voltage	Oct-May	Jun-Sep	R
Demand Charge per Month per kW	$10.49	$14.79	
Energy Charge per kWh	$0.03407		R
Energy Charge Credit per Month per kWh			
All kWh in Excess of 400 Hours Times the Billing Demand	$0.01518		R

	January - December		
Voltage Discounts per Month	Per kW	Per kWh	
Primary Voltage	$0.80	$0.00105	R
Transmission Transformed Voltage	$1.55	$0.00267	R
Transmission Voltage	$2.35	$0.00277	R

In addition, customer bills under this rate are subject to the following adjustments and/or charges.

FUEL CLAUSE
Bills are subject to the adjustments provided for in the Fuel Clause Rider.

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider, the Renewable Development Fund Rider, the Transmission Cost Recovery Rider, the Renewable Energy Standard Rider and the Mercury Cost Recovery Rider.

(Continued on Sheet No. 5-27)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

GENERAL SERVICE Section No. 5
RATE CODE A14 30th Revised Sheet No. 26

AVAILABILITY
Available to any non-residential customer for general service where customer is not required to be on a time-of-day rate schedule. Once the customer's 15-minute measured demands are equal to or greater than 1,000 kW for at least 4 of the past 12 consecutive months, the customer will be transferred to the General Time of Day service.

DETERMINATION OF CUSTOMER BILLS
Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and / or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

RATE

Customer Charge per Month		$25.64	
Service at Secondary Voltage	Oct-May	Jun-Sep	R
Demand Charge per Month per kW	$11.00	$15.54	
Energy Charge per kWh		$0.03577	R
Energy Charge Credit per Month per kWh			
All kWh in Excess of 400 Hours Times the Billing Demand		$0.01593	R

Voltage Discounts per Month	January - December Per kW	Per kWh	
Primary Voltage	$0.80	$0.00108	R
Transmission Transformed Voltage	$1.55	$0.00274	R
Transmission Voltage	$2.35	$0.00285	R

In addition, customer bills under this rate are subject to the following adjustments and/or charges.

FUEL CLAUSE
Bills are subject to the adjustments provided for in the Fuel Clause Rider.

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider, the Renewable Development Fund Rider, the Transmission Cost Recovery Rider, the Renewable Energy Standard Rider and the Mercury Cost Recovery Rider.

(Continued on Sheet No. 5-27)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

GENERAL SERVICE Section No. 5
RATE CODE A14 29th Revised Sheet No. 26

AVAILABILITY
Available to any non-residential customer for general service where customer is not required to be on a time-of-day rate schedule. Once the customer's 15-minute measured demands are equal to or greater than 1,000 kW for at least 4 of the past 12 consecutive months, the customer will be transferred to the General Time of Day service.

DETERMINATION OF CUSTOMER BILLS
Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and / or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

RATE

Customer Charge per Month	$25.64		R
Service at Secondary Voltage	Oct-May	Jun-Sep	R
Demand Charge per Month per kW	$10.71	$15.25	
Energy Charge per kWh	$0.03498		R
Energy Charge Credit per Month per kWh All kWh in Excess of 400 Hours Times the Billing Demand	$0.01558		R

Voltage Discounts per Month	January - December Per kW	 Per kWh	
Primary Voltage	$0.80	$0.00106	R
Transmission Transformed Voltage	$1.55	$0.00271	R
Transmission Voltage	$2.35	$0.00281	R

In addition, customer bills under this rate are subject to the following adjustments and/or charges. D

FUEL CLAUSE
Bills are subject to the adjustments provided for in the Fuel Clause Rider.

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider, the Renewable Development Fund Rider, the Transmission Cost Recovery Rider, the Renewable Energy Standard Rider and the Mercury Cost Recovery Rider.

(Continued on Sheet No. 5-27)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

GENERAL SERVICE (Continued) Section No. 5
RATE CODE A14 8th Revised Sheet No. 27

ENVIRONMENTAL IMPROVEMENT RIDER
Bills are subject to the adjustments provided for in the Environmental Improvement Rider.

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

LOW INCOME ENERGY DISCOUNT RIDER
Bills are subject to the adjustment provided for in the Low Income Energy Discount Rider.

The following are terms and conditions for service under this tariff.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

DETERMINATION OF DEMAND
The adjusted demand in kW for billing purposes shall be determined by dividing the maximum actual demand in kW by the power factor expressed in percent but not more than a 90% power factor and multiplying the quotient so obtained by 90% and rounding to the nearest whole kW. In no month shall the demand to be billed be considered as less than current month's adjusted demand in kW or 50% of the greatest monthly adjusted demand in kW during the preceding 11 months. In no month shall the billing demand be greater than the value in kW determined by dividing the kWh sales for the billing month by 100 hours per month.

The greatest monthly adjusted demand in kW during the preceding 11 months shall not include the additional demand which may result from customer's use of standby capacity contracted for under the Standby Service Rider.

MAXIMUM DEMAND
The maximum actual demand in kW shall be the greatest 15 minute load during the month for which bill is rendered.

POWER FACTOR
For three phase customers with services above 200 amperes or above 480 volts, the power factor for the month shall be determined by permanently installed metering equipment. For all single phase customers and three phase customers with services 200 amperes or less, a power factor of 90% will be assumed.

(Continued on Sheet No. 5-28)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK – MPUC NO. 2

GENERAL SERVICE (Continued) Section No. 5
RATE CODE A14 7th Revised Sheet No. 28

OFF SEASON LOAD SERVICE
The optional Off Season Load Service is available under this schedule subject to the provisions contained in the Off Season Load Rider.

STANDBY SERVICE
Standby Service and Supplemental Generation Service are available under this schedule subject to the provisions contained in the Standby Service Rider or Supplemental Generation Service Rider.

COMPETITIVE SERVICE
Competitive Service is available under this schedule subject to the provisions contained in the Competitive Response Rider.

MINIMUM DEMAND TO BE BILLED
The monthly minimum billing demand shall not be less than provided above.

SPLIT SERVICE
When approved by Company, customer's service may be split between General Service and General Time of Day Service rates. Only Company approved storage space cooling and storage space heating equipment qualifies for the General Time of Day Service portion of a split service installation. The thermal storage equipment shall be permanently wired, separately served and metered, and at no time connected to the general service portion of the split service installation. Each portion of customer's split service installation will be considered separately for all other rate application purposes.

(Continued on Sheet No. 28.1)

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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

GENERAL SERVICE (Continued) Section No. 5
RATE CODE A14 5th Revised Sheet No. 28.1

TERMS AND CONDITIONS OF SERVICE

1. Alternating current service is provided at the following nominal voltage:
   a. Secondary Voltage: Single or three phase from 208 volts up to but not including 2,400 volts,
   b. Primary Voltage: Three phase from 2,400 volts up to but not including 69,000 volts,
   c. Transmission Transformed Voltage: Three phase from 2,400 volts up to but not including 69,000 volts, where service is provided at the Company's disconnecting means of a distribution substation transformer, or
   d. Transmission Voltage: Three phase at 69,000 volts or higher.

   Service voltage available in any given case is dependent upon voltage and capacity of Company lines in vicinity of customer's premises.

2. Transmission Transformed Service is available only to customers served by an exclusively dedicated distribution feeder. Customer will be responsible for the cost of all facilities necessary to interconnect at the Company's disconnecting means of a distribution substation transformer.

3. Transmission Service is available at transmission voltage, subject to the terms and conditions contained in the Company's General Rules and Regulations, Section 5.1(B).

4. Customer selecting General Service will remain on this rate for a period of not less than 12 months.

5. If a customer has a billing demand of less than 25 kW for 12 consecutive months, the customer will be given the option of returning to the Small General Service schedule.

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

GENERAL TIME OF DAY SERVICE
RATE CODE A15, A17, A19

Section No. 5
27th Revised Sheet No. 29

AVAILABILITY-MANDATORY
Effective November 1, 2007, this rate schedule is mandatory for any non-residential customer for general service having a 15-minute measured demand equal to or greater than 1,000 kW for at least 4 of the past 12 consecutive months. Customer will remain on this rate schedule on a mandatory basis unless their demand remains below 1,000 kW for 12 consecutive months.

AVAILABILITY-OPTIONAL
This rate schedule is optional for any non-residential customer for general service where customer is not required to be on a time-of-day rate.

DETERMINATION OF CUSTOMER BILLS
Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and / or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

RATE

Customer Charge per Month – Time Of Day Metered (A15)	$29.64		
-- kWh Metered (A17)	$25.64		
-- Unmetered (A19)	$21.64		
Service at Secondary Voltage	Oct-May	Jun-Sep	
Demand Charge per Month per kW			
On Peak Period Demand	$10.49	$14.79	R
Off Peak Period Demand in Excess of On Peak Period Demand	$2.35	$2.35	
Energy Charge per kWh			
On Peak Period Energy	$0.04855		R
Off Peak Period Energy	$0.02341		R
Energy Charge Credit per Month per kWh			
All kWh in Excess of 400 Hours Times the On Peak Period Billing Demand, Not to Exceed 50% of Total kWh	$0.01518		R
	January - December		
Voltage Discounts per Month	Per kW	Per kWh	
Primary Voltage	$0.80	$0.00105	R
Transmission Transformed Voltage	$1.55	$0.00267	R
Transmission Voltage	$2.35	$0.00277	R

(Continued on Sheet No. 5-30)

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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

GENERAL TIME OF DAY SERVICE
RATE CODE A15, A17, A19

Section No. 5
26th Revised Sheet No. 29

AVAILABILITY-MANDATORY
Effective November 1, 2007, this rate schedule is mandatory for any non-residential customer for general service having a 15-minute measured demand equal to or greater than 1,000 kW for at least 4 of the past 12 consecutive months. Customer will remain on this rate schedule on a mandatory basis unless their demand remains below 1,000 kW for 12 consecutive months.

AVAILABILITY-OPTIONAL
This rate schedule is optional for any non-residential customer for general service where customer is not required to be on a time-of-day rate.

DETERMINATION OF CUSTOMER BILLS
Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and / or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

RATE

Customer Charge per Month – Time Of Day Metered (A15)	$29.64		
-- kWh Metered (A17)	$25.64		
-- Unmetered (A19)	$21.64		
Service at Secondary Voltage	Oct-May	Jun-Sep	
Demand Charge per Month per kW			
On Peak Period Demand	$11.00	$15.54	R
Off Peak Period Demand in Excess of On Peak Period Demand	$2.35	$2.35	
Energy Charge per kWh			
On Peak Period Energy	$0.05098		R
Off Peak Period Energy	$0.02458		R
Energy Charge Credit per Month per kWh			
All kWh in Excess of 400 Hours Times the On Peak Period Billing Demand, Not to Exceed 50% of Total kWh	$0.01593		R
	January - December		
Voltage Discounts per Month	Per kW	Per kWh	
Primary Voltage	$0.80	$0.00108	R
Transmission Transformed Voltage	$1.55	$0.00274	R
Transmission Voltage	$2.35	$0.00285	R

(Continued on Sheet No. 5-30)

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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

GENERAL TIME OF DAY SERVICE
RATE CODE A15, A17, A19

Section No. 5
25th Revised Sheet No. 29

AVAILABILITY-MANDATORY
Effective November 1, 2007, this rate schedule is mandatory for any non-residential customer for general service having a 15-minute measured demand equal to or greater than 1,000 kW for at least 4 of the past 12 consecutive months. Customer will remain on this rate schedule on a mandatory basis unless their demand remains below 1,000 kW for 12 consecutive months.

AVAILABILITY-OPTIONAL
This rate schedule is optional for any non-residential customer for general service where customer is not required to be on a time-of-day rate.

DETERMINATION OF CUSTOMER BILLS
Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and / or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

RATE

Customer Charge per Month – Time Of Day Metered (A15)	$29.64		R
-- kWh Metered (A17)	$25.64		R
-- Unmetered (A19)	$21.64		R
Service at Secondary Voltage	Oct-May	Jun-Sep	
Demand Charge per Month per kW			
On Peak Period Demand	$10.71	$15.25	R
Off Peak Period Demand in Excess of On Peak Period Demand	$2.35	$2.35	R
Energy Charge per kWh			
On Peak Period Energy	$0.04986		R
Off Peak Period Energy	$0.02404		R
Energy Charge Credit per Month per kWh			
All kWh in Excess of 400 Hours Times the On Peak Period Billing Demand, Not to Exceed 50% of Total kWh	$0.01558		R
	January - December		
Voltage Discounts per Month	Per kW	Per kWh	
Primary Voltage	$0.80	$0.00106	R
Transmission Transformed Voltage	$1.55	$0.00271	R
Transmission Voltage	$2.35	$0.00281	R

D

(Continued on Sheet No. 5-30)

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President, Northern States Power Company, a Minnesota corporation
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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

GENERAL TIME OF DAY SERVICE (Continued) Section No. 5
RATE CODE A15, A17, A19 15th Revised Sheet No. 30

In addition, customer bills under this rate are subject to the following adjustments and/or charges.

FUEL CLAUSE
Bills are subject to the adjustments provided for in the Fuel Clause Rider.

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider, the Renewable Development Fund Rider, the Transmission Cost Recovery Rider, the Renewable Energy Standard Rider and the Mercury Cost Recovery Rider.

ENVIRONMENTAL IMPROVEMENT RIDER
Bills are subject to the adjustments provided for in the Environmental Improvement Rider.

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

LOW INCOME ENERGY DISCOUNT RIDER
Bills are subject to the adjustment provided for in the Low Income Energy Discount Rider.

The following are terms and conditions for service under this tariff.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

DEFINITION OF PEAK PERIODS
The on peak period is defined as those hours between 9:00 a.m. and 9:00 p.m. Monday through Friday, except the following holidays: New Year's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. When a designated holiday occurs on Saturday, the preceding Friday will be designated a holiday. When a designated holiday occurs on Sunday, the following Monday will be designated a holiday. The off peak period is defined as all other hours. Definition of on peak and off peak period is subject to change with change in Company's system operating characteristics.

(Continued on Sheet No. 5-31)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

GENERAL TIME OF DAY SERVICE (Continued) Section No. 5
RATE CODE A15, A17, A19 8th Revised Sheet No. 31

DETERMINATION OF ON PEAK PERIOD DEMAND
The actual on peak period demand in kW shall be the greatest 15-minute load for the on peak period during the month for which the bill is rendered. The adjusted demand in kW for billing purposes shall be determined by dividing the actual on peak demand by the power factor expressed in percent but not more than 90%, multiplying the quotient so obtained by 90%, and rounding to the nearest whole kW. In no month shall the on peak period demand to be billed be considered as less than the current month's adjusted on peak period demand in kW, or 50% of the greatest monthly adjusted on peak period demand in kW during the preceding 11 months. In no month shall the on peak billing demand be greater than the value in kW determined by dividing the kWh sales for the billing month by 100 hours per month.

The greatest monthly adjusted on peak period demand in kW during the preceding 11 months shall not include the additional demand which may result from customer's use of standby capacity contracted for under the Standby Service Rider.

DETERMINATION OF OFF PEAK PERIOD DEMAND IN EXCESS OF ON PEAK PERIOD DEMAND
The actual off peak period demand in kilowatts shall be the greatest 15-minute load for the off peak period during the month for which the bill is rendered rounded to the nearest whole kW. In no month shall the off peak period demand for billing purposes be considered as less than the current month's actual off peak period demand in kW, or 50% of the greatest monthly actual off peak period demand in kW during the preceding 11 months.

The greatest monthly adjusted off peak period demand in kW during the preceding 11 months shall not include the additional demand which may result from customer's use of standby capacity contracted for under the Standby Service Rider.

The off peak period demand in excess of on peak period demand in kW to be billed shall be determined by subtracting the billing on peak period demand from the actual off peak period demand as defined above only the off peak period demand is greater.

POWER FACTOR
For three phase customers with services above 200 amperes, or above 480 volts, the power factor for the month shall be determined by permanently installed metering equipment. For all single phase customers and three phase customers with services 200 amperes or less, a power factor of 90% will be assumed.

(Continued on Sheet No. 5-32)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

GENERAL TIME OF DAY SERVICE (Continued) Section No. 5
RATE CODE A15, A17, A19 6th Revised Sheet No. 32

COMPETITIVE SERVICE
Competitive Service is available under this schedule subject to the provisions contained in the Competitive Response Rider.

STANDBY SERVICE
Standby Service is available under this schedule subject to the provisions contained in the Standby Service Rider.

MINIMUM DEMAND TO BE BILLED
The monthly minimum on peak period billing demand shall not be less than provided above.

SPLIT SERVICE
When approved by Company, customer's service may be split between General Service and General Time of Day Service rates. Only Company approved storage space cooling and storage space heating equipment qualifies for the General Time of Day Service portion of a split service installation. The thermal storage equipment shall be permanently wired, separately served and metered, and at no time connected to the general service portion of the split service installation. Each portion of customer's split service installation will be considered separately for all other rate application purposes.

OPTIONAL TRIAL SERVICE
Customers may elect time of day service for a trial period of three months. If a customer chooses to return to non-time of day service after the trial period, the customer will pay a charge of $35.00 for removal of time of day metering equipment.

TERMS AND CONDITIONS OF SERVICE
1. Alternating current service is provided at the following nominal voltages:
   a. Secondary Voltage: Single or three phase from 208 volts up to but not including 2,400 volts,
   b. Primary Voltage: Three phase from 2,400 volts up to but not including 69,000 volts,
   c. Transmission Transformed Voltage: Three phase from 2,400 volts up to but not including 69,000 volts, where service is provided at the Company's disconnecting means of a distribution substation transformer, or
   d. Transmission Voltage: Three phase at 69,000 volts or higher.

   Service voltage available in any given case is dependent upon voltage and capacity of Company lines in vicinity of customer's premises.

(Continued on Sheet No. 5-32.1)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

GENERAL TIME OF DAY SERVICE (Continued) Section No. 5
RATE CODE A15, A17, A19 5th Revised Sheet No. 32.1

TERMS AND CONDITIONS OF SERVICE (Continued)

2. Transmission Transformed Service is available only to customers served by an exclusively dedicated distribution feeder. Customer will be responsible for the cost of all facilities necessary to interconnect at the Company's disconnecting means of a distribution substation transformer.

3. Transmission Service is available at transmission voltage, subject to the terms and conditions contained in the Company's General Rules and Regulations, Section 5.1(B).

4. Customer selecting the above time of day rate schedule will remain on this rate for a period of not less than 12 months.

5. If a customer has a billing demand of less than 25 kW for 12 consecutive months, the customer will be given the option of returning to the Small General Time of Day Service schedule.

6. Optional Metering Service: Optional metering is available subject to the provisions in the General Rules and Regulations, Section 1.5, for the following applications:
   a. Kilowatt-hour Metered Service: For applications where a non-time of day meter is used, the time of day metering charge will be waived and the applicable lower monthly Customer Charge shall apply.
   b. Unmetered Service: This rate is for applications where no metering is installed and the applicable lower monthly Customer Charge shall apply. If requested by Company, the customer agrees to receive one or more combined bills for all their unmetered service locations. For purposes of applying the appropriate customer service charge, one customer service charge shall be applied for every point of delivery. A point of delivery shall be any location where a meter would otherwise be required under this schedule.

Northern States Power Company, a Minnesota corporation
and wholly owned subsidiary of Xcel Energy Inc.
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

PEAK CONTROLLED SERVICE (CLOSED) Section No. 5
RATE CODE A20 13th Revised Sheet No. 33

CANCELED

Northern States Power Company, a Minnesota corporation
and wholly owned subsidiary of Xcel Energy Inc.
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

PEAK CONTROLLED SERVICE (CLOSED) (Continued) Section No. 5
RATE CODE A20 3rd Revised Sheet No. 34

CANCELED

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President and CEO of Northern States Power Company
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Northern States Power Company, a Minnesota corporation
and wholly owned subsidiary of Xcel Energy Inc.
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

PEAK CONTROLLED SERVICE (CLOSED) (Continued) Section No. 5
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and wholly owned subsidiary of Xcel Energy Inc.
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MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

PEAK CONTROLLED SERVICE (CLOSED) (Continued) Section No. 5
RATE CODE A20 1st Revised Sheet No. 35.1

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Northern States Power Company, a Minnesota corporation
and wholly owned subsidiary of Xcel Energy Inc.
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

PEAK CONTROLLED TIME OF DAY SERVICE (CLOSED) Section No. 5
RATE CODE A21 8th Revised Sheet No. 36

CANCELED

Northern States Power Company, a Minnesota corporation
and wholly owned subsidiary of Xcel Energy Inc.
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

PEAK CONTROLLED TIME OF DAY SERVICE (CLOSED) Section No. 5
(Continued) 8th Revised Sheet No. 37
RATE CODE A21

CANCELED

Northern States Power Company, a Minnesota corporation
and wholly owned subsidiary of Xcel Energy Inc.
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

PEAK CONTROLLED TIME OF DAY SERVICE (CLOSED) Section No. 5
(Continued) 2nd Revised Sheet No. 38
RATE CODE A21

CANCELED

Northern States Power Company, a Minnesota corporation
and wholly owned subsidiary of Xcel Energy Inc.
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

PEAK CONTROLLED TIME OF DAY SERVICE
(CLOSED) (Continued)
RATE CODE A21

Section No. 5
1st Revised Sheet No. 39

CANCELED

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

PEAK CONTROLLED SERVICE Section No. 5
RATE CODE A23 22nd Revised Sheet No. 40

AVAILABILITY
Available to any non-residential customer for general service who agrees to control demand to a predetermined level whenever required by Company and where customer is not required to be on a time-of-day rate schedule. Once the customer's total 15-minute measured demands (Firm plus Controllable) are equal to or greater than 1000 kW for at least 4 of the past 12 consecutive months, the customer will be transferred to the Peak Controlled Time of Day service. Availability is restricted to customers with a minimum Controllable demand of 50 kW.

DETERMINATION OF CUSTOMER BILLS
Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and / or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

RATE

Customer Charge per Month		$55.00	
Service at Secondary Voltage			
Energy Charge per kWh		$0.03407	R
Energy Charge Credit per Month per kWh			
All kWh in Excess of 400 Hours		$0.01518	R
Times the Sum of All Billing Demands			
Demand Charge per Month per kW	Tier 1	Tier 2	
Firm Demand			
June - September	$14.79	$14.79	R
Other Months	$10.49	$10.49	R
Controllable Demand (Jan-Dec)			
Level A: < 65% PF	Not Available	$8.88	R
Level B: ≥ 65% and < 85% PF	$7.15	$7.86	R
Level C: ≥ 85% PF	$6.56	$7.34	R
Short Notice Rider	$6.09	Not Available	R
	January – December		
Voltage Discounts per Month	Per kW	Per kWh	
Primary Voltage	$0.80	$0.00105	R
Transmission Transformed Voltage	$1.55	$0.00267	R
Transmission Voltage	$2.35	$0.00277	R

(Continued on Sheet No. 5-41)

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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

PEAK CONTROLLED SERVICE Section No. 5
RATE CODE A23 21st Revised Sheet No. 40

AVAILABILITY
Available to any non-residential customer for general service who agrees to control demand to a predetermined level whenever required by Company and where customer is not required to be on a time-of-day rate schedule. Once the customer's total 15-minute measured demands (Firm plus Controllable) are equal to or greater than 1000 kW for at least 4 of the past 12 consecutive months, the customer will be transferred to the Peak Controlled Time of Day service. Availability is restricted to customers with a minimum Controllable demand of 50 kW.

DETERMINATION OF CUSTOMER BILLS
Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and / or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

RATE

Customer Charge per Month		$55.00	
Service at Secondary Voltage			
Energy Charge per kWh		$0.03577	R
Energy Charge Credit per Month per kWh			
All kWh in Excess of 400 Hours		$0.01593	R
Times the Sum of All Billing Demands			
Demand Charge per Month per kW	Tier 1	Tier 2	
Firm Demand			
June - September	$15.54	$15.54	R
Other Months	11.00	$11.00	R
Controllable Demand (Jan-Dec)			
Level A: < 65% PF	Not Available	$9.32	R
Level B: ≥ 65% and < 85% PF	$7.51	$8.25	R
Level C: ≥ 85% PF	$6.89	$7.71	R
Short Notice Rider	$6.39	Not Available	R
	January - December		
Voltage Discounts per Month	Per kW	Per kWh	
Primary Voltage	$0.80	$0.00108	R
Transmission Transformed Voltage	$1.55	$0.00274	R
Transmission Voltage	$2.35	$0.00285	R

(Continued on Sheet No. 5-41)

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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

PEAK CONTROLLED SERVICE Section No. 5
RATE CODE A23 20th Revised Sheet No. 40

AVAILABILITY
Available to any non-residential customer for general service who agrees to control demand to a predetermined level whenever required by Company and where customer is not required to be on a time-of-day rate schedule. Once the customer's total 15-minute measured demands (Firm plus Controllable) are equal to or greater than 1000 kW for at least 4 of the past 12 consecutive months, the customer will be transferred to the Peak Controlled Time of Day service. Availability is restricted to customers with a minimum Controllable demand of 50 kW.

DETERMINATION OF CUSTOMER BILLS
Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and / or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

RATE

Customer Charge per Month		$55.00	
Service at Secondary Voltage			
Energy Charge per kWh		$0.03498	R
Energy Charge Credit per Month per kWh			
All kWh in Excess of 400 Hours		$0.01558	R
Times the Sum of All Billing Demands			
Demand Charge per Month per kW	Tier 1	Tier 2	
Firm Demand			
June - September	$15.25	$15.25	R
Other Months	$10.71	$10.71	R
Controllable Demand (Jan-Dec)			
Level A: < 65% PF	Not Available	$9.05	R
Level B: ≥ 65% and < 85% PF	$7.35	$8.07	R
Level C: ≥ 85% PF	$6.75	$7.55	R
Short Notice Rider	$6.25	Not Available	R
	January - December		
Voltage Discounts per Month	Per kW	Per kWh	
Primary Voltage	$0.80	$0.00106	R
Transmission Transformed Voltage	$1.55	$0.00271	R
Transmission Voltage	$2.35	$0.00281	R

(Continued on Sheet No. 5-41)

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MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

PEAK CONTROLLED SERVICE (Continued) Section No. 5
RATE CODE A23 18th Revised Sheet No. 41

D

In addition, customer bills under this rate are subject to the following adjustments and/or charges.

FUEL CLAUSE
Bills are subject to the adjustments provided for in the Fuel Clause Rider.

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider, the Renewable Development Fund Rider, the Transmission Cost Recovery Rider, the Renewable Energy Standard Rider and the Mercury Cost Recovery Rider.

ENVIRONMENTAL IMPROVEMENT RIDER
Bills are subject to the adjustments provided for in the Environmental Improvement Rider.

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

LOW INCOME ENERGY DISCOUNT RIDER
Bills are subject to the adjustment provided for in the Low Income Energy Discount Rider.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

DEFINITION OF PERFORMANCE FACTOR (PF)
Performance factor is defined in percentage terms as the average of the July and August calendar month unadjusted maximum Controllable Demand occurring from 1:00 p.m. to 7:00 p.m. on weekdays, or which has been permanently shifted out of normal control period times, divided by the unadjusted maximum annual Controllable Demand. Customers claiming permanent load shifts must provide verification to Company, based on NSP's established criteria.

DETERMINATION OF DEMAND
Maximum Actual Demand in kW shall be the greatest 15-minute load during the billing month.

Adjusted Demand in kW for billing purposes shall be determined by dividing the Maximum Actual Demand in kW by the power factor expressed in percent but not more than a 90% power factor and multiplying the quotient so obtained by 90% and rounding to the nearest whole kW.

(Continued on Sheet No. 5-42)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

PEAK CONTROLLED SERVICE (Continued) Section No. 5
RATE CODE A23 6th Revised Sheet No. 42

DETERMINATION OF DEMAND (Continued)
Predetermined Demand shall be specified and agreed to by the customer and Company. Customer's Adjusted Demand must not exceed the Predetermined Demand Level (PDL) during a control period.

Standard PDL customers must agree to a fixed demand level and limit load to that level during a control period.

Optional PDL customers must agree to reduce demand by a fixed amount during a control period. Customer's Firm Demand will vary from month-to-month while the Controllable Demand remains fixed each month. The Firm Demand will be the Adjusted Demand (based on the Maximum Actual Demand for the month) less the fixed amount of Controllable Demand. Customer's PDL will be the monthly adjusted demand less the fixed load reduction. Customers selecting the Optional PDL must either be equipped with back-up generation to provide the fixed load reduction or have a specific load that can be separately sub-metered and has an annual load factor of 90% or greater.

Firm Demand for the billing month shall be the lesser of Predetermined Demand or Adjusted Demand, except in months when customer fails to control load to Predetermined Demand Level when requested by Company. In these months, Firm Demand shall be the adjusted demand established during the control period. For optional PDL customers, Firm Demand shall be Adjusted Demand less Controllable Demand, except in months when customer fails to control the full amount of their fixed Controllable Demand. In these months the Firm Demand shall be the Adjusted Demand less the amount of Demand that was controlled as shown by meter measurement.

Controllable Demand shall be the difference between Adjusted Demand during the billing month and the greater of Predetermined Demand or Firm Demand, but never less than zero.

Minimum Demand to be billed each month as either Firm Demand, Controllable Demand or a combination of both shall not be less than the current month's adjusted demand in kW.

POWER FACTOR
The power factor for the month shall be determined by permanently installed metering equipment.

ANNUAL MINIMUM DEMAND CHARGE
The Annual Minimum Demand Charge shall be no less than six times the average monthly Firm Demand Charge per kW times the maximum Predetermined Demand, plus six times the Controllable Demand Charge per kW times the maximum Controllable Demand.

(Continued on Sheet No. 5-43)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

PEAK CONTROLLED SERVICE (Continued) Section No. 5
RATE CODE A23 6th Revised Sheet No. 43

TIER 1 PEAK CONTROLLED SHORT NOTICE
Tier 1 Peak Controlled Short Notice is available under this schedule subject to the provisions contained in the Tier 1 Peak Controlled Short Notice Rider.

COMPETITIVE SERVICE
Competitive Service is available under this schedule subject to the provisions contained in the Competitive Response Rider.

OTHER PROVISIONS
Peak Controlled Service is also subject to provisions contained in Rules for Application of Peak Controlled Services.

TERMS AND CONDITIONS OF SERVICE
1. Alternating current service is provided at the following nominal voltages:
   a. Secondary Voltage: Single or three phase from 208 volts up to but not including 2,400 volts,
   b. Primary Voltage: Three phase from 2,400 volts up to but not including 69,000 volts,
   c. Transmission Transformed Voltage: Three phase from 2,400 volts up to but not including 69,000 volts, where service is provided at the Company's disconnecting means of a distribution substation transformer, or
   d. Transmission Voltage: Three phase at 69,000 volts or higher.

   Service voltage available in any given case is dependent upon voltage and capacity of Company lines in vicinity of customer's premises.

2. Transmission Transformed Service is available only to customers served by an exclusively dedicated distribution feeder. Customer will be responsible for the cost of all facilities necessary to interconnect at the Company's disconnecting means of a distribution substation transformer.

3. Transmission Service is available at transmission voltage, subject to the terms and conditions contained in the Company's General Rules and Regulations, Section 5.1(B).

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

PEAK CONTROLLED TIME OF DAY SERVICE Section No. 5
RATE CODE A24 17th Revised Sheet No. 44

AVAILABILITY
Available to any non-residential customer for general service who agrees to control demand to a predetermined level whenever required by Company. Availability is restricted to customers with a minimum controllable demand of 50 kW.

AVAILABILITY-MANDATORY
Effective November 1, 2007, this rate schedule is mandatory for any Peak Controlled customer having a 15-minute measured demand equal to or greater than 1000 kW for at least 4 of the past 12 consecutive months. Customer will remain on this rate schedule on a mandatory basis unless their demand remains below 1000 kW for 12 consecutive months.

AVAILABILITY-OPTIONAL
This rate schedule is optional for any non-residential customer for general service where customer is not required to be on a time-of-day rate.

DETERMINATION OF CUSTOMER BILLS
Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and / or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

RATE

Customer Charge per Month	$55.00	
Service at Secondary Voltage		
Energy Charge per kWh		
On Peak Period Energy	$0.04855	R
Off Peak Period Energy	$0.02341	R
Energy Charge Credit per Month per kWh		
All kWh in Excess of 400 Hours Times the Sum of All On Peak Period Billing Demands, Not to Exceed 50% of Total kWh	$0.01518	R

(Continued on Sheet No. 5-45)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

PEAK CONTROLLED TIME OF DAY SERVICE Section No. 5
RATE CODE A24 16th Revised Sheet No. 44

AVAILABILITY
Available to any non-residential customer for general service who agrees to control demand to a predetermined level whenever required by Company. Availability is restricted to customers with a minimum controllable demand of 50 kW.

AVAILABILITY-MANDATORY
Effective November 1, 2007, this rate schedule is mandatory for any Peak Controlled customer having a 15-minute measured demand equal to or greater than 1000 kW for at least 4 of the past 12 consecutive months. Customer will remain on this rate schedule on a mandatory basis unless their demand remains below 1000 kW for 12 consecutive months.

AVAILABILITY-OPTIONAL
This rate schedule is optional for any non-residential customer for general service where customer is not required to be on a time-of-day rate.

DETERMINATION OF CUSTOMER BILLS
Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and / or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

RATE

Customer Charge per Month	$55.00	
Service at Secondary Voltage		
Energy Charge per kWh		
On Peak Period Energy	$0.05098	R
Off Peak Period Energy	$0.02458	R
Energy Charge Credit per Month per kWh		
All kWh in Excess of 400 Hours Times the Sum of All On Peak Period Billing Demands, Not to Exceed 50% of Total kWh	$0.01593	R

(Continued on Sheet No. 5-45)

Date Filed: 10-01-18 By: Christopher B. Clark Effective Date: 01-01-19
President, Northern States Power Company, a Minnesota corporation
Docket No. E002/GR-15-826 Order Date: 06-12-17

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

PEAK CONTROLLED TIME OF DAY SERVICE Section No. 5
RATE CODE A24 15th Revised Sheet No. 44

AVAILABILITY
Available to any non-residential customer for general service who agrees to control demand to a predetermined level whenever required by Company. Availability is restricted to customers with a minimum controllable demand of 50 kW.

AVAILABILITY-MANDATORY
Effective November 1, 2007, this rate schedule is mandatory for any Peak Controlled customer having a 15-minute measured demand equal to or greater than 1000 kW for at least 4 of the past 12 consecutive months. Customer will remain on this rate schedule on a mandatory basis unless their demand remains below 1000 kW for 12 consecutive months.

AVAILABILITY-OPTIONAL
This rate schedule is optional for any non-residential customer for general service where customer is not required to be on a time-of-day rate.

DETERMINATION OF CUSTOMER BILLS
Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and / or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

RATE

Customer Charge per Month	$55.00	
Service at Secondary Voltage		
Energy Charge per kWh		
On Peak Period Energy	$0.04986	R
Off Peak Period Energy	$0.02404	R
Energy Charge Credit per Month per kWh		
All kWh in Excess of 400 Hours Times the Sum of All On Peak Period Billing Demands, Not to Exceed 50% of Total kWh	$0.01558	R

(Continued on Sheet No. 5-45)

Northern States Power Company, a Minnesota corporation
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MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

PEAK CONTROLLED TIME OF DAY SERVICE (Continued)
RATE CODE A24

Section No. 5
25th Revised Sheet No. 45

RATE (Continued)

	Tier 1	Tier 2	
Demand Charge per Month per kW			
On Peak Period Demand			
Firm Demand			
June - September	$14.79	$14.79	R
Other Months	$10.49	$10.49	R
Controllable Demand (Jan-Dec)			
Level A: < 65% PF	Not Available	$8.88	R
Level B: ≥ 65% and < 85% PF	$7.15	$7.86	R
Level C: ≥ 85% PF	$6.56	$7.34	R
Short Notice Rider	$6.09	Not Available	R
Off Peak Period Demand in Excess of On Peak Period Demand (Jan-Dec)	$2.35	$2.35	

	January - December		
Voltage Discounts per Month	Per kW	Per kWh	
Primary Voltage	$0.80	$0.00105	R
Transmission Transformed Voltage	$1.55	$0.00267	R
Transmission Voltage	$2.35	$0.00277	R

In addition, customer bills under this rate are subject to the following adjustments and/or charges.

FUEL CLAUSE
Bills are subject to the adjustments provided for in the Fuel Clause Rider.

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider, the Renewable Development Fund Rider, the Transmission Cost Recovery Rider, the Renewable Energy Standard Rider and the Mercury Cost Recovery Rider.

ENVIRONMENTAL IMPROVEMENT RIDER
Bills are subject to the adjustments provided for in the Environmental Improvement Rider.

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

(Continued on Sheet No. 5-46)

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MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

PEAK CONTROLLED TIME OF DAY SERVICE (Continued)
RATE CODE A24

Section No. 5
24th Revised Sheet No. 45

RATE (Continued)

	Tier 1	Tier 2	
Demand Charge per Month per kW			
On Peak Period Demand			
Firm Demand			
June - September	$15.54	$15.54	R
Other Months	$11.00	$11.00	R
Controllable Demand (Jan-Dec)			
Level A: < 65% PF	Not Available	$9.32	R
Level B: ≥ 65% and < 85% PF	$7.51	$8.25	R
Level C: ≥ 85% PF	$6.89	$7.71	R
Short Notice Rider	$6.39	Not Available	R
Off Peak Period Demand in Excess of On Peak Period Demand (Jan-Dec)	$2.35	$2.35	

	January - December		
Voltage Discounts per Month	Per kW	Per kWh	
Primary Voltage	$0.80	$0.00108	R
Transmission Transformed Voltage	$1.55	$0.00274	R
Transmission Voltage	$2.35	$0.00285	R

In addition, customer bills under this rate are subject to the following adjustments and/or charges.

FUEL CLAUSE
Bills are subject to the adjustments provided for in the Fuel Clause Rider.

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider, the Renewable Development Fund Rider, the Transmission Cost Recovery Rider, the Renewable Energy Standard Rider and the Mercury Cost Recovery Rider.

ENVIRONMENTAL IMPROVEMENT RIDER
Bills are subject to the adjustments provided for in the Environmental Improvement Rider.

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

(Continued on Sheet No. 5-46)

Northern States Power Company, a Minnesota corporation
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MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

PEAK CONTROLLED TIME OF DAY SERVICE (Continued)
RATE CODE A24

Section No. 5
23rd Revised Sheet No. 45

RATE (Continued)

Demand Charge per Month per kW	Tier 1	Tier 2	
On Peak Period Demand			
Firm Demand			
June - September	$15.25	$15.25	R
Other Months	$10.71	$10.71	R
Controllable Demand (Jan-Dec)			
Level A: < 65% PF	Not Available	$9.05	R
Level B: ≥ 65% and < 85% PF	$7.35	$8.07	R
Level C: ≥ 85% PF	$6.75	$7.55	R
Short Notice Rider	6.25	Not Available	R
Off Peak Period Demand in Excess of On Peak Period Demand (Jan-Dec)	$2.35	$2.35	R

	January - December		
Voltage Discounts per Month	Per kW	Per kWh	
Primary Voltage	$0.80	$0.00106	R
Transmission Transformed Voltage	$1.55	$0.00271	R
Transmission Voltage	$2.35	$0.00281	R

In addition, customer bills under this rate are subject to the following adjustments and/or charges. D

FUEL CLAUSE
Bills are subject to the adjustments provided for in the Fuel Clause Rider.

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider, the Renewable Development Fund Rider, the Transmission Cost Recovery Rider, the Renewable Energy Standard Rider and the Mercury Cost Recovery Rider.

ENVIRONMENTAL IMPROVEMENT RIDER
Bills are subject to the adjustments provided for in the Environmental Improvement Rider.

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

(Continued on Sheet No. 5-46)

Northern States Power Company, a Minnesota corporation
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MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

PEAK CONTROLLED TIME OF DAY SERVICE Section No. 5
(Continued) 12th Revised Sheet No. 46
RATE CODE A24

LOW INCOME ENERGY DISCOUNT RIDER
Bills are subject to the adjustment provided for in the Low Income Energy Discount Rider.

The following are terms and conditions for service under this tariff.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

DEFINITION OF PEAK PERIODS
The on peak period is defined as those hours between 9:00 a.m. and 9:00 p.m. Monday through Friday, except the following holidays: New Year's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. When a designated holiday occurs on Saturday, the preceding Friday will be designated a holiday. When a designated holiday occurs on Sunday, the following Monday will be designated a holiday. The off peak period is defined as all other hours. Definition of on peak and off peak period is subject to change with change in Company's system operating characteristics.

DEFINITION OF PERFORMANCE FACTOR (PF)
Performance factor is defined in percentage terms as the average of the July and August calendar month unadjusted maximum Controllable Demand occurring from 1 p.m. to 7 p.m. on weekdays, or which has been permanently shifted out of normal control period times, divided by the unadjusted maximum annual Controllable Demand. Customers claiming permanent load shifts must provide verification to Company, based on NSP established criteria.

DETERMINATION OF DEMAND
Maximum Actual On Peak Period Demand in kW shall be the greatest 15-minute load for the on peak period during the billing month.

Adjusted On Peak Period Demand in kW for billing purposes shall be determined by dividing the Maximum Actual on peak demand by the power factor expressed in percent but not more than 90%, multiplying the quotient so obtained by 90%, and rounding to the nearest whole kW.

Maximum Actual Off Peak Period Demand in kW shall be the greatest 15-minute load for the off peak period during the billing month rounded to the nearest whole kW. In no month shall the off peak period demand for billing purposes be considered as less than the current month's actual off peak period demand in kW.

Off Peak Period Demand in Excess of On Peak Period Demand in kW to be billed shall be determined by subtracting the billing on peak period demand from the actual off peak period demand only if the off peak period demand is greater.

(Continued on Sheet No. 5-47)

Northern States Power Company, a Minnesota corporation
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MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

PEAK CONTROLLED TIME OF DAY SERVICE Section No. 5
(Continued) 7th Revised Sheet No. 47
RATE CODE A24

Predetermined Demand shall be specified and agreed to by the customer and Company. Customer's adjusted on peak demand must not exceed the predetermined demand level (PDL) during a control period.

Standard PDL customers must agree to a fixed demand level and limit load to that level during a control period.

Optional PDL customers must agree to reduce demand by a fixed amount during a control period. Customer's Firm Demand will vary from month-to-month while the Controllable Demand remains fixed each month. The Firm Demand will be the Adjusted Demand (based on the Maximum Actual Demand for the month) less the fixed amount of Controllable Demand. Customer's PDL will be the monthly adjusted on peak demand less the fixed load reduction. Customers selecting the Optional PDL must either be equipped with back-up generation to provide the fixed load reduction or have a specific load than can be separately sub-metered and has an annual load factor of 90% or greater.

Firm Demand for the billing month shall be the lesser of Predetermined Demand or Adjusted on Peak Period Demand, except in months when customer fails to control load to Predetermined Demand Level when requested by Company. In these months, Firm Demand shall be the adjusted on peak period demand established during the control period. For Optional PDL customers, Firm Demand shall be Adjusted On Peak Demand less Controllable Demand, except in months when customer fails to control the full amount of their fixed Controllable Demand, In the months the Firm Demand shall be the Adjusted On Peak Period Demand less the amount of Demand that was controlled as shown by meter measurement.

Controllable Demand shall be the difference between Adjusted on Peak Period Demand during the billing month and the greater of Predetermined Demand or firm demand, but never less than zero.

Minimum On Peak Demand to be billed each month as either Firm Demand Controllable Demand or combination of both shall not be less than the current month's Adjusted on Peak Period Demand in kW.

POWER FACTOR
The power factor for the month shall be determined by permanently installed metering equipment.

ANNUAL MINIMUM DEMAND CHARGE
The Annual Minimum Demand Charge shall be no less than six times the average monthly Firm Demand Charge per kW times the predetermined demand, plus six times the Controllable Demand Charge per kW times the maximum Controllable Demand.

(Continued on Sheet No. 47.1)

Northern States Power Company, a Minnesota corporation
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MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

PEAK CONTROLLED TIME OF DAY SERVICE (Continued) Section No. 5
RATE CODE A24 6th Revised Sheet No. 47.1

TIER 1 ENERGY CONTROLLED SERVICE
Tier 1 Energy Controlled Service is available under this schedule subject to the provisions contained in the Tier 1 Energy Controlled Service Rider.

TIER 1 PEAK CONTROLLED SHORT NOTICE
Tier 1 Peak Controlled Short Notice option is available under this schedule subject to the provisions contained in the Tier 1 Peak Controlled Short Notice Rider.

COMPETITIVE SERVICE
Competitive Service is available under this schedule subject to the provisions contained in the Competitive Response Rider.

OTHER PROVISIONS
Peak Controlled Time of Day Service is also subject to provisions contained in Rules for Application of Peak Controlled Services.

TERMS AND CONDITIONS OF SERVICE
1. Alternating current service is provided at the following nominal voltages:
   a. Secondary Voltage: Single or three phase from 208 volts up to but not including 2,400 volts,
   b. Primary Voltage: Three phase from 2,400 volts up to but not including 69,000 volts,
   c. Transmission Transformed Voltage: Three phase from 2,400 volts up to but not including 69,000 volts, where service is provided at the Company's disconnecting means of a distribution substation transformer, or
   d. Transmission Voltage: Three phase at 69,000 volts or higher.

   Service voltage available in any given case is dependent upon voltage and capacity of Company lines in vicinity of customer's premises.

2. Transmission Transformed Service is available only to customers served by an exclusively dedicated distribution feeder. Customer will be responsible for the cost of all facilities necessary to interconnect at the Company's disconnecting means of a distribution substation transformer.

3. Transmission Service is available at transmission voltage, subject to the terms and conditions contained in the Company's General Rules and Regulations, Section 5.1(B).

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MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

RULES FOR APPLICATION OF PEAK CONTROLLED SERVICES

Section No. 5
7th Revised Sheet No. 48

1. Customer has the responsibility of controlling own load to Predetermined Demand Level.

2. Customer must allow Company to inspect and approve the load control installation and equipment provided by customer.

3. If controlled demand is 10,000 kW or larger, Company may require customer to:
   a. Provide auxiliary contacts for remote indication of position of switch or circuit breaker used to control demand and wire auxiliary contacts into a connection point designated by Company,
   b. Install the remote breaker indication equipment provided by Company, and
   c. Provide a continuous 120 volt AC power source at the connection point for operation of the Company remote breaker indication equipment.

4. Company will endeavor to give customer one hour notice of commencement of control period, and as much additional notice as is practical. However, control period may be commenced without notice should Company determine such action is necessary.

5. Failure to Control Charge: An additional charge of $8.00 ($10.00 for Tier 1) per kW will apply during each Company specified control period to the amount by which customer's Maximum Adjusted Demand or Maximum Adjusted On Peak Period Demand exceeds their predetermined demand level. After three such customer failures to control load to their Predetermined Demand Level, Company reserves the right to increase the Predetermined Demand Level, or transfer customer to General Service or General Time of Day Service and apply the cancellation charge specified in customer's Electric Service Agreement.

6. The duration and frequency of control periods shall be at the discretion of Company. Control periods will normally occur when:
   a. Company expects a reasonable possibility of system load levels surpassing the level for which NSP has sufficient accredited capacity under the Midwest Reliability Organization (MRO) or any successor organization, including reserve requirements, or
   b. In Company's opinion, the reliability of the system is endangered.

(Continued on Sheet No. 5-49)

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MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

RULES FOR APPLICATION OF PEAK CONTROLLED SERVICES (Continued)

Section No. 5
6th Revised Sheet No. 49

7. Customer must execute an Electric Service Agreement with Company which will include:

   Peak Controlled Service - Tier 1
   a. A minimum initial 10 year term of service which includes a one year trial period and a three year cancellation notice effective after the initial term of service,
   b. The Predetermined Demand Level, or the fixed Controllable Demand if Optional PDL is selected which may be revised subject to approval by Company,
   c. Maximum 150 hours of interruption,
   d. Cancellation charge terms, and
   e. Control period notice.

   Peak Controlled Service - Tier 2
   a. A minimum initial five year term of service which includes a one year trial period and a six month cancellation notice effective after the initial term of service,
   b. The Predetermined Demand Level, or the fixed Controllable Demand if Optional PDL is selected which may be revised subject to approval by Company,
   c. Maximum 80 hours of interruption,
   d. Cancellation charge terms, and
   e. Control period notice.

8. Peak Controlled Service customers choosing the Tier 1 rate option will be subject to an additional monthly charge for a Company approved and installed two-way communications system. The system equipment allows NSP to determine remotely customer load levels and to notify customers of control periods.

9. Minimum Controllable Demand during the Company's peak season shall be 50 kW.

10. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service.

11. Company will determine, at a service location designated by Company, the number of services supplied. Customers requesting special facilities will be charged the additional costs incurred for such facilities.

(Continued on Sheet No. 5-50)

Northern States Power Company, a Minnesota corporation
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MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

RULES FOR APPLICATION OF PEAK CONTROLLED SERVICES (Continued)

Section No. 5
6th Revised Sheet No. 50

12. Customers choosing the Predetermined Demand Level option requiring a fixed demand reduction will be subject to an additional charge for metering and billing when additional metering equipment is necessary. The additional charge is $17.00 per month for an application using a single meter in close proximity to customer's service point. The additional charge for more complex applications will be based on the actual costs of the specific application.

13. Company will maintain Firm Demand Charge rates at the General Service and General Time of Day Service levels, whichever is applicable.

14. Any customer with generating equipment which is operated in parallel with Company must comply with all requirements associated with parallel operations as specified in the General Rules and Regulations of the Company.

15. Any load served by customer generation during Company requested control periods must be served by Company at all other times.

16. Customers selecting Peak Controlled Services will normally remain at a specific Performance Factor level for a minimum of one year, subject to the Company's discretion. The Company may transfer customers between Performance Factor levels following verification of a customer's performance, as defined in the applicable rate schedule and as specified in the customer's Electric Service Agreement. This rate contemplates that increases in summer Controllable Demand, which thereby affect a customer's Performance Factor level, will be at sufficient consumption levels to yield a July and August calendar month load factor of 34% or greater. The Company reserves the right to limit the customer's eligibility to be on a higher Performance Factor level due to the above restriction.

Northern States Power Company, a Minnesota corporation
and wholly owned subsidiary of Xcel Energy Inc.
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ENERGY CONTROLLED SERVICE (CLOSED) Section No. 5
RATE CODE A26 8th Revised Sheet No. 51

CANCELED

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President and CEO of Northern States Power Company
Docket No. E002/GR-05-1428 Order Date: 09-01-06

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ENERGY CONTROLLED SERVICE (CLOSED) Section No. 5
(Continued) 8th Revised Sheet No. 52
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MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

ENERGY CONTROLLED SERVICE (CLOSED) Section No. 5
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ENERGY CONTROLLED SERVICE (CLOSED) Section No. 5
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ENERGY CONTROLLED SERVICE (CLOSED) Section No. 5
(Continued) 1st Revised Sheet No. 55
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ENERGY CONTROLLED SERVICE (CLOSED) (Continued) Section No. 5
RATE CODE A26 1st Revised Sheet No. 56

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Northern States Power Company, a Minnesota corporation
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ENERGY CONTROLLED SERVICE (CLOSED) Section No. 5
(Continued) 1st Revised Sheet No. 57
RATE CODE A26

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MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

EXPERIMENTAL REAL TIME PRICING SERVICE (CLOSED)
RATE CODE A60 (FIRM) AND
RATE CODE A61 (CONTROLLABLE)

Section No. 5
7th Revised Sheet No. 58

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EXPERIMENTAL REAL TIME PRICING SERVICE (CLOSED) Section No. 5
(Continued) 9th Revised Sheet No. 59
RATE CODE A60 (FIRM) AND
RATE CODE A61 (CONTROLLABLE)

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MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

EXPERIMENTAL REAL TIME PRICING SERVICE (CLOSED) Section No. 5
(Continued) 2nd Revised Sheet No. 60
RATE CODE A60 (FIRM) AND
RATE CODE A61 (CONTROLLABLE)

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EXPERIMENTAL REAL TIME PRICING SERVICE (CLOSED)
(Continued)
RATE CODE A60 (FIRM) AND
RATE CODE A61 (CONTROLLABLE)

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MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

EXPERIMENTAL REAL TIME PRICING SERVICE (CLOSED) Section No. 5
(Continued) 2nd Revised Sheet No. 62
RATE CODE A60 (FIRM) AND
RATE CODE A61 (CONTROLLABLE)

CANCELED

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MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

EXPERIMENTAL REAL TIME PRICING SERVICE (CLOSED) Section No. 5
(Continued) 2nd Revised Sheet No. 63
RATE CODE A60 (FIRM) AND
RATE CODE A61 (CONTROLLABLE)

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MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

REAL TIME PRICING SERVICE Section No. 5
RATE CODE: A62 (FIRM), A63 (CONTROLLABLE) 11th Revised Sheet No. 64

AVAILABILITY

Available to customers with a minimum peak demand of 1,000 kW. Availability may be restricted to limit total customer peak demand to a maximum of 150,000 kW. The controllable service option requires a minimum controllable load of 500 kW.

RATE

Customer Charge per Month $300.00

Demand Charge per Month per kW
Contract Demand $9.94 R

Distribution Demand by Voltage

Secondary	Primary	Transmission Transformed	Transmission
$1.97	$0.97	$0.36	$0.00

R

Energy Charge per kWh

	Day-Type 1	2	3	4	5	6	7	8	
12 a.m.-6 a.m.	$0.03432	$0.02800	$0.02552	$0.02391	$0.02324	$0.02189	$0.02113	$0.01978	R
6 a.m.- 9 a.m.	$0.06181	$0.04925	$0.03932	$0.04111	$0.03977	$0.03446	$0.02775	$0.02243	R
9 a.m.-12 p.m.	$0.16995	$0.09623	$0.06050	$0.04817	$0.03701	$0.02991	$0.02471	$0.02331	
12 p.m.- 6 p.m.	$0.28050	$0.18790	$0.09735	$0.05743	$0.03701	$0.02991	$0.02471	$0.02331	R
6 p.m.- 9 p.m.	$0.20679	$0.13310	$0.07845	$0.04959	$0.03701	$0.02991	$0.02471	$0.02331	
9 p.m.-12 a.m.	$0.06181	$0.04925	$0.04302	$0.03724	$0.03051	$0.02784	$0.02425	$0.02243	R

Day-type energy charges are subject to the Stability Factor Adjustment provision. R

Annual Day-Type Distribution

Normal	5	5	10	35	60	110	60	80	R
Maximum	8	8	16	50	n/a	n/a	n/a	n/a	

Limited Energy Surcharge per kWh $0.2000
All kWh during peak period hours in excess of Contract Demand

Energy Charge Credit per Month $0.01143
All kWh in excess of 400 times Contract Demand, not to exceed 50% of total kWh R

Energy Charge Voltage Discount per kWh

Primary	Transmission Transformed	Transmission
$0.00105	$0.00267	$0.00277

R

R

(Continued on Sheet No. 5-65)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

REAL TIME PRICING SERVICE Section No. 5
RATE CODE: A62 (FIRM), A63 (CONTROLLABLE) 10th Revised Sheet No. 64

AVAILABILITY
Available to customers with a minimum peak demand of 1,000 kW. Availability may be restricted to limit total customer peak demand to a maximum of 150,000 kW. The controllable service option requires a minimum controllable load of 500 kW.

RATE

Customer Charge per Month $300.00

Demand Charge per Month per kW
Contract Demand $10.43

Distribution Demand by Voltage

Secondary	Primary	Transmission Transformed	Transmission
$2.07	$1.07	$0.46	$0.00

Energy Charge per kWh

	Day-Type 1	2	3	4	5	6	7	8	
12 a.m.-6 a.m.	$0.03603	$0.02939	$0.02679	$0.02510	$0.02440	$0.02298	$0.02218	$0.02076	R
6 a.m.- 9 a.m.	$0.06489	$0.05170	$0.04128	$0.04315	$0.04175	$0.03617	$0.02913	$0.02355	R
9 a.m.-12 p.m.	$0.17840	$0.10102	$0.06351	$0.05057	$0.03885	$0.03140	$0.02594	$0.02447	R
12 p.m.- 6 p.m.	$0.29445	$0.19725	$0.10219	$0.06029	$0.03885	$0.03140	$0.02594	$0.02447	R
6 p.m.- 9 p.m.	$0.21708	$0.13972	$0.08235	$0.05206	$0.03885	$0.03140	$0.02594	$0.02447	R
9 p.m.-12 a.m.	$0.06489	$0.05170	$0.04516	$0.03909	$0.03203	$0.02922	$0.02546	$0.02355	R

Day-type energy charges are subject to the Stability Factor Adjustment provision.

Annual Day-Type Distribution

Normal	5	5	10	35	60	110	60	80
Maximum	8	8	16	50	n/a	n/a	n/a	n/a

Limited Energy Surcharge per kWh $0.2100
All kWh during peak period hours in excess of Contract Demand

Energy Charge Credit per Month $0.0120
All kWh in excess of 400 times Contract Demand, not to exceed 50% of total kWh

Energy Charge Voltage Discount per kWh

Primary	Transmission Transformed	Transmission	
$0.00108	$0.00274	$0.00285	R

(Continued on Sheet No. 5-65)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

REAL TIME PRICING SERVICE Section No. 5
RATE CODE: A62 (FIRM), A63 (CONTROLLABLE) 9th Revised Sheet No. 64

AVAILABILITY

Available to customers with a minimum peak demand of 1,000 kW. Availability may be restricted to limit total customer peak demand to a maximum of 150,000 kW. The controllable service option requires a minimum controllable load of 500 kW.

RATE

Customer Charge per Month $300.00

Demand Charge per Month per kW
Contract Demand $10.14 R

Distribution Demand by Voltage

Secondary	Primary	Transmission Transformed	Transmission
$2.07	$1.07	$0.46	$0.00

Energy Charge per kWh	Day-Type 1	2	3	4	5	6	7	8	
12 a.m.-6 a.m.	$0.03524	$0.02878	$0.02626	$0.02462	$0.02393	$0.02255	$0.02178	$0.02040	R
6 a.m.- 9 a.m.	$0.06328	$0.05046	$0.04033	$0.04215	$0.04080	$0.03537	$0.02853	$0.02311	R
9 a.m.-12 p.m.	$0.17355	$0.09838	$0.06193	$0.04936	$0.03797	$0.03073	$0.02543	$0.02401	R
12 p.m.- 6 p.m.	$0.28629	$0.19186	$0.09951	$0.05880	$0.03797	$0.03073	$0.02543	$0.02401	R
6 p.m.- 9 p.m.	$0.21113	$0.13597	$0.08023	$0.05081	$0.03797	$0.03073	$0.02543	$0.02401	R
9 p.m.-12 a.m.	$0.06328	$0.05046	$0.04410	$0.03821	$0.03135	$0.02862	$0.02496	$0.02311	R

Day-type energy charges are subject to the Stability Factor Adjustment provision.

Annual Day-Type Distribution	1	2	3	4	5	6	7	8
Normal	5	5	10	35	60	110	60	80
Maximum	8	8	16	50	n/a	n/a	n/a	n/a

Limited Energy Surcharge per kWh $0.2100 R
All kWh during peak period hours in excess of Contract Demand

Energy Charge Credit per Month $0.0120
All kWh in excess of 400 times Contract Demand, not to exceed 50% of total kWh

Energy Charge Voltage Discount per kWh

Primary	Transmission Transformed	Transmission	
$0.00106	$0.00271	$0.00281	R

(Continued on Sheet No. 5-65)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

REAL TIME PRICING SERVICE (Continued) Section No. 5
RATE CODE: A62 (FIRM), A63 (CONTROLLABLE) 22nd Revised Sheet No. 65

DAY-TYPE
Separate energy charges are defined for each of eight day-types. Company will normally designate the applicable day-type for each day by 4:00 p.m. of the preceding day. If Company has not designated the applicable day by 4:00 p.m., the day-type will be the same as the last designated day-type, unless Company later designates a lower cost day-type.

CONTRACT
Customers must contract for this service through an Electric Service Agreement with Company. Contract period will normally be for one year.

FUEL CLAUSE
Bills are subject to the adjustments provided for in the Fuel Clause Rider.

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider, the Renewable Development Fund Rider, the Transmission Cost Recovery Rider, the Renewable Energy Standard Rider and the Mercury Cost Recovery Rider.

ENVIRONMENTAL IMPROVEMENT RIDER
Bills are subject to the adjustments provided for in the Environmental Improvement Rider.

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

LOW INCOME ENERGY DISCOUNT RIDER
Bills are subject to the adjustment provided for in the Low Income Energy Discount Rider.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

PEAK PERIOD HOURS DEFINITION
Peak period hours are the nine hours between 9:00 a.m. and 6:00 p.m. for day-types 1, 2, 3, 4, 5, and 6. No peak period hours are applicable for day-types 7 and 8.

(Continued on Sheet No. 5-65.1)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

REAL TIME PRICING SERVICE (Continued) Section No. 5
RATE CODE: A62 (FIRM), A63 (CONTROLLABLE) 5th Revised Sheet No. 65.1

STABILITY FACTOR ADJUSTMENT

Day-type energy charges will be adjusted by a stability factor to compensate for departures from the normal distribution of day-types. The average day-type energy charge, weighted with system loads, will be determined for actual and normal day-types. Stability factors of no more than five percent will be implemented following an annualized differential that exceeds two percent, and discontinued after the differential for the preceding 12 months is less than one percent. Customers will be notified of the effective date and amount of any stability factor adjustment before that adjustment is implemented, changed or discontinued. No stability factor adjustment will apply to customers receiving this service for fewer months than used to determine the adjustment.

POWER FACTOR

The power factor for the month shall be determined by permanently installed metering equipment. Company may require customer to install Company-approved equipment to maintain a power factor of not less than 90%.

(Continued on Sheet No. 5-66)

Date Filed: 11-02-15 By: Christopher B. Clark Effective Date: 10-01-17
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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

REAL TIME PRICING SERVICE (Continued) Section No. 5
RATE CODE: A62 (FIRM), A63 (CONTROLLABLE) 9th Revised Sheet No. 66

DETERMINATION OF DEMAND

Contract Demand in kW is designated by customer and is fixed for no less than 12 months. Customers are allowed a maximum of one opportunity to revise to their contract demand level in any continuous 12-month period. In no month shall the demand to be billed be considered as less than the actual or expected average kW load during peak period hours of the billing month. In all months, the Contract Demand designated by customer shall be used to determine the kWh sales applied to the Limited Energy Surcharge and the Energy Charge Credit.

Distribution Demand in kW shall be the greatest 15 minute load that occurred during the past 12 months, including the current billing month, rounded to the nearest whole kW. Additional demand that may result from customer's use of contracted standby or supplemental capacity is not included in the determination of distribution demand.

CONTROLLABLE SERVICE OPTION

The controllable service option is available to customers that agree to control a minimum load of 500 kW to a predetermined level whenever required by Company. The applicable monthly controllable demand credit is applied customer's monthly controllable demand. The applicable limited energy charge per kWh replaces the charge for firm service.

Controllable Demand Credit per Month per kW			Limited Energy Surcharge per kWh	
	Jun-Sep	Other Months		
Level A: < 65% PF	$5.36	$1.04	$0.1353	R
Level B: ≥ 65% and < 85% PF	$6.16	$1.84	$0.0962	R
Level C: ≥ 85% PF	$6.67	$2.34	$0.0772	R

Controllable Demand in kW is the difference between Contract Demand for the billing month and Predetermined Demand Level.

Predetermined Demand Level shall be specified and agreed to by the customer and Company, and may not exceed the Contract Demand. Customer's demand must not exceed the predetermined demand level (PDL) during a control period.

Performance Factor (PF) is defined in percentage terms as the average of the July and August calendar month maximum Controllable Demand occurring from 1:00 p.m. to 7:00 p.m. on weekdays, divided by the maximum annual Controllable Demand. Customer's representative load characteristics will be used to determine customer's performance factor. Company reserves the right to determine customer's eligibility for performance factor levels and may transfer customers between levels following verification of a customer's performance.

(Continued on Sheet No. 5-67)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

REAL TIME PRICING SERVICE (Continued) Section No. 5
RATE CODE: A62 (FIRM), A63 (CONTROLLABLE) 8th Revised Sheet No. 66

DETERMINATION OF DEMAND

Contract Demand in kW is designated by customer and is fixed for no less than 12 months. Customers are allowed a maximum of one opportunity to revise to their contract demand level in any continuous 12-month period. In no month shall the demand to be billed be considered as less than the actual or expected average kW load during peak period hours of the billing month. In all months, the Contract Demand designated by customer shall be used to determine the kWh sales applied to the Limited Energy Surcharge and the Energy Charge Credit.

Distribution Demand in kW shall be the greatest 15 minute load that occurred during the past 12 months, including the current billing month, rounded to the nearest whole kW. Additional demand that may result from customer's use of contracted standby or supplemental capacity is not included in the determination of distribution demand.

CONTROLLABLE SERVICE OPTION

The controllable service option is available to customers that agree to control a minimum load of 500 kW to a predetermined level whenever required by Company. The applicable monthly controllable demand credit is applied customer's monthly controllable demand. The applicable limited energy charge per kWh replaces the charge for firm service.

Controllable Demand Credit per Month per kW			Limited Energy Surcharge per kWh	
	Jun-Sep	Other Months		
Level A: < 65% PF	$5.63	$1.09	$0.1420	R
Level B: ≥ 65% and < 85% PF	$6.47	$1.93	$0.1010	R
Level C: ≥ 85% PF	$7.00	$2.46	$0.0810	R

Controllable Demand in kW is the difference between Contract Demand for the billing month and Predetermined Demand Level.

Predetermined Demand Level shall be specified and agreed to by the customer and Company, and may not exceed the Contract Demand. Customer's demand must not exceed the predetermined demand level (PDL) during a control period.

Performance Factor (PF) is defined in percentage terms as the average of the July and August calendar month maximum Controllable Demand occurring from 1:00 p.m. to 7:00 p.m. on weekdays, divided by the maximum annual Controllable Demand. Customer's representative load characteristics will be used to determine customer's performance factor. Company reserves the right to determine customer's eligibility for performance factor levels and may transfer customers between levels following verification of a customer's performance.

(Continued on Sheet No. 5-67)

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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

REAL TIME PRICING SERVICE (Continued) Section No. 5
RATE CODE: A62 (FIRM), A63 (CONTROLLABLE) 7th Revised Sheet No. 66

DETERMINATION OF DEMAND

Contract Demand in kW is designated by customer and is fixed for no less than 12 months. Customers are allowed a maximum of one opportunity to revise to their contract demand level in any continuous 12-month period. In no month shall the demand to be billed be considered as less than the actual or expected average kW load during peak period hours of the billing month. In all months, the Contract Demand designated by customer shall be used to determine the kWh sales applied to the Limited Energy Surcharge and the Energy Charge Credit.

Distribution Demand in kW shall be the greatest 15 minute load that occurred during the past 12 months, including the current billing month, rounded to the nearest whole kW. Additional demand that may result from customer's use of contracted standby or supplemental capacity is not included in the determination of distribution demand.

CONTROLLABLE SERVICE OPTION

The controllable service option is available to customers that agree to control a minimum load of 500 kW to a predetermined level whenever required by Company. The applicable monthly controllable demand credit is applied customer's monthly controllable demand. The applicable limited energy charge per kWh replaces the charge for firm service.

Controllable Demand Credit per Month per kW			Limited Energy Surcharge per kWh	
	Jun-Sep	Other Months		
Level A: < 65% PF	$5.63	$1.09	$0.1380	R
Level B: ≥ 65% and < 85% PF	$6.47	$1.93	$0.0980	R
Level C: ≥ 85% PF	$7.00	$2.46	$0.0780	R

Controllable Demand in kW is the difference between Contract Demand for the billing month and Predetermined Demand Level.

Predetermined Demand Level shall be specified and agreed to by the customer and Company, and may not exceed the Contract Demand. Customer's demand must not exceed the predetermined demand level (PDL) during a control period.

Performance Factor (PF) is defined in percentage terms as the average of the July and August calendar month maximum Controllable Demand occurring from 1:00 p.m. to 7:00 p.m. on weekdays, divided by the maximum annual Controllable Demand. Customer's representative load characteristics will be used to determine customer's performance factor. Company reserves the right to determine customer's eligibility for performance factor levels and may transfer customers between levels following verification of a customer's performance.

(Continued on Sheet No. 5-67)

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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

REAL TIME PRICING SERVICE (Continued) Section No. 5
RATE CODE: A62 (FIRM), A63 (CONTROLLABLE) 6th Revised Sheet No. 67

Controllable Service Terms and Conditions

1. Company will endeavor to give customer one hour notice of commencement of control period.

2. An additional charge of $8.00 per kW for failure to control will apply during each Company specified control period to the amount that customer's maximum power factor adjusted on peak demand exceeds their predetermined demand level.

3. The duration and frequency of control periods shall be at the discretion of Company. Control periods will normally occur when Company expects a reasonable possibility of system load levels surpassing the level for which NSP has sufficient accredited capacity under the Midwest Reliability Organization (MRO) or any successor organization, including reserve requirements, or when in Company's opinion, the reliability of the system is endangered. Customers will be separated into two groups by Company with control periods applicable to one or both groups. Customer groups are determined by geographical location and equivalent total controllable load. Control periods will apply to both customer groups at times of the highest forecast system load levels. Control periods at other high load times may apply to only one of the customer groups. Customer groups will be defined as subject to control periods on either even or odd numbered days.

4. Maximum duration of all control periods specified by Company will be 80 hours per year.

5. Customer may revise predetermined demand level subject to approval by Company.

6. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service.

7. Any customer with generating equipment that is operated in parallel with Company must comply with all requirements associated with parallel operations as specified in the General Rules and Regulations of the Company.

8. Any load served by customer generation during Company requested control periods must normally be served by Company.

(Continued on Sheet No. 5-68)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

REAL TIME PRICING SERVICE (Continued) Section No. 5
RATE CODE: A62 (FIRM), A63 (CONTROLLABLE) 5th Revised Sheet No. 68

STANDBY SERVICE
Standby service is available under this schedule subject to the provisions contained in the Standby Service Rider.

TERMS AND CONDITIONS OF SERVICE
1. Alternating current service is provided at the following nominal voltages:
   a. Secondary Voltage: Single or three phase from 208 volts up to but not including 2,400 volts,
   b. Primary Voltage: Three phase from 2,400 volts up to but not including 69,000 volts,
   c. Transmission Transformed Voltage: Three phase from 2,400 volts up to but not including 69,000 volts, where service is provided at the Company's disconnecting means of a distribution substation transformer, or
   d. Transmission Voltage: Three phase at 69,000 volts or higher.

   Service voltage available in any given case is dependent upon voltage and capacity of Company lines in vicinity of customer's premises.

2. Transmission Transformed Service is available only to customers served by an exclusively dedicated distribution feeder. Customer will be responsible for the cost of all facilities necessary to interconnect at the Company's disconnecting means of a distribution substation transformer.

3. Transmission Service is available at transmission voltage, subject to the terms and conditions contained in the Company's General Rules and Regulations, Section 5.1(B).

4. Company will provide, install, and maintain equipment necessary to communicate real-time prices to customers. Customer will provide for a dedicated telephone line service approved by Company.

5. Customer will pay a cancellation charge for contract cancellation prior to the end of a contract period. The cancellation charge is $1,000.00, plus the difference between customer's bills recalculated using customer's previous rate schedule and this rate schedule if such difference is greater than zero.

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

LIGHT RAIL LINE TARIFF
RATE CODE A29

Section No. 5
17th Revised Sheet No. 71

AVAILABILITY
Available to the Metropolitan Council's light rail transit lines for all electric power and energy required by its Traction Station service locations. Traction Stations will be aggregated as lines as they are put into service. Traction Stations common to more than one line will be aggregated with the line with which they were originally put into service.

RATE

Customer Charge per Month per Traction Station		$100.00	
Transmission and Distribution Demand Charge per Month per kW			
All Traction Station On Peak Non-Coincident Billing Demands		$5.28	R
Off Peak Period Non-Coincident Demand in Excess of On Peak Period Non-Coincident Demand		$1.55	
Generation Demand Charge per Month per kW	**OCT-MAY**	**JUN-SEP**	
Rail Line On Peak Coincident Billing Demand	$4.41	$8.71	R
Energy Charge per kWh			
On Peak Period Energy		$0.04750	
Off Peak Period Energy		$0.02236	R
Energy Charge Credit per Month per kWh			
All Energy in Excess of 400 Hours Times the On Peak Period Coincident Billing Demand, Not to Exceed 50% of the Energy		$0.01303	R

In addition, customer bills under this rate are subject to the following adjustments and/or charges.

FUEL CLAUSE R
Bills are subject to the adjustments provided for in the Fuel Clause Rider.

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider, the Renewable Development Fund Rider, the Transmission Cost Recovery Rider, the Renewable Energy Standard Rider and the Mercury Cost Recovery Rider.

ENVIRONMENTAL IMPROVEMENT RIDER
Bills are subject to the adjustments provided for in the Environmental Improvement Rider.

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

(Continued on Sheet No. 5-72)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

LIGHT RAIL LINE TARIFF
RATE CODE A29

Section No. 5
16th Revised Sheet No. 71

AVAILABILITY
Available to the Metropolitan Council's light rail transit lines for all electric power and energy required by its Traction Station service locations. Traction Stations will be aggregated as lines as they are put into service. Traction Stations common to more than one line will be aggregated with the line with which they were originally put into service.

RATE

Customer Charge per Month per Traction Station		$100.00	
Transmission and Distribution Demand Charge per Month per kW			
All Traction Station On Peak Non-Coincident Billing Demands		$5.54	
Off Peak Period Non-Coincident Demand in Excess of On Peak Period Non-Coincident Demand		$1.55	
Generation Demand Charge per Month per kW	**OCT-MAY**	**JUN-SEP**	
Rail Line On Peak Coincident Billing Demand	$4.66	$9.20	R
Energy Charge per kWh			
On Peak Period Energy		$0.04990	R
Off Peak Period Energy		$0.02350	R
Energy Charge Credit per Month per kWh			
All Energy in Excess of 400 Hours Times the On Peak Period Coincident Billing Demand, Not to Exceed 50% of the Energy		$0.01370	R

In addition, customer bills under this rate are subject to the following adjustments and/or charges.

FUEL CLAUSE
Bills are subject to the adjustments provided for in the Fuel Clause Rider.

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider, the Renewable Development Fund Rider, the Transmission Cost Recovery Rider, the Renewable Energy Standard Rider and the Mercury Cost Recovery Rider.

ENVIRONMENTAL IMPROVEMENT RIDER
Bills are subject to the adjustments provided for in the Environmental Improvement Rider.

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

(Continued on Sheet No. 5-72)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

LIGHT RAIL LINE TARIFF
RATE CODE A29

Section No. 5
15th Revised Sheet No. 71

AVAILABILITY
Available to the Metropolitan Council's light rail transit lines for all electric power and energy required by its Traction Station service locations. Traction Stations will be aggregated as lines as they are put into service. Traction Stations common to more than one line will be aggregated with the line with which they were originally put into service.

RATE

Customer Charge per Month per Traction Station		$100.00	
Transmission and Distribution Demand Charge per Month per kW			
All Traction Station On Peak Non-Coincident Billing Demands		$5.54	R
Off Peak Period Non-Coincident Demand in Excess of On Peak Period Non-Coincident Demand		$1.55	R
Generation Demand Charge per Month per kW	**OCT-MAY**	**JUN-SEP**	
Rail Line On Peak Coincident Billing Demand	$4.37	$8.91	R
Energy Charge per kWh			
On Peak Period Energy		$0.04880	R
Off Peak Period Energy		$0.02298	R
Energy Charge Credit per Month per kWh			
All Energy in Excess of 400 Hours Times the On Peak Period Coincident Billing Demand, Not to Exceed 50% of the Energy		$0.01340	R

In addition, customer bills under this rate are subject to the following adjustments and/or charges. D

FUEL CLAUSE
Bills are subject to the adjustments provided for in the Fuel Clause Rider.

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider, the Renewable Development Fund Rider, the Transmission Cost Recovery Rider, the Renewable Energy Standard Rider and the Mercury Cost Recovery Rider.

ENVIRONMENTAL IMPROVEMENT RIDER
Bills are subject to the adjustments provided for in the Environmental Improvement Rider.

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

(Continued on Sheet No. 5-72)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

LIGHT RAIL LINE TARIFF (Continued) Section No. 5
RATE CODE A29 7th Revised Sheet No. 72

LOW INCOME ENERGY DISCOUNT RIDER
Bills are subject to the adjustment provided for in the Low Income Energy Discount Rider.

The following are terms and conditions for service under this tariff.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge of $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

DEFINITION OF PEAK PERIODS
The on peak period is defined as those hours between 9:00 a.m. and 9:00 p.m. The on peak period occurs Monday through Friday, except the following holidays: New Year's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. When a designated holiday occurs on Saturday, the preceding Friday will be designated a holiday. When the designated holiday occurs on a Sunday, the following Monday will be designated a holiday. The off peak period is defined as all other hours. Definition of on peak and off peak period is subject to change with change in Company's system operating characteristics.

DETERMINATION OF TRACTION STATION ON PEAK PERIOD NON-COINCIDENT DEMAND
The individual Traction Station Actual On Peak Period Non-Coincident Demand in kW shall be the greatest 15-minute load during the on peak periods during the month for which the bill is rendered for each and every Traction Station along the Light Rail Line. The individual Traction Station Adjusted On Peak Period Non-Coincident Demand in kW for any one Traction Station for billing purposes shall be determined by dividing the Actual On Peak Period Non-Coincident Demand by the power factor expressed in percent but not more than 90%, multiplying the quotient so obtained by 90%, and rounding to the nearest whole kW. The total Traction Station Adjusted On Peak Period Non-Coincident Demand in kW for billing purposes shall be the sum of the individual Adjusted On Peak Period Non-Coincident Demands from each and every Traction Station.

DETERMINATION OF TRACTION STATION OFF PEAK PERIOD NON-COINCIDENT DEMAND
The individual Traction Station Actual Off Peak Period Non-Coincident Demand in kW shall be the greatest 15-minute load during the off peak periods during the month for which the bill is rendered for each and every Traction Station along the Light Rail Line. The individual Traction Station Adjusted Off Peak Period Non-Coincident Demand in kW for any one Traction Station for billing purposes shall be determined by dividing the Actual Off Peak Period Non-Coincident Demand by the power factor expressed in percent but not more than 90%, multiplying the quotient so obtained by 90%, and rounding to the nearest whole kW. The total Traction Station Adjusted Off Peak Period Non-Coincident Demand in kW for billing purposes shall be the sum of the individual Adjusted Off Peak Period Non-Coincident Demands from each and every Traction Station.

(Continued on Sheet No. 5-73)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

LIGHT RAIL LINE TARIFF (Continued) Section No. 5
RATE CODE A29 6th Revised Sheet No. 73

DETERMINATION OF RAIL LINE ON PEAK PERIOD COINCIDENT DEMAND

The Rail Line Actual On Peak Period Coincident Demand in kW shall be the greatest simultaneous 15-minute load during the on peak periods during the month for which the bill is rendered for all of the Traction Stations along the Light Rail Line. The Rail Line Adjusted On Peak Period Coincident Demand in kW for billing purposes shall be determined by dividing the Actual On Peak Period Coincident Demand by the power factor expressed in percent but not more that 90%, multiplying the quotient so obtained by 90%, and rounding to the nearest whole kW.

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President, Northern States Power Company, a Minnesota corporation
Docket No. E002/GR-15-826 Order Date: 06-12-17

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

STREET LIGHTING SYSTEM SERVICE Section No. 5
RATE CODE A30 26th Revised Sheet No. 74

AVAILABILITY

Available for year-round illumination of public streets, parkways, and highways by High Pressure Sodium (HPS), Metal Halide or Light Emitting Diode (LED) luminaires supported on poles, where the facilities for this service are furnished by Company. Underground Service under this schedule is limited to areas having a Company owned underground electric distribution system. Standard Service includes a monthly payment for the lighting system cost. Pre-Pay Option requires customer payment for the lighting system cost before establishing service.

DETERMINATION OF CUSTOMER BILLS

Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and / or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

RATE

	Monthly Rate Per Luminaire				
	Standard Service			Pre-Pay	
Designation of Lamp (Lumens)	Overhead	Underground	Decorative	Option	
70W High Pressure Sodium	$9.63	$19.54	--	$5.97	R
100W High Pressure Sodium	$10.17	$20.07	$31.67	$6.66	
150W High Pressure Sodium	$10.95	$20.86	$32.84	$7.54	
200W High Pressure Sodium*	$12.88	--	--	--	
250W High Pressure Sodium	$13.87	$23.38	$34.89	$9.61	
400W High Pressure Sodium	$16.85	$26.06	$37.38	$12.42	
175W Metal Halide	$14.98	$27.90	$37.38	$13.54	
30-40W Light Emitting Diode (*4,000*)	$10.32	$20.22	--	$4.90	
50-75W Light Emitting Diode (*6,000*)	$11.01	$20.91	--	$5.49	
110-165W Light Emitting Diode (*14,000*)	$14.46	$23.96	--	$7.05	
200-250W Light Emitting Diode (*25,000*)	$17.98	$27.19	--	$8.93	R

*Closed to new customers

(Continued on Sheet No 5-74.1)

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President, Northern States Power Company, a Minnesota corporation
Docket No. E,G999/CI-17-895 Order Date: 05-10-19

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

STREET LIGHTING SYSTEM SERVICE Section No. 5
RATE CODE A30 25th Revised Sheet No. 74

AVAILABILITY

Available for year-round illumination of public streets, parkways, and highways by High Pressure Sodium (HPS), Metal Halide or Light Emitting Diode (LED) luminaires supported on poles, where the facilities for this service are furnished by Company. Underground Service under this schedule is limited to areas having a Company owned underground electric distribution system. Standard Service includes a monthly payment for the lighting system cost. Pre-Pay Option requires customer payment for the lighting system cost before establishing service.

DETERMINATION OF CUSTOMER BILLS

Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and / or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

RATE

	Monthly Rate Per Luminaire				
	Standard Service			Pre-Pay	
Designation of Lamp (Lumens)	Overhead	Underground	Decorative	Option	
70W High Pressure Sodium	$10.02	$20.32	--	$6.21	R
100W High Pressure Sodium	$10.58	$20.88	$32.94	$6.93	
150W High Pressure Sodium	$11.39	$21.70	$34.16	$7.84	
200W High Pressure Sodium*	$13.40	--	--	--	
250W High Pressure Sodium	$14.43	$24.32	$36.29	$10.00	
400W High Pressure Sodium	$17.53	$27.11	$38.88	$12.92	
175W Metal Halide	$15.58	$29.02	$38.88	$14.08	
30-40W Light Emitting Diode (*4,000*)	$10.73	$21.03	--	$5.17	
50-75W Light Emitting Diode (*6,000*)	$11.45	$21.75	--	$5.79	
110-165W Light Emitting Diode (*14,000*)	$15.02	$24.90	--	$7.44	
200-250W Light Emitting Diode (*25,000*)	$18.66	$28.24	--	$9.43	R

*Closed to new customers

(Continued on Sheet No 5-74.1)

Date Filed: 10-01-18 By: Christopher B. Clark Effective Date: 01-01-19
President, Northern States Power Company, a Minnesota corporation
Docket No. E002/GR-15-826 Order Date: 06-12-17

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

STREET LIGHTING SYSTEM SERVICE Section No. 5
RATE CODE A30 24th Revised Sheet No. 74

AVAILABILITY

Available for year-round illumination of public streets, parkways, and highways by High Pressure Sodium (HPS), Metal Halide or Light Emitting Diode (LED) luminaires supported on poles, where the facilities for this service are furnished by Company. Underground Service under this schedule is limited to areas having a Company owned underground electric distribution system. Standard Service includes a monthly payment for the lighting system cost. Pre-Pay Option requires customer payment for the lighting system cost before establishing service.

DETERMINATION OF CUSTOMER BILLS

Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and / or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

RATE

	Monthly Rate Per Luminaire				
	Standard Service				Pre-Pay
Designation of Lamp (Lumens)	Overhead	Underground	Decorative		Option
70W High Pressure Sodium	$9.82	$20.11	--		$6.09
100W High Pressure Sodium	$10.36	$20.66	$32.78		$6.79
150W High Pressure Sodium	$11.16	$21.45	$33.96		$7.68
200W High Pressure Sodium*	$13.13	--	--		--
250W High Pressure Sodium	$14.14	$23.96	$36.03		$9.78
400W High Pressure Sodium	$17.15	$26.68	$38.56		$12.62
175W Metal Halide	$15.28	$28.59	$38.56		$13.82
30-40W Light Emitting Diode (*4,000*)	$10.51	$20.81	--		$5.03
50-75W Light Emitting Diode (*6,000*)	$11.22	$21.50	--		$5.63
110-165W Light Emitting Diode (*14,000*)	$14.73	$24.54	--		$7.22
200-250W Light Emitting Diode (*25,000*)	$18.28	$27.81	--		$9.13

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*Closed to new customers

(Continued on Sheet No 5-74.1)

Date Filed: 11-02-15 By: Christopher B. Clark Effective Date: 10-01-17
President, Northern States Power Company, a Minnesota corporation
Docket No. E002/GR-15-826 Order Date: 06-12-17

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

STREET LIGHTING SYSTEM SERVICE (Continued) Section No. 5
RATE CODE A30 11th Revised Sheet No. 74.1

PRE-PAY OPTION SURCHARGE
A monthly surcharge per luminaire of 0.2% applies to the amount the purchase price exceeds $1,200.

In addition, customer bills under this rate are subject to the following adjustments and/or charges.

FUEL CLAUSE
Bills are subject to the adjustments provided for in the Fuel Clause Rider.

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider, the Renewable Development Fund Rider, the Transmission Cost Recovery Rider, the Renewable Energy Standard Rider and the Mercury Cost Recovery Rider.

ENVIRONMENTAL IMPROVEMENT RIDER
Bills are subject to the adjustments provided for in the Environmental Improvement Rider.

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

OTHER PROVISIONS
This schedule is also subject to provisions contained in Rules for Application of Street Lighting Rates.

Northern States Power Company, a Minnesota corporation
and wholly owned subsidiary of Xcel Energy Inc.
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

STREET LIGHTING SYSTEM SERVICE (CLOSED) Section No. 5
RATE CODE A31 11th Revised Sheet No. 75

CANCELED

Date Filed: 11-02-05 By: Cynthia L. Lesher Effective Date: 02-01-07
President and CEO of Northern States Power Company
Docket No. E002/GR-05-1428 Order Date: 09-01-06

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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

STREET LIGHTING ENERGY SERVICE (CLOSED) Section No. 5
RATE CODE A32 24th Revised Sheet No. 76

AVAILABILITY

Available for year-round illumination of public streets, parkways, and highways by electric lamps mounted on standards where customer owns a Company approved ornamental street lighting system complete with standards, luminaires with globes, lamps, and other appurtenances, together with all necessary cables extending between standards and to point of connection to Company's facilities as designated by Company. Service is limited to existing lighting systems being served under this schedule.

DETERMINATION OF CUSTOMER BILLS

Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and / or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

RATE

Designation of Lamp	Monthly Rate per Luminaire	
100W Mercury	$2.45	R
175W Mercury	$3.64	
250W Mercury	$4.94	
400W Mercury	$7.69	
700W Mercury	$12.78	
1,000W Mercury	$17.77	
50W High Pressure Sodium	$1.37	
70W High Pressure Sodium	$1.73	
100W High Pressure Sodium	$2.29	
150W High Pressure Sodium	$3.14	
200W High Pressure Sodium	$4.18	
250W High Pressure Sodium	$5.28	
400W High Pressure Sodium	$8.03	
750W High Pressure Sodium	$13.78	R
F72HO Fluorescent	$3.61	

(Continued on Sheet No. 5-77)

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President, Northern States Power Company, a Minnesota corporation
Docket No. E,G999/CI-17-895 Order Date: 05-10-19

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

STREET LIGHTING ENERGY SERVICE (CLOSED) Section No. 5
RATE CODE A32 23rd Revised Sheet No. 76

AVAILABILITY
Available for year-round illumination of public streets, parkways, and highways by electric lamps mounted on standards where customer owns a Company approved ornamental street lighting system complete with standards, luminaires with globes, lamps, and other appurtenances, together with all necessary cables extending between standards and to point of connection to Company's facilities as designated by Company. Service is limited to existing lighting systems being served under this schedule.

DETERMINATION OF CUSTOMER BILLS
Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and / or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

RATE

Designation of Lamp	Monthly Rate per Luminaire	
100W Mercury	$2.53	R
175W Mercury	$3.77	
250W Mercury	$5.12	
400W Mercury	$7.98	
700W Mercury	$13.27	
1,000W Mercury	$18.47	
50W High Pressure Sodium	$1.40	
70W High Pressure Sodium	$1.78	
100W High Pressure Sodium	$2.37	
150W High Pressure Sodium	$3.25	
200W High Pressure Sodium	$4.33	
250W High Pressure Sodium	$5.47	
400W High Pressure Sodium	$8.33	
750W High Pressure Sodium	$14.32	R
F72HO Fluorescent	$3.61	

(Continued on Sheet No. 5-77)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

STREET LIGHTING ENERGY SERVICE (CLOSED) Section No. 5
RATE CODE A32 22nd Revised Sheet No. 76

AVAILABILITY
Available for year-round illumination of public streets, parkways, and highways by electric lamps mounted on standards where customer owns a Company approved ornamental street lighting system complete with standards, luminaires with globes, lamps, and other appurtenances, together with all necessary cables extending between standards and to point of connection to Company's facilities as designated by Company. Service is limited to existing lighting systems being served under this schedule.

DETERMINATION OF CUSTOMER BILLS
Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and / or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

RATE

Designation of Lamp	Monthly Rate per Luminaire	
100W Mercury	$2.47	R
175W Mercury	$3.68	
250W Mercury	$4.99	
400W Mercury	$7.77	
700W Mercury	$12.92	
1,000W Mercury	$17.98	
50W High Pressure Sodium	$1.38	
70W High Pressure Sodium	$1.74	
100W High Pressure Sodium	$2.32	
150W High Pressure Sodium	$3.17	
200W High Pressure Sodium	$4.22	
250W High Pressure Sodium	$5.34	
400W High Pressure Sodium	$8.12	
750W High Pressure Sodium	$13.94	R
F72HO Fluorescent	$3.61	D

(Continued on Sheet No. 5-77)

Date Filed: 11-02-15 By: Christopher B. Clark Effective Date: 10-01-17
President, Northern States Power Company, a Minnesota corporation
Docket No. E002/GR-15-826 Order Date: 06-12-17

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

STREET LIGHTING ENERGY SERVICE (CLOSED) Section No. 5
(Continued) 11th Revised Sheet No. 77
RATE CODE A32

In addition, customer bills under this rate are subject to the following adjustments and/or charges.

FUEL CLAUSE
Bills are subject to the adjustments provided for in the Fuel Clause Rider.

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider, the Renewable Development Fund Rider, the Transmission Cost Recovery Rider, the Renewable Energy Standard Rider and the Mercury Cost Recovery Rider.

ENVIRONMENTAL IMPROVEMENT RIDER
Bills are subject to the adjustments provided for in the Environmental Improvement Rider.

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

OTHER PROVISIONS
This schedule is also subject to provisions contained in Rules for Application of Street Lighting Rates.

Date Filed: 11-02-15 By: Christopher B. Clark Effective Date: 10-01-17
President, Northern States Power Company, a Minnesota corporation
Docket No. E002/GR-15-826 Order Date: 06-12-17

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

STREET LIGHTING ENERGY SERVICE - METERED Section No. 5
RATE CODE A34 29th Revised Sheet No. 78

AVAILABILITY
Available for year-round illumination of public streets, parkways, and highways by electric lamps mounted on standards where customer owns and maintains an ornamental street lighting system complete with standards, luminaires with globes, lamps, photocells, and other appurtenances, together with all necessary cables extending between standards and to point of connection to Company's meter as designated by Company.

DETERMINATION OF CUSTOMER BILLS
Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and / or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

RATE

Customer Charge per Meter per Month	$5.00	
Energy Charge per kWh	$0.04534	R

FUEL CLAUSE
Bills are subject to the adjustments provided for in the Fuel Clause Rider.

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider, the Renewable Development Fund Rider, the Transmission Cost Recovery Rider, the Renewable Energy Standard Rider and the Mercury Cost Recovery Rider.

ENVIRONMENTAL IMPROVEMENT RIDER
Bills are subject to the adjustments provided for in the Environmental Improvement Rider.

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

(Continued on Sheet No. 78.1)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

STREET LIGHTING ENERGY SERVICE - METERED Section No. 5
RATE CODE A34 28th Revised Sheet No. 78

AVAILABILITY
Available for year-round illumination of public streets, parkways, and highways by electric lamps mounted on standards where customer owns and maintains an ornamental street lighting system complete with standards, luminaires with globes, lamps, photocells, and other appurtenances, together with all necessary cables extending between standards and to point of connection to Company's meter as designated by Company.

DETERMINATION OF CUSTOMER BILLS
Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and / or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

RATE

Customer Charge per Meter per Month	$5.00	
Energy Charge per kWh	$0.04716	R

FUEL CLAUSE
Bills are subject to the adjustments provided for in the Fuel Clause Rider.

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider, the Renewable Development Fund Rider, the Transmission Cost Recovery Rider, the Renewable Energy Standard Rider and the Mercury Cost Recovery Rider.

ENVIRONMENTAL IMPROVEMENT RIDER
Bills are subject to the adjustments provided for in the Environmental Improvement Rider.

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

(Continued on Sheet No. 78.1)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

STREET LIGHTING ENERGY SERVICE - METERED Section No. 5
RATE CODE A34 27th Revised Sheet No. 78

AVAILABILITY
Available for year-round illumination of public streets, parkways, and highways by electric lamps mounted on standards where customer owns and maintains an ornamental street lighting system complete with standards, luminaires with globes, lamps, photocells, and other appurtenances, together with all necessary cables extending between standards and to point of connection to Company's meter as designated by Company.

DETERMINATION OF CUSTOMER BILLS
Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and / or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

RATE

Customer Charge per Meter per Month	$5.00	R
Energy Charge per kWh	$0.04587	R

FUEL CLAUSE D
Bills are subject to the adjustments provided for in the Fuel Clause Rider.

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider, the Renewable Development Fund Rider, the Transmission Cost Recovery Rider, the Renewable Energy Standard Rider and the Mercury Cost Recovery Rider.

ENVIRONMENTAL IMPROVEMENT RIDER
Bills are subject to the adjustments provided for in the Environmental Improvement Rider.

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

(Continued on Sheet No. 78.1)

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President, Northern States Power Company, a Minnesota corporation
Docket No. E002/GR-15-826 Order Date: 06-12-17

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

STREET LIGHTING ENERGY SERVICE – METERED (Continued) Section No. 5
RATE CODE A34 6th Revised Sheet No. 78.1

In addition, customer bills under this rate are subject to the following adjustments and/or charges.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

CONDITIONS OF SERVICE
The customer owns and maintains ornamental street lighting system including underground cables, posts, lamps, ballasts, photocells, and glassware. Ballasts shall provide a power factor of at least 90% and photocells shall conform to specified daily operating schedule. Company furnishes energy only at central metered distribution points designated by Company. The daily operating schedule of the lamps shall be from approximately one-half hour after sunset until one-half hour before sunrise.

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President, Northern States Power Company, a Minnesota corporation
Docket No. E002/GR-15-826 Order Date: 06-12-17

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

STREET LIGHTING SERVICE - CITY OF ST. PAUL Section No. 5
RATE CODE A37 26th Revised Sheet No. 80

AVAILABILITY
Available to the City of St. Paul for furnishing, maintaining, and operating certain electrical connections, lines, and appurtenances thereto, and supplying electric current for city street lighting.

DETERMINATION OF CUSTOMER BILLS
Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and / or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

RATE

Designation of Lamp	Monthly Rate per Luminaire	
100W High Pressure Sodium	$5.48	R
150W High Pressure Sodium	$6.14	R
250W High Pressure Sodium	$8.60	R

In addition, customer bills under this rate are subject to the following adjustments and/or charges.

FUEL CLAUSE
Bills are subject to the adjustments provided for in the Fuel Clause Rider.

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider, the Renewable Development Fund Rider, the Transmission Cost Recovery Rider, the Renewable Energy Standard Rider and the Mercury Cost Recovery Rider.

ENVIRONMENTAL IMPROVEMENT RIDER
Bills are subject to the adjustments provided for in the Environmental Improvement Rider.

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

The following are terms and conditions for service under this tariff.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

(Continued on Sheet No. 5-81)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

STREET LIGHTING SERVICE - CITY OF ST. PAUL Section No. 5
RATE CODE A37 25th Revised Sheet No. 80

AVAILABILITY
Available to the City of St. Paul for furnishing, maintaining, and operating certain electrical connections, lines, and appurtenances thereto, and supplying electric current for city street lighting.

DETERMINATION OF CUSTOMER BILLS
Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and / or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

RATE

Designation of Lamp	Monthly Rate per Luminaire	
100W High Pressure Sodium	$5.70	R
150W High Pressure Sodium	$6.39	R
250W High Pressure Sodium	$8.95	R

In addition, customer bills under this rate are subject to the following adjustments and/or charges. D

FUEL CLAUSE
Bills are subject to the adjustments provided for in the Fuel Clause Rider.

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider, the Renewable Development Fund Rider, the Transmission Cost Recovery Rider, the Renewable Energy Standard Rider and the Mercury Cost Recovery Rider.

ENVIRONMENTAL IMPROVEMENT RIDER
Bills are subject to the adjustments provided for in the Environmental Improvement Rider.

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

The following are terms and conditions for service under this tariff.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

(Continued on Sheet No. 5-81)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

STREET LIGHTING SERVICE – CITY OF ST. PAUL Section No. 5
RATE CODE A37 14th Revised Sheet No. 81

OTHER PROVISIONS
This schedule is also subject to provisions contained in Rules for Application of Street Lighting Rates.

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Docket No. E002/GR-15-826 Order Date: 06-12-17

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

RULES FOR APPLICATION OF STREET LIGHTING RATES

Section No. 5
7th Revised Sheet No. 82

1. SERVICE INCLUDED IN RATE

a. *Street Lighting System Service*

Overhead, Underground, and Decorative
Company shall own, operate, and maintain the overhead and underground street lighting systems using Company's standard street lighting equipment.

Company Property
All poles, other material and equipment that may be used by Company in carrying out street lighting service shall be and remain the property of Company. Company shall have the right to install poles and other materials for street lighting service on or along public streets and alleys of customer and to remove the same upon expiration of term.

Terms and Conditions:

Standard Service
Except for customers choosing the pre-pay option for street lighting system service, the term of service will be a minimum of five (5) years. After the minimum five year service term, service shall continue thereafter for one (1) year terms, unless either party provides written notice at least ninety (90) days prior to the expiration of a term that customer intends to terminate the service. Existing lights that have been in service for more than five years at the time this Tariff provision is approved by the Commission will continue on 1-year terms until either party terminates the service based on the provisions listed above. Company shall furnish all electric energy necessary to operate the street lighting system, shall make all lamp and glassware renewals, clean the glassware, light and extinguish all lamps, make all ballast and starter renewals, and furnish all the materials and labor necessary for these services. Company shall also repair all damaged equipment.

Pre-Pay Option
Customer shall pay the Company upfront the costs associated with the entire ornamental street lighting system including underground cables, posts, lamps, ballasts, starters, photocells, and glassware. The Company retains ownership of the street lighting system. The street lighting system shall be Company approved and include a lamp type and wattage combination that corresponds to an existing Pre-Pay Option rate. Company shall furnish all electric energy necessary to operate the street lighting system, shall make all lamp and glassware renewals, clean the glassware, light and extinguish all lamps, make all ballast and starter renewals, and furnish all the materials and labor necessary for these services. Company shall also repair all damaged equipment for 25 years from the installation date. After 25 years, Company will repair damaged equipment when the damage is not associated with the age of the street lighting system. These repairs are routine in nature such as lamp, photo control, starter, and fuses.

(Continued on Sheet No. 5-83)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

RULES FOR APPLICATION OF Section No. 5
STREET LIGHTING RATES (Continued) 6th Revised Sheet No. 83

1. SERVICE INCLUDED IN RATE (Continued)

Prepay Option (Continued)
If in the Company's opinion, the condition of the street lighting system is such that replacement or significant renovation of the system is necessary (for example, due to underground faults, pole deterioration, ballast outage), the customer shall have two options:

(1) the customer must either transfer to the Street Lighting Energy Service – Metered rate, or
(2) reimburse Company for the installed cost of a replacement system.

Attachments
The Customer may not make any attachments, including but not limited to, banners, flags, signs, or holiday lighting, to the poles without the express written permission of Company. Approval of any such attachments will be at the sole discretion of the Company. In the event that any such attachments are made without written Company authorization, customer shall remove such attachments upon notice from Company. Any damage to Company property or other Company equipment caused by an unauthorized attachment by customer shall, after notice of damage to the customer be repaired by Company at the customer's expense. However, notice to customer prior to repair will not be required in case of an emergency or any other reason that requires immediate repair. In addition, if a street light outage is caused by an unauthorized attachment to Company property, service outage credits will not apply as described in paragraph 3 below.

b. *Street Lighting Energy Service*
The customer owns and maintains entire ornamental street lighting system including underground cables, posts, lamps, ballasts, photocells, and glassware. Ballasts shall provide a power factor of at least 90% and photocells shall conform to specified daily operating schedule. Company furnishes energy only at central distribution points designated by Company.

c. *City of St. Paul*
City owns and maintains lamp units, lamps, photocells, and glassware. Company owns and maintains distribution system, including hangers and furnishes energy at the lamp unit. Ballasts shall provide a power factor of at least 90% and photocells shall conform to specified daily operating schedule.

2. DAILY OPERATING SCHEDULE
The daily operating schedule of lamps shall be from approximately one-half hour after sunset until one-half hour before sunrise.

(Continued on Sheet No. 5-84)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

RULES FOR APPLICATION OF Section No. 5
STREET LIGHTING RATES (Continued) 6th Revised Sheet No. 84

3. OUTAGES

If illumination from any non-metered lamp is interrupted and the illumination is not resumed within 2 business days from the time the Company receives notice, 1/30th of the applicable monthly metered energy and fuel cost charges for the affected lamp(s) for each night of service outage shall be credited to the customer.

The Company shall apply such credits to all affected customers one time annually in the month of December of each year, together with an itemized list of the street lamps and/or poles associated with the credits.

Interruption of Company Performance:
In the event of the total or partial interruption of service where the Company is prevented from providing service, a customer shall not be charged under this tariff for the duration of time service cannot be provided. The Company will proceed with all reasonable diligence to put itself and its works in condition to resume and continue the supply of electric energy and the performance of the service. The Company shall not be responsible for any loss or damage resulting from the interruption or disturbance of service for any cause other than gross negligence of the Company. The Company shall not be liable for any loss of profits or other consequential damages resulting from the use of service or any interruption or disturbance of service.

4. SPECIAL SERVICES

a. *Street Lighting System Service*

Temporary Disconnection of Service (Street lighting facilities remain in place.)
When requested by the customer, Company will temporarily disconnect service to individual street lighting units provided the customer pays a monthly facilities charge equal to the regular monthly rate less the product of the average monthly kWh for the lighting unit and the energy charge from the Street Lighting Energy Service - Metered rate schedule. The customer must pay a charge of $25.00 to disconnect or reconnect each lighting unit.

Termination of Street Lighting Facilities
When requested by the customer, except for Pre-Pay Option lighting service, Company will remove all or a portion of a street lighting system and cease billing. The customer must pay termination costs for the removal and undepreciated value of facilities, less any salvage value, if the number of lights requested to be removed in any 12 month period exceeds 5% of the municipality's street lighting system.

(Continued on Sheet No. 5-84.1)

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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

RULES FOR APPLICATION OF Section No. 5
STREET LIGHTING RATES (Continued) 4th Revised Sheet No. 84.1

4. SPECIAL SERVICES (Continued)

b. *Street Lighting Energy Service*

Daily Operating Schedule Option

Reduced hours of operation from the standard daily operating schedule is available under the applicable commercial and industrial rate, subject to the following provisions:

(1) customer must install a meter socket at the service point, and
(2) customer shall provide all maintenance to lighting units and identify the lighting units with Company approved markings.

Disconnection of Service

During the period between customer disconnection and reconnection of street lighting units, Company will cease billing provided the disconnection is made on the line side of the lighting unit ballast. Customer disconnection not on the line side will require the customer to pay a charge to compensate for the lighting unit ballast core loss. When requested by the customer, Company will disconnect or reconnect street lighting units provided the customer pays a charge of $25.00 for the disconnection or reconnection of each lighting unit. The customer must identify all disconnected street lighting units with Company approved markings.

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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

SMALL MUNICIPAL PUMPING SERVICE Section No. 5
RATE CODE A40 30th Revised Sheet No. 85

AVAILABILITY
Available to municipal owned water works and municipal sewage systems for operation of pumping and treatment plants. (Rate schedule is applied separately to each delivery point.)

DETERMINATION OF CUSTOMER BILLS
Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and / or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

RATE

	Oct-May	Jun-Sep
Customer Charge per Month	$10.00	$10.00
Energy Charge per kWh	$0.07757	$0.09256

R

In addition, customer bills under this rate are subject to the following adjustments and/or charges.

FUEL CLAUSE
Bills are subject to the adjustments provided for in the Fuel Clause Rider.

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider, the Renewable Development Fund Rider, the Transmission Cost Recovery Rider, the Renewable Energy Standard Rider and the Mercury Cost Recovery Rider.

ENVIRONMENTAL IMPROVEMENT RIDER
Bills are subject to the adjustments provided for in the Environmental Improvement Rider.

MONTHLY MINIMUM CHARGE
Customer Charge.

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

LOW INCOME ENERGY DISCOUNT RIDER
Bills are subject to the adjustment provided for in the Low Income Energy Discount Rider.

(Continued on Sheet No. 5-86)

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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

SMALL MUNICIPAL PUMPING SERVICE Section No. 5
RATE CODE A40 29th Revised Sheet No. 85

AVAILABILITY
Available to municipal owned water works and municipal sewage systems for operation of pumping and treatment plants. (Rate schedule is applied separately to each delivery point.)

DETERMINATION OF CUSTOMER BILLS
Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and / or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

RATE

	Oct-May	Jun-Sep
Customer Charge per Month	$10.00	$10.00
Energy Charge per kWh	$0.08156	$0.09728

R

In addition, customer bills under this rate are subject to the following adjustments and/or charges.

FUEL CLAUSE
Bills are subject to the adjustments provided for in the Fuel Clause Rider.

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider, the Renewable Development Fund Rider, the Transmission Cost Recovery Rider, the Renewable Energy Standard Rider and the Mercury Cost Recovery Rider.

ENVIRONMENTAL IMPROVEMENT RIDER
Bills are subject to the adjustments provided for in the Environmental Improvement Rider.

MONTHLY MINIMUM CHARGE
Customer Charge.

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

LOW INCOME ENERGY DISCOUNT RIDER
Bills are subject to the adjustment provided for in the Low Income Energy Discount Rider.

(Continued on Sheet No. 5-86)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

SMALL MUNICIPAL PUMPING SERVICE Section No. 5
RATE CODE A40 28th Revised Sheet No. 85

AVAILABILITY
Available to municipal owned water works and municipal sewage systems for operation of pumping and treatment plants. (Rate schedule is applied separately to each delivery point.)

DETERMINATION OF CUSTOMER BILLS
Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and / or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

RATE

	Oct-May	Jun-Sep	
Customer Charge per Month	$10.00	$10.00	
Energy Charge per kWh	$0.07965	$0.09514	R

In addition, customer bills under this rate are subject to the following adjustments and/or charges. D

FUEL CLAUSE
Bills are subject to the adjustments provided for in the Fuel Clause Rider.

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider, the Renewable Development Fund Rider, the Transmission Cost Recovery Rider, the Renewable Energy Standard Rider and the Mercury Cost Recovery Rider.

ENVIRONMENTAL IMPROVEMENT RIDER
Bills are subject to the adjustments provided for in the Environmental Improvement Rider.

MONTHLY MINIMUM CHARGE
Customer Charge.

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

LOW INCOME ENERGY DISCOUNT RIDER
Bills are subject to the adjustment provided for in the Low Income Energy Discount Rider.

(Continued on Sheet No. 5-86)

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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

SMALL MUNICIPAL PUMPING SERVICE (Continued) Section No. 5
RATE CODE A40 7th Revised Sheet No. 86

The following are terms and conditions for service under this tariff.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

INSTALLATION OF DEMAND METERS
The Company shall install a demand meter for a customer when:
1. Customer's connected load is estimated to be 20 kW or greater, or
2. Customer is served single phase and has a service entrance capacity greater than 200 amperes, or
3. Customer is served three phase at 120/208 or 120/240 volts and has a service entrance capacity greater than 200 amperes, or
4. Customer is served three phase at 240/480 or 277/480 volts and has a service entrance capacity greater than 100 amperes, or

Customer's average monthly kWh use for four consecutive months exceeds 3,500 kWh.

If a demand meter is installed in accordance with the above, the customer may remain on the Small Municipal Pumping Service schedule as long as customer’s maximum demand is less than 25 kW. When the customer achieves an actual maximum demand of 25 kW or greater, the customer will be placed on the Municipal Pumping Service schedule in the next billing month. Customers with a billing demand of less than 25 kW for 12 consecutive months will be given the option of returning to the Small Municipal Pumping Service schedule.

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

MUNICIPAL PUMPING SERVICE Section No. 5
RATE CODE A41 31st Revised Sheet No. 87

AVAILABILITY
Available to municipal owned water works and municipal sewage systems for operation of pumping and treatment plants. (Rate schedule is applied separately to each delivery point.)

RATE

Customer Charge per Month	$25.64		
	Oct-May	Jun-Sep	
Service at Secondary Voltage			
Demand Charge per Month per kW	$10.49	$14.79	R
Energy Charge per kWh	$0.03407		R
Energy Charge Credit per Month per kWh			
All kWh in Excess of 400 Hours Times the Billing Demand	$0.01518		R
	January - December		
Voltage Discounts per Month	Per kW	Per kWh	
Primary Voltage	$0.80	$0.00105	R

In addition, customer bills under this rate are subject to the following adjustments and/or charges.

FUEL CLAUSE
Bills are subject to the adjustments provided for in the Fuel Clause Rider.

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider, the Renewable Development Fund Rider, the Transmission Cost Recovery Rider, the Renewable Energy Standard Rider and the Mercury Cost Recovery Rider.

ENVIRONMENTAL IMPROVEMENT RIDER
Bills are subject to the adjustments provided for in the Environmental Improvement Rider.

(Continued on Sheet No. 5-88)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

MUNICIPAL PUMPING SERVICE Section No. 5
RATE CODE A41 30th Revised Sheet No. 87

AVAILABILITY
Available to municipal owned water works and municipal sewage systems for operation of pumping and treatment plants. (Rate schedule is applied separately to each delivery point.)

RATE

Customer Charge per Month	$25.64		
	Oct-May	Jun-Sep	
Service at Secondary Voltage			
Demand Charge per Month per kW	$11.00	$15.54	R
Energy Charge per kWh	$0.03577		R
Energy Charge Credit per Month per kWh			
All kWh in Excess of 400 Hours Times the Billing Demand	$0.01593		R
	January - December		
Voltage Discounts per Month	Per kW	Per kWh	
Primary Voltage	$0.80	$0.00108	R

In addition, customer bills under this rate are subject to the following adjustments and/or charges.

FUEL CLAUSE
Bills are subject to the adjustments provided for in the Fuel Clause Rider.

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider, the Renewable Development Fund Rider, the Transmission Cost Recovery Rider, the Renewable Energy Standard Rider and the Mercury Cost Recovery Rider.

ENVIRONMENTAL IMPROVEMENT RIDER
Bills are subject to the adjustments provided for in the Environmental Improvement Rider.

(Continued on Sheet No. 5-88)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

MUNICIPAL PUMPING SERVICE Section No. 5
RATE CODE A41 29th Revised Sheet No. 87

AVAILABILITY
Available to municipal owned water works and municipal sewage systems for operation of pumping and treatment plants. (Rate schedule is applied separately to each delivery point.)

RATE

Customer Charge per Month	$25.64		R
	Oct-May	Jun-Sep	
Service at Secondary Voltage			
Demand Charge per Month per kW	$10.71	$15.25	R
Energy Charge per kWh	$0.03498		R
Energy Charge Credit per Month per kWh			
All kWh in Excess of 400 Hours Times the Billing Demand	$0.01558		R
	January - December		
Voltage Discounts per Month	Per kW	Per kWh	
Primary Voltage	$0.80	$0.00106	R

In addition, customer bills under this rate are subject to the following adjustments and/or charges. D

FUEL CLAUSE
Bills are subject to the adjustments provided for in the Fuel Clause Rider.

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider, the Renewable Development Fund Rider, the Transmission Cost Recovery Rider, the Renewable Energy Standard Rider and the Mercury Cost Recovery Rider.

ENVIRONMENTAL IMPROVEMENT RIDER
Bills are subject to the adjustments provided for in the Environmental Improvement Rider.

(Continued on Sheet No. 5-88)

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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

MUNICIPAL PUMPING SERVICE (Continued) Section No. 5
RATE CODE A41 8th Revised Sheet No. 88

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

LOW INCOME ENERGY DISCOUNT RIDER
Bills are subject to the adjustment provided for in the Low Income Energy Discount Rider.

The following are terms and conditions for service under this tariff.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

DETERMINATION OF DEMAND
The adjusted demand in kW for billing purposes shall be determined by dividing the maximum actual demand in kW by the power factor expressed in percent but not more than a 90% power factor and multiplying the quotient so obtained by 90% and rounding to the nearest whole kW. In no month shall the demand to be billed be considered as less than the current month's adjusted demand in kW nor greater than the value in kW determined by dividing the kWh sales for the billing month by 75 hours per month.

MAXIMUM DEMAND
The maximum actual demand in kW shall be the greatest 15 minute load during the month for which bill is rendered.

POWER FACTOR
For three phase customers with services above 200 amperes, or above 480 volts, the power factor for the month shall be determined by permanently installed metering equipment. For all single phase customers and three phase customers with services 200 amperes or less, a power factor of 90% will be assumed.

MINIMUM DEMAND TO BE BILLED
The monthly minimum billing demand shall not be less than provided above.

TERMS AND CONDITIONS OF SERVICE
Alternating current service is provided at the following nominal voltages:

1. Secondary Voltage: Single or three phase from 208 volts up to but not including 2,400 volts, or
2. Primary Voltage: Three phase from 2,400 volts up to but not including 69,000 volts.

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

FIRE AND CIVIL DEFENSE SIREN SERVICE Section No. 5
RATE CODE A42 14th Revised Sheet No. 89

AVAILABILITY
Available for power service for the operation of municipal fire and civil defense warning sirens having a rated capacity not in excess of 25 horsepower.

DETERMINATION OF CUSTOMER BILLS
Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and / or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

RATE
Per Month per Horsepower of Connected Capacity $0.76 R

In addition, customer bills under this rate are subject to the following adjustments and/or charges.

MONTHLY MINIMUM CHARGE
Net per Month $3.66 R

The following are terms and conditions for service under this tariff.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

CONNECTION
Under the above rate, the Company will make no extension for service other than a normal service span. Where conditions are such that a long service connection or extra transformer capacity, or both, are necessary, the customer shall either pay the entire cost of such extra equipment or pay a monthly facilities charge based on such costs.

The circuit serving the siren must be in conduit from the entrance to the motor with an enclosed entrance switch box, which may be sealed and operated from an external appliance.

OPTIONAL
In case the customer already has a service connection of sufficient capacity to permit operation of the siren without unduly disturbing conditions on the Company's nearby circuits, the siren may be connected at the option of the customer on the load side of the customer's existing meter and the commercial rate applied to the total load.

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

FIRE AND CIVIL DEFENSE SIREN SERVICE Section No. 5
RATE CODE A42 13th Revised Sheet No. 89

AVAILABILITY
Available for power service for the operation of municipal fire and civil defense warning sirens having a rated capacity not in excess of 25 horsepower.

DETERMINATION OF CUSTOMER BILLS
Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and / or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

RATE
Per Month per Horsepower of Connected Capacity $0.79 R

In addition, customer bills under this rate are subject to the following adjustments and/or charges.

MONTHLY MINIMUM CHARGE
Net per Month $3.79 R

The following are terms and conditions for service under this tariff. D

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

CONNECTION
Under the above rate, the Company will make no extension for service other than a normal service span. Where conditions are such that a long service connection or extra transformer capacity, or both, are necessary, the customer shall either pay the entire cost of such extra equipment or pay a monthly facilities charge based on such costs.

The circuit serving the siren must be in conduit from the entrance to the motor with an enclosed entrance switch box, which may be sealed and operated from an external appliance.

OPTIONAL
In case the customer already has a service connection of sufficient capacity to permit operation of the siren without unduly disturbing conditions on the Company's nearby circuits, the siren may be connected at the option of the customer on the load side of the customer's existing meter and the commercial rate applied to the total load.

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

FUEL CLAUSE RIDER Section No. 5
29th Revised Sheet No. 91

FUEL CLAUSE CHARGE
There shall be added to or deducted from the monthly bill a Fuel Cost Charge calculated by multiplying the applicable monthly billing kilowatt hours (kWh) by the billed Fuel Adjustment Factor (FAF) per kWh. The billed FAF is calculated by prorating each calendar month FAF by the number of customer billing days in each calendar month, and rounding to the nearest $0.00001 per kWh.

EXEMPTION
For customers participating in Company's Renewable*Connect and Renewable*Connect Government pilot programs, or the Windsource® Program under the Voluntary Renewable and High-Efficiency Energy Purchase Rider, the applicable billing kWh subject to the FAF shall be reduced by the elected Voluntary Renewable Adjustment energy blocks. In the event that a customer's metered energy use is lower than the subscribed energy blocks, the applicable billing kWh for the FAF for that month is zero. L

For customer premises recognized by the Company as not being subject to any of the costs of satisfying the solar energy standard under Minn. Stat. § 216B.1691, subd. 2f ("SES Costs"), the SES Costs reflected in the Fuel Clause Charge assessed to the accounts associated with these premises may be credited to these accounts, and the dollar amount of these credits shall be added back into the Current Period Cost of Energy applicable to the time period when the credit is issued. N N N N N

FUEL ADJUSTMENT FACTOR (FAF)
A separate FAF will be determined for each service category defined by customer class and time-of-day (TOD) period within the Commercial and Industrial – Demand class. The FAF for each service category is the sum of the Current Period Cost of Energy multiplied by the applicable FAF Ratio, and the applicable Energy Cost True-up Factor. The FAF Ratio is the Class Cost Ratio multiplied by the corresponding TOD Ratio:

Service Category	Class Cost Ratio	TOD Ratio	FAF Ratio
Residential	1.0177	1.0000	1.0177
C&I Non-Demand	1.0305	1.0000	1.0305
C&I Demand	0.9930	1.0054	0.9984
C&I Demand TOD On-Peak	0.9930	1.2574	1.2486
C&I Demand TOD Off-Peak	0.9930	0.8224	0.8166
Outdoor Lighting	0.7976	1.0000	0.7976

BASE COST OF ENERGY
The System Base Cost of Energy is $0.02680 per kWh. The FAF for each service category includes a Base Cost of Energy, which is the System Base Cost of Energy multiplied by the applicable FAF Ratio.

Service Category	Base Cost of Energy
Residential	$0.02727
C&I Non-Demand	$0.02762
C&I Demand Non-TOD	$0.02676
C&I Demand TOD On-Peak	$0.03346
C&I Demand TOD Off-Peak	$0.02188
Outdoor Lighting	$0.02138

(Continued on Sheet No. 5-91.1)

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President, Northern States Power Company, a Minnesota corporation
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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

FUEL CLAUSE RIDER (Continued)

Section No. 5
16th Revised Sheet No. 91.1

CURRENT PERIOD COST OF ENERGY

The Current Period Cost of Energy per kWh is defined as the qualifying costs, forecasted to be incurred during the calendar month, divided by the kWh sales forecasted for the same month. Qualifying kWh sales are all kWh sales excluding intersystem, Renewable*Connect, Renewable*Connect Government and Windsource® Program kWh sales. Qualifying costs are the sum of the following:

1. The cost of fuels consumed in the Company's generating stations as recorded in Federal Energy Regulatory Commission (FERC) Accounts 151 and 518.

2. The cost of energy purchases as recorded in FERC Account 555, exclusive of capacity or demand charges, irrespective of the designation assigned to such transaction, when such energy is purchased on an economic dispatch basis.

3. All Midwest ISO (MISO) costs and revenues authorized by the Commission to flow through this Fuel Clause Rider and excluding MISO costs and revenues that are recoverable in base rates, as prescribed in applicable Commission Orders.

4. All fuel and purchased energy expenses incurred by the Company over the duration of any Commission-approved contract, as provided for by Minnesota Statutes, Section 216B.1645, except any such expenses recovered in base rates or other riders.

5. The energy cost of purchases from a qualifying facility, as that term is defined in 18 C.F.R. Part 292 and Minn. Rule 7835.0100, Subp. 19, as amended, and the net cost of energy (and capacity if purchased on an energy output basis) purchases from any qualifying facility using wind energy conversion systems for the generation of electric energy, whether or not those purchases occur on an economic dispatch basis. Capacity costs associated with such purchased power contracts, which are in excess of 100 kW and commenced after the date of the Commission's final order in Docket No. E002/GR-05-1428, shall be excluded from Fuel Cost Charge recovery.

6. Less the fuel-related costs recovered through intersystem sales.

7. Less purchased power costs for the Renewable*Connect and Renewable*Connect Government pilot programs and for the Windsource® Program as recorded in FERC account 555.

8. Less neutrality charge cost recovery for the Renewable*Connect and Renewable*Connect Government pilot programs.

(Continued on Sheet No. 5-91.2)

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President, Northern States Power Company, a Minnesota corporation
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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

FUEL CLAUSE RIDER (Continued)

Section No. 5
10th Revised Sheet No. 91.2

ENERGY COST TRUE-UP FACTORS

An Energy Cost True-up Factor per kWh is calculated for each Class and TOD category by dividing the Energy Cost True-up Amount by the qualifying kWh sales forecasted for the calendar month. The Energy Cost True-up Amount is the cumulative balance of the unrecovered and over-recovered actual energy costs and MISO Day 2 expenses from prior months and the retail share of intersystem margins pursuant to the Margin-Sharing program approved by the Commission. The asset based margins are defined as sales revenues less the sum of fuel and energy costs (including costs associated with MISO Day 2 markets that are booked to FERC Account 555) and any additional transmission costs incurred that are required to make such sales. The retail share of intersystem margins is the following:

Asset Based Margins: One hundred percent (100%) of the Minnesota State jurisdiction share of margins from intersystem sales of ancillary services and intersystem sales of excess generation. These margins shall be the actual amounts of such margins recorded and are subject to any MISO resettlements.

(Continued on Sheet No. 5-91.3)

Date Filed: 05-31-17 By: Christopher B. Clark Effective Date: 12-01-17
President, Northern States Power Company, a Minnesota corporation
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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

FUEL CLAUSE RIDER (Continued)

Section No. 5
14th Revised Sheet No. 91.3

RATE SCHEDULES BY SERVICE CATEGORY

Residential
Residential (A00, A01, A03)
Residential TOD (A02, A04)
Residential TOU Pilot Program (A72, A74)
Energy Controlled (A05)
Limited Off-Peak (A06)
Residential Electric Vehicle (A08)
Residential Electric Vehicle Pilot (A80, A81)

Commercial and Industrial Non-Demand
Energy Controlled (A05)
Limited Off Peak (A06)
Small General (A09, A10, A11, A13)
Small General TOD (A12, A16, A18, A22)
Small Municipal Pumping (A40)
Fire and Civil Defense Siren (A42)

Commercial and Industrial Demand – Non-TOD
General (A14)
Peak Controlled (A23)
Municipal Pumping (A41)

N

Commercial and Industrial Demand – TOD
General TOD (A15, A17, A19)
Peak Controlled TOD (A24)
Tier 1 Energy Controlled Rider (A27)
Real Time Pricing (A62, A63)
Light Rail Line (A29)

Outdoor Lighting
Automatic Protective (A07)
Street Lighting System (A30)
Street Lighting Energy (Closed) (A32)
Street Lighting Energy – Metered (A34)
Street Lighting - City of St. Paul (A37)

PROVISION OF FORECAST DATA
To assist commercial and industrial customers in budgeting and managing their energy costs, the Company will annually make available on October 1st a 24-month forecast of the fuel and purchased energy costs applicable to demand billed C&I customers under this Rider. The forecast period begins January 1st of the following year. This forecast will be provided only to customers who have signed a protective agreement with the Company. Quarterly forecasts of the fuel and purchased energy costs will also be available.

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

FUEL CLAUSE RIDER (Continued)

Section No. 5
13th Revised Sheet No. 91.3

RATE SCHEDULES BY SERVICE CATEGORY

Residential
Residential (A00, A01, A03)
Residential TOD (A02, A04)
Energy Controlled (A05)
Limited Off-Peak (A06)
Residential Electric Vehicle (A08)
Residential Electric Vehicle Pilot (A80, A81) N

Commercial and Industrial Non-Demand
Energy Controlled (A05)
Limited Off Peak (A06)
Small General (A09, A10, A11, A13)
Small General TOD (A12, A16, A18, A22)
Small Municipal Pumping (A40)
Fire and Civil Defense Siren (A42)

Commercial and Industrial Demand – Non-TOD
General (A14)
Peak Controlled (A23)
Municipal Pumping (A41)

Commercial and Industrial Demand – TOD
General TOD (A15, A17, A19)
Peak Controlled TOD (A24)
Tier 1 Energy Controlled Rider (A27)
Real Time Pricing (A62, A63)
Light Rail Line (A29)

Outdoor Lighting
Automatic Protective (A07)
Street Lighting System (A30)
Street Lighting Energy (Closed) (A32)
Street Lighting Energy – Metered (A34)
Street Lighting - City of St. Paul (A37)

PROVISION OF FORECAST DATA
To assist commercial and industrial customers in budgeting and managing their energy costs, the Company will annually make available on October 1st a 24-month forecast of the fuel and purchased energy costs applicable to demand billed C&I customers under this Rider. The forecast period begins January 1st of the following year. This forecast will be provided only to customers who have signed a protective agreement with the Company. Quarterly forecasts of the fuel and purchased energy costs will also be available.

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President, Northern States Power Company, a Minnesota corporation
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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

FUEL CLAUSE RIDER (Continued)

Section No. 5
12th Revised Sheet No. 91.3

RATE SCHEDULES BY SERVICE CATEGORY

Residential
Residential (A00, A01, A03)
Residential TOD (A02, A04)
Energy Controlled (A05)
Limited Off-Peak (A06)
Residential Electric Vehicle (A08)

Commercial and Industrial Non-Demand
Energy Controlled (A05)
Limited Off Peak (A06)
Small General (A09, A10, A11, A13)
Small General TOD (A12, A16, A18, A22)
Small Municipal Pumping (A40)
Fire and Civil Defense Siren (A42)

Commercial and Industrial Demand – Non-TOD
General (A14)
Peak Controlled (A23)
Municipal Pumping (A41)

Commercial and Industrial Demand – TOD
General TOD (A15, A17, A19)
Peak Controlled TOD (A24)
Tier 1 Energy Controlled Rider (A27)
Real Time Pricing (A62, A63)
Light Rail Line (A29)

Outdoor Lighting
Automatic Protective (A07)
Street Lighting System (A30)
Street Lighting Energy (Closed) (A32)
Street Lighting Energy – Metered (A34)
Street Lighting - City of St. Paul (A37)

PROVISION OF FORECAST DATA
To assist commercial and industrial customers in budgeting and managing their energy costs, the Company will annually make available on October 1st a 24-month forecast of the fuel and purchased energy costs applicable to demand billed C&I customers under this Rider. The forecast period begins January 1st of the following year. This forecast will be provided only to customers who have signed a protective agreement with the Company. Quarterly forecasts of the fuel and purchased energy costs will also be available.

Date Filed: 05-31-17 By: Christopher B. Clark Effective Date: 12-01-17
President, Northern States Power Company, a Minnesota corporation
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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

CONSERVATION IMPROVEMENT PROGRAM Section No. 5
ADJUSTMENT RIDER 19th Revised Sheet No. 92

APPLICABILITY
Applicable to bills for electric service provided under the Company's retail rate schedules. Exemptions are as follows:

"Large Customer Facility" customers that have been exempted from the Company's Conservation Improvement Program charges pursuant to Minn. Stat. 216B.241 subd. 1a (b) shall receive a monthly exemption from conservation improvement program charges pursuant to Minn. Stat. 216B.16, subd. 6b Energy Conservation Improvement. Such monthly exemption will be effective beginning January 1 of the year following the grant of exemption. Upon exemption from conservation program charges, the "Large Customer Facility" customers can no longer participate in the Company's Energy Conservation Improvement Program.

RIDER
There shall be included on each non-exempt customer's monthly bill a Conservation Improvement Program (CIP) Adjustment, which shall be calculated by multiplying the monthly applicable billing kilowatt hours (kWh) by the CIP Adjustment Factor.

DETERMINATION OF CONSERVATION IMPROVEMENT PROGRAM ADJUSTMENT FACTOR
The CIP Adjustment Factor shall be calculated for each customer class by dividing the Recoverable Conservation Improvement Program Expense by the Projected Retail Sales for a designated recovery period. The factor may be adjusted annually with approval of the Minnesota Public Utilities Commission. The CIP Adjustment Factor for all rate schedules is:

All Classes	$0.001813 per kWh	R

Recoverable Conservation Improvement Program Expense shall be the CIP expense not recovered through base rates as determined from the CIP Tracker account balance for a designated period. All costs appropriately charged to the CIP Tracker Account shall be eligible for recovery through this Rider. All revenues received from the CIP Adjustment Factor shall be credited to the CIP Tracker Account.

Projected Retail Sales shall be the estimated kilowatt-hour sales to all non-exempt customers for the designated recovery period.

(Continued on Sheet No. 5-92.1)

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President, Northern States Power Company, a Minnesota corporation
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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

CONSERVATION IMPROVEMENT PROGRAM Section No. 5
ADJUSTMENT RIDER 18th Revised Sheet No. 92

APPLICABILITY
Applicable to bills for electric service provided under the Company's retail rate schedules. Exemptions are as follows:

"Large Customer Facility" customers that have been exempted from the Company's Conservation Improvement Program charges pursuant to Minn. Stat. 216B.241 subd. 1a (b) shall receive a monthly exemption from conservation improvement program charges pursuant to Minn. Stat. 216B.16, subd. 6b Energy Conservation Improvement. Such monthly exemption will be effective beginning January 1 of the year following the grant of exemption. Upon exemption from conservation program charges, the "Large Customer Facility" customers can no longer participate in the Company's Energy Conservation Improvement Program.

RIDER
There shall be included on each non-exempt customer's monthly bill a Conservation Improvement Program (CIP) Adjustment, which shall be calculated by multiplying the monthly applicable billing kilowatt hours (kWh) by the CIP Adjustment Factor.

DETERMINATION OF CONSERVATION IMPROVEMENT PROGRAM ADJUSTMENT FACTOR
The CIP Adjustment Factor shall be calculated for each customer class by dividing the Recoverable Conservation Improvement Program Expense by the Projected Retail Sales for a designated recovery period. The factor may be adjusted annually with approval of the Minnesota Public Utilities Commission. The CIP Adjustment Factor for all rate schedules is:

All Classes	$0.001875 per kWh	R

Recoverable Conservation Improvement Program Expense shall be the CIP expense not recovered through base rates as determined from the CIP Tracker account balance for a designated period. All costs appropriately charged to the CIP Tracker Account shall be eligible for recovery through this Rider. All revenues received from the CIP Adjustment Factor shall be credited to the CIP Tracker Account.

Projected Retail Sales shall be the estimated kilowatt-hour sales to all non-exempt customers for the designated recovery period.

(Continued on Sheet No. 5-92.1)

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President, Northern States Power Company, a Minnesota corporation
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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

CONSERVATION IMPROVEMENT PROGRAM Section No. 5
ADJUSTMENT RIDER (Continued) 7th Revised Sheet No. 92.1

DETERMINATION OF CONSERVATION COST RECOVERY CHARGE (CCRC)
The CCRC is the amount included in base rates dedicated to the recovery of CIP costs as approved by the Minnesota Public Utilities Commission (or successor agency) in the Company's last general rate case. The CCRC is approved and applied on a per kWh basis by dividing the test-year CIP expenses by the test-year sales volumes (net of CIP-exempt volumes). All revenues received from the CCRC shall be credited to the CIP Tracker Account. The CCRC for all rate schedules is:

All Classes	$0.003133 per kWh

DETERMINATION OF CCRC EXEMPTION ADJUSTMENT FACTOR
For "Large Customer Facilities", as defined in Minn. Stat. 216B.241 subd. 1, granted exemption by the Commissioner of the Minnesota Department of Commerce, Division of Energy Resources, pursuant to Minn. Stat. 216B.241, the CIP Adjustment Factor shall not apply and monthly bills will include a CCRC Exemption Adjustment credit determined by multiplying total billing kWh by the applicable CCRC Exemption Adjustment Factor. Customers' accounts granted exemption by a decision of the Commissioner after the beginning of a calendar year shall be credited for any CIP collections billed after January 1st of the year following the Commissioner's decision. The CCRC Exemption Adjustment Factor for all rate classes is:

All Classes	$0.003133 per kWh

PROVISION OF FORECAST DATA
To assist commercial and industrial customers in budgeting and managing their energy costs, the Company will annually make available on April 1st a 24-month forecast of the CIP Adjustment Factor applicable to demand billed C&I customers under this Rider. The forecast period begins January 1st of the following year.

EXEMPTION
For customer premises recognized by the Company as not being subject to any of the costs of satisfying the solar energy standard under Minn. Stat. § 216B.1691, subd. 2f ("SES Costs"), the SES Costs reflected in the CIP Adjustment assessed to the accounts associated with these premises may be credited to these accounts, and the dollar amount of these credits shall be added as part of the Recoverable Conservation Improvement Program Expense applicable to the time period when the credit is issued. N N

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President, Northern States Power Company, a Minnesota corporation
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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK – MPUC NO. 2

SURCHARGE RIDER

Section No. 5
8th Revised Sheet No. 93

A surcharge will be included in the monthly customer bills in Minnesota communities in an amount equal to any franchise gross earnings or other fee, permit or usage fee, excise, city sales or other charge or tax now or hereafter imposed upon Company by a community, whether by ordinance, franchise or otherwise, applicable to electric service supplied by Company to a customer.

The Company remits 100% of these fees collected from ratepayers to the local government unit.*

The Company will notify the Minnesota Public Utilities Commission of any new, renewed, expired, or changed fee, authorized by Minn. Stat. § 216B.36 to raise revenue, at least 60 days prior to its implementation. If the Company receives less than 60 days' notice of a repealed or reduced fee from a city, the Company will notify the Minnesota Public Utilities Commission within 10 business days of receiving notice. Notification to the Minnesota Public Utilities Commission will include a copy of the relevant franchise fee ordinance, or other operative document authorizing imposition of, or change in, the fee.

Affected customers will be notified on the first bill on which a new or modified fee is listed via the standard bill message below:

> *[The municipality] imposes a [X% of gross revenues/$X per meter/$X per kWh/$X per therm] fee on Xcel Energy collectable through a fee on Xcel Energy [electric/gas] accounts effective [effective date]. The line item appears on your bill as "City Fees." Xcel Energy remits 100% of this fee to [the municipality].*

*The amount collected for Baker is applied to the community's street lighting bill.

Date Filed: 11-02-15 By: Christopher B. Clark Effective Date: 10-01-17
President, Northern States Power Company, a Minnesota corporation
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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK – MPUC NO. 2

FRANCHISE AND OTHER CITY FEES

Section No. 5
23rd Revised Sheet No. 93.1

Franchise and other city fees, as designated below will be included in the customers' monthly bills computed under the indicated rate classes and effective in the following Minnesota communities:

The Company remits 100% of these fees collected from ratepayers to the local government unit.
— Indicates fee is not applied

Franchise Fees										
City	Residential	Small C&I Non-demand	Small C&I Demand	Large C&I	Public Street Lighting	Municipal Pumping Non-demand	Municipal Pumping Demand	Effective Date	Expiration Date	
Afton	$2.00	$2.00	$5.00	$5.00	$1.00	$1.00	$1.00	01/2005	08/16/2024	
Albertville	$2.50	$5.00	$10.00	$50.00	$2.00	—	—	03/2011	09/07/2029	
Bayport	$1.50	$3.00	$25.00	$50.00	$3.00	$3.00	$25.00	01/2014	05/04/2028	
Big Lake	$4.00	$8.00	$8.00	$8.00	—	—	—	10/2014	07/04/2034	
Bloomington	$3.75	$7.50	$40.00	$115.00	—	—	—	04/2016	12/20/2035	
Brooklyn Center	$1.60	$4.00	$22.00	$100.00	$13.00	$13.00	$13.00	01/2017	12/08/2023	
Brooklyn Park	$7.00	$7.50	$45.00	$160.00	—	—	—	03/2016	12/31/2028	
Burnsville	$1.00	$3.00	$10.00	$45.00	—	—	—	07/2016	02/15/2036	
Centerville	$4.00	$8.00	$8.00	$8.00	—	—	—	05/2016	01/26/2036	
Champlin	$3.58	$9.70	$40.80	$142.81	$17.34	$17.34	$17.34	01/2019	11/23/2028	R
Chisago City	$1.30	$5.00	$15.00	$55.00	$5.00	$5.00	$15.00	06/2009	02/28/2029	
Circle Pines	$2.75	$3.00	$35.00	—	$3.00	—	—	10/2009	08/24/2029	
Clara City	$2.00	$2.00	$15.00	$68.00	$2.00	$2.00	$15.00	01/2014	10/07/2033	
Clements	$1.00	$1.00	$1.00	$1.00	—	—	—	07/2012	06/09/2024	
Coon Rapids[1]	4.0%	4.0%	4.0%	4.0%	—	—	—	04/2018	01/13/2032	
Cottage Grove	$1.65	$1.65	$8.25	$33.00	$3.30	$0.75	$8.25	03/2016	11/04/2023	

[1] Coon Rapids: The franchise fee excludes rate schedules for highway lighting, municipal street lighting, municipal water pumping, municipal fire sirens, and municipal sewage disposal service. For all consumers, the four percent franchise fee is applicable to the first $950,000 of calendar year gross operating revenues. The franchise fee is reduced to one half percent (0.5%) for the remaining amount of annual gross operating revenues exceeding $950,000.

(Continued on Sheet No. 5-93.1a)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK – MPUC NO. 2

FRANCHISE AND OTHER CITY FEES

Section No. 5
22nd Revised Sheet No. 93.1

Franchise and other city fees, as designated below will be included in the customers' monthly bills computed under the indicated rate classes and effective in the following Minnesota communities:

The Company remits 100% of these fees collected from ratepayers to the local government unit.
— Indicates fee is not applied

Franchise Fees									
City	Residential	Small C&I Non-demand	Small C&I Demand	Large C&I	Public Street Lighting	Municipal Pumping Non-demand	Municipal Pumping Demand	Effective Date	Expiration Date
Afton	$2.00	$2.00	$5.00	$5.00	$1.00	$1.00	$1.00	01/2005	08/16/2024
Albertville	$2.50	$5.00	$10.00	$50.00	$2.00	—	—	03/2011	09/07/2029
Bayport	$1.50	$3.00	$25.00	$50.00	$3.00	$3.00	$25.00	01/2014	05/04/2028
Big Lake	$4.00	$8.00	$8.00	$8.00	—	—	—	10/2014	07/04/2034
Bloomington	$3.75	$7.50	$40.00	$115.00	—	—	—	04/2016	12/20/2035
Brooklyn Center	$1.60	$4.00	$22.00	$100.00	$13.00	$13.00	$13.00	01/2017	12/08/2023
Brooklyn Park	$7.00	$7.50	$45.00	$160.00	—	—	—	03/2016	12/31/2028
Burnsville	$1.00	$3.00	$10.00	$45.00	—	—	—	07/2016	02/15/2036
Centerville	$4.00	$8.00	$8.00	$8.00	—	—	—	05/2016	01/26/2036
Champlin	$3.54	$9.60	$40.40	$141.40	$17.17	$17.17	$17.17	01/2018	11/23/2028
Chisago City	$1.30	$5.00	$15.00	$55.00	$5.00	$5.00	$15.00	06/2009	02/28/2029
Circle Pines	$2.75	$3.00	$35.00	—	$3.00	—	—	10/2009	08/24/2029
Clara City	$2.00	$2.00	$15.00	$68.00	$2.00	$2.00	$15.00	01/2014	10/07/2033
Clements	$1.00	$1.00	$1.00	$1.00	—	—	—	07/2012	06/09/2024
Coon Rapids[1]	4.0%	4.0%	4.0%	4.0%	—	—	—	04/2018	01/13/2032
Cottage Grove	$1.65	$1.65	$8.25	$33.00	$3.30	$0.75	$8.25	03/2016	11/04/2023

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[1] Coon Rapids: The franchise fee excludes rate schedules for highway lighting, municipal street lighting, municipal water pumping, municipal fire sirens, and municipal sewage disposal service. For all consumers, the four percent franchise fee is applicable to the first $950,000 of calendar year gross operating revenues. The franchise fee is reduced to one half percent (0.5%) for the remaining amount of annual gross operating revenues exceeding $950,000.

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(Continued on Sheet No. 5-93.1a)

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President, Northern States Power Company, a Minnesota corporation
Docket No. E,G999/CI-09-970 Order Date: 03-23-11

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK – MPUC NO. 2

FRANCHISE AND OTHER CITY FEES

Section No. 5
7th Revised Sheet No. 93.1a

Franchise and other city fees, as designated below will be included in the customers' monthly bills computed under the indicated rate classes and effective in the following Minnesota communities:

The Company remits 100% of these fees collected from ratepayers to the local government unit.
— Indicates fee is not applied

Franchise Fees										
City	Residential	Small C&I Non-demand	Small C&I Demand	Large C&I	Public Street Lighting	Municipal Pumping Non-demand	Municipal Pumping Demand	Effective Date	Expiration Date	
Deephaven	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	04/2002	11/02/2030	
Dilworth	$2.60	$6.00	$21.00	$136.50	—	$6.00	$21.00	05/2018	02/25/2038	
Eagle Lake	$0.50	$0.50	$0.50	$0.50	—	—	—	10/2012	05/06/2032	
Eden Prairie	$4.00	$5.00	$12.50	$55.00	—	—	—	04/2018	06/18/2032	
Edina	$2.40	$4.08	$11.40	$48.60	—	—	—	07/2018	11/03/2035	
Excelsior	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	11/2012	08/02/2032	
Falcon Heights	$2.25	$3.50	$22.00	$200.00	$2.00	—	—	10/2018	06/12/2038	
Faribault[1]	$1.48	$1.76	$35.20	$308.00	—	—	—	01/2019	12/31/2019	R
Faribault[1]	$1.63	$1.94	$38.72	$338.80	—	—	—	01/2020	11/08/2024	R
Forest Lake	$4.00	$2.50	$18.50	$75.00	$7.50	$2.50	$18.50	05/2013	01/27/2033	
Golden Valley	$6.00	$6.00	$30.00	$258.00	—	—	—	04/2018	12/17/2027	

[1] Faribault: The franchise fee excludes invoices to the city for street lighting and municipal pumping.

(Continued on Sheet No. 5-93.2)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK – MPUC NO. 2

FRANCHISE AND OTHER CITY FEES

Section No. 5
6th Revised Sheet No. 93.1a

Franchise and other city fees, as designated below will be included in the customers' monthly bills computed under the indicated rate classes and effective in the following Minnesota communities:

The Company remits 100% of these fees collected from ratepayers to the local government unit.
— Indicates fee is not applied

Franchise Fees										
City	Residential	Small C&I Non-demand	Small C&I Demand	Large C&I	Public Street Lighting	Municipal Pumping Non-demand	Municipal Pumping Demand	Effective Date	Expiration Date	
Deephaven	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	04/2002	11/02/2030	
Dilworth	$2.60	$6.00	$21.00	$136.50	—	$6.00	$21.00	05/2018	02/25/2038	
Eagle Lake	$0.50	$0.50	$0.50	$0.50	—	—	—	10/2012	05/06/2032	
Eden Prairie	$4.00	$5.00	$12.50	$55.00	—	—	—	04/2018	06/18/2032	
Edina	$2.40	$4.08	$11.40	$48.60	—	—	—	07/2018	11/03/2035	
Excelsior	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	11/2012	08/02/2032	
Falcon Heights	$2.25	$3.50	$22.00	$200.00	$2.00	—	—	10/2018	06/12/2038	
Faribault[1]	$1.35	$1.60	$32.00	$280.00	—	—	—	01/2006	11/08/2024	L
Forest Lake	$4.00	$2.50	$18.50	$75.00	$7.50	$2.50	$18.50	05/2013	01/27/2033	L
Golden Valley	$6.00	$6.00	$30.00	$258.00	—	—	—	04/2018	12/17/2027	L

[1] Faribault: The franchise fee excludes invoices to the city for street lighting and municipal pumping.

(Continued on Sheet No. 5-93.2)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK – MPUC NO. 2

FRANCHISE AND OTHER CITY FEES

Section No. 5
5th Revised Sheet No. 93.1a

Franchise and other city fees, as designated below will be included in the customers' monthly bills computed under the indicated rate classes and effective in the following Minnesota communities:

The Company remits 100% of these fees collected from ratepayers to the local government unit.
— Indicates fee is not applied

Franchise Fees									
City	Residential	Small C&I Non-demand	Small C&I Demand	Large C&I	Public Street Lighting	Municipal Pumping Non-demand	Municipal Pumping Demand	Effective Date	Expiration Date
Deephaven	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	04/2002	11/02/2030
Dilworth	$2.60	$6.00	$21.00	$136.50	—	$6.00	$21.00	05/2018	02/25/2038
Eagle Lake	$0.50	$0.50	$0.50	$0.50	—	—	—	10/2012	05/06/2032
Eden Prairie	$4.00	$5.00	$12.50	$55.00	—	—	—	04/2018	06/18/2032
Edina	$2.40	$4.08	$11.40	$48.60	—	—	—	07/2018	11/03/2035
Excelsior	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	11/2012	08/02/2032
Falcon Heights	$2.25	$3.50	$22.00	$200.00	$2.00	—	—	10/2018	06/12/2038

N

(Continued on Sheet No. 5-93.2)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK – MPUC NO. 2

FRANCHISE AND OTHER CITY FEES

Section No. 5
4th Revised Sheet No. 93.1a

Franchise and other city fees, as designated below will be included in the customers' monthly bills computed under the indicated rate classes and effective in the following Minnesota communities:

The Company remits 100% of these fees collected from ratepayers to the local government unit.
— Indicates fee is not applied

Franchise Fees										
City	Residential	Small C&I Non-demand	Small C&I Demand	Large C&I	Public Street Lighting	Municipal Pumping Non-demand	Municipal Pumping Demand	Effective Date	Expiration Date	
Deephaven	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	04/2002	11/02/2030	
Dilworth	$2.60	$6.00	$21.00	$136.50	—	$6.00	$21.00	05/2018	02/25/2038	
Eagle Lake	$0.50	$0.50	$0.50	$0.50	—	—	—	10/2012	05/06/2032	
Eden Prairie	$4.00	$5.00	$12.50	$55.00	—	—	—	04/2018	06/18/2032	
Edina	$2.40	$4.08	$11.40	$48.60	—	—	—	07/2018	11/03/2035	R
Excelsior	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	11/2012	08/02/2032	

(Continued on Sheet No. 5-93.2)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK – MPUC NO. 2

FRANCHISE AND OTHER CITY FEES

Section No. 5
3rd Revised Sheet No. 93.1a

Franchise and other city fees, as designated below will be included in the customers' monthly bills computed under the indicated rate classes and effective in the following Minnesota communities:

The Company remits 100% of these fees collected from ratepayers to the local government unit.
— Indicates fee is not applied

Franchise Fees										
City	Residential	Small C&I Non-demand	Small C&I Demand	Large C&I	Public Street Lighting	Municipal Pumping Non-demand	Municipal Pumping Demand	Effective Date	Expiration Date	
Deephaven	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	04/2002	11/02/2030	
Dilworth	$2.60	$6.00	$21.00	$136.50	—	$6.00	$21.00	05/2018	02/25/2038	C
Eagle Lake	$0.50	$0.50	$0.50	$0.50	—	—	—	10/2012	05/06/2032	
Eden Prairie	$4.00	$5.00	$12.50	$55.00	—	—	—	04/2018	06/18/2032	
Edina	$1.95	$3.40	$9.50	$40.50	—	—	—	03/2016	11/03/2035	
Excelsior	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50	11/2012	08/02/2032	

(Continued on Sheet No. 5-93.2)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK – MPUC NO. 2

FRANCHISE AND OTHER CITY FEES (Continued)

Section No. 5
20th Revised Sheet No. 93.2

Franchise and other city fees, as designated below will be included in the customers' monthly bills computed under the indicated rate classes and effective in the following Minnesota communities:

The Company remits 100% of these fees collected from ratepayers to the local government unit.
— Indicates fee is not applied

Franchise Fees									
City	Residential	Small C&I Non-demand	Small C&I Demand	Large C&I	Public Street Lighting	Municipal Pumping Non-demand	Municipal Pumping Demand	Effective Date	Expiration Date
Goodview	$2.75	$3.00	$25.00	$110.00	$25.00	$2.50	$10.00	07/2006	04/30/2026
Grant	$2.35	$2.00	$14.00	$75.00	$2.00	$2.00	$2.00	01/2015	12/01/2023
Hayfield	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	01/2015	04/17/2031
Henderson	$3.00	$3.00	$3.00	$3.00	—	—	—	04/2012	08/16/2031
Hopkins	$3.50	$6.15	$24.70	$170.50	—	—	—	01/2019	12/31/2023 R
Inver Grove Heights	$2.75	$3.00	$25.00	$95.00	—	—	—	01/2018	06/30/2029
Landfall Village	$2.25	$4.75	$14.00	$65.00	$15.50	—	—	04/2014	12/10/2033
Lexington	$4.00	$6.50	$40.00	$170.00	—	—	—	03/2017	10/05/2031
Lindstrom	$2.50	$5.00	$24.00	$70.00	$7.00	$7.00	$7.00	04/2016	12/17/2028
Little Canada	$2.75	$5.25	$40.00	$230.00	$15.50	$2.00	$3.00	07/2010	08/26/2023
Madison Lake	$1.00	$1.00	$1.00	$1.00	$1.00	$1.00	$1.00	05/2013	02/03/2033
Mahtomedi	$1.30	$1.38	$14.40	$110.28	$12.71	$0.63	$14.84	01/2005	10/18/2024
Mankato	$1.00	$1.55	$16.50	$223.00	$1.00	$0.25	$1.00	02/2015	09/21/2034
Mantorville	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	11/2012	08/12/2032
Maplewood	$3.00	$4.75	$30.00	$180.00	$4.00	$4.00	$4.00	11/2018	09/26/2024

(Continued on Sheet No. 5-93.3)

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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK – MPUC NO. 2

FRANCHISE AND OTHER CITY FEES (Continued)

Section No. 5
19th Revised Sheet No. 93.2

Franchise and other city fees, as designated below will be included in the customers' monthly bills computed under the indicated rate classes and effective in the following Minnesota communities:

The Company remits 100% of these fees collected from ratepayers to the local government unit.
— Indicates fee is not applied

Franchise Fees										
City	Residential	Small C&I Non-demand	Small C&I Demand	Large C&I	Public Street Lighting	Municipal Pumping Non-demand	Municipal Pumping Demand	Effective Date	Expiration Date	
Goodview	$2.75	$3.00	$25.00	$110.00	$25.00	$2.50	$10.00	07/2006	04/30/2026	L
Grant	$2.35	$2.00	$14.00	$75.00	$2.00	$2.00	$2.00	01/2015	12/01/2023	
Hayfield	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	01/2015	04/17/2031	
Henderson	$3.00	$3.00	$3.00	$3.00	—	—	—	04/2012	08/16/2031	
Hopkins	$2.20	$3.85	$15.50	$105.50	—	—	—	01/2014	12/31/2018	
Inver Grove Heights	$2.75	$3.00	$25.00	$95.00	—	—	—	01/2018	06/30/2029	
Landfall Village	$2.25	$4.75	$14.00	$65.00	$15.50	—	—	04/2014	12/10/2033	
Lexington	$4.00	$6.50	$40.00	$170.00	—	—	—	03/2017	10/05/2031	
Lindstrom	$2.50	$5.00	$24.00	$70.00	$7.00	$7.00	$7.00	04/2016	12/17/2028	
Little Canada	$2.75	$5.25	$40.00	$230.00	$15.50	$2.00	$3.00	07/2010	08/26/2023	
Madison Lake	$1.00	$1.00	$1.00	$1.00	$1.00	$1.00	$1.00	05/2013	02/03/2033	
Mahtomedi	$1.30	$1.38	$14.40	$110.28	$12.71	$0.63	$14.84	01/2005	10/18/2024	
Mankato	$1.00	$1.55	$16.50	$223.00	$1.00	$0.25	$1.00	02/2015	09/21/2034	
Mantorville	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	11/2012	08/12/2032	
Maplewood	$3.00	$4.75	$30.00	$180.00	$4.00	$4.00	$4.00	11/2018	09/26/2024	R

(Continued on Sheet No. 5-93.3)

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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK – MPUC NO. 2

FRANCHISE AND OTHER CITY FEES (Continued)

Section No. 5
18th Revised Sheet No. 93.2

Franchise and other city fees, as designated below will be included in the customers' monthly bills computed under the indicated rate classes and effective in the following Minnesota communities:

The Company remits 100% of these fees collected from ratepayers to the local government unit.
— Indicates fee is not applied

Franchise Fees									
City	Residential	Small C&I Non-demand	Small C&I Demand	Large C&I	Public Street Lighting	Municipal Pumping Non-demand	Municipal Pumping Demand	Effective Date	Expiration Date
Faribault[1]	$1.35	$1.60	$32.00	$280.00	—	—	—	01/2006	11/08/2024
Forest Lake	$4.00	$2.50	$18.50	$75.00	$7.50	$2.50	$18.50	05/2013	01/27/2033
Golden Valley	$6.00	$6.00	$30.00	$258.00	—	—	—	04/2018	12/17/2027
Goodview	$2.75	$3.00	$25.00	$110.00	$25.00	$2.50	$10.00	07/2006	04/30/2026
Grant	$2.35	$2.00	$14.00	$75.00	$2.00	$2.00	$2.00	01/2015	12/01/2023
Hayfield	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	01/2015	04/17/2031
Henderson	$3.00	$3.00	$3.00	$3.00	—	—	—	04/2012	08/16/2031
Hopkins	$2.20	$3.85	$15.50	$105.50	—	—	—	01/2014	12/31/2018
Inver Grove Heights	$2.75	$3.00	$25.00	$95.00	—	—	—	01/2018	06/30/2029
Landfall Village	$2.25	$4.75	$14.00	$65.00	$15.50	—	—	04/2014	12/10/2033
Lexington	$4.00	$6.50	$40.00	$170.00	—	—	—	03/2017	10/05/2031
Lindstrom	$2.50	$5.00	$24.00	$70.00	$7.00	$7.00	$7.00	04/2016	12/17/2028
Little Canada	$2.75	$5.25	$40.00	$230.00	$15.50	$2.00	$3.00	07/2010	08/26/2023
Madison Lake	$1.00	$1.00	$1.00	$1.00	$1.00	$1.00	$1.00	05/2013	02/03/2033
Mahtomedi	$1.30	$1.38	$14.40	$110.28	$12.71	$0.63	$14.84	01/2005	10/18/2024
Mankato	$1.00	$1.55	$16.50	$223.00	$1.00	$0.25	$1.00	02/2015	09/21/2034
Mantorville	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	11/2012	08/12/2032
Maplewood	$1.25	$2.50	$15.00	$112.50	$1.25	$1.25	$1.25	12/2013	09/26/2024

R

[1] Faribault: The franchise fee excludes invoices to the city for street lighting and municipal pumping.

(Continued on Sheet No. 5-93.3)

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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK – MPUC NO. 2

FRANCHISE AND OTHER CITY FEES (Continued)

Section No. 5
18th Revised Sheet No. 93.3

Franchise and other city fees, as designated below will be included in the customers' monthly bills computed under the indicated rate classes and effective in the following Minnesota communities:

The Company remits 100% of these fees collected from ratepayers to the local government unit.
— Indicates fee is not applied

Franchise Fees										
City	Residential	Small C&I Non-demand	Small C&I Demand	Large C&I	Public Street Lighting	Municipal Pumping Non-demand	Municipal Pumping Demand	Effective Date	Expiration Date	
Minneapolis	5.0%	5.5% <100 kW	5.5% <100 kW	3.5% ≥100 kW at primary or higher voltage 5.5% ≥100 kW at secondary voltage	5.5%	5.5%	5.5%	03/2018	10/16/2024	
Minnetonka	$4.50	$4.50	$13.50	$45.00	—	$4.50	$4.50	01/2019	05/14/2038	R
Monticello	$1.95	$5.50	$31.00	$190.00	$12.00	$12.00	$31.00	06/2007	05/31/2027	
Mound	$2.75	$2.75	$2.75	$2.75	$2.75	$2.75	$2.75	01/2017	12/31/2020	
Mounds View	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	01/2019	12/31/2021	C
New Brighton	$0.0047 per kWh	$0.0043 per kWh	$0.0033 per kWh	$0.0017 per kWh	$0.0054 per kWh	$0.0046 per kWh	$0.0033 per kWh	03/2016	11/25/2022	
New Hope	$3.00	$6.00	$26.00	$115.00	—	—	—	01/2017	06/26/2031	
New Richland	$1.00	$1.00	$1.00	$1.00	—	—	—	02/2013	07/11/2024	
Newport	$1.00	$1.50	$14.00	$70.00	$5.00	$1.00	$10.00	01/2011	10/18/2026	
North Branch	$3.50	$3.50	$8.75	$17.50	—	—	—	08/2018	04/09/2038	

(Continued on Sheet No. 5-93.4)

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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK – MPUC NO. 2

FRANCHISE AND OTHER CITY FEES (Continued)

Section No. 5
17th Revised Sheet No. 93.3

Franchise and other city fees, as designated below will be included in the customers' monthly bills computed under the indicated rate classes and effective in the following Minnesota communities:

The Company remits 100% of these fees collected from ratepayers to the local government unit.
— Indicates fee is not applied

Franchise Fees										
City	Residential	Small C&I Non-demand	Small C&I Demand	Large C&I	Public Street Lighting	Municipal Pumping Non-demand	Municipal Pumping Demand	Effective Date	Expiration Date	
Minneapolis	5.0%	5.5% <100 kW	5.5% <100 kW	3.5% ≥100 kW at primary or higher voltage 5.5% ≥100 kW at secondary voltage	5.5%	5.5%	5.5%	03/2018	10/16/2024	
Minnetonka	$2.50	$4.50	$4.50	$4.50	—	$4.50	$4.50	08/2018	05/14/2038	C
Monticello	$1.95	$5.50	$31.00	$190.00	$12.00	$12.00	$31.00	06/2007	05/31/2027	
Mound	$2.75	$2.75	$2.75	$2.75	$2.75	$2.75	$2.75	01/2017	12/31/2020	
Mounds View	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	01/2018	12/31/2018	
New Brighton	$0.0047 per kWh	$0.0043 per kWh	$0.0033 per kWh	$0.0017 per kWh	$0.0054 per kWh	$0.0046 per kWh	$0.0033 per kWh	03/2016	11/25/2022	
New Hope	$3.00	$6.00	$26.00	$115.00	—	—	—	01/2017	06/26/2031	
New Richland	$1.00	$1.00	$1.00	$1.00	—	—	—	02/2013	07/11/2024	
Newport	$1.00	$1.50	$14.00	$70.00	$5.00	$1.00	$10.00	01/2011	10/18/2026	
North Branch	$3.50	$3.50	$8.75	$17.50	—	—	—	08/2018	04/09/2038	N

(Continued on Sheet No. 5-93.4)

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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK – MPUC NO. 2

FRANCHISE AND OTHER CITY FEES (Continued)

Section No. 5
16th Revised Sheet No. 93.3

Franchise and other city fees, as designated below will be included in the customers' monthly bills computed under the indicated rate classes and effective in the following Minnesota communities:

The Company remits 100% of these fees collected from ratepayers to the local government unit.
— Indicates fee is not applied

Franchise Fees										
City	Residential	Small C&I Non-demand	Small C&I Demand	Large C&I	Public Street Lighting	Municipal Pumping Non-demand	Municipal Pumping Demand	Effective Date	Expiration Date	
Minneapolis	5.0%	5.5% <100 kW	5.5% <100 kW	3.5% ≥100 kW at primary or higher voltage 5.5% ≥100 kW at secondary voltage	5.5%	5.5%	5.5%	03/2018	10/16/2024	R R R
Minnetonka	$2.50	$4.50	$4.50	$4.50	—	$4.50	$4.50	11/2007	08/09/2018	
Monticello	$1.95	$5.50	$31.00	$190.00	$12.00	$12.00	$31.00	06/2007	05/31/2027	
Mound	$2.75	$2.75	$2.75	$2.75	$2.75	$2.75	$2.75	01/2017	12/31/2020	
Mounds View	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	01/2018	12/31/2018	
New Brighton	$0.0047 per kWh	$0.0043 per kWh	$0.0033 per kWh	$0.0017 per kWh	$0.0054 per kWh	$0.0046 per kWh	$0.0033 per kWh	03/2016	11/25/2022	
New Hope	$3.00	$6.00	$26.00	$115.00	—	—	—	01/2017	06/26/2031	
New Richland	$1.00	$1.00	$1.00	$1.00	—	—	—	02/2013	07/11/2024	
Newport	$1.00	$1.50	$14.00	$70.00	$5.00	$1.00	$10.00	01/2011	10/18/2026	

(Continued on Sheet No. 5-93.4)

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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK – MPUC NO. 2

FRANCHISE AND OTHER CITY FEES (Continued)

Section No. 5
21st Revised Sheet No. 93.4

Franchise and other city fees, as designated below will be included in the customers' monthly bills computed under the indicated rate classes and effective in the following Minnesota communities:

The Company remits 100% of these fees collected from ratepayers to the local government unit.
— Indicates fee is not applied

Franchise Fees										
City	Residential	Small C&I Non-demand	Small C&I Demand	Large C&I	Public Street Lighting	Municipal Pumping Non-demand	Municipal Pumping Demand	Effective Date	Expiration Date	
North Mankato	$1.00	$1.55	$16.50	$223.00	$17.62	$1.46	$12.30	04/2015	10/05/2034	
Oakdale	$1.50	$3.00	$10.00	$8.00	$6.00	$2.00	$8.00	11/2013	10/27/2023	
Osseo	$1.28	$2.07	$17.57	$102.65	$6.20	$0.45	$2.55	03/2012	10/26/2023	
Owatonna	$0.0016 per kWh Customer peak demand less than 100 kW in calendar year $0.0014 per kWh Customer peak demand greater than 100 kW in calendar year							01/2003	04/01/2022	
Plymouth	$2.12	$3.18	$10.61	$42.44	—	—	—	08/2018	07/09/2027	
Prior Lake	$1.50	$5.00	$10.00	$50.00	—	—	—	07/2006	03/19/2026	
Richmond	$1.00	$1.00	$1.00	$1.00	—	—	—	05/2013	05/03/2031	
Richfield	$4.10	$12.50	$30.00	$185.00	—	—	—	04/2014	03/12/2027	
Robbinsdale	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	06/2019	07/01/2021	R
Rogers	$5.00	$7.00	$45.00	$210.00	$17.00	$12.00	$65.00	01/2016	11/22/2024	
Sartell	$4.00	$6.75	$15.00	$109.00	—	—	—	01/2017	09/11/2036	
Sauk Rapids	4.0% Customers who purchase $50,000 or less in calendar year 1.5% That part which exceeds $50,000 in calendar year							02/2016	06/15/2023	
Shakopee[1]	3.0%	3.0%	3.0%	3.0%	—	—	—	01/2017	08/06/2021	
Shoreview	$2.50	$3.00	$30.00	$310.00	—	—	—	10/2013	07/17/2031	

[1] Shakopee: The fee collected shall total three percent (3%) of the Company's gross revenues from its operations within the City collected from each customer of each class. For customers in the Large C&I class, the three percent franchise fee is applicable to the first $950,000 of calendar year gross revenues. The franchise fee is reduced to one-half percent (0.5%) for the remaining amount of annual gross revenues exceeding $950,000.

(Continued on Sheet No. 5-93.5)

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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK – MPUC NO. 2

FRANCHISE AND OTHER CITY FEES (Continued)

Section No. 5
20th Revised Sheet No. 93.4

Franchise and other city fees, as designated below will be included in the customers' monthly bills computed under the indicated rate classes and effective in the following Minnesota communities:

The Company remits 100% of these fees collected from ratepayers to the local government unit.
— Indicates fee is not applied

Franchise Fees										
City	Residential	Small C&I Non-demand	Small C&I Demand	Large C&I	Public Street Lighting	Municipal Pumping Non-demand	Municipal Pumping Demand	Effective Date	Expiration Date	
North Mankato	$1.00	$1.55	$16.50	$223.00	$17.62	$1.46	$12.30	04/2015	10/05/2034	
Oakdale	$1.50	$3.00	$10.00	$8.00	$6.00	$2.00	$8.00	11/2013	10/27/2023	
Osseo	$1.28	$2.07	$17.57	$102.65	$6.20	$0.45	$2.55	03/2012	10/26/2023	
Owatonna	$0.0016 per kWh Customer peak demand less than 100 kW in calendar year $0.0014 per kWh Customer peak demand greater than 100 kW in calendar year							01/2003	04/01/2022	
Plymouth	$2.12	$3.18	$10.61	$42.44	—	—	—	08/2018	07/09/2027	R
Prior Lake	$1.50	$5.00	$10.00	$50.00	—	—	—	07/2006	03/19/2026	
Richmond	$1.00	$1.00	$1.00	$1.00	—	—	—	05/2013	05/03/2031	
Richfield	$4.10	$12.50	$30.00	$185.00	—	—	—	04/2014	03/12/2027	
Robbinsdale	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	06/2017	07/01/2019	
Rogers	$5.00	$7.00	$45.00	$210.00	$17.00	$12.00	$65.00	01/2016	11/22/2024	
Sartell	$4.00	$6.75	$15.00	$109.00	—	—	—	01/2017	09/11/2036	
Sauk Rapids	4.0% Customers who purchase $50,000 or less in calendar year 1.5% That part which exceeds $50,000 in calendar year							02/2016	06/15/2023	
Shakopee[1]	3.0%	3.0%	3.0%	3.0%	—	—	—	01/2017	08/06/2021	
Shoreview	$2.50	$3.00	$30.00	$310.00	—	—	—	10/2013	07/17/2031	

[1] Shakopee: The fee collected shall total three percent (3%) of the Company's gross revenues from its operations within the City collected from each customer of each class. For customers in the Large C&I class, the three percent franchise fee is applicable to the first $950,000 of calendar year gross revenues. The franchise fee is reduced to one-half percent (0.5%) for the remaining amount of annual gross revenues exceeding $950,000.

(Continued on Sheet No. 5-93.5)

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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK – MPUC NO. 2

FRANCHISE AND OTHER CITY FEES (Continued)

Section No. 5
19th Revised Sheet No. 93.4

Franchise and other city fees, as designated below will be included in the customers' monthly bills computed under the indicated rate classes and effective in the following Minnesota communities:

The Company remits 100% of these fees collected from ratepayers to the local government unit.
— Indicates fee is not applied

Franchise Fees									
City	Residential	Small C&I Non-demand	Small C&I Demand	Large C&I	Public Street Lighting	Municipal Pumping Non-demand	Municipal Pumping Demand	Effective Date	Expiration Date
North Mankato	$1.00	$1.55	$16.50	$223.00	$17.62	$1.46	$12.30	04/2015	10/05/2034
Oakdale	$1.50	$3.00	$10.00	$8.00	$6.00	$2.00	$8.00	11/2013	10/27/2023
Osseo	$1.28	$2.07	$17.57	$102.65	$6.20	$0.45	$2.55	03/2012	10/26/2023
Owatonna	$0.0016 per kWh Customer peak demand less than 100 kW in calendar year $0.0014 per kWh Customer peak demand greater than 100 kW in calendar year							01/2003	04/01/2022
Plymouth	$2.06	$3.09	$10.30	$41.20	—	—	—	06/2017	07/09/2027
Prior Lake	$1.50	$5.00	$10.00	$50.00	—	—	—	07/2006	03/19/2026
Richmond	$1.00	$1.00	$1.00	$1.00	—	—	—	05/2013	05/03/2031
Richfield	$4.10	$12.50	$30.00	$185.00	—	—	—	04/2014	03/12/2027
Robbinsdale	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	06/2017	07/01/2019
Rogers	$5.00	$7.00	$45.00	$210.00	$17.00	$12.00	$65.00	01/2016	11/22/2024
Sartell	$4.00	$6.75	$15.00	$109.00	—	—	—	01/2017	09/11/2036
Sauk Rapids	4.0% Customers who purchase $50,000 or less in calendar year 1.5% That part which exceeds $50,000 in calendar year							02/2016	06/15/2023
Shakopee[1]	3.0%	3.0%	3.0%	3.0%	—	—	—	01/2017	08/06/2021
Shoreview	$2.50	$3.00	$30.00	$310.00	—	—	—	10/2013	07/17/2031

[1] Shakopee: The fee collected shall total three percent (3%) of the Company's gross revenues from its operations within the City collected from each customer of each class. For customers in the Large C&I class, the three percent franchise fee is applicable to the first $950,000 of calendar year gross revenues. The franchise fee is reduced to one-half percent (0.5%) for the remaining amount of annual gross revenues exceeding $950,000.

(Continued on Sheet No. 5-93.5)

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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK – MPUC NO. 2

FRANCHISE AND OTHER CITY FEES (Continued)

Section No. 5
18th Revised Sheet No. 93.5

Franchise and other city fees, as designated below will be included in the customers' monthly bills computed under the indicated rate classes and effective in the following Minnesota communities:

The Company remits 100% of these fees collected from ratepayers to the local government unit.
— Indicates fee is not applied

Franchise Fees										
City	Residential	Small C&I Non-demand	Small C&I Demand	Large C&I	Public Street Lighting	Municipal Pumping Non-demand	Municipal Pumping Demand	Effective Date	Expiration Date	
Shorewood	$4.00	$8.00	$10.00	$25.00	—	—	—	10/2018	06/24/2038	
South St. Paul[1]	5.0%	5.0%	5.0%	5.0%	—	—	—	04/2018	04/05/2030	
Spicer	$1.00	$1.00	$8.00	$8.00	—	—	—	02/2013	10/01/2032	
Spring Lake Park	$0.80	$1.20	$8.50	$50.00	—	—	—	04/2015	01/04/2035	
St. Cloud[2]	4.0%	4.0%	4.0%	4.0%	—	—	—	12/2017	12/31/2024	
St. Joseph	$1.00	$1.75	$10.00	2% purchase ≤$100,000 in calendar year 1.5% that part >$100,000 in calendar year	$8.00	$1.00	$10.00	02/2004	11/19/2023	
St. Louis Park	$5.50	$10.00	$46.50	$146.50	—	$10.00	$46.50	06/2019	09/18/2036	R
St. Michael	$3.50	$2.50	$2.50	$10.00	$10.00	$2.50	$10.00	05/2011	11/24/2023	
St. Paul[3]	See fee schedule in the Notes section on the following sheets.							11/2006	08/31/2026	
St. Paul Park	$1.50	$2.00	$25.00	$335.00	$10.00	$1.00	$5.00	08/2005	05/15/2025	
Stillwater	$2.00	$2.50	$18.00	$125.00	$4.00	$2.00	$18.00	06/2015	02/16/2035	

[1] South St. Paul: The franchise fee excludes rate schedules for highway lighting, municipal street lighting, municipal water pumping, municipal traffic signals, municipal fire sirens, and municipal sewage disposal service.

[2] St. Cloud: The franchise fee for residential heating customers will be 1.5% during the months of November – April.

[3] St. Paul: The monthly franchise fee will be as stated on the following sheets. The residential service franchise fee will be as stated except during the months of November - April when there will be no fee. The fee shall not exceed $620,000 during any calendar year from any large commercial and industrial customer qualifying for service on the Competitive Market Rider. The schedule on the following sheets show the meter, energy, and demand factor for each year of the St. Paul franchise and for each of the customer classifications.

(Continued on Sheet No. 5-93.6)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK – MPUC NO. 2

FRANCHISE AND OTHER CITY FEES (Continued)

Section No. 5
17th Revised Sheet No. 93.5

Franchise and other city fees, as designated below will be included in the customers' monthly bills computed under the indicated rate classes and effective in the following Minnesota communities:

The Company remits 100% of these fees collected from ratepayers to the local government unit.
— Indicates fee is not applied

Franchise Fees										
City	Residential	Small C&I Non-demand	Small C&I Demand	Large C&I	Public Street Lighting	Municipal Pumping Non-demand	Municipal Pumping Demand	Effective Date	Expiration Date	
Shorewood	$4.00	$8.00	$10.00	$25.00	—	—	—	10/2018	06/24/2038	N
South St. Paul[1]	5.0%	5.0%	5.0%	5.0%	—	—	—	04/2018	04/05/2030	
Spicer	$1.00	$1.00	$8.00	$8.00	—	—	—	02/2013	10/01/2032	
Spring Lake Park	$0.80	$1.20	$8.50	$50.00	—	—	—	04/2015	01/04/2035	
St. Cloud[2]	4.0%	4.0%	4.0%	4.0%	—	—	—	12/2017	12/31/2024	
St. Joseph	$1.00	$1.75	$10.00	2% purchase ≤$100,000 in calendar year 1.5% that part >$100,000 in calendar year	$8.00	$1.00	$10.00	02/2004	11/19/2023	
St. Louis Park	$4.00	$8.50	$45.00	$145.00	—	$8.50	$45.00	02/2017	09/18/2036	
St. Michael	$3.50	$2.50	$2.50	$10.00	$10.00	$2.50	$10.00	05/2011	11/24/2023	
St. Paul[3]	See fee schedule in the Notes section on the following sheets.							11/2006	08/31/2026	
St. Paul Park	$1.50	$2.00	$25.00	$335.00	$10.00	$1.00	$5.00	08/2005	05/15/2025	
Stillwater	$2.00	$2.50	$18.00	$125.00	$4.00	$2.00	$18.00	06/2015	02/16/2035	

[1] South St. Paul: The franchise fee excludes rate schedules for highway lighting, municipal street lighting, municipal water pumping, municipal traffic signals, municipal fire sirens, and municipal sewage disposal service.

[2] St. Cloud: The franchise fee for residential heating customers will be 1.5% during the months of November – April.

[3] St. Paul: The monthly franchise fee will be as stated on the following sheets. The residential service franchise fee will be as stated except during the months of November - April when there will be no fee. The fee shall not exceed $620,000 during any calendar year from any large commercial and industrial customer qualifying for service on the Competitive Market Rider. The schedule on the following sheets show the meter, energy, and demand factor for each year of the St. Paul franchise and for each of the customer classifications.

(Continued on Sheet No. 5-93.6)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK – MPUC NO. 2

FRANCHISE AND OTHER CITY FEES (Continued)

Section No. 5
16th Revised Sheet No. 93.5

Franchise and other city fees, as designated below will be included in the customers' monthly bills computed under the indicated rate classes and effective in the following Minnesota communities:

The Company remits 100% of these fees collected from ratepayers to the local government unit.
— Indicates fee is not applied

Franchise Fees										
City	Residential	Small C&I Non-demand	Small C&I Demand	Large C&I	Public Street Lighting	Municipal Pumping Non-demand	Municipal Pumping Demand	Effective Date	Expiration Date	
South St. Paul[1]	5.0%	5.0%	5.0%	5.0%	—	—	—	04/2018	04/05/2030	R
Spicer	$1.00	$1.00	$8.00	$8.00	—	—	—	02/2013	10/01/2032	
Spring Lake Park	$0.80	$1.20	$8.50	$50.00	—	—	—	04/2015	01/04/2035	
St. Cloud[2]	4.0%	4.0%	4.0%	4.0%	—	—	—	12/2017	12/31/2024	
St. Joseph	$1.00	$1.75	$10.00	2% purchase ≤$100,000 in calendar year 1.5% that part >$100,000 in calendar year	$8.00	$1.00	$10.00	02/2004	11/19/2023	
St. Louis Park	$4.00	$8.50	$45.00	$145.00	—	$8.50	$45.00	02/2017	09/18/2036	
St. Michael	$3.50	$2.50	$2.50	$10.00	$10.00	$2.50	$10.00	05/2011	11/24/2023	
St. Paul[3]	See fee schedule in the Notes section on the following sheets.							11/2006	08/31/2026	
St. Paul Park	$1.50	$2.00	$25.00	$335.00	$10.00	$1.00	$5.00	08/2005	05/15/2025	
Stillwater	$2.00	$2.50	$18.00	$125.00	$4.00	$2.00	$18.00	06/2015	02/16/2035	

[1] South St. Paul: The franchise fee excludes rate schedules for highway lighting, municipal street lighting, municipal water pumping, municipal traffic signals, municipal fire sirens, and municipal sewage disposal service.

[2] St. Cloud: The franchise fee for residential heating customers will be 1.5% during the months of November – April.

[3] St. Paul: The monthly franchise fee will be as stated on the following sheets. The residential service franchise fee will be as stated except during the months of November - April when there will be no fee. The fee shall not exceed $620,000 during any calendar year from any large commercial and industrial customer qualifying for service on the Competitive Market Rider. The schedule on the following sheets show the meter, energy, and demand factor for each year of the St. Paul franchise and for each of the customer classifications.

(Continued on Sheet No. 5-93.6)

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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK – MPUC NO. 2

FRANCHISE AND OTHER CITY FEES (Continued)

Section No. 5
4th Revised Sheet No. 93.6

Notes:
[3] St. Paul (continued)

Customer Class	Meter Factor - Monthly Charge per Account				
Start Date	1-Nov-2006	1-Nov-2008	1-Nov-2010	1-Nov-2012	1-Nov-2014
End Date	31-Oct-2008	31-Oct-2010	31-Oct-2012	31-Oct-2014	31-Oct-2016
Residential (May - October)	$2.63	$2.70	$2.77	$2.84	$2.91
Small Commercial & Industrial					
Non-Demand	$2.96	$3.09	$3.22	$3.35	$3.48
Firm Secondary	$2.96	$3.09	$3.22	$3.35	$3.48
Firm Primary	$2.96	$3.09	$3.22	$3.35	$3.48
Interruptible Secondary	$2.96	$3.09	$3.22	$3.35	$3.48
Interruptible Primary	$2.96	$3.09	$3.22	$3.35	$3.48
Large Commercial & Industrial					
Special	$5.04	$5.11	$5.18	$5.25	$5.32
Firm Secondary	$5.04	$5.11	$5.18	$5.25	$5.32
Firm Primary	$5.04	$5.11	$5.18	$5.25	$5.32
Firm Trans. Transf.	$5.04	$5.11	$5.18	$5.25	$5.32
Interruptible Secondary	$5.04	$5.11	$5.18	$5.25	$5.32
Interruptible Primary	$5.04	$5.11	$5.18	$5.25	$5.32
Interruptible TT	$5.04	$5.11	$5.18	$5.25	$5.32
Standby Service	None	None	None	None	None
Public Street & Highway Lighting	$6.74	$6.81	$6.88	$6.95	$7.02
Small Municipal Pumping					
Non-Demand	$2.96	$3.09	$3.22	$3.35	$3.48
Demand Secondary	$2.96	$3.09	$3.22	$3.35	$3.48
Demand Primary	$2.96	$3.09	$3.22	$3.35	$3.48
Large Municipal Pumping					
Demand Primary (Sec cust)	$2.96	$3.09	$3.22	$3.35	$3.48
Fire and Civil Defense Siren Service	$2.96	$3.09	$3.22	$3.35	$3.48

(Continued on Sheet No. 5-93.7)

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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK – MPUC NO. 2

FRANCHISE AND OTHER CITY FEES (Continued)

Section No. 5
4th Revised Sheet No. 93.7

Notes:
[3] St. Paul (continued)

Customer Class	Meter Factor - Monthly Charge per Account				
Start Date	1-Nov-2016	1-Nov-2018	1-Nov-2020	1-Nov-2022	1-Nov-2024
End Date	31-Oct-2018	31-Oct-2020	31-Oct-2022	31-Oct-2024	31-Aug-2026
Residential (May - October)	$3.03	$3.15	$3.27	$3.40	$3.54
Small Commercial & Industrial					
Non-Demand	$3.62	$3.76	$3.91	$4.07	$4.23
Firm Secondary	$3.62	$3.76	$3.91	$4.07	$4.23
Firm Primary	$3.62	$3.76	$3.91	$4.07	$4.23
Interruptible Secondary	$3.62	$3.76	$3.91	$4.07	$4.23
Interruptible Primary	$3.62	$3.76	$3.91	$4.07	$4.23
Large Commercial & Industrial					
Special	$5.53	$5.75	$5.98	$6.22	$6.47
Firm Secondary	$5.53	$5.75	$5.98	$6.22	$6.47
Firm Primary	$5.53	$5.75	$5.98	$6.22	$6.47
Firm Trans. Transf.	$5.53	$5.75	$5.98	$6.22	$6.47
Interruptible Secondary	$5.53	$5.75	$5.98	$6.22	$6.47
Interruptible Primary	$5.53	$5.75	$5.98	$6.22	$6.47
Interruptible TT	$5.53	$5.75	$5.98	$6.22	$6.47
Standby Service	None	None	None	None	None
Public Street & Highway Lighting	$7.30	$7.59	$7.90	$8.21	$8.54
Small Municipal Pumping					
Non-Demand	$3.62	$3.76	$3.91	$4.07	$4.23
Demand Secondary	$3.62	$3.76	$3.91	$4.07	$4.23
Demand Primary	$3.62	$3.76	$3.91	$4.07	$4.23
Large Municipal Pumping					
Demand Primary (Sec cust)	$3.62	$3.76	$3.91	$4.07	$4.23
Fire and Civil Defense Siren Service	$3.62	$3.76	$3.91	$4.07	$4.23

(Continued on Sheet No. 5-93.8)

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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK – MPUC NO. 2

FRANCHISE AND OTHER CITY FEES (Continued)

Section No. 5
4th Revised Sheet No. 93.8

Notes:
[3] St. Paul (continued)

Customer Class	Energy Factor - Monthly Charge per kWh				
Start Date	1-Nov-2006	1-Nov-2008	1-Nov-2010	1-Nov-2012	1-Nov-2014
End Date	31-Oct-2008	31-Oct-2010	31-Oct-2012	31-Oct-2014	31-Oct-2016
Residential (May - October)	$0.0094	$0.0095	$0.0096	$0.0097	$0.0098
Small Commercial & Industrial					
Non-Demand	$0.0040	$0.0040	$0.0040	$0.0040	$0.0040
Firm Secondary	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018
Firm Primary	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018
Interruptible Secondary	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018
Interruptible Primary	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018
Large Commercial & Industrial					
Special	$0.0028	$0.0028	$0.0028	$0.0028	$0.0028
Firm Secondary	$0.0013	$0.0013	$0.0013	$0.0013	$0.0013
Firm Primary	$0.0013	$0.0013	$0.0013	$0.0013	$0.0013
Firm Trans. Transf.	$0.0013	$0.0013	$0.0013	$0.0013	$0.0013
Interruptible Secondary	$0.0013	$0.0013	$0.0013	$0.0013	$0.0013
Interruptible Primary	$0.0013	$0.0013	$0.0013	$0.0013	$0.0013
Interruptible TT	$0.0013	$0.0013	$0.0013	$0.0013	$0.0013
Standby Service	None	None	None	None	None
Public Street & Highway Lighting	$0.0040	$0.0040	$0.0040	$0.0040	$0.0040
Small Municipal Pumping					
Non-Demand	$0.0040	$0.0040	$0.0040	$0.0040	$0.0040
Demand Secondary	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018
Demand Primary	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018
Large Municipal Pumping					
Demand Primary (Sec cust)	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018
Fire and Civil Defense Siren Service	$0.0018	$0.0018	$0.0018	$0.0018	$0.0018

(Continued on Sheet No. 5-93.9)

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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK – MPUC NO. 2

FRANCHISE AND OTHER CITY FEES (Continued)

Section No. 5
4th Revised Sheet No. 93.9

Notes:
[3] St. Paul (continued)

Customer Class	Energy Factor - Monthly Charge per kWh				
Start Date	1-Nov-2016	1-Nov-2018	1-Nov-2020	1-Nov-2022	1-Nov-2024
End Date	31-Oct-2018	31-Oct-2020	31-Oct-2022	31-Oct-2024	31-Aug-2026
Residential (May - October)	$0.0102	$0.0106	$0.0110	$0.0115	$0.0119
Small Commercial & Industrial					
Non-Demand	$0.0042	$0.0043	$0.0045	$0.0047	$0.0049
Firm Secondary	$0.0019	$0.0019	$0.0020	$0.0021	$0.0022
Firm Primary	$0.0019	$0.0019	$0.0020	$0.0021	$0.0022
Interruptible Secondary	$0.0019	$0.0019	$0.0020	$0.0021	$0.0022
Interruptible Primary	$0.0019	$0.0019	$0.0020	$0.0021	$0.0022
Large Commercial & Industrial					
Special	$0.0029	$0.0030	$0.0031	$0.0033	$0.0034
Firm Secondary	$0.0014	$0.0014	$0.0015	$0.0015	$0.0016
Firm Primary	$0.0014	$0.0014	$0.0015	$0.0015	$0.0016
Firm Trans. Transf.	$0.0014	$0.0014	$0.0015	$0.0015	$0.0016
Interruptible Secondary	$0.0014	$0.0014	$0.0015	$0.0015	$0.0016
Interruptible Primary	$0.0014	$0.0014	$0.0015	$0.0015	$0.0016
Interruptible TT	$0.0014	$0.0014	$0.0015	$0.0015	$0.0016
Standby Service	None	None	None	None	None
Public Street & Highway Lighting	$0.0042	$0.0043	$0.0045	$0.0047	$0.0049
Small Municipal Pumping					
Non-Demand	$0.0042	$0.0043	$0.0045	$0.0047	$0.0049
Demand Secondary	$0.0019	$0.0019	$0.0020	$0.0021	$0.0022
Demand Primary	$0.0019	$0.0019	$0.0020	$0.0021	$0.0022
Large Municipal Pumping					
Demand Primary (Sec cust)	$0.0019	$0.0019	$0.0020	$0.0021	$0.0022
Fire and Civil Defense Siren Service	$0.0019	$0.0019	$0.0020	$0.0021	$0.0022

(Continued on Sheet No. 5-93.10)

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Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK – MPUC NO. 2

FRANCHISE AND OTHER CITY FEES (Continued)

Section No. 5
4th Revised Sheet No. 93.10

Notes:
[3] St. Paul (continued)

Customer Class	Demand Factor - Monthly Charge per kW				
Start Date	1-Nov-2006	1-Nov-2008	1-Nov-2010	1-Nov-2012	1-Nov-2014
End Date	31-Oct-2008	31-Oct-2010	31-Oct-2012	31-Oct-2014	31-Oct-2016
Residential (May - October)	None	None	None	None	None
Small Commercial & Industrial					
Non-Demand	None	None	None	None	None
Firm Secondary	$1.10	$1.10	$1.10	$1.10	$1.10
Firm Primary	$1.06	$1.06	$1.06	$1.06	$1.06
Interruptible Secondary	$1.10	$1.10	$1.10	$1.10	$1.10
Interruptible Primary	$1.06	$1.06	$1.06	$1.06	$1.06
Large Commercial & Industrial					
Special	None	None	None	None	None
Firm Secondary	$1.10	$1.10	$1.10	$1.10	$1.10
Firm Primary	$1.06	$1.06	$1.06	$1.06	$1.06
Firm Trans. Transf.	$1.06	$1.06	$1.06	$1.06	$1.06
Interruptible Secondary	$0.81	$0.81	$0.81	$0.81	$0.81
Interruptible Primary	$0.71	$0.71	$0.71	$0.71	$0.71
Interruptible TT	$0.51	$0.54	$0.57	$0.60	$0.63
Standby Service	$0.30	$0.33	$0.36	$0.39	$0.42
Public Street & Highway Lighting	None	None	None	None	None
Small Municipal Pumping					
Non-Demand	None	None	None	None	None
Demand Secondary	$1.10	$1.10	$1.10	$1.10	$1.10
Demand Primary	$1.06	$1.06	$1.06	$1.06	$1.06
Large Municipal Pumping					
Demand Primary (Sec cust)	$1.06	$1.06	$1.06	$1.06	$1.06
Fire and Civil Defense Siren Service	$1.06	$1.06	$1.06	$1.06	$1.06

(Continued on Sheet No. 5-93.11)

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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK – MPUC NO. 2

FRANCHISE AND OTHER CITY FEES (Continued)

Section No. 5
4th Revised Sheet No. 93.11

Notes:
[3] St. Paul (continued)

Customer Class	Demand Factor - Monthly Charge per kW				
Start Date	1-Nov-2016	1-Nov-2018	1-Nov-2020	1-Nov-2022	1-Nov-2024
End Date	31-Oct-2018	31-Oct-2020	31-Oct-2022	31-Oct-2024	31-Aug-2026
Residential (May - October)	None	None	None	None	None
Small Commercial & Industrial					
Non-Demand	None	None	None	None	None
Firm Secondary	$1.14	$1.19	$1.24	$1.29	$1.34
Firm Primary	$1.10	$1.15	$1.19	$1.24	$1.29
Interruptible Secondary	$1.14	$1.19	$1.24	$1.29	$1.34
Interruptible Primary	$1.10	$1.15	$1.19	$1.24	$1.29
Large Commercial & Industrial					
Special	None	None	None	None	None
Firm Secondary	$1.14	$1.19	$1.24	$1.29	$1.34
Firm Primary	$1.10	$1.15	$1.19	$1.24	$1.29
Firm Trans. Transf.	$1.10	$1.15	$1.19	$1.24	$1.29
Interruptible Secondary	$0.84	$0.88	$0.91	$0.95	$0.99
Interruptible Primary	$0.74	$0.77	$0.80	$0.83	$0.86
Interruptible TT	$0.66	$0.68	$0.71	$0.74	$0.77
Standby Service	$0.44	$0.45	$0.47	$0.49	$0.51
Public Street & Highway Lighting	None	None	None	None	None
Small Municipal Pumping					
Non-Demand	None	None	None	None	None
Demand Secondary	$1.14	$1.19	$1.24	$1.29	$1.34
Demand Primary	$1.10	$1.15	$1.19	$1.24	$1.29
Large Municipal Pumping					
Demand Primary (Sec cust)	$1.10	$1.15	$1.19	$1.24	$1.29
Fire and Civil Defense Siren Service	$1.10	$1.15	$1.19	$1.24	$1.29

(Continued on Sheet No. 5-93.12)

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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK – MPUC NO. 2

FRANCHISE AND OTHER CITY FEES (Continued)

Section No. 5
10th Revised Sheet No. 93.12

Franchise and other city fees, as designated below will be included in the customers' monthly bills computed under the indicated rate classes and effective in the following Minnesota communities:

The Company remits 100% of these fees collected from ratepayers to the local governmental unit.
— Indicates fee is not applied

Franchise Fees									
City	Residential	Small C&I Non-demand	Small C&I Demand	Large C&I	Public Street Lighting	Municipal Pumping Non-demand	Municipal Pumping Demand	Effective Date	Expiration Date
Vadnais Heights	$2.00	$3.00	$13.00	$60.00	—	—	—	05/2018	01/01/2038
Victoria	$3.00	$10.00	$10.00	$10.00	—	—	—	02/2017	10/09/2036
Waite Park	$4.00	$6.75	$15.00	$109.00	—	—	—	01/2019	06/10/2032
Watertown	$3.00	$4.50	$16.00	$51.00	—	$13.50	$21.00	04/2010	04/10/2027
Wayzata	$2.06	$4.64	$4.64	$15.45	$1.03	$1.03	$1.03	03/2011	11/30/2026
White Bear Lake	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	05/2018	01/08/2038
Winona	4.0% Customers who purchase $100,000 or less in calendar year 1.5% That part which exceeds $100,000 in calendar year							06/2003	06/15/2023
Winsted	$2.00	$2.00	$2.00	$2.00	—	—	—	05/2012	12/19/2031

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(Continued on Sheet No. 5-93.13)

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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK – MPUC NO. 2

FRANCHISE AND OTHER CITY FEES (Continued)

Section No. 5
9th Revised Sheet No. 93.12

Franchise and other city fees, as designated below will be included in the customers' monthly bills computed under the indicated rate classes and effective in the following Minnesota communities:

The Company remits 100% of these fees collected from ratepayers to the local governmental unit.
— Indicates fee is not applied

Franchise Fees										
City	Residential	Small C&I Non-demand	Small C&I Demand	Large C&I	Public Street Lighting	Municipal Pumping Non-demand	Municipal Pumping Demand	Effective Date	Expiration Date	
Vadnais Heights	$2.00	$3.00	$13.00	$60.00	—	—	—	05/2018	01/01/2038	N
Victoria	$3.00	$10.00	$10.00	$10.00	—	—	—	02/2017	10/09/2036	
Watertown	$3.00	$4.50	$16.00	$51.00	—	$13.50	$21.00	04/2010	04/10/2027	
Wayzata	$2.06	$4.64	$4.64	$15.45	$1.03	$1.03	$1.03	03/2011	11/30/2026	
White Bear Lake	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	05/2018	01/08/2038	C
Winona	4.0% Customers who purchase $100,000 or less in calendar year 1.5% That part which exceeds $100,000 in calendar year							06/2003	06/15/2023	
Winsted	$2.00	$2.00	$2.00	$2.00	—	—	—	05/2012	12/19/2031	

(Continued on Sheet No. 5-93.13)

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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK – MPUC NO. 2

FRANCHISE AND OTHER CITY FEES

Section No. 5
4th Revised Sheet No. 93.13

Franchise and other city fees, as designated below will be included in the customers' monthly bills computed under the indicated rate classes and effective in the following Minnesota communities:

The Company remits 100% of these fees collected from ratepayers to the local government unit.*
(U) Indicates unincorporated community

Other City Fees			
City	**Description**	**Effective Date**	**Expiration Date**
West St. Paul	Pursuant to city code, the Company collects a 6.38% of gross earnings tax derived from the sale of electricity within the City of West St. Paul excluding electric energy supplied to the City for municipal services. The amount collected is remitted to the City of West St. Paul.	07/2018	--
FEES NOT REMITTED DIRECTLY TO CITY			
Baker (U)	The Company collects a fee of $3.25 per residential and small commercial and industrial customer in the community of Baker for energy usage and maintenance on community street lighting. The amount collected is applied to Baker's street lighting bill.	03/1994	--

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*Except Baker. See above.

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Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK – MPUC NO. 2

FRANCHISE AND OTHER CITY FEES

Section No. 5
3rd Revised Sheet No. 93.13

Franchise and other city fees, as designated below will be included in the customers' monthly bills computed under the indicated rate classes and effective in the following Minnesota communities:

The Company remits 100% of these fees collected from ratepayers to the local government unit.*
(U) Indicates unincorporated community

Other City Fees			
City	**Description**	**Effective Date**	**Expiration Date**
West St. Paul	Pursuant to city code, the Company collects a 5.26% of gross earnings tax derived from the sale of electricity within the City of West St. Paul excluding electric energy supplied to the City for municipal services. The amount collected is remitted to the City of West St. Paul.	12/1996	--
FEES NOT REMITTED DIRECTLY TO CITY			
Baker (U)	The Company collects a fee of $3.25 per residential and small commercial and industrial customer in the community of Baker for energy usage and maintenance on community street lighting. The amount collected is applied to Baker's street lighting bill.	03/1994	--

*Except Baker. See above.

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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
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INTERIM RATE SURCHARGE RIDER

Section No. 5
12th Revised Sheet No. 94

CANCELED C

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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

LOW INCOME ENERGY DISCOUNT RIDER Section No. 5
9th Revised Sheet No. 95

DISCOUNT PROGRAM D
Eligible Senior and / or Disabled customers receive a $15 discount in each monthly billing period. Customers must be certified annually by an authorized agency as receiving assistance from the Low Income Home Energy Assistance Program. N N N

PowerOn PROGRAM
Eligible Seniors and / or Disabled, and Customers Under 62 Years of Age with no Disability.
A customer using more than 3% of their annual household income for electric use may be eligible for the Company's PowerOn affordability program. Customers must be certified annually by an authorized agency as receiving assistance from the Low Income Home Energy Assistance Program. The Company will offer customers with the lowest income, and a history of electric consumption that exceeds the residential average of 750 kWh per month, an affordable monthly bill. For a customer to be eligible for a supplemental reduction in their electric bill, the customer must agree to affordable monthly payments. N N

Medical Affordability PROGRAM N
Available to customers with certified medical circumstances and an income level up to 50 percent of the state median income guidelines. Availability will be extended to medically certified customers with income up to 60 percent of the state median income guidelines if funds are available. Availability is on a first-come/first-served basis until the budget is exhausted.

- Affordability Credit: Participating customers will receive an affordability credit limiting their bill to 3% of household income.
- Arrearage Credit: Participating customers will receive an arrearage credit. Receipt of the arrearage forgiveness credit will require a customer copayment that does not exceed 3% of the customer's annual income. The arrearage credit is designed to eliminate customer arrears over a period of 12 to 24 months.
- Customer Payment Requirements: Participating customers that miss two consecutive monthly payments will be removed from the program and subject to regular collection practices, including service disconnection. N

TERMS AND CONDITIONS OF SERVICE

1. The company will review current billing information, approved LIHEAP benefits and household income to make payment arrangements with the customer. A mutually agreed to payment plan will be offered to the customer and a payment schedule provided.

2. Customer must maintain an active account registered under customer's name with the Company to be eligible for this discount Rider.

3. Customers receiving assistance from LIHEAP with electric service through one meter for domestic and non-domestic purposes jointly may be eligible for this Discount Rider subject to Company's verification and approval. The Company shall determine the kWh use that is for domestic purposes. This Discount Rider only applies to kWh use for domestic purposes.

(Continued on Sheet No. 5-96)

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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
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LOW INCOME ENERGY DISCOUNT RIDER Section No. 5
(Continued) 12th Revised Sheet No. 96

TERMS AND CONDITIONS OF SERVICE (Continued)

4. Qualified customers are only eligible to receive an energy discount under this Rider at one residential location at any one time and the discount only applies to a qualified customer's permanent primary residence. This Rider will not be available when, in the opinion of the Company, the customer's accommodation or occupancy is of temporary nature.

5. The discount shall be prospective and may not be applicable to past due bills or non-electric services.

6. An annual application and eligibility declaration is required for each request for service under this Rider. Without declaration of continuing eligibility, the discount ends in the September calendar month of each year.

7. It is the customer's responsibility to notify the Company if there is a change of address or eligibility status.

8. Discounts will be credited to the eligible customer bills one billing month after Company's receipt of notification of LIHEAP certification. The applicable discount under this Rider will be retroactive to the October billing month during that same LIHEAP fiscal year.

9. Refusal or failure of a customer or agencies to provide documentation of eligibility acceptable to the Company may result in removal from this Rider.

10. Customers may be rebilled for periods of ineligibility under the applicable rate schedule.

11. This Rider shall meet the conditions of Minnesota Statutes, Chapter 216B.16, Subd. 14 on low income discount rates.

PROGRAM SURCHARGE

Rider program costs shall be recovered in the following per month amounts, with the total surcharge as a separate line item on customer billing statements:

Service Category	Base	PowerOn	Medical Affordability	Total	
Residential	$0.58	$0.21	$0.19	$0.98	R
C&I Non-Demand	$0.78	$0.26	$0.23	$1.27	R
C&I Demand	$2.34	$0.66	$0.60	$3.60	R

Xcel Energy customers who receive LIHEAP assistance in the current LIHEAP year (October 1–September 30) and Lighting class service customers are exempt from paying the program surcharge.

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Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

LOW INCOME ENERGY DISCOUNT RIDER Section No. 5
(Continued) 11th Revised Sheet No. 96

TERMS AND CONDITIONS OF SERVICE (Continued)

4. Qualified customers are only eligible to receive an energy discount under this Rider at one residential location at any one time and the discount only applies to a qualified customer's permanent primary residence. This Rider will not be available when, in the opinion of the Company, the customer's accommodation or occupancy is of temporary nature.

5. The discount shall be prospective and may not be applicable to past due bills or non-electric services.

6. An annual application and eligibility declaration is required for each request for service under this Rider. Without declaration of continuing eligibility, the discount ends in the September calendar month of each year.

7. It is the customer's responsibility to notify the Company if there is a change of address or eligibility status.

8. Discounts will be credited to the eligible customer bills one billing month after Company's receipt of notification of LIHEAP certification. The applicable discount under this Rider will be retroactive to the October billing month during that same LIHEAP fiscal year.

9. Refusal or failure of a customer or agencies to provide documentation of eligibility acceptable to the Company may result in removal from this Rider.

10. Customers may be rebilled for periods of ineligibility under the applicable rate schedule.

11. This Rider shall meet the conditions of Minnesota Statutes, Chapter 216B.16, Subd. 14 on low income discount rates.

PROGRAM SURCHARGE

Rider program costs shall be recovered in the following per month amounts, with the total surcharge as a separate line item on customer billing statements:

Service Category	**Base**	**PowerOn**	**Medical Affordability**	**Total**	
Residential	$0.57	$0.21	$0.19	$0.97	N
C&I Non-Demand	$0.77	$0.26	$0.23	$1.26	N
C&I Demand	$2.30	$0.66	$0.60	$3.56	N

N
TN

Xcel Energy customers who receive LIHEAP assistance in the current LIHEAP year (October 1–September 30) and Lighting class service customers are exempt from paying the program surcharge.

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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

RESIDENTIAL CONTROLLED AIR CONDITIONING AND WATER HEATING RIDER

Section No. 5
8th Revised Sheet No. 97

AVAILABILITY

Available to Residential Service customers with:

1. Company controlled central air conditioning, or
2. Company controlled heat pumps receiving Energy Controlled Service (Non-Demand Metered) with optional non-interruptible service during June through September.

Company controlled electric water heating is also available to residential customers with a controlled central air conditioner or heat pump, except electric water heaters served with the Energy Controlled Service (Non-Demand Metered) rate schedule. Availability is limited to customers located in areas which are within the operating range of radio control transmitters.

In addition, customer bills under this rate are subject to the following adjustments and/or charges.

RIDER

Residential Central Air Conditioning. A 15% discount will apply to the energy and fuel cost charges up to a maximum of 4,000 kWh per month during the billing months of June through September.

Residential Electric Water Heating. A 2% discount will apply to the energy and fuel cost charges up to a maximum of 4,000 kWh per month during each billing month provided total energy use is not less than 300 kWh.

TERMS AND CONDITIONS OF SERVICE

1. The duration and frequency of interruptions will be determined by Company. Customer's air conditioning equipment will normally be cycled on a schedule designed to achieve a 50% reduction in the homes air conditioning requirements during load management period. Air conditioning interruptions will normally occur on high demand days during summer months. Water heating interruptions will normally occur on high demand days during summer and winter months. Interruption will normally be based on meeting peak demands and system economic dispatch requirements of Company. However, interruption may also occur at times when, in the Company's opinion, the reliability of the system may be at risk. Air conditioning and water heating interruptions will not normally occur during the observation day of the following holidays: New Year's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. The interruptions as described above, will be made so as to benefit native load and may occur up to a maximum of 300 hours per calendar year.

2. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service.

3. To be eligible for this service, customer must agree to Company load control for a minimum term of one year.

(Continued on Sheet No. 5-98)

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Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK – MPUC NO. 2

RESIDENTIAL CONTROLLED AIR CONDITIONING AND WATER HEATING RIDER (Continued)

Section No. 5
5th Revised Sheet No. 98

TERMS AND CONDITIONS OF SERVICE (Continued)

4. The storage capacity of the water heater shall be 40 gallons or more in order to be eligible for this service.

5. The residential central air conditioning energy charge discount for Energy Controlled Service (Non-Demand Metered) customers will also apply to their standard service energy charge.

6. Rider availability for heat pump installations is limited to those sized for summer cooling requirements, as determined by Company.

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK – MPUC NO. 2

COMMERCIAL AND INDUSTRIAL Section No. 5
CONTROLLED AIR CONDITIONING RIDER 8th Revised Sheet No. 99

AVAILABILITY
Available to non-residential customers with Company controlled central air conditioning. Availability is restricted to customers with single and/or dual stage air conditioning units.

RIDER
A $5.00 per ton per month credit shall be applied to customer's bill during each of the four summer billing months (June through September).

TERMS AND CONDITIONS OF SERVICE

1. The duration and frequency of interruptions will be determined by the Company. Customer single and dual stage air conditioners will be cycled on a schedule designed to achieve a 50% reduction in the building air conditioning requirements during a load management period. Dual stage air conditioners will be allowed to have the first stage run without interruption while the second stage will be shut off for the entire load management period. Air conditioning interruptions will normally occur on high demand days during summer months. Interruption will normally be based on meeting peak demands and system economic dispatch requirements of Company. However, interruption may also occur at times when, in the Company's opinion, the reliability of the system may be at risk. Air conditioning interruptions will not normally occur during the observation day of the following holidays: New Year's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. The interruptions as described above, will be made so as to benefit native load and may occur up to a maximum of 300 hours per calendar year.

2. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service.

3. To be eligible for this service, customer must be on Small General Service, Small General Time of Day Service, General Service, or General Time of Day Service and customer must agree to Company load control for no less than one year.

4. Rider will not be available to customers that have an air conditioning system which significantly exceeds summer cooling requirements, as determined by Company.

5. Company will normally control every air conditioning unit at the customer's building. Subject to Company approval, customers may exclude individual air conditioning units from Company control where those units serve either a sufficiently isolated area within a building or a separate building.

6. Availability is limited to customers located within the operating range of radio control transmitters.

7. Those air conditioning units that the Company is not able to install equipment on will be excluded.

(Continued on Sheet No. 5-99.1)

Northern States Power Company, a Minnesota corporation
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COMMERCIAL AND INDUSTRIAL Section No. 5
CONTROLLED AIR CONDITIONING RIDER (Continued) 5th Revised Sheet No. 99.1

TERMS AND CONDITIONS OF SERVICE (Continued)

8. If the Company determines that its load management equipment on the customer's premises has been rendered ineffective due to tampering by use of mechanical, electrical, or other devices or actions, then the Company may discontinue the customer's participation in the program. The customer would be billed for all expenses involved with the removal of the load management equipment and any charges resulting from the investigation of the device tampering. The Company may rebill all prior load management credits received by the customer to the date the tampering appears to have first occurred or the previous twelve months, which ever is longer. The customer will be removed from the program and is not eligible to participate again for twelve months. The Company will verify installation has been corrected before the customer is permitted to participate in the program.

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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

OFF SEASON LOAD RIDER

Section No. 5
5th Revised Sheet No. 100

AVAILABILITY
Available to any General Service customer whose maximum monthly demand occurs during the usage months of April, May, October, or November. Typical applications would be agricultural grain drying and handling loads.

RATE
The General Service rate provisions apply except the adjusted demands established during the usage months of April, May, October, and November are not included in determining the 50% demand ratchet contained in the General Service determination of demand provision.

TERMS AND CONDITIONS OF SERVICE
1. The customer's usage months for this Rider must be contained by the following meter reading schedule. The two month fall season begins no earlier than the billing cycle 11 meter reading date in mid-September and ends no later than the billing cycle 10 meter reading date in mid-December. The two month spring season begins no earlier than the billing cycle 11 meter reading date in mid-March and ends no later than the billing cycle 10 meter reading date in mid-June.

2. Customer must compensate Company for the costs associated with local distribution facilities required to serve customer load during the months of April, May, October, and November, which is in excess of customer's base load during the remaining months.

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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

STANDBY SERVICE RIDER

Section No. 5
20th Revised Sheet No. 101

AVAILABILITY

Applicable to customers that use a customer-sited generation source with a capacity greater than 100 kW to serve a defined portion of the customer's total electric energy requirements and where customer chooses to use the Company's electric service to serve that defined load when the customer-sited generation is either partly or wholly unavailable. Customer must select one of the following services types: Firm Unscheduled Maintenance, Firm Scheduled Maintenance, or Non-Firm service. This Rider is not available to solar photovoltaic generation systems and is closed to new wind generation systems.

Under this tariff the Company will provide Standby Service in accordance with the provisions of this tariff as well as those of Section 2.4 of the General Rules and Regulations.

RATE

	Firm Standby		Non-Firm	
	Unscheduled Maintenance	Scheduled Maintenance	Standby	
Customer Charge per Month	$25.64	$25.64	$25.64	
Reservation Demand Charge per Month per kW of Contracted Standby Capacity				
Secondary Voltage Service	$3.06	$2.96	$2.35	R
Primary Voltage Service	$2.26	$2.16	$1.55	R
Transmission Transformed Voltage Service	$1.51	$1.41	$0.80	R
Transmission Voltage Service	$0.71	$0.61	$0.00	R
Peak Period Standby Energy Surcharge per kWh				
June – September		$0.06312		R
Other Months		$0.04130		R

Energy Charge per kWh. All energy used under this Rider will be charged at the applicable energy rate of the base tariff to which this Rider is attached and is not applicable to the base tariff Energy Charge Credit.

STANDBY ENERGY USAGE

Standby energy usage occurs when the customer-sited generation source output in kW is less than contracted standby kW capacity. Standby energy usage in kWh is measured in 15-minute intervals and is defined as the kWh energy associated with constant operation of customer-sited generation at the contract standby kW capacity level less actual energy production of customer-sited generation, but not less than zero kWh for each 15-minute interval. Actual energy production of customer-sited generation will be measured by Company-owned and installed production metering equipment.

(Continued on Sheet No. 5-101.1)

Northern States Power Company, a Minnesota corporation
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MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

STANDBY SERVICE RIDER Section No. 5
19th Revised Sheet No. 101

AVAILABILITY
Applicable to customers that use a customer-sited generation source with a capacity greater than 100 kW to serve a defined portion of the customer's total electric energy requirements and where customer chooses to use the Company's electric service to serve that defined load when the customer-sited generation is either partly or wholly unavailable. Customer must select one of the following services types: Firm Unscheduled Maintenance, Firm Scheduled Maintenance, or Non-Firm service. This Rider is not available to solar photovoltaic generation systems and is closed to new wind generation systems.

Under this tariff the Company will provide Standby Service in accordance with the provisions of this tariff as well as those of Section 2.4 of the General Rules and Regulations.

RATE

	Firm Standby		Non-Firm	
	Unscheduled Maintenance	Scheduled Maintenance	Standby	
Customer Charge per Month	$25.64	$25.64	$25.64	
Reservation Demand Charge per Month per kW of Contracted Standby Capacity				
Secondary Voltage Service	$3.10	$3.00	$2.35	R
Primary Voltage Service	$2.30	$2.20	$1.55	R
Transmission Transformed Voltage Service	$1.55	$1.45	$0.80	R
Transmission Voltage Service	$0.75	$0.65	$0.00	R
Peak Period Standby Energy Surcharge per kWh				
June – September		$0.06693		R
Other Months		$0.04389		R

Energy Charge per kWh. All energy used under this Rider will be charged at the applicable energy rate of the base tariff to which this Rider is attached and is not applicable to the base tariff Energy Charge Credit.

STANDBY ENERGY USAGE
Standby energy usage occurs when the customer-sited generation source output in kW is less than contracted standby kW capacity. Standby energy usage in kWh is measured in 15-minute intervals and is defined as the kWh energy associated with constant operation of customer-sited generation at the contract standby kW capacity level less actual energy production of customer-sited generation, but not less than zero kWh for each 15-minute interval. Actual energy production of customer-sited generation will be measured by Company-owned and installed production metering equipment.

(Continued on Sheet No. 5-101.1)

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MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

STANDBY SERVICE RIDER

Section No. 5
18th Revised Sheet No. 101

AVAILABILITY

Applicable to customers that use a customer-sited generation source with a capacity greater than 100 kW to serve a defined portion of the customer's total electric energy requirements and where customer chooses to use the Company's electric service to serve that defined load when the customer-sited generation is either partly or wholly unavailable. Customer must select one of the following services types: Firm Unscheduled Maintenance, Firm Scheduled Maintenance, or Non-Firm service. This Rider is not available to solar photovoltaic generation systems and is closed to new wind generation systems. C C C C C C

Under this tariff the Company will provide Standby Service in accordance with the provisions of this tariff as well as those of Section 2.4 of the General Rules and Regulations.

RATE C

	Firm Standby		Non-Firm	
	Unscheduled Maintenance	Scheduled Maintenance	Standby	
Customer Charge per Month	$25.64	$25.64	$25.64	
Reservation Demand Charge per Month per kW of Contracted Standby Capacity				CL L
Secondary Voltage Service	$3.08	$2.98	$2.35	R
Primary Voltage Service	$2.28	$2.18	$1.55	R
Transmission Transformed Voltage Service	$1.53	$1.43	$0.80	R
Transmission Voltage Service	$0.73	$0.63	$0.00	R
Peak Period Standby Energy Surcharge per kWh				D
June – September		$0.06545		N
Other Months		$0.04242		N

Energy Charge per kWh. All energy used under this Rider will be charged at the applicable energy rate of the base tariff to which this Rider is attached and is not applicable to the base tariff Energy Charge Credit. LC LN

STANDBY ENERGY USAGE N

Standby energy usage occurs when the customer-sited generation source output in kW is less than contracted standby kW capacity. Standby energy usage in kWh is measured in 15-minute intervals and is defined as the kWh energy associated with constant operation of customer-sited generation at the contract standby kW capacity level less actual energy production of customer-sited generation, but not less than zero kWh for each 15-minute interval. Actual energy production of customer-sited generation will be measured by Company-owned and installed production metering equipment. N N N N N N

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(Continued on Sheet No. 5-101.1)

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MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

STANDBY SERVICE RIDER Section No. 5
17th Revised Sheet No. 101

AVAILABILITY
Applicable to customers that use an alternative generation source with a capacity greater than 100 kW, where the alternative generation serves all or a portion of customer's electric energy requirements and where customer chooses to use the Company's electric service to serve that load when the alternative generation is either partly or wholly unavailable.

Under this tariff the Company will provide Standby Service in accordance with the provisions of this tariff as well as those of Section 2.4 of the General Rules and Regulations.

RESERVATION RATE

	Firm Standby		Non-Firm	
	Unscheduled Maintenance	Scheduled Maintenance	Standby	
Customer Charge per Month	$25.64	$25.64	$25.64	R
Demand Charge per Month per kW of Contracted Standby Capacity				
Secondary Voltage Service	$3.54	$3.44	$2.35	R
Primary Voltage Service	$2.74	$2.64	$1.55	R
Transmission Transformed Voltage Service	$1.99	$1.89	$0.80	R
Transmission Voltage Service	$1.19	$1.09	$0.00	R
Hours per kW of Contracted Standby Capacity - Annual Grace Period Use of Unscheduled Standby, Exemption from the Demand Charge Component of the “Usage Rates” below.	964	964	0	

USAGE RATES
Demand Charge per kW of Standby Capacity Used. After the Annual Grace Period hours provided for Unscheduled and Scheduled Service are used up, the Demand Charge of the base tariff, to which this Rider is attached, replaces the above Reservation Rate.

Energy Charge per kWh of Standby Energy Used. All energy used under this Rider will be charged at the applicable energy rate of the base tariff to which this Rider is attached.

PHOTOVOLTAIC SOLAR CREDIT
A capacity credit of $5.15 per month per kW is applicable when the alternative generation source used by the customer is photovoltaic solar. This credit shall only be applied to the applicable Demand Charge of the base tariff for the contracted demand component of the Usage Rates outside of the Grace Period.

In addition, customer bills under this rate are subject to the following adjustments and/or charges.

FUEL CLAUSE
Bills are subject to the adjustments provided for in the Fuel Clause Rider.

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STANDBY SERVICE RIDER (Continued)

Section No. 5
Original Sheet No. 101.1

PEAK PERIOD STANDBY ENERGY USAGE N
Peak period standby energy usage is the amount of Standby Energy Usage occurring during the peak period N
that does not occur during a qualifying scheduled maintenance period or is associated with Non-Firm service. N
Peak period standby energy usage is subject to the Peak Period Standby Energy Surcharge. N

DEFINITION OF PEAK PERIOD N
Peak period hours are the six hours between 1:00 p.m. and 7 p.m. for all days. N

In addition, customer bills under this rate are subject to the following adjustments and/or charges. L

FUEL CLAUSE L
Bills are subject to the adjustments provided for in the Fuel Clause Rider. L

RESOURCE ADJUSTMENT L
Bills are subject to the adjustments provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider, the Renewable Development Fund Rider, the Transmission Cost Recovery Rider, the Renewable Energy Standard Rider and the Mercury Cost Recovery Rider.

ENVIRONMENTAL IMPROVEMENT RIDER
Bills are subject to the adjustments provided for in the Environmental Improvement Rider.

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

LOW INCOME ENERGY DISCOUNT RIDER
Bills are subject to the adjustment provided for in the Low Income Energy Discount Rider.

In addition, customer bills under this rate are subject to the following adjustments and/or charges.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5. L

(Continued on Sheet No. 5-102)

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MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

STANDBY SERVICE RIDER (Continued)

Section No. 5
14th Revised Sheet No. 102

L

DETERMINATION OF DEMAND

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The billing demand in kW for application to the Standby Service Reservation Demand Charge rate will be the contracted Standby capacity specified in the customer's Electric Service Agreement, which is the maximum capacity of Standby Service the Company is obligated to supply, and is the amount of load expected to be served by the customer-sited generation source. In no case shall the contracted Standby capacity be established at more than the capacity of the customer-sited generation source. Contracted Standby capacity may be different for the summer and winter seasons or by month.

The metered capacity in kW supplied by Company for Standby Energy Usage by customer will be excluded from the actual demand in kW used to determine any billed demand for the base tariff to which this Rider is attached. This exclusion is determined as the maximum total customer demand, defined as the total of capacity supplied by the customer-sited generation source and the Company measured in 15-minutes intervals, less contracted Standby capacity. All demand measurements will be determined with Company owned and installed meters. The exclusion of capacity supplied by Company for Standby Energy Usage by customer from any base tariff determination of demand calculation is represented by the equation: Base tariff actual demand in kW = Site load (Company supplied capacity in kW measured by the base tariff service meter + Customer supplied capacity in kW measured by production metering of customer-sited generation) – Contracted Standby capacity in kW as determined by the customer nomination in effect for the applicable billing period.

Any billing demand in kW for the base tariff to which this Rider is attached will be calculated using the applicable determination of demand provision defined in the base tariff. For a time of day base tariff, the on-peak and off-peak periods used for billed demand calculations will be based on the definition of peak periods included in the time of day base tariff.

C

TERMS AND CONDITIONS OF SERVICE

1. Standby Service Rider is applicable to any customer who requires greater than 100 kW of Standby capacity. Standby Service may not be used by a customer to serve controllable demand that is subject to interruption as determined by the Company under the Company's controllable service schedules.

(Continued on Sheet No. 5-103)

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STANDBY SERVICE RIDER (Continued) Section No. 5
13th Revised Sheet No. 102

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider, the Renewable Development Fund Rider, the Transmission Cost Recovery Rider, the Renewable Energy Standard Rider and the Mercury Cost Recovery Rider.

ENVIRONMENTAL IMPROVEMENT RIDER
Bills are subject to the adjustments provided for in the Environmental Improvement Rider.

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

LOW INCOME ENERGY DISCOUNT RIDER
Bills are subject to the adjustment provided for in the Low Income Energy Discount Rider.

In addition, customer bills under this rate are subject to the following adjustments and/or charges.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

DETERMINATION OF DEMAND
The billing demand applicable to this Standby Service Rider is determined separately from the billing demand applicable to the base tariff to which this Rider attaches. The demand associated with actual use of Standby Service will be subtracted from the total metered demand, to determine the demand for standard service, to which the base tariff demand charge applies.

For applying the Standby Service Reservation Rate, the billing demand will be the contracted Standby capacity specified in the customer's Electric Service Agreement, which is the maximum capacity of Standby Service the Company is obligated to supply, and is the amount of load served by the customer's alternative generation. In no case shall the contracted Standby capacity be established at more than the capacity of the customer's generation facility. This contracted Standby capacity may be different for the summer and winter seasons.

For applying the demand component of the Usage Rates, the billing demand shall be the capacity actually used by the customer, when customer's generator is wholly or partly out of service. This amount of Standby capacity actually used shall be the contracted Standby capacity less the actual capacity supplied by the customer's generating facilities (assuming it is operating, but not at full capacity), but not less than zero.

TERMS AND CONDITIONS OF SERVICE
1. Standby Service Rider is applicable to any customer who requires greater than 100 kW of Standby capacity. Standby Service may not be used by a customer to serve controllable demand that is subject to interruption as determined by the Company under the Company's controllable service schedules.

(Continued on Sheet No. 5-103)

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Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

STANDBY SERVICE RIDER (Continued) Section No. 5
7th Revised Sheet No. 103

TERMS AND CONDITIONS OF SERVICE (Continued)

2. Customer will execute an Electric Service Agreement with the Company which will specify:
   a. Type of Standby Service elected by the customer and the base tariff to which this Rider is attached.
   b. The total Standby capacity requirements for which Company will be providing Standby power and to which the Standby Service reservation rate applies as well as the expected level of standard service the customer will take, even if the standard service level is expected to be zero. T
   c. The process and requirements for nominating contracted Standby capacity, including seasonal or monthly levels. N N

3. The Company's standard service meter will be detented to measure only the amount of capacity and energy provided by the Company to the customer.

4. Company will not be obligated to supply Standby Service to back-up a customer's generator at a level in excess of the Standby capacity for which customer has contracted. This restriction in no way limits the amount of standard service the customer requires from the Company under the standard service tariff to which this Rider is attached. Any limits on standard service are governed by the provisions contained in the standard service tariffs.

5. Customer will be liable for all damages allowed by law to the extent caused by customer's use of Standby power in excess of contracted Standby capacity.

6. Company will require customer to revise the Electric Service Agreement to contract for additional Standby capacity if the customer exceeds the contract amount in any three of the preceding 12 months.

7. Customer will annually furnish documentation to Company confirming the maximum capacity and reliability of the power source for which customer requires Standby Service. The Company and the customer will review the actual output and performance of the power source relative to the capacity nominated for Standby Service in the Electric Service Agreement. If this review shows a significant and consistent shortfall between the power source's actual performance and the nominated capacity due to factors reasonably within the customer's control, the Company will notify the customer of its intent to refuse to provide Standby Service. Upon receipt of such notice, the customer may agree to reduce the Standby Service nomination in its Electric Service Agreement or to take such action as necessary to operate the power source at or reasonably near the nominated Standby Service capacity. If the customer's power source does not operate at or reasonably near that level during the 12 months immediately following the Company's notice, the Company may refuse to provide Standby Service until such time as the customer agrees to reduce its Standby Service nomination or provide the Company with documentation demonstrating the power source's actual performance at or reasonably near the nominated Standby Service capacity for a trial period of three consecutive months.

8. Customer will remain on Standby Service for a period of not less than 12 months.

(Continued on Sheet No. 5-104)

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STANDBY SERVICE RIDER (Continued)

Section No. 5
6th Revised Sheet No. 103

TERMS AND CONDITIONS OF SERVICE (Continued)

2. Customer will execute an Electric Service Agreement with the Company which will specify:
   a. Type of Standby Service elected by the customer and the base tariff to which this Rider is attached.
   b. The total Standby capacity requirements for which Company will be providing Standby power and to which the Standby Service reservation rate applies as well as the expected level of standard service the customer will take, even if the standard service level is expected to be zero.

3. The Company's standard service meter will be detented to measure only the amount of capacity and energy provided by the Company to the customer.

4. Company will not be obligated to supply Standby Service to back-up a customer's generator at a level in excess of the Standby capacity for which customer has contracted. This restriction in no way limits the amount of standard service the customer requires from the Company under the standard service tariff to which this Rider is attached. Any limits on standard service are governed by the provisions contained in the standard service tariffs.

5. Customer will be liable for all damages allowed by law to the extent caused by customer's use of Standby power in excess of contracted Standby capacity.

6. Company will require customer to revise the Electric Service Agreement to contract for additional Standby capacity if the customer exceeds the contract amount in any three of the preceding 12 months.

7. Customer will annually furnish documentation to Company confirming the maximum capacity and reliability of the power source for which customer requires Standby Service. The Company and the customer will review the actual output and performance of the power source relative to the capacity nominated for Standby Service in the Electric Service Agreement. If this review shows a significant and consistent shortfall between the power source's actual performance and the nominated capacity due to factors reasonably within the customer's control, the Company will notify the customer of its intent to refuse to provide Standby Service. Upon receipt of such notice, the customer may agree to reduce the Standby Service nomination in its Electric Service Agreement or to take such action as necessary to operate the power source at or reasonably near the nominated Standby Service capacity. If the customer's power source does not operate at or reasonably near that level during the 12 months immediately following the Company's notice, the Company may refuse to provide Standby Service until such time as the customer agrees to reduce its Standby Service nomination or provide the Company with documentation demonstrating the power source's actual performance at or reasonably near the nominated Standby Service capacity for a trial period of three consecutive months.

8. Customer will remain on Standby Service for a period of not less than 12 months.

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STANDBY SERVICE RIDER (Continued) Section No. 5
8th Revised Sheet No. 104

TERMS AND CONDITIONS OF SERVICE (Continued)

9. In the event Company provides advance notice to customer of expected system peak load conditions for a specified time period and customer uses unscheduled standby backup demand during that time period, the backup demand quantity used will be billed at the firm service demand charge from the base tariff to which this Rider is attached instead of the Reservation Demand charge. The quantity of unscheduled standby backup demand used for this provision will be the maximum 15-minute measured interval of unscheduled standby backup demand used during the specified system peak hours, measured as contracted standby capacity less the capacity provided by the customer-sited generation source. Company notice of expected system peak load conditions for this provision will be provided through the same means Company uses to notify interruptible customers of an interruption requirement. N N N N N N N N N

10. Company will install and charge customer for the additional metering necessary, to allow for determining Peak Period Standby Energy usage. In particular, the Company will install a separate meter that measures the flow of power and energy from the customer's own generating facility. Customer shall reimburse the Company for the costs of installing, operating, and maintaining the required additional metering and for any other facilities required to serve the customer's Standby load. If, as a result of the customer's construction and installation of their generating facility, it is more practical for the customer to install some or all of the metering equipment required, the customer may be permitted to do so, subject to Company's approval of such equipment. LC C L

(Continued on Sheet No. 5-105)

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STANDBY SERVICE RIDER (Continued) Section No. 5
7th Revised Sheet No. 104

TERMS AND CONDITIONS OF SERVICE (Continued)

9. Customer will be allowed annually a Grace Period as specified above for use of unscheduled Standby Service without incurring additional demand charges for use of Standby Service. Use of this Grace Period will be measured in terms of Standby energy used by customer with the maximum amount of grace energy being the hours specified above times the contracted Standby capacity. After the Grace Period has been exhausted and customer uses unscheduled Standby Service, the customer shall pay the Demand Charge specified in the Usage Rates instead of the Reservation Fees as listed above. In a billing month, when customer uses Standby Service, the base tariff billing demand and the Standby Service billing demand will be determined individually. The base tariff billing demand will be the greatest 15 minute load determined after separating Standby Service usage from the total metered demands. The time of this determined greatest 15 minute demand for application to the base tariff may or may not occur at the same time when Standby Service is used. Billed demand charges for usage of Standby Service will be in addition to the billed demand charges for the base tariff as just described.

   Customers contracting for Standby Service to back up a solar photovoltaic system have the option to move their annual start date and subsequent Grace Periods forward to June 1. However, a customer shall not receive two annual Grace Periods for the same solar photovoltaic system in any rolling 12-month billing period.

10. Notwithstanding the Grace Period noted in provision 9 above, in the event customer requires unscheduled Standby Service at the times of Company's system peak hours in which the Company would have insufficient accredited capacity under the Midwest Reliability Organization (MRO) or any successor organization, and the Company incurs additional capacity costs as a result of such unscheduled Standby Service, customer shall pay Peak Demand Charges described below for the month in which such unscheduled Standby Service occurs and for each of the five succeeding months, instead of the above listed demand charges, or the demand charges under Section 9 above. Such Peak Demand Charges shall be based upon the following:

    a. If customer has notified Company of an unscheduled outage at least three hours prior to Company's system peak hour, such Peak Demand Charges shall be based on one-sixth of any additional capacity costs incurred by the Company as a result of the unscheduled outage. Such additional capacity costs shall not include any after-the-fact capacity purchase costs incurred by the Company.

    b. If customer has not notified the Company of any unscheduled outage at least three hours prior to the Company's system peak hour, such peak demand charges shall be based on one-sixth of any additional capacity costs or after-the-fact purchase costs incurred by the Company as a result of the unscheduled outage. The demand for billing purposes for the succeeding five months shall be equal to the demand placed on the system during the time of the Company's system peak hour in which the said additional capacity costs were incurred.

(Continued on Sheet No. 5-105)

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STANDBY SERVICE RIDER (Continued) Section No. 5
8th Revised Sheet No. 105

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ADDITIONAL TERMS AND CONDITIONS OF SERVICE ASSOCIATED WITH THE SCHEDULED MAINTENANCE OPTION

1. The optional Scheduled Maintenance rates are available to Standby Service customers who agree to schedule maintenance of their power source during qualifying scheduled maintenance periods.

2. Qualifying Scheduled Maintenance Periods

   Maintenance may occur within the calendar months of April, May, October, and November without written customer notice to Company prior to the beginning of the maintenance period regardless of the size of the contracted Standby capacity.

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   LC

   In other months for customers with a base time of day tariff to which this Rider is attached, regardless of the size of the contracted Standby capacity, scheduled maintenance may occur, with Company approval, during weekends and holidays as identified in the time of day base tariff, where a documented customer request is provided no less than 48 hours prior to the beginning of the planned maintenance period. Company will endeavor to approve or deny the customer request within 24 hours of receiving the request.

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   For months other than April, May, October, and November, customers with a minimum contracted Standby capacity of 1,000 kW may schedule maintenance at a time period mutually agreed to by Company and customer, following a documented customer request. These time periods for scheduled maintenance will normally not include those times when Company expects high system seasonal peak load conditions or high energy production costs.

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   Customer shall provide an annual projection of scheduled maintenance to the Company. Customer shall be allowed changes or additions to this projection upon notice to the Company based on the following schedule:

Outage Length	Required Notice
Less than 72 hours	24 hours
3 days to 30 days	7 days
Over 30 days	90 days

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3. The duration of qualifying scheduled maintenance periods may not exceed a total of 56 days in any 12 month period.

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(Continued on Sheet No. 5-106)

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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

STANDBY SERVICE RIDER (Continued) Section No. 5
7th Revised Sheet No. 105

TERMS AND CONDITIONS OF SERVICE (Continued)

The provisions of this Section 10 shall not apply if appropriate capacity accreditation has been obtained for the customer's generation from the Midwest Reliability Organization (MRO), or any successor organization. Customer must take responsibility for the preparation of the information necessary for the accreditation filing. The Company will advise and assist the Customer in this process but failure of customer in the preparation of the information and/or failure to obtain accreditation of the customer's generation will result in the customer being ineligible for the exemption from the provisions of this Section 10.

11. In the event any portion of the capacity obtained by the Company, at additional costs, and which is attributable to the customer's use of Standby Service under Section 10 above, is subsequently also used to satisfy the requirements of the Company's other customers, the Peak Demand Charges under Section 10 above shall be reduced relative to the portion of said capacity used to serve other customers.

12. The Company shall provide notice to the Standby customers when peak load conditions are expected to occur through the same means that the Company notifies interruptible customers of the potential interruption.

13. Company will install and charge customer for the additional metering necessary, to allow for determination of the separate billing demand applicable to the base tariff and Standby Rider and for determining energy use under the Grace Period identified above. In particular, the Company will install a separate meter that measures the flow of power and energy from the customer's own generating facility. Customer shall reimburse the Company for the costs of installing, operating, and maintaining the required additional metering and for any other facilities required to serve the customer's Standby load. If, as a result of the customer's construction and installation of their generating facility, it is more practical for the customer to install some or all of the metering equipment required, the customer may be permitted to do so, subject to Company's approval of such equipment.

(Continued on Sheet No. 5-106)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK – MPUC NO. 2

STANDBY SERVICE RIDER (Continued)

Section No. 5
8th Revised Sheet No. 106

ADDITIONAL TERMS AND CONDITIONS OF SERVICE ASSOCIATED WITH THE SCHEDULED MAINTENANCE OPTION (Continued)

4. If customer does not comply with all terms and conditions for qualifying scheduled maintenance periods during any billing month, all use of Standby Service for the same month will be subject to the Peak Period Standby Energy charge provision. Company may determine partial non-compliance and limit the quantity of Standby Service usage subject to the Peak Period Standby Energy charge provision. Company reserves the right to remove availability of the Scheduled Maintenance Option for any customer upon a determination of significant and multiple occurrences of failure to comply with all associated terms and conditions.

5. The use of Standby Service during qualifying scheduled maintenance periods will not be included in the determination of Peak Period Standby Energy usage.

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(Continued on Sheet No. 5-107)

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MINNESOTA ELECTRIC RATE BOOK – MPUC NO. 2

STANDBY SERVICE RIDER (Continued) Section No. 5
7th Revised Sheet No. 106

ADDITIONAL TERMS AND CONDITIONS OF SERVICE ASSOCIATED WITH THE SCHEDULED MAINTENANCE OPTION

1. The optional Scheduled Maintenance rates are available to Standby Service customers who agree to schedule maintenance of their power source during qualifying scheduled maintenance periods.

2. Qualifying Scheduled Maintenance Periods

   Customers With Greater Than 100 kW to 10,000 kW of Contracted Standby Capacity. Maintenance must occur within the calendar months of April, May, October, and November. Customer must provide Company with written notice of scheduled maintenance prior to the beginning of the maintenance period.

   Customers With Greater Than 10,000 kW of Contracted Standby Capacity. Maintenance must occur at a time period mutually agreed to by Company and customer. These time periods will normally not include those times when Company expects system seasonal peak load conditions to occur, nor at those times when Company is required to use generation or to purchase power, with production costs of $70 or more per MWh. Customer shall provide an annual projection of scheduled maintenance to the Company. Customer shall be allowed changes or additions to this projection upon notice to the Company based on the following schedule:

Outage Length	Required Notice
Less than 48 hours	24 hours
2 days to 30 days	7 days
Over 30 days	90 days

3. The duration of qualifying scheduled maintenance periods may not exceed a total of six weeks in any 12 month period.

4. An additional charge shall apply if customer does not comply with all terms and conditions for qualifying scheduled maintenance periods. The additional charge shall be determined by calculating the additional charges which would have applied if customer were billed on the Unscheduled Maintenance Option for the period extending back to the customer's last scheduled maintenance period.

5. The demand charges of the base tariffs shall not apply to use of Standby Service during qualifying scheduled maintenance periods. Also, use of Standby Service during qualifying scheduled maintenance periods, will not count against the grace period.

(Continued on Sheet No. 5-107)

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STANDBY SERVICE RIDER (Continued)

Section No. 5
5th Revised Sheet No. 107

ADDITIONAL TERMS AND CONDITIONS OF SERVICE FOR NON-FIRM STANDBY OPTION

1. Non-firm standby rates are available to customers who agree to use Standby Service only by prearrangement with the Company.

2. Company makes no guarantee that Standby Service will be available to Non-Firm Standby Service customers; however, the Company will make reasonable efforts to provide Standby Service whenever possible.

3. Customer must request use of Standby Service and receive approval from the Company prior to actually using Standby Service.

4. Use of Standby Service without prior approval by the Company shall subject the Non-Firm Standby Service customer to the following:
   a. The monthly demand charges from the base tariff applied to the unapproved Standby Service used in the month in which unapproved use of Standby Service occurred, plus
   b. Firm Standby Service unscheduled maintenance option reservation fees retroactively applied to the six months prior to the month in which unapproved use of Standby Service occurred.

5. If unapproved use of Standby Service occurs twice in any 12 month period, the Company reserves the right to convert the Non-Firm Standby Service customer to Firm Standby Service.

6. Non-Firm Standby Service customers will remain on Non-Firm Standby Service for a period of not less than five years which includes a one year trial period.

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Minneapolis, Minnesota 55401
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SUPPLEMENTAL GENERATION SERVICE RIDER Section No. 5
12th Revised Sheet No. 108

AVAILABILITY
Applicability of Supplemental Service is similar to that of Standby Service Rider, where customers with an alternative generation source greater than 60 kW, which serves all or a portion of the customer's electric energy requirements and where customer chooses to use the Company's electric service when the alternative generation is either partly or wholly unavailable.

Specifically, Supplemental Service is targeted at applications where the output of the alternative generation is designed primarily to meet the customer's thermal-load requirements and as such, the generator's electric energy output is variable because it is dependent on the customer's thermal requirements.

The normal expectation of this Rider is that the customer will contract for a firm portion of their backup supply from the Company under the Standby Service Rider and will contract for the variable portion under this Supplemental Generation Service Rider. Each customer request for service under this Rider will be evaluated on a customer specific basis to determine eligibility.

Under this service, the Company will provide Supplemental Generation Service in accordance with the provisions of the General Rules and Regulations, Section 2.4.

In addition, customer bills under this rate are subject to the following adjustments and/or charges.

RESERVATION RATES

Customer Charge per Month	$25.64	
Demand Charge per Month per kW of Contracted Supplemental Service		
Secondary Voltage Service	$3.40	R
Primary Voltage Service	$2.60	R
Transmission Transformed Voltage Service	$1.85	R
Transmission Voltage Service	$1.05	R

USAGE RATES
Demand Charge per Month per kW of Supplemental Generation Capacity Used. There will be no Usage Rate demand charge for Supplemental capacity actually used under this Rider except if that capacity is used during one of the Company's energy controlled or peak controlled interrupt periods. In such case, the demand will be charged as described below.

Energy Charge per kWh of Supplemental Generation Energy Used. Energy actually used under this Rider during normal time periods will be charged at the same energy and fuel cost charges as contained in the base tariff to which this Rider is attached. However, if energy is used during one of the Company's energy controlled or peak controlled interrupt periods, the energy will be charged as described below.

(Continued on Sheet No. 5-109)

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MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

SUPPLEMENTAL GENERATION SERVICE RIDER Section No. 5
11th Revised Sheet No. 108

AVAILABILITY
Applicability of Supplemental Service is similar to that of Standby Service Rider, where customers with an alternative generation source greater than 60 kW, which serves all or a portion of the customer's electric energy requirements and where customer chooses to use the Company's electric service when the alternative generation is either partly or wholly unavailable.

Specifically, Supplemental Service is targeted at applications where the output of the alternative generation is designed primarily to meet the customer's thermal-load requirements and as such, the generator's electric energy output is variable because it is dependent on the customer's thermal requirements.

The normal expectation of this Rider is that the customer will contract for a firm portion of their backup supply from the Company under the Standby Service Rider and will contract for the variable portion under this Supplemental Generation Service Rider. Each customer request for service under this Rider will be evaluated on a customer specific basis to determine eligibility.

Under this service, the Company will provide Supplemental Generation Service in accordance with the provisions of the General Rules and Regulations, Section 2.4.

In addition, customer bills under this rate are subject to the following adjustments and/or charges.

RESERVATION RATES

Customer Charge per Month	$25.64	
Demand Charge per Month per kW of Contracted Supplemental Service		
Secondary Voltage Service	$3.47	R
Primary Voltage Service	$2.67	R
Transmission Transformed Voltage Service	$1.92	R
Transmission Voltage Service	$1.12	R

USAGE RATES
Demand Charge per Month per kW of Supplemental Generation Capacity Used. There will be no Usage Rate demand charge for Supplemental capacity actually used under this Rider except if that capacity is used during one of the Company's energy controlled or peak controlled interrupt periods. In such case, the demand will be charged as described below.

Energy Charge per kWh of Supplemental Generation Energy Used. Energy actually used under this Rider during normal time periods will be charged at the same energy and fuel cost charges as contained in the base tariff to which this Rider is attached. However, if energy is used during one of the Company's energy controlled or peak controlled interrupt periods, the energy will be charged as described below.

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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

SUPPLEMENTAL GENERATION SERVICE RIDER Section No. 5
10th Revised Sheet No. 108

AVAILABILITY
Applicability of Supplemental Service is similar to that of Standby Service Rider, where customers with an alternative generation source greater than 60 kW, which serves all or a portion of the customer's electric energy requirements and where customer chooses to use the Company's electric service when the alternative generation is either partly or wholly unavailable.

Specifically, Supplemental Service is targeted at applications where the output of the alternative generation is designed primarily to meet the customer's thermal-load requirements and as such, the generator's electric energy output is variable because it is dependent on the customer's thermal requirements.

The normal expectation of this Rider is that the customer will contract for a firm portion of their backup supply from the Company under the Standby Service Rider and will contract for the variable portion under this Supplemental Generation Service Rider. Each customer request for service under this Rider will be evaluated on a customer specific basis to determine eligibility.

Under this service, the Company will provide Supplemental Generation Service in accordance with the provisions of the General Rules and Regulations, Section 2.4.

In addition, customer bills under this rate are subject to the following adjustments and/or charges.

RESERVATION RATES

Customer Charge per Month	$25.64	R
Demand Charge per Month per kW of Contracted Supplemental Service		
Secondary Voltage Service	$3.44	R
Primary Voltage Service	$2.64	R
Transmission Transformed Voltage Service	$1.89	R
Transmission Voltage Service	$1.09	R

USAGE RATES
Demand Charge per Month per kW of Supplemental Generation Capacity Used. There will be no Usage Rate demand charge for Supplemental capacity actually used under this Rider except if that capacity is used during one of the Company's energy controlled or peak controlled interrupt periods. In such case, the demand will be charged as described below.

Energy Charge per kWh of Supplemental Generation Energy Used. Energy actually used under this Rider during normal time periods will be charged at the same energy and fuel cost charges as contained in the base tariff to which this Rider is attached. However, if energy is used during one of the Company's energy controlled or peak controlled interrupt periods, the energy will be charged as described below.

(Continued on Sheet No. 5-109)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

SUPPLEMENTAL GENERATION SERVICE RIDER Section No. 5
(Continued) 15th Revised Sheet No. 109

FUEL CLAUSE
Bills are subject to the adjustments provided for in the Fuel Clause Rider.

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider, and the Renewable Development Fund Rider, the Transmission Cost Recovery Rider, the Renewable Energy Standard Rider and the Mercury Cost Recovery Rider.

ENVIRONMENTAL IMPROVEMENT RIDER
Bills are subject to the adjustments provided for in the Environmental Improvement Rider.

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

LOW INCOME ENERGY DISCOUNT RIDER
Bills are subject to the adjustment provided for in the Low Income Energy Discount Rider.

In addition, customer bills under this rate are subject to the following adjustments and/or charges.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

DETERMINATION OF SUPPLEMENTAL GENERATION DEMAND
The billing demand applicable to this Supplemental Generation Service Rider is determined separately from the billing demand applicable to the base tariff to which this Rider is attached. The billing demand for this Rider will be the quantity specified in the customer's Electric Service Agreement which is the maximum capacity of Supplemental Generation Service the Company is obligated to supply. The demand applicable to this Rider may be a different amount specified for each month where it is dependent on the variable thermal load requirements.

The amount of Supplemental Service capacity actually used by the customer, when customer's generator is wholly or partly out of service, will have no effect on the billing demand under the base tariff and will be subtracted from the total metered demand, to determine the demand for standard service, to which the base tariff demand charge applies. The amount of Supplemental Service capacity actually used, is the amount of the Supplemental Service capacity contracted for, less the actual capacity supplied by the customer's generating facilities (assuming it is operating, but not at full capacity) but not less than zero. For applying the Usage Rate, as referenced in Section 10 below of this Rider, the Supplemental Generation Demand will be the maximum actual demand (as adjusted for power factor) that is supplied by the Company to serve that portion of the customer's load, up to the contracted Supplemental Generation Capacity, not served by the customer's alternative source of electric energy supply.

(Continued on Sheet No. 5-110)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

SUPPLEMENTAL GENERATION SERVICE RIDER Section No. 5
(Continued) 8th Revised Sheet No. 110

DETERMINATION OF SUPPLEMENTAL GENERATION ENERGY

Supplemental Generation Energy shall be that portion of the customer's total energy requirements provided by the Company to supplement the customer's generation. Supplemental Generation Energy shall be calculated hourly, and shall be Supplemental Generation Capacity for which the customer has contracted, less generation output above the contracted Standby capacity (as defined in the Standby Service Rider), but not less than zero.

TERMS AND CONDITIONS OF SERVICE

1. This Supplemental Generation Service Rider is applicable to any customer who requires greater than 60 kW of backup capacity from the Company. Supplemental Generation Service may not be used by a customer to serve controllable demand that is subject to interruption as determined by the Company under the Company's controllable service schedules.

   The Company and customer will develop and attach to the Electric Service Agreement, a load control procedure for the customer that specifies the customer's demand side load reductions or alternative generation capacity the customer intends to use to avoid Supplemental Generation Demand Usage Rate charges. This attachment will specifically state that when customer has been notified that an energy control or peak control period has been initiated, the customer must reduce the load served by Company by an amount equal to the difference between actual generator output and contracted Supplemental Generation Capacity. Additionally, the customer's demand served under the base tariff to which this rider is attached, shall not increase during any energy control or peak control period. If customer fails at either of these requirements, customer will incur Supplemental Generation usage charges as defined in Section 10 below.

2. Customer will execute an Electric Service Agreement with the Company which will specify:
   a. Type of Standby Service elected by the customer under the Standby Service Rider and the base tariff to which the Standby and Supplement Service Riders are attached,
   b. The individual and total capacity requirements for which Company will be providing Standby and Supplemental Generation Service and to which the respective Rider charges apply, and
   c. The expected initial level of firm service the customer will take under their base tariff, even if that expected level is zero, as well as any expected changes in load over the term of the agreement.

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Minneapolis, Minnesota 55401
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SUPPLEMENTAL GENERATION SERVICE RIDER Section No. 5
(Continued) 7th Revised Sheet No. 111

TERMS AND CONDITIONS OF SERVICE (Continued)

3. The Company's standard service meter will be detented to measure only the amount of capacity and energy provided by the Company to the customer.

4. Company will not be obligated to supply Supplemental Generation Service to backup a customer's generator at a level in excess of the Supplemental Generation Capacity for which customer has contracted. This restriction in no way limits the amount of standard service the customer requires from the Company under the base tariff to which this Rider is attached. Any limits on standard service are governed by the provisions contained in the standard service tariffs.

5. Customer will be liable for all damages allowed by law to the extent caused by customer's use of Supplemental power in excess of contracted Supplemental Generation Capacity.

6. Company will require customer to revise the Electric Service Agreement to contract for additional Supplemental Generation Capacity if the customer exceeds the contract amounts in any three of the preceding 12 months.

7. Customer will annually furnish documentation to Company confirming the maximum capacity and reliability of the power source for which customer requires Supplemental Generation Service. Company and customer will review actual output and performance of the power source relative to the capacity nominated for Supplemental Generation Service in the Electric Service Agreement. If this review shows a significant and consistent shortfall between the power source's actual performance and the nominated capacity due to factors reasonably within customer's control, Company will notify customer of its intent to refuse to provide Supplemental Generation Service. Upon receipt of such notice, customer may agree to reduce the Supplemental Generation Service nomination in its Electric Service Agreement or to take such action as necessary to operate the power source at or reasonably near the nominated Supplemental Generation Service Capacity. If customer's power source does not operate at or reasonably near that level during the 12 months immediately following Company's notice, Company may refuse to provide Supplemental Generation Service until such time as customer agrees to reduce its Supplemental Generation Service nomination or provide Company with documentation demonstrating the power source's actual performance at or reasonably near the nominated Supplemental Generation Service for a trial period of three consecutive months.

8. Customer will remain on Supplemental Generation Service for a period of not less than 12 months.

(Continued on Sheet No. 5-112)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

SUPPLEMENTAL GENERATION SERVICE RIDER Section No. 5
(Continued) 8th Revised Sheet No. 112

TERMS AND CONDITIONS OF SERVICE (Continued)

9. Customer will be allowed to take Supplemental Generation Energy from the Company at any time, up to the maximum contracted level of Supplemental Generation Demand, without incurring any usage demand charges except during the periods listed below.

10. In the event customer requires Supplemental Generation Service during one of the Company's energy control periods, customer will pay for the Supplemental Generation Energy used during the energy control period at the applicable control period energy rate as listed in Company's Energy Controlled Service tariff.

    In the event customer requires Supplemental Generation Service during one of the Company's peak control periods, as defined in the Rules for Application of Peak Controlled Services, customer will pay for the Supplemental Generation Energy used during the peak control period at twice the applicable control period energy rate as listed in Company's Energy Controlled Service tariff plus a fee of $10.00 per kW of maximum Supplemental Generation Capacity used during the peak control period.

    However, if this use occurs at the times of Company's system peak hours in which the Company would have insufficient Accredited Capacity under the Midwest Reliability Organization (MRO) or any successor organization, and the Company incurs additional capacity costs as a result of such Supplemental Generation Service used by customer, customer shall pay Peak Demand Charges for the month in which such Supplemental Generation Service use occurs and for each of the five succeeding months, instead of the above listed demand charges and/or Reservation Fees. Such Peak Demand Charges shall be based upon the following:

    a. If customer has notified Company of the need to use Supplemental Generation Service at least three hours prior to Company's system peak hour, such Supplemental Generation Peak Demand charges shall be based on one-sixth of any additional capacity costs incurred by the Company as a result of using Supplemental Generation Service. Such additional capacity costs shall not include any after-the-fact capacity purchase costs incurred by the Company.

    b. If customer has not notified the Company of any need for Supplemental Generation Service at least three hours prior to the Company's system peak hour, such Supplemental Generation Peak Demand charges shall be based on one-sixth of any additional capacity costs or after-the-fact purchase costs incurred by the Company as a result of using Supplemental Generation Service. The demand for billing purposes for the succeeding five months shall be equal to the Supplemental Generation Demand placed on the system during the time of the Company's system peak hour.

(Continued on Sheet No. 5-113)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

SUPPLEMENTAL GENERATION SERVICE RIDER Section No. 5
(Continued) 8th Revised Sheet No. 113

TERMS AND CONDITIONS OF SERVICE (Continued)

The potential capacity charge provisions of this Section 10 shall not apply if appropriate capacity accreditation has been obtained for the customer's generation from the Midwest Reliability Organization (MRO), or any successor organization. Customer must take responsibility for the preparation of the information necessary for the accreditation filing. The Company can advise and assist the Customer in this process but failure of customer in the preparation of the information and/or failure to obtain accreditation of the customer's generation will result in the customer being ineligible for the exemption from the capacity charge provisions of this Section 10.

11. In the event any portion of the capacity obtained by the Company at additional costs and which is attributable to the customer's use of Supplemental Service under Section 10 above, is subsequently also used to satisfy the requirements of the Company's other customers, the peak demand charges under Section 10 above shall be reduced relative to the portion of said capacity used to serve the other customers.

12. The Company shall provide notice to the Supplemental Generation Service customers when energy control or peak control conditions are expected to occur through the same means that the Company notifies interruptible customers of the potential interruption.

13. Company will install and charge customer for the additional metering necessary, as determined by the Company, to allow for determination of the separate billing demands applicable to the base tariff, Standby Service Rider and Supplemental Generation Service Rider demands. In particular, the Company will install a separate meter that measures the flow of power and energy from the customer's own generating facility. Customer shall reimburse the Company for the costs of installing, operating, and maintaining the required additional metering and for any other facilities required to serve the customer's Supplemental Generation load. If, as a result of the customer's construction and installation of their generating facility, it is more practical for the customer to install some or all of the metering equipment required, customer may be permitted to do so subject to Company's approval of such equipment.

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SUPPLEMENTAL GENERATION SERVICE RIDER Section No. 5
(Continued) 7th Revised Sheet No. 114

ADDITIONAL TERMS AND CONDITIONS ASSOCIATED WITH SCHEDULING MAINTENANCE

1. Supplemental Generation Service customers shall schedule maintenance of their power source during qualifying scheduled maintenance periods.

2. Qualifying Scheduled Maintenance Periods

   Customers With Greater than 60 kW up to 10,000 kW of Contracted Standby and Supplemental Generation Capacity. Maintenance must occur within the calendar months of April, May, October, and November. Customer must provide Company with written notice of scheduled maintenance prior to the beginning of the maintenance period.

   Customers With Greater Than 10,000 kW of Contracted Standby and Supplemental Generation Capacity. Maintenance must occur at a time period mutually agreed to by Company and customer. These time periods will normally not include those times when Company expects system seasonal peak load conditions to occur, nor at those times when Company is required to use generation equipment or to purchase power that results in production costs of $70 or more per MWh. Customer shall provide an annual projection of scheduled maintenance to the Company. Customer shall be allowed changes or additions to this projection upon notice to the Company based on the following schedule:

Outage Length	Required Notice
Less than 48 hours	24 hours
2 days to 30 days	7 days
Over 30 days	90 days

3. The duration of qualifying scheduled maintenance periods may not exceed a total of six weeks in any 12 month period.

4. An additional charge shall apply if customer does not comply with all terms and conditions for qualifying scheduled maintenance periods. The additional charge shall be determined by calculating the additional charges which would have applied if customer were billed on the Unscheduled Maintenance Option for the period extending back to the customer's last scheduled maintenance period.

5. The demand charges of the base tariffs of General Service or General Time of Day Service shall not apply to use of Supplemental Service during qualifying scheduled maintenance periods.

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Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

TIER 1 ENERGY CONTROLLED SERVICE RIDER Section No. 5
RATE CODE A27 13th Revised Sheet No. 115

AVAILABILITY
Availability is restricted to customers who are taking service on the Tier 1 option of the Peak Controlled Time of Day Service.

In addition, customer bills under this rate are subject to the following adjustments and/or charges.

RATE
The rates and provisions of Tier 1 of the Peak Controlled Time of Day Service schedule shall apply except that the on peak and off peak energy charges for secondary voltage are replaced as follows:

Energy Charge per kWh		
Firm On Peak Period Energy	$0.04855	R
Firm Off Peak Period Energy	$0.02341	R
Controllable On Peak Period Energy	$0.04647	R
Controllable Off Peak Period Energy	$0.02280	R
Control Period Energy	$0.09000	

TERMS AND CONDITIONS OF SERVICE
1. Failure to Control Charge: Except as provided for under Control Period Energy Service described below, the following charges will apply in any month customer fails to control load to Predetermined Demand Level or fails to control the full amount of their fixed Controllable Demand under the Optional PDL:
   a. An additional charge of $10.00 per kW will apply during each Company specified control period to the amount by which customer's Maximum Adjusted Demand exceeds their Predetermined Demand Level, and
   b. The Control Period Energy charge will apply to the energy used during the control period that is associated with the customer's Controllable Demand.

   After three such customer failures to control load to their Predetermined Demand Level, Company reserves the right to increase the Predetermined Demand Level or remove customer from Tier 1 Energy Controlled Service Rider and apply the cancellation charge specified in customer's Electric Service Agreement.

(Continued on Sheet No. 5-116)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

TIER 1 ENERGY CONTROLLED SERVICE RIDER Section No. 5
RATE CODE A27 12th Revised Sheet No. 115

AVAILABILITY
Availability is restricted to customers who are taking service on the Tier 1 option of the Peak Controlled Time of Day Service.

In addition, customer bills under this rate are subject to the following adjustments and/or charges.

RATE
The rates and provisions of Tier 1 of the Peak Controlled Time of Day Service schedule shall apply except that the on peak and off peak energy charges for secondary voltage are replaced as follows:

Energy Charge per kWh

Firm On Peak Period Energy	$0.05098	R
Firm Off Peak Period Energy	$0.02458	R
Controllable On Peak Period Energy	$0.04878	R
Controllable Off Peak Period Energy	$0.02393	R
Control Period Energy	$0.09000	

TERMS AND CONDITIONS OF SERVICE
1. Failure to Control Charge: Except as provided for under Control Period Energy Service described below, the following charges will apply in any month customer fails to control load to Predetermined Demand Level or fails to control the full amount of their fixed Controllable Demand under the Optional PDL:
   a. An additional charge of $10.00 per kW will apply during each Company specified control period to the amount by which customer's Maximum Adjusted Demand exceeds their Predetermined Demand Level, and
   b. The Control Period Energy charge will apply to the energy used during the control period that is associated with the customer's Controllable Demand.

   After three such customer failures to control load to their Predetermined Demand Level, Company reserves the right to increase the Predetermined Demand Level or remove customer from Tier 1 Energy Controlled Service Rider and apply the cancellation charge specified in customer's Electric Service Agreement.

(Continued on Sheet No. 5-116)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

TIER 1 ENERGY CONTROLLED SERVICE RIDER Section No. 5
RATE CODE A27 11th Revised Sheet No. 115

AVAILABILITY
Availability is restricted to customers who are taking service on the Tier 1 option of the Peak Controlled Time of Day Service.

In addition, customer bills under this rate are subject to the following adjustments and/or charges.

RATE
The rates and provisions of Tier 1 of the Peak Controlled Time of Day Service schedule shall apply except that the on peak and off peak energy charges for secondary voltage are replaced as follows:

Energy Charge per kWh

Firm On Peak Period Energy	$0.04986	R
Firm Off Peak Period Energy	$0.02404	R
Controllable On Peak Period Energy	$0.04767	R
Controllable Off Peak Period Energy	$0.02340	R
Control Period Energy	$0.09000	

TERMS AND CONDITIONS OF SERVICE
1. Failure to Control Charge: Except as provided for under Control Period Energy Service described below, the following charges will apply in any month customer fails to control load to Predetermined Demand Level or fails to control the full amount of their fixed Controllable Demand under the Optional PDL:
   a. An additional charge of $10.00 per kW will apply during each Company specified control period to the amount by which customer's Maximum Adjusted Demand exceeds their Predetermined Demand Level, and
   b. The Control Period Energy charge will apply to the energy used during the control period that is associated with the customer's Controllable Demand.

   After three such customer failures to control load to their Predetermined Demand Level, Company reserves the right to increase the Predetermined Demand Level or remove customer from Tier 1 Energy Controlled Service Rider and apply the cancellation charge specified in customer's Electric Service Agreement.

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(Continued on Sheet No. 5-116)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

TIER 1 ENERGY CONTROLLED SERVICE RIDER Section No. 5
(Continued) 8th Revised Sheet No. 116
RATE CODE A27

TERMS AND CONDITIONS OF SERVICE (Continued)

2. The duration and frequency of interruption periods shall be at the discretion of Company. Interruption periods will normally occur at such times when:
   a. Company is required to use generation equipment or to purchase power that results in production costs in excess of $70 per MWH,
   b. Company expects a reasonable possibility of system load levels surpassing the level for which NSP has sufficient accredited capacity under the Midwest Reliability Organization (MRO) or any successor organization, including reserve requirements, or
   c. In Company's opinion, the reliability of the system is endangered.

3. Customer's Electric Service Agreement with Company will include a maximum of 300 hours of interruption per year.

4. All other provisions of Tier 1 of the Peak Controlled Time of Day Service schedule not in conflict with the Tier 1 Energy Controlled Service Rider shall apply.

CONTROL PERIOD ENERGY SERVICE

AVAILABILITY

Available to Tier 1 Energy Controlled Service Rider customers for supply of Controllable Demand related energy during control periods. The Control Period Energy charge will apply when the Company is required to use generation equipment or to purchase power that results in production costs in excess of $70 per MWh. Control Period Energy Service will not be available when Company expects system peak load conditions or during system emergencies.

In addition, customer bills under this rate are subject to the following adjustments and/or charges.

RATE

The control period energy charge will apply to all Controllable Demand related energy used during the control period.

TERMS AND CONDITIONS OF SERVICE

1. Control Period Energy Service will be available provided such service will not adversely affect firm service to any customer.

2. Company reserves the right to refuse or control the supply of Control Period Energy Service if its capacity is not adequate to furnish such service.

(Continued on Sheet No. 116.1)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

TIER 1 ENERGY CONTROLLED SERVICE RIDER Section No. 5
(Continued) 5th Revised Sheet No. 116.1
RATE CODE A27

TERMS AND CONDITIONS OF SERVICE (Continued)

3. All other provisions of the Tier 1 Energy Controlled Service Rider not in conflict with Control Period Energy Service shall apply.

4. Company notice of commencement of control period will include notice of availability of Control Period Energy Service.

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President, Northern States Power Company, a Minnesota corporation
Docket No. E002/GR-15-826 Order Date: 06-12-17

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

REVENUE DECOUPLING MECHANISM RIDER Section No. 5
PILOT PROGRAM 5th Revised Sheet No. 117

APPLICABILITY
Applicable to bills for electric service provided under the Company's Residential and non-demand-metered Small General Service schedules, excluding lighting services.

RIDER
For customers subject to this rider, there shall be included on each customer's monthly bill a Revenue Decoupling Mechanism Rider (RDM Rider) which shall be the applicable Revenue Decoupling Mechanism Rider factor multiplied by the customer's monthly kWh electric consumption.

DETERMINATION OF RDM RIDER FACTORS
Annual RDM Rider Factor
Each year during the term of this rider the Company will calculate an RDM Rider factor for each applicable class. These factors will be based on revenues billed through December 31 and applied to bills from April 1 through the March 31 of the following year. The RDM Rider factors are:

Residential without Space Heating (A01, A02, A03, A04, A05, A06)	$0.001625 per kWh credit	R
Residential with Space Heating (A00, A01, A02, A03, A04, A05, A06)	$0.001056 per kWh credit	R
Small General Service (non-demand) (A05, A06, A09, A10, A11, A12, A16, A18, A22)	$0.000213 per kWh credit	R

The calculation for the RDM Rider factor is:

Annual RDM Rider factor = RDM Rider Deferral / Forecasted Sales

For purposes of this section the following definitions apply:

RDM Rider Deferral — Annual RDM Rider Deferral = the sum of the 12 monthly RDM Rider Deferrals plus any under- or over-recovery of the previous Annual RDM Rider Deferral as described in item 3 of the RDM Rider Deferral Account on tariff sheet 5-118.

Forecasted Sales — Forecasted Usage = forecasted use in kWh for the timeframe the RDM Rider factor to be in place.

The Annual RDM Rider factor to collect under-recovered revenues shall be capped at +3% of the total customer group base revenue for each of the rate classes, unless the Company is granted approval from the Minnesota Public Utilities Commission (Commission) to recover revenues in excess of the 3% cap. The RDM Rider factor to return over-recovered revenues shall not be capped.

(Continued on Sheet No. 5-118)

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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

REVENUE DECOUPLING MECHANISM RIDER Section No. 5
PILOT PROGRAM 4th Revised Sheet No. 117

APPLICABILITY
Applicable to bills for electric service provided under the Company's Residential and non-demand-metered Small General Service schedules, excluding lighting services.

RIDER
For customers subject to this rider, there shall be included on each customer's monthly bill a Revenue Decoupling Mechanism Rider (RDM Rider) which shall be the applicable Revenue Decoupling Mechanism Rider factor multiplied by the customer's monthly kWh electric consumption.

DETERMINATION OF RDM RIDER FACTORS
Annual RDM Rider Factor
Each year during the term of this rider the Company will calculate an RDM Rider factor for each applicable class. These factors will be based on revenues billed through December 31 and applied to bills from April 1 through the March 31 of the following year. The RDM Rider factors are:

Residential without Space Heating (A01, A02, A03, A04, A05, A06)	$0.003064 per kWh surcharge	R
Residential with Space Heating (A00, A01, A02, A03, A04, A05, A06)	$0.002361 per kWh surcharge	R
Small General Service (non-demand) (A05, A06, A09, A10, A11, A12, A16, A18, A22)	$0.001245 per kWh surcharge	R

The calculation for the RDM Rider factor is:

Annual RDM Rider factor = RDM Rider Deferral / Forecasted Sales

For purposes of this section the following definitions apply:

RDM Rider Deferral — Annual RDM Rider Deferral = the sum of the 12 monthly RDM Rider Deferrals plus any under- or over-recovery of the previous Annual RDM Rider Deferral as described in item 3 of the RDM Rider Deferral Account on tariff sheet 5-118.

Forecasted Sales — Forecasted Usage = forecasted use in kWh for the timeframe the RDM Rider factor to be in place.

The Annual RDM Rider factor to collect under-recovered revenues shall be capped at +3% of the total customer group base revenue for each of the rate classes, unless the Company is granted approval from the Minnesota Public Utilities Commission (Commission) to recover revenues in excess of the 3% cap. The RDM Rider factor to return over-recovered revenues shall not be capped.

(Continued on Sheet No. 5-118)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK – MPUC NO. 2

REVENUE DECOUPLING MECHANISM RIDER (Continued) Section No. 5
PILOT PROGRAM 3rd Revised Sheet No. 118

DETERMINATION OF RDM RIDER FACTORS (Continued)
RDM Rider Deferral Account

1. Each month the Company will calculate the Monthly RDM Rider Deferral, which will be entered in the RDM Rider Deferral Account. Separate deferrals will be calculated for Residential Standard, Residential with Electric Space Heating, and non-demand-metered Small General services.

   Monthly RDM Rider Deferral = (FRC x C) – (FEC x Sales)

   For purposes of this section, the following definitions apply:

   FRC Fixed Revenue per Customer = Energy charge revenues divided by customer count, calculated monthly from test year data. Expressed in dollars per customer

   C Customer Count = Actual customer count for deferral month.

   FEC Fixed Energy Charge = Average energy charge for each month of test year. Expressed in dollars per kWh

   Sales Actual Sales = Actual billed sales for deferral month. Expressed in kWh.

2. The Company will defer and amortize the Monthly RDM Deferrals in Account 182.3 or 254.

3. Any under- or over-recovery of the Annual RDM Rider Deferral will be included as a deferral in the RDM Rider Deferral Account and reflected in the calculation of the following year's Annual RDM Rider factor.

TERM
The Company will begin calculating Monthly RDM Rider Deferrals in the first full month after receiving a Final Order from the Commission in Docket No. E002/GR-13-868, but not before January 1, 2016.

The Company will file its proposed Annual RDM Rider factor surcharge or credit with the Commission annually on February 1, beginning on February 1, 2017. The proposed rate will become effective on April 1 each year and remain in effect for the next 12 months, or until April 1 of the following year. In the event the Company files a rate case during the pilot program, the RDM rider factors from deferrals in a test year will not be applied to bills until final rates in that proceeding have been approved by the Commission.

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK – MPUC NO. 2

AREA DEVELOPMENT RIDER Section No. 5
5th Revised Sheet No. 119

AVAILABILITY
Available to new or existing demand metered customers located in Area Development Zones whose proper Standard Industrial Classification (SIC) is manufacturing or wholesale trade and who qualify for other development incentives offered by local government entities. The availability of this Rider is limited to specific Area Development Zones that meet the criteria listed below as set forth by the Commission.

ZONE DESIGNATION
Area Development Zones in the seven county Twin Cities' metropolitan area (Anoka, Carver, Dakota, Hennepin, Ramsey, Scott, and Washington Counties) must be located within one of the cities lying within the "Fully Developed Area" as classified by the Metropolitan Council in the document entitled "Metropolitan Development and Investment Framework (December 1988)" that has experienced a decline in combined employment in manufacturing and wholesale trade between 1980 and the most recent year for which data are available as published by the Minnesota Department of Economic Security. Eligible communities are Bloomington, Columbia Heights/Hilltop, Crystal, Fridley, Golden Valley, Hopkins, Minneapolis, New Brighton, Roseville, South St. Paul, St. Louis Park, and St. Paul. Area Development Zones in cities located outside the seven county Twin Cities' metropolitan area must be located in a city with a minimum population of 25,000 based on the most recent U.S. Census of Population and must be located in a county (or counties) that have experienced a decline in combined employment in manufacturing and wholesale trade between 1987 and the most recent year for which data are available as published by the Minnesota Department of Economic Security. The Area Development Zone must be an existing or proposed industrial park with a minimum size of ten acres. The maximum total number of active zones at any time is 18; the maximum number of active zones in the seven county Twin Cities' metropolitan area is 15. The maximum number of active zones in any community is three. A zone can be "decertified" and a new Area Development Zone established at any time as long as there are no more than three Area Development Zones in a community at any point in time.

RATE
The rates and provisions of the customer's regular rate schedule shall apply except monthly demand charges for customer's Qualified Billing Demand shall be reduced as follows:

Years	Percent Reduction
1 - 3	50%
4	30%
5	20%
6	0%

(Continued on Sheet No. 5-120)

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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK – MPUC NO. 2

AREA DEVELOPMENT RIDER (Continued)

Section No. 5
5th Revised Sheet No. 120

QUALIFIED BILLING DEMAND
The portion of the customer's billing demand that qualifies for reduced demand charges.

New Customers. The total billing demand of new customers shall be defined as Qualified Billing Demand.

Existing Customers. The billing demand in excess of customer's base billing demand shall be defined as qualified billing demand. The base billing demand for each month will be calculated by averaging the monthly billing demands from the two-year period immediately preceding the customer's application for this Rider.

NEW CUSTOMERS
To be considered a new customer for the purpose of this Rider, an applicant must demonstrate one of the following:

1. That business has not been conducted at the premises for at least three monthly billing periods prior to application,
2. That the predecessor customer is in bankruptcy and the applicant has obtained the business in a liquidation of assets sale,
3. Customer's activities are largely or entirely different in nature from that of the previous customer, or
4. If the activities are not so different, that the owner(s), operator(s), or manager(s) are substantially different.

EXISTING CUSTOMERS
Existing customers who materially increase their use of electric service may qualify for service under this Rider, provided such material increase is the result of the addition of equipment, or expansion of the customer's facility or operations. The customer shall notify the Company in writing and document the basis for the material increase in its use of electric service. Following such notification, the Company will review the customer's monthly billing demands. If the billing demands for each of the next three consecutive months exceed that from the comparable monthly period of the preceding year by at least 25%, the customer will be eligible thereafter to receive service under this Rider.

RIGHT TO REFUSE SERVICE
The Company reserves the right to refuse applicants for service under this Rider if it determines that significant additional capital expenditures will be required to provide service to that applicant. In such cases, an applicant may be able to qualify for service by making a non-refundable contribution to compensate for the significant additional capital costs incurred by the Company to supply service to the applicant.

(Continued on Sheet No. 5-121)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK – MPUC NO. 2

AREA DEVELOPMENT RIDER (Continued)

Section No. 5
5th Revised Sheet No. 121

ENERGY EFFICIENCY
For service taken on this Rider, the Company will conduct an energy audit and inform the customer of the conservation programs available from the Company.

ELECTRIC SERVICE AGREEMENT
Any customer taking service under this Area Development Rider shall execute an Electric Service Agreement, or amend their existing Electric Service Agreement, with the Company for a period of six years beginning on the effective date on which the customer commences taking service under this Rider; however, customers who began service under the Pilot Area Development Rider before June 28, 1995, with Electric Service Agreement terms of five years, will not be required to amend or modify those agreements. Such Electric Service Agreements (new or amended) shall state the increased or new load level of the customer as well as the customer's obligation to continue to purchase all of their electric power and electric energy from the Company during the term of the agreement.

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK – MPUC NO. 2

COMPETITIVE RESPONSE RIDER Section No. 5
5th Revised Sheet No. 122

AVAILABILITY
Available at Company's discretion to demand-metered commercial and industrial customers that are subject to effective competition.

Effective competition exists if a customer is located in Company's service territory and has the ability to obtain its energy requirements from an energy supplier not rate regulated by the Minnesota Public Utilities Commission.

RATE
Standard service rates and provisions, including controllable service provisions, apply except the level of the demand charges, energy charges, or both may be reduced for each customer as described below.

TERMS AND CONDITIONS OF SERVICE
1. Customer must provide Company with information that documents that service to the customer is subject to effective competition. The Company will treat information provided by the customer to the Company concerning load or effective competition that meets the definition of trade secret information under the Minnesota Government Data Practices Act ("Act") as trade secret information and, if provided to the Commission or other state agency, will request that the Commission or any other state agency treat the information as trade secret under the Act..

2. Minimum load served under this Rider is 2 MW. Any rate offered under this Rider shall not be available for any month in which the load served under this Rider falls below 2 MW.

3. Customer must execute an Electric Service Agreement with Company, or amend its existing Electric Service Agreement with the Company, to include:
   a. The rate under this Rider, which:
      i) must recover at least the incremental cost of providing service, including the cost of incremental capacity that is to be added while the rate is in effect and any applicable on peak or off peak differential;
      ii) must not exceed the difference between the standard tariff and the cost to the customer of the lowest cost competitive energy supply; and
      iii) includes an annual minimum charge to fully recover distribution costs.

(Continued on Sheet No. 5-123)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK – MPUC NO. 2

COMPETITIVE RESPONSE RIDER (Continued) Section No. 5
6th Revised Sheet No. 123

TERMS AND CONDITIONS OF SERVICE

3. Customer must execute an Electric Service Agreement with Company, or amend its existing Electric (Continued)
   b. The term of service under this Rider, which must be no less than one year and no longer than seven years, beginning on the date the customer begins taking service under this rider,
   c. The size of the load served under this Rider,
   d. Verification that customer has been fully informed of the availability of energy audits. If no energy audit is performed for customer, an explanation of why an energy audit was not necessary will be included.
   e. Establishing the effective date of the rate, which must be at least 60 days after the date upon which the Company files its petition for Commission approval of the Electric Service Agreement,
   f. If the Customer requests that the rate be implemented on an interim rate basis, a statement that the rate will be treated as an interim rate as of the effective date and until Commission approval, modification or disapproval is received. If a modified rate is approved and accepted by the customer and Company, or if the rate is disapproved, the Company will recover the difference between the interim rate and the approved rate (modified or base) from the customer, and
   g. Requirements for a bond or other security acceptable to the Company to provide full recovery of any portion of any interim rate discount disallowed by the Commission.

4. For existing customers receiving a discount, the Company, within a general rate case, is allowed to seek recovery of the difference between the applicable commercial and industrial tariff and this Rider times the usage level during the test year period.

5. A rate under this Rider shall meet the conditions of Minnesota Statutes, Section 216B.03, Reasonable Rate, for other customers in this same customer class.

6. Unless the Commission determines that it would be in the public interest, a rate under this Rider shall not compete with district heating or cooling provided by a district heating utility defined by Minnesota Statutes, Section 216B.166, Subdivision 2, Paragraph (c).

7. A rate offered under this Rider may not be offered to a customer in which the Company has a financial interest greater than 50%.

(Continued on Sheet No. 5-124)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK – MPUC NO. 2

COMPETITIVE RESPONSE RIDER (Continued)

Section No. 5
6th Revised Sheet No. 124

REGULATORY REVIEW

If the Customer requests that the rate be implemented on an interim rate basis, the rate offered under this Rider will be effective on an interim basis after filing by Company of the proposed rate with the Commission and upon the date specified in the Electric Service Agreement. If the Commission does not approve the rate, Company may seek to recover the difference in revenues between the interim competitive rate and the modified rate or the standard tariff rate, as applicable, from the customer who was offered the competitive rate.

The Commission has the authority to approve, modify, or reject a rate under this Rider. If the Commission approves the rate, it is effective as agreed to by the Company and customer. If the rate is modified by the Commission, the Commission shall issue an order modifying the rate subject to the approval of the Company and the customer. Each party has ten days in which to reject the proposed modification. If no party rejects the proposed modifications, the Commission's order becomes final. If either party rejects the Commission's proposed modifications, the Company on its behalf or on the behalf of the customer, may submit to the Commission a modified version of the Commission's proposal, which modified rate shall become an interim rate. The Commission shall accept or reject the modified version within 30 days. If the Commission rejects the rate, it shall issue an order indicating the reasons for the rejection.

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Docket No. E002/GR-15-826 Order Date: 06-12-17

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK – MPUC NO. 2

PHOTOVOLTAIC DEMAND CREDIT RIDER
RATE CODE A85 (CLOSED)
RATE CODE A86

Section No. 5
4th Revised Sheet No. 125

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AVAILABILITY – GENERAL
Applicable by customer request to demand-metered commercial and industrial customers that use Solar Photovoltaic as a customer-sited generation source with a capacity greater than 40 kW (AC) with a single production meter to serve all or a portion of customer's electric energy requirements. Not available to customer-sited generation that is the subject of another incentive program such as Solar*Rewards.

AVAILABILITY – CLOSED RATE
Availability of the closed rate is limited to qualifying customer account locations that: 1) are receiving Standby Service Rider tariff service with the Photovoltaic Solar Credit on the date this Rider is originally approved by the Commission, or 2) have enrolled for the Rider before the date the credit rate in this Rider is revised by the Commission. The closed rate will remain fixed for a six year period beginning with the original Commission order date approving this Rider, expiring April 20, 2024. After expiration of the closed rate, the applicable standard rate will replace the closed rate.

The standard rate will apply to customer account locations that do not qualify for the closed rate. The standard rate may be revised at any time subject to approval by the Commission.

RATE
Customer Charge per Month $25.75

Credit per kWh of Peak Period Solar Photovoltaic Generation (A85 - Closed)	$0.07139
Credit per kWh of Peak Period Solar Photovoltaic Generation (A86 - Standard)	$0.07139

CREDIT KWH LIMIT
The maximum kWh applied to the Rider credit per kWh each billing period is the Peak Period maximum 15-minute Solar Photovoltaic kW output for the billing period times 100 hours for billing periods ending in the months of June, July, August or September and 75 hours for billing periods ending in other months.

CREDIT LIMIT
The maximum credit for each billing period is the applicable standard or on-peak billed demand charge from the base tariff associated with this Rider. For Peak-Controlled Service and Peak-Controlled Time of Day Service customers, the maximum credit for each billing period is the billed demand charge for Firm Demand.

DEFINITION OF PEAK PERIOD
Peak period hours are the six hours between 1:00 p.m. and 7 p.m. for all days.

TERMS AND CONDITIONS OF SERVICE
1. Customer will execute an Electric Service Agreement with the Company that will specify:
   a) The base tariff associated with this Rider, and
   b) The installed capacity (AC) of customer's Solar Photovoltaic generation.
2. Company will install, own, and maintain the metering to measure the electric power and energy supplied by customer generation to allow for proper billing of the customer under this Rider. If, as a result of the customer's construction and installation of their generating facility, it is more practical for the customer to install some or all of the metering equipment required, the customer may be permitted to do so, subject to Company's approval of such equipment.
3. Company reserves the right to limit availability of this Rider to customer situations where the Solar Photovoltaic generation used by customer does not significantly affect the monthly peak demand of customer.
4. For Solar Photovoltaic generation, this Rider supersedes other Standby Service tariff provisions. N

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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

TIER 1 PEAK CONTROLLED SHORT NOTICE RIDER Section No. 5
11th Revised Sheet No. 126

AVAILABILITY
Availability is restricted to customers who are taking service on the Tier 1 option of Peak Controlled Service or Peak Controlled Time of Day Service. Customers choosing service under this rider shall agree to allow the Company to interrupt customer's load to a predetermined level within 10 minutes notice of a control period. Availability is restricted to customers with a minimum certified controllable load of 3,000 kW. Participation is limited to 100,000 kW of controllable demand, which may be exceeded if part of a customer's controllable load is within the participation limit, subject to Company approval.

CONTRACT
Customers must contract for this service rider through an Electric Service Agreement with Company. Contract period will normally be for 24 months.

RATE
The rates and provisions of Tier 1 of the applicable Peak Controlled Service schedule shall apply with the customer's Controllable Demand billed at the Short Notice Controllable Demand charge.

TERMS AND CONDITIONS OF SERVICE
1. Within 10-minutes of notification from the Company, customer's controllable load shall be curtailed by Company-initiated automatic control for the duration of the control period as determined by the Company.

2. Customers taking service under this rider will be required to certify their interruptible load as described below under Certification of Interruptible Load. Customer will cooperate fully with and assist in the required certification process. Failure of customer to assist in the certification process and/or failure to obtain certification of the Controllable Demand level will result in the customer being ineligible for this tariff.

3. Certification of Interruptible Load: To be eligible, the customer's interruptible load must complete an annual control test, prior to the beginning of the Company's summer peak load season. The control test must:
   - Demonstrate that the load is controlled by the Company from its control center;
   - That the load is curtailed within ten minutes of a Company declared control period.
   - The controlled load must remain off for at least four (4) hours in the first year of application and at least one (1) hour in subsequent years.
   - The timing of the control test will be coordinated with the customer but must be conducted at a time when the customer's load is at or near the level expected during actual control periods.

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

TIER 1 PEAK CONTROLLED SCHEDULE L Section No. 5
INTERRUPTION RIDER (Continued) 10th Revised Sheet No. 127

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CANCELED

(Continued on Sheet No. 5-128)

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President and CEO of Northern States Power Company, a Minnesota corporation
Docket No. E002/GR-08-1065 Order Date: 10-23-09

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Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

TIER 1 PEAK CONTROLLED SCHEDULE L Section No. 5
INTERRUPTION RIDER (Continued) 4th Revised Sheet No. 128

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CANCELED

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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK – MPUC NO. 2

CITY REQUESTED FACILITIES SURCHARGE RIDER Section No. 5
7th Revised Sheet No. 131

APPLICABILITY
Applicable to bills for electric service provided under the Company's retail rate schedules in a City ordering the installation of non-standard underground Distribution Facilities. The Excess Expenditure costs for these Special Facilities are to be collected from customers located within such City in accordance with the provisions in the General Rules and Regulations, Section 5.3, SPECIAL FACILITIES.

The Company will provide notice to the affected City of any miscellaneous rate filing by Company under Minn. Stat. §216.B16, Subd. 1 to establish a Special Facilities surcharge applicable to customers in such City.

RATE
In each applicable City, there shall be included in the monthly minimum billing on each customer's bill a separately itemized surcharge line item determined in accordance with this Rider entitled "City Req Fac Srchg". The City Requested Special Facilities Surcharge shall not be subject to current month billing adjustments or City surcharges and shall be subject to any applicable sales taxes.

DETERMINATION OF CITY REQUESTED FACILITIES SURCHARGE
The City Requested Special Facilities Surcharge for each applicable City project shall be calculated by determining a Class Facilities Surcharge to be applied to the Average Monthly Customers in the designated City such that the total Excess Expenditure plus carrying charges in the City Project Tracker Account are recovered over the designated Recovery Period.

Average Monthly Customers shall be the projected average number of active customers in each applicable customer classification located in the City for the designated Recovery Period.

Class Facilities Surcharge shall be the surcharge amount for each applicable customer classification determined in accordance with the Rules for Application.

City Project Tracker Account is a regulatory asset account representing the sum of the following:

(1) The total Excess Expenditures for each Distribution Facilities undergrounding project in such City,

(2) Monthly carrying charges on the under recovered or over recovered monthly balance in the City Project Tracker Account based on the overall rate of return from the Company's most recent electric general rate case decision,

(3) Less the recovered project costs collected to date through the applicable City's Facilities Surcharge.

Recovery Period is the number of months the City Requested Special Facilities Surcharge shall be applied to bills for a designated City project determined in accordance with the Rules for Application.

Excess Expenditures shall be determined in accordance with the provisions in the General Rules and Regulations, Section 5.3.

(Continued on Sheet No. 5-132)

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CITY REQUESTED FACILITIES SURCHARGE RIDER Section No. 5
(Continued) 6th Revised Sheet No. 132

RULES FOR APPLICATION

1. The Recovery Period shall not commence until the City Requested Facilities Surcharge to be applied to bills is at least $0.25 per customer per month. A surcharge of $0.25 up to and including $1.00 per customer regardless of customer class may be applied for a Recovery Period of exactly one month (e.g., a one-time surcharge).

2. For a Recovery Period greater than one month, the Class Facilities Surcharge per month per customer in each non-residential customer class for any month in which a Residential Class Facilities Surcharge is applicable shall be as follows:

   a. Commercial & Industrial (C&I), Street Lighting and Municipal – Non-Demand Billed: Equal to the Residential Class Facilities Surcharge.

   b. Small C&I and Small Municipal – Demand Billed: Three times the Residential Class Facilities Surcharge.

   c. Large C&I – Demand Billed (actual demand greater than 100 kW): Four times the Residential Class Facilities Surcharge.

   However, whenever the Non-residential Class Facilities Surcharges to be billed exceed the Customer Charge applicable on a customer account, the Class Facilities Surcharge for that account shall be equal to such Customer Charge.

3. A Residential Class Facilities Surcharge of $0.25 up to and including $1.00 per Residential customer per month will be applied each month whenever the City Project Tracker Account balance to be collected allows for a Recovery Period of 36 months or less.

4. A Residential Class Facilities Surcharge of over $1.00, up to and including $5.00, per Residential customer per month will be applied each month for a Recovery Period of 36 months whenever the City Project Tracker Account balance is uncollectable at a Residential Class Facilities Surcharge level of $1.00 or less, provided that the surcharge amount for any Residential class customer account receiving a Low Income Energy Discount shall not exceed $1.00 per month.

5. A Residential Class Facilities Surcharge of $5.00 per Residential customer per month for a Recovery Period of 36 months up to and including 60 months will be applied only when necessary to recover the City Project Tracker Account balance, provided a surcharge of $5.00 may be collected pending Commission action on a Company petition or City complaint to modify the design of the rate surcharge for a specific project which cannot be recovered in 60 months.

(Continued on Sheet No. 5-133)

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CITY REQUESTED FACILITIES SURCHARGE RIDER Section No. 5
(Continued) 6th Revised Sheet No. 133

RULES FOR APPLICATION (Continued)

6. The Class Facilities Surcharges may be adjusted annually and in the last 6 months of the Recovery Period to more closely recover the balance remaining in the City Project Tracker Account.

7. Subject to the limits on monthly surcharge amounts set forth above, the Class Facilities Surcharges may also be increased at any time and the Recovery Period may be updated, with notice as provided in Section 5.3 of the General Rules and Regulations, in order to recover Excess Expenditures associated with additional Distribution Facilities undergrounding projects requested or ordered by City.

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Minneapolis, Minnesota 55401
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VOLUNTARY RENEWABLE AND HIGH-EFFICIENCY ENERGY PURCHASE (WINDSOURCE PROGRAM) RIDER
Section No. 5
7th Revised Sheet No. 134

AVAILABILITY
Available to any customer who elects to apply an adjustment to the customer's electric energy usage to contribute to the development of renewable and high-efficiency energy resources as defined by Minn. Stat. §216B.169.

In addition, customer bills under this rate are subject to the following adjustments and/or charges.

RIDER
A Voluntary Renewable Adjustment ("Adjustment") may be elected in blocks of 100 kWh or for the customer's entire monthly usage or for a single event. Each month the Adjustment will add **$3.53** per 100 kWh block of renewable usage and will be prorated on a kWh basis based on the customer's actual metered energy usage for the billing period not to exceed their subscription level. The Adjustment shall be applied to the customer's bill under the standard retail tariff each billing month according to the number of energy block(s) or total amount purchased. The Adjustment is not subject to the Fuel Clause Rider but is subject to any other applicable adjustments and surcharges, including city surcharge or sales tax. The Voluntary Renewable Adjustment will appear on the bill as "Windsource Program." Amounts collected pursuant to the Adjustment will be expended on a program, filed with the Commission, to develop renewable and high efficiency energy resources.

DETERMINATION OF VOLUNTARY RENEWABLE ADJUSTMENT
The Voluntary Renewable Adjustment shall be calculated by dividing the recoverable program expenses and annual tracker balance by the forecasted renewable energy for a designated recovery period. The recoverable program expenses include renewable energy purchases, marketing, other costs and true up of tracker balance for this program. The Adjustment may be revised annually with approval of the Minnesota Public Utilities Commission.

FORECASTED RENEWABLE ENERGY
Forecasted renewable energy sales shall be the estimated total Windsource MWh sales for the designated annual tracker recovery period.

TRACKER ACCOUNT
Due to the variability of renewable resources, the Windsource program may have an excess or shortage of supply in any given hour but will approximately balance out during the year. The Company will maintain accounting of the monthly balance of total revenues collected under the Adjustment and the expenses associated with offering this Adjustment, including the renewable energy purchases, marketing and other costs for this program. The Company may petition the Commission annually to true up the tracker balance in its November 1st report.

(Continued on Sheet No. 134.1)

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VOLUNTARY RENEWABLE AND HIGH-EFFICIENCY ENERGY PURCHASE (WINDSOURCE PROGRAM) RIDER (Continued)

Section No. 5
6th Revised Sheet No. 134.1

TERMS AND CONDITIONS OF SERVICE

1. A customer may elect to subscribe either by purchasing a specified number of 100 kWh blocks or the customer's entire usage. The minimum subscription to be billed each month is one 100 kWh block. In the event a customer's metered energy usage results in the partial consumption of a 100 kWh block, the charge on that block will be prorated accordingly.

2. The minimum subscription periods are one year for residential customers and three years for non-residential customers. After the minimum period, a customer may continue to subscribe on a month to month basis and may terminate the customer's subscription with a 30-day notice.

3. The Company will submit reports to the Commission each May 1 and November 1, or as otherwise ordered in relation to the tracker accounting.

4. For customers on time of day tariffs, their Windsource usage and any excess, non-Windsource usage shall both be assigned to the on-peak and off-peak periods in proportion to the customer's total billing period on-peak and off-peak usage.

5. Xcel Energy may in its discretion allow a non-Windsource customer a limited subscription to Windsource to apply the Adjustment to the energy used by a single event or series of events without making a long-term purchase commitment.

6. The discounts under Residential Controlled Air Conditioning and Water Heating Rider and Commercial and Industrial Controlled Air Conditioning Riders are not applicable to the charges under this Rider.

7. This Rider is provided to satisfy the conditions of Minn. Stat. §216B.169, subd.2 related to renewable and high-efficiency energy rate options. The sales arrangements of renewable energy from the Windsource program supplies are such that the power supply is sold only once to retail customers.

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WAPA BILL CREDITING PROGRAM RIDER Section No. 5
5th Revised Sheet No. 135

AVAILABILITY
This rider is available on a voluntary basis and is limited to customers who are eligible for the Western Area Power Administration ("Western" or "WAPA") Bill Crediting Program.

TERM OF SERVICE
Service under this rider shall be for a period not less than 90 days.

PRICING METHODOLOGY
The WAPA Bill Credit shall be calculated as specified in the Commission approved Bill Crediting Agreement between the customer and the Company.

BILL DETERMINATION
The WAPA Bill Credit will be applied to the customer's standard monthly bill rendered after each monthly billing period.

SPECIAL PROVISIONS
1. Eligibility for the Program, and thus this Rider, is determined by the customer and Western, and not by Xcel Energy.

2. If there is a change in the legal identity of the customer receiving service under this Rider, credit under this Rider shall be terminated unless Xcel Energy, Western and the customer determine otherwise.

3. Changes are subject to the Agreement for Bill Crediting arrangements between Xcel Energy, Western and the customer, a copy of which is contained in Section 7 of this Electric Rate Book.

RULES AND REGULATIONS
Service under this Rider is subject to orders of the Minnesota Public Utilities Commission and to the General Rules and Regulations section of this Electric Rate Book.

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MERCURY COST RECOVERY RIDER

Section No. 5
8th Revised Sheet No. 136

APPLICATION
Applicable to bills for electric service provided under the Company's retail rate schedules.

RIDER
There shall be included on each customer's monthly bill a Mercury Cost Recovery (MCR) Rider adjustment which will be the MCR Adjustment Factor multiplied by the customer's monthly billing kWh for electric service. This MCR adjustment shall be calculated before city charges and sales tax.

DETERMINATION OF MERCURY COST RECOVERY FACTOR
The MCR Adjustment Factor shall be the average retail cost per kWh. The average retail cost per kWh shall be determined by the forecasted balance of the MCR Tracker Account plus the Mercury Costs divided by the forecast retail sales for the designated period. The MCR Adjustment Factor shall be rounded to the nearest $0.000001 per kWh.

The MCR Adjustment Factor may be adjusted with the approval of the Minnesota Public Utilities Commission (Commission). The MCR Adjustment Factor for each rate schedule is:

All Classes	$0.000000 per kWh

MERCURY COSTS
Recoverable mercury costs shall be the revenue requirements for the designated period including operation and maintenance (O&M) expenses associated with projects eligible for recovery under Minnesota Statute Sections 216B.68 to 216B.688 that are determined by the Commission to be eligible for recovery under this Mercury Cost Recovery Rider. A standard model will be used to calculate the total forecasted revenue requirements for eligible projects for the designated period that is determined by the Commission to be eligible for recovery under this MCR Rider.

FORECASTED RETAIL SALES
Forecasted Retail Sales shall be the estimated total retail electric sales for the designated recovery period.

MCR TRACKER ACCOUNT
For each designated true-up period, a true-up adjustment to the MCR Tracker Account will be calculated reflecting the difference between the MCR Adjustment recoveries and the actual expenditures for such period. The true-up adjustment shall be included in calculating the MCR Adjustment Factor effective with the start of the next designated recovery period.

The MCR Adjustment Factor includes a true-up of actuals as available for the previous recovery period and forecast information for the remainder of the recovery period. The Final true-up adjustment for a previous recovery period will be determined by October 1 of the following year, at which time the Company will record a Final adjustment to the MCR Tracker Account. All costs appropriately charged to the MCR Tracker Account shall be eligible for recovery through this rider.

(Continued on Sheet No. 5-136.1)

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MERCURY COST RECOVERY RIDER (Continued) Section No. 5
7th Revised Sheet No. 136.1

PROVISION OF FORECAST DATA

To assist commercial and industrial customers in budgeting and managing their energy costs, the Company will annually make available on October 1st a 24-month forecast of the MCR Adjustment Factor applicable to demand billed C&I customers under this Rider. The forecast period begins January 1st of the following year. This forecast will be provided only to customers who have signed a protective agreement with the Company.

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ENVIRONMENTAL IMPROVEMENT RIDER Section No. 5
12th Revised Sheet No. 137

APPLICATION
Applicable to bills for electric service provided under the Company's retail rate schedules.

RIDER
There shall be included on each customer's monthly bill an Environmental Improvement Rider (EIR) adjustment. For all but demand-billed customers, the adjustment shall be the Full EIR Energy Adjustment Factor multiplied by the customer's monthly billing kWh for electric service. For demand-billed customers, the adjustment shall be the Reduced EIR Energy Adjustment Factor multiplied by the customer's monthly billing kWh for electric service, plus the EIR Demand Adjustment Factor multiplied by the customer's monthly kW billing demand. These EIR adjustments shall be calculated before city surcharge and sales tax.

DETERMINATION OF EIR ADJUSTMENT FACTORS
The Full EIR Energy Adjustment Factor shall be the quotient obtained by dividing the forecasted balance of the EIR Tracker Account by the forecasted retail sales for the calendar year. The Reduced EIR Energy Adjustment Factor shall be the Full EIR Energy Adjustment Factor multiplied by 50%. The EIR Demand Adjustment Factor shall be the difference between the Full and Reduced factors, multiplied by the class load factor of 53.27% and multiplied by 730 hours in an average month. All factors shall be rounded to the nearest $0.000001 per kWh. The EIR Adjustment Factors may be adjusted annually with approval of the Minnesota Public Utilities Commission (Commission). The EIR Adjustment Factors shall apply to bills rendered on and after January 1st of the year.

The EIR Adjustment Factor for each customer group may be adjusted annually. Each EIR Adjustment Factor shall apply to bills rendered on and after January 1 of the year. The EIR factor for each rate schedule is:

Non-Demand Customers	$0.000000 per kWh
Demand Customers	$0.000000 per kWh and $0.00 per kW

Recoverable EIR Costs shall be the annual revenue requirements associated with emissions reduction projects (a) not recovered through base rates, (b) recorded in the EIR Tracker Account for the designated period, and (c) determined by the Commission to be eligible for recovery under this Rider pursuant to the terms of the Settlement Agreement approved by the Commission on March 8, 2004. A standard model will be used to calculate the total forecasted revenue requirements for eligible projects for the designated period. All costs appropriately charged to the EIR Tracker Account shall be eligible for recovery through this Rider, and all revenues recovered from the EIR Adjustment shall be credited to the EIR Tracker Account.

Forecasted retail sales shall be the estimated retail electric sales for the designated recovery period.

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ENVIRONMENTAL IMPROVEMENT RIDER (Continued)

Section No. 5
5th Revised Sheet No. 138

TRUE-UP

For each 12-month period ending December 31, a true-up adjustment to the EIR Tracker Account will be calculated reflecting the difference between the EIR Adjustment recoveries and the revenue requirements for such period. The true-up adjustment shall be calculated and recorded by no later than May 1 of the following calendar year and will be included in calculating the EIR Adjustment Factor for each customer group effective with the start of the next designated recovery period. No carrying cost shall be applied.

PROVISION OF FORECAST DATA

To assist commercial and industrial customers in budgeting and managing their energy costs, the Company will annually make available on October 1st a 24-month forecast of the EIR Adjustment Factors applicable to demand billed C&I customers under this Rider. The forecast period begins January 1st of the following year. This forecast will be provided only to customers who have signed a protective agreement with the Company.

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Minneapolis, Minnesota 55401
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BUSINESS INCENTIVE AND SUSTAINABILITY RIDER Section No. 5
2nd Revised Sheet No. 139

AVAILABILITY
Available to new or existing demand-metered commercial and industrial customers with significant new Qualified Billing Demand. Service under the Rider is limited to customers whose application for service under the Rider is approved by the Company.

RATE
The rates and provisions of the customer's regular demand-metered rate schedule shall apply except monthly demand charges for customer's Qualified Billing Demand, before the application of voltage discounts, shall be reduced as follows:

Years:	1 - 3	4	5	6
Percent Reduction:	40%	20%	10%	0%

QUALIFIED BILLING DEMAND
The portion of the customer's billing demand that qualifies for reduced demand charges. Qualified billing demand includes billing demands for standard demand, on-peak period demand, firm demand and controllable demand. Qualified billing demand does not include billing demands for off-peak period demand, distribution demand, transmission and distribution demand, contracted standby demand or contracted supplemental demand.

New Customers. This Rider is available for new load that is associated with initial permanent service. For new Customers, the Qualified Billing Demand under this Rider must be a minimum of 350 kW at a single delivery point. The demand charge reduction shall not apply during any month in which the Qualified Billing Demand is below 350 kW; provided, however, the demand charge reduction shall apply during any month in which the Qualified Billing Demand is below 350 kW as a consequence of new conservation or load control by the customer.

Existing Customers. For existing customers, Qualified Billing Demand is the new load of 350 kW or greater at a single delivery point incremental to that existing prior to approval for service under this Rider. The demand charge reduction shall not apply during any month in which the Qualified Billing Demand is below 350 kW; provided, however, the demand charge reduction shall apply during any month in which the Qualified Billing Demand is below 350 kW as a consequence of new conservation or load control by the customer.

NEW CUSTOMERS
To be considered a new customer for the purpose of this Rider, an applicant must demonstrate one of the following:
1. That business has not been conducted at the premises for at least three monthly billing periods prior to application,
2. That the predecessor customer is in bankruptcy and the applicant has obtained the business in a liquidation of assets sale; or
3. Customer's activities are largely or entirely different in nature from that of the previous customer.

(Continued on Sheet No. 5-140)

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BUSINESS INCENTIVE AND SUSTAINABILITY RIDER Section No. 5
(Continued) 2nd Revised Sheet No. 140

EXISTING CUSTOMERS
Existing customers who materially increase their use of electric service may qualify for service under this Rider, provided such material increase is the result of the addition of equipment, or expansion of the customer's facility or operations. The customer shall notify the Company in writing and document the basis for the material increase in its use of electric service. Following such notification, the Company will review the customer's monthly billing demands. If the billing demands for each of the next three consecutive months exceed that from the comparable monthly period of the preceding year by at least 350 kW at one delivery point, the customer will be eligible thereafter to receive service under this Rider. If a customer's activities are very similar to the customer's previous activities, then the customer is considered to be an existing customer whether or not the owner(s) operator(s), or manager(s) are substantially different.

APPLICATION
As a condition of qualifying for a discount, Customer must make an application on a Commission approved form demonstrating that it meets the Qualified Billing Demand requirement. Information related to the Qualified Billing Demand and Investment is trade secret information under the Minnesota Government Data Practices Act ("Act").

RIGHT TO REFUSE SERVICE
The Company reserves the right to refuse applicants for service under this Rider if it determines that significant additional capital expenditures will be required to provide service to that applicant. In such cases, an applicant may be able to qualify for service by making a non-refundable contribution to compensate for the significant additional capital costs incurred by the Company to supply service to the applicant.

ENERGY EFFICIENCY
For service taken on this Rider, the Company will conduct an energy audit and inform the customer of the conservation programs available from the Company. Customer will be responsible for some portion of the cost of the energy audit. Customer must also participate in the Company's Energy Assistance Design program or other energy efficiency program.

ELECTRIC SERVICE AGREEMENT
Any customer taking service under this Stimulation Rider shall execute an Electric Service Agreement, or amend their existing Electric Service Agreement, with the Company for a period of six years beginning on the effective date on which the customer commences taking service under this Rider. Such Electric Service Agreements (new or amended) shall state the increased or new load level of the customer as well as the customer's obligation to continue to purchase all of their electric power and electric energy from the Company during the term of the agreement. The effective date of service under this rider will be set forth in the Electric Service Agreement but not before three months of qualified billing demand has occurred after the application. The Electric Service Agreement entered into pursuant to this Agreement and provision of the discount is not subject to Commission Approval.

(Continued on Sheet No. 5-141)

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BUSINESS INCENTIVE AND SUSTAINABILITY RIDER Section No. 5
(Continued) 2nd Revised Sheet No. 141

REPORTING REQUIREMENT
No later than 30 days after the Company signs a new ESA with a customer to be served under the BIS Rider, the Company must file with the Commission a report showing the incremental revenues and the incremental costs associated with the new ESA. If no party objects to the ESA within 30 days of the filing date, the ESA is deemed to be approved. One year from the effective date of this tariff, and annually thereafter, the Company shall file a report with the Commission identifying the number of customers receiving service under this Rider and the associated incremental additional revenues received by the Company and the incremental additional costs experienced by the Company.

REVENUE RECOVERY
The Company, within a general rate case, is allowed to seek recovery of the difference between the applicable commercial and industrial tariff and this Rider times the usage level during the test year period.

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STATE ENERGY POLICY RATE RIDER Section No. 5
15th Revised Sheet No. 142

APPLICATION
Applicable to bills for electric service provided under the Company's retail rate schedules.

RIDER
There shall be included on each customer's monthly bill a State Energy Policy Rate Rider which shall be the applicable State Energy Policy Rate Rider factor multiplied by the customer's monthly kWh electric consumption.

DETERMINATION OF STATE ENERGY POLICY RATE FACTOR
The applicable State Energy Policy Rate Rider shall be the quotient obtained by dividing the annual State Energy Policy Tracker amount by the annual forecasted kWh sales. The factor may be adjusted annually with approval of the Minnesota Public Utilities Commission.

Residential	$0.000000 per kWh
Commercial	$0.000000 per kWh

Recoverable State Energy Policy Rate Expense
All costs appropriately charged to the State Energy Policy Tracker account shall be eligible for recovery through this Rider, and all revenues received from the State Energy Policy adjustment portion of the Resource Adjustment shall be credited to the State Energy Policy Tracker account.

PROVISION OF FORECAST DATA
To assist commercial and industrial customers in budgeting and managing their energy costs, the Company will annually make available on March 1st a 24-month forecast of the State Energy Policy Rate Factor applicable to demand billed C&I customers under this Rider. The forecast period begins January 1st of the following year. This forecast will be provided only to customers who have signed a protective agreement with the Company.

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RENEWABLE DEVELOPMENT FUND RIDER

Section No. 5
22nd Revised Sheet No. 143

APPLICATION
Applicable to bills for electric service provided under the Company's retail rate schedules.

RIDER
There shall be included on each customer's monthly bill a Renewable Development Fund charge that shall be the applicable Renewable Development Fund factor multiplied by the customer's monthly kWh electric consumption.

DETERMINATION OF RENEWABLE DEVELOPMENT FUND FACTOR
The applicable Renewable Development Fund factor shall be the quotient obtained by dividing the annual Renewable Development Fund Tracker amount by the annual forecasted kWh sales. The factor may be adjusted annually with approval of the Minnesota Public Utilities Commission.

Residential	$0.001357 per kWh	R
Commercial	$0.001357 per kWh	R

Recoverable Renewable Development Fund Expense
All costs appropriately charged to the Renewable Development Fund Tracker account shall be eligible for recovery through this Rider, and all revenues received from the Renewable Development Fund portion of the Resource Adjustment shall be credited to the Renewable Development Fund Tracker account.

PROVISION OF FORECAST DATA
To assist commercial and industrial customers in budgeting and managing their energy costs, the Company will annually make available on October 1st a 24-month forecast of the Renewable Development Fund Factor applicable to demand billed C&I customers under this Rider. The forecast period begins January 1st of the following year. This forecast will be provided only to customers who have signed a protective agreement with the Company.

EXEMPTION
For customer premises recognized by the Company as not being subject to any of the costs of satisfying the solar energy standard under Minn. Stat. § 216B.1691, subd. 2f ("SES Costs"), the SES Costs reflected in the Renewable Development Fund charge assessed to the accounts associated with these premises may be credited to these accounts, and the dollar amount of these credits shall be added as part of the annual Renewable Development Fund Tracker applicable to the time period when the credit is issued.

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RENEWABLE DEVELOPMENT FUND RIDER

Section No. 5
21st Revised Sheet No. 143

APPLICATION
Applicable to bills for electric service provided under the Company's retail rate schedules.

RIDER
There shall be included on each customer's monthly bill a Renewable Development Fund charge that shall be the applicable Renewable Development Fund factor multiplied by the customer's monthly kWh electric consumption.

DETERMINATION OF RENEWABLE DEVELOPMENT FUND FACTOR
The applicable Renewable Development Fund factor shall be the quotient obtained by dividing the annual Renewable Development Fund Tracker amount by the annual forecasted kWh sales. The factor may be adjusted annually with approval of the Minnesota Public Utilities Commission.

Residential	$0.001417 per kWh	R
Commercial	$0.001417 per kWh	R

Recoverable Renewable Development Fund Expense
All costs appropriately charged to the Renewable Development Fund Tracker account shall be eligible for recovery through this Rider, and all revenues received from the Renewable Development Fund portion of the Resource Adjustment shall be credited to the Renewable Development Fund Tracker account.

PROVISION OF FORECAST DATA
To assist commercial and industrial customers in budgeting and managing their energy costs, the Company will annually make available on October 1st a 24-month forecast of the Renewable Development Fund Factor applicable to demand billed C&I customers under this Rider. The forecast period begins January 1st of the following year. This forecast will be provided only to customers who have signed a protective agreement with the Company.

EXEMPTION
For customer premises recognized by the Company as not being subject to any of the costs of satisfying the solar energy standard under Minn. Stat. § 216B.1691, subd. 2f ("SES Costs"), the SES Costs reflected in the Renewable Development Fund charge assessed to the accounts associated with these premises may be credited to these accounts, and the dollar amount of these credits shall be added as part of the annual Renewable Development Fund Tracker applicable to the time period when the credit is issued.

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RENEWABLE DEVELOPMENT FUND RIDER

Section No. 5
20th Revised Sheet No. 143

APPLICATION
Applicable to bills for electric service provided under the Company's retail rate schedules.

RIDER
There shall be included on each customer's monthly bill a Renewable Development Fund charge that shall be the applicable Renewable Development Fund factor multiplied by the customer's monthly kWh electric consumption.

DETERMINATION OF RENEWABLE DEVELOPMENT FUND FACTOR
The applicable Renewable Development Fund factor shall be the quotient obtained by dividing the annual Renewable Development Fund Tracker amount by the annual forecasted kWh sales. The factor may be adjusted annually with approval of the Minnesota Public Utilities Commission.

Residential	$0.001318 per kWh	R
Commercial	$0.001318 per kWh	R

Recoverable Renewable Development Fund Expense
All costs appropriately charged to the Renewable Development Fund Tracker account shall be eligible for recovery through this Rider, and all revenues received from the Renewable Development Fund portion of the Resource Adjustment shall be credited to the Renewable Development Fund Tracker account.

PROVISION OF FORECAST DATA
To assist commercial and industrial customers in budgeting and managing their energy costs, the Company will annually make available on October 1st a 24-month forecast of the Renewable Development Fund Factor applicable to demand billed C&I customers under this Rider. The forecast period begins January 1st of the following year. This forecast will be provided only to customers who have signed a protective agreement with the Company.

EXEMPTION
For customer premises recognized by the Company as not being subject to any of the costs of satisfying the solar energy standard under Minn. Stat. § 216B.1691, subd. 2f ("SES Costs"), the SES Costs reflected in the Renewable Development Fund charge assessed to the accounts associated with these premises may be credited to these accounts, and the dollar amount of these credits shall be added as part of the annual Renewable Development Fund Tracker applicable to the time period when the credit is issued.

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

RENEWABLE DEVELOPMENT FUND RIDER

Section No. 5
19th Revised Sheet No. 143

APPLICATION
Applicable to bills for electric service provided under the Company's retail rate schedules.

RIDER
There shall be included on each customer's monthly bill a Renewable Development Fund charge that shall be the applicable Renewable Development Fund factor multiplied by the customer's monthly kWh electric consumption.

DETERMINATION OF RENEWABLE DEVELOPMENT FUND FACTOR
The applicable Renewable Development Fund factor shall be the quotient obtained by dividing the annual Renewable Development Fund Tracker amount by the annual forecasted kWh sales. The factor may be adjusted annually with approval of the Minnesota Public Utilities Commission.

Residential	$0.001034 per kWh
Commercial	$0.001034 per kWh

Recoverable Renewable Development Fund Expense
All costs appropriately charged to the Renewable Development Fund Tracker account shall be eligible for recovery through this Rider, and all revenues received from the Renewable Development Fund portion of the Resource Adjustment shall be credited to the Renewable Development Fund Tracker account.

PROVISION OF FORECAST DATA
To assist commercial and industrial customers in budgeting and managing their energy costs, the Company will annually make available on October 1st a 24-month forecast of the Renewable Development Fund Factor applicable to demand billed C&I customers under this Rider. The forecast period begins January 1st of the following year. This forecast will be provided only to customers who have signed a protective agreement with the Company.

EXEMPTION
For customer premises recognized by the Company as not being subject to any of the costs of satisfying the solar energy standard under Minn. Stat. § 216B.1691, subd. 2f ("SES Costs"), the SES Costs reflected in the Renewable Development Fund charge assessed to the accounts associated with these premises may be credited to these accounts, and the dollar amount of these credits shall be added as part of the annual Renewable Development Fund Tracker applicable to the time period when the credit is issued. N N

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President, Northern States Power Company, a Minnesota corporation
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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

TRANSMISSION COST RECOVERY RIDER Section No. 5
13th Revised Sheet No. 144

APPLICATION
Applicable to bills for electric service provided under the Company's retail rate schedules.

RIDER
There shall be included on each customer's monthly bill a Transmission Cost Recovery (TCR) adjustment, which shall be the TCR Adjustment Factor multiplied by the customer's monthly billing energy or demand for electric service as described below. This TCR Adjustment shall be calculated before city surcharge and sales tax.

DETERMINATION OF TCR ADJUSTMENT FACTORS
A separate TCR Adjustment Factor shall be calculated for the following four customer groups: (1) Residential, (2) Commercial Non-Demand, (3) Demand Billed, and (4) Street Lighting. The TCR Adjustment Factor for each group shall be the value obtained by multiplying each group's weighting factor by the average retail cost per kWh. The average retail cost per kWh shall be determined by the forecasted balance of the TCR Tracker Account, divided by the forecasted retail sales for the calendar year. The Demand Billed customers' TCR Adjustment Factor is calculated similarly, but the resulting per kWh charge is converted to a per kW charge for application to billed kW rather than billed kWh. TCR Adjustment Factors shall be rounded to the nearest $0.000001 per kWh or $0.001 per kW.

The TCR Adjustment Factor for each customer group may be adjusted annually with approval of the Minnesota Public Utilities Commission (Commission). Each TCR Adjustment Factor shall apply to bills rendered subsequent to approval by the Minnesota Public Utilities Commission. The TCR factor for each rate schedule is:

Residential	$0.003503 per kWh
Commercial (Non-Demand)	$0.003384 per kWh
Demand Billed	$1.017 per kW

Recoverable Transmission Costs shall be the annual revenue requirements for transmission costs associated with transmission projects eligible for recovery under Minnesota Statute Sections 216B.1645 or 216B.16, subd. 7b that are determined by the Commission to be eligible for recovery under this Transmission Cost Recovery Rider. A standard model will be used to calculate the total forecasted revenue requirements for eligible projects for the designated period. All costs appropriately charged to the Transmission Tracker Account shall be eligible for recovery through this Rider, and all revenues recovered from the TCR Adjustment shall be credited to the Transmission Tracker Account.

Forecasted retail kWh sales and kW demands shall be those for the designated recovery period.

(Continued on Sheet No. 5-145)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MNNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

TRANSMISSION COST RECOVERY RIDER Section No. 5
(Continued) 5th Revised Sheet No. 145

TRUE-UP

For each 12-month period ending December 31, a true-up adjustment to the Tracker Account will be calculated reflecting the difference between the TCR Adjustment recoveries and the revenue requirements for such period. The total retail true-up adjustment shall be calculated and recorded by no later than May 1 of the following calendar year and will be included in average retail cost used to calculate the TCR Adjustment Factor for each customer group effective with the start of the next designated recovery period.

For example, the Year 1 revenue requirements versus TCR Adjustment recoveries would be determined by May 1 of Year 2, at which time the Company would record an adjustment to the Tracker Account. The difference between the Year 1 revenue requirements and Year 1 TCR Adjustment recoveries would be included in the calculation of the TCR Adjustment factors filed on September 1 of Year 2 to be effective January 1 of Year 3.

PROVISION OF FORECAST DATA

To assist commercial and industrial customers in budgeting and managing their energy costs, the Company will annually make available on September 1st a 24-month forecast of the TCR Adjustment Factor applicable to demand billed C&I customers under this Rider. The forecast period begins January 1st of the following year. This forecast will be provided only to customers who have signed a protective agreement with the Company.

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Docket No. E002/GR-15-826 Order Date: 06-12-17

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

RENEWABLE ENERGY STANDARD RIDER Section No. 5
10th Revised Sheet No. 146

APPLICATION
Applicable to bills for electric service provided under the Company's retail rate schedules.

RIDER
There shall be included on each customer's monthly bill a Renewable Energy Standard (RES) adjustment which will be the RES Adjustment Factor applied to:

1. Customer, Energy, Demand and Minimum Charges
2. Energy Charge Credits
3. Limited Energy Surcharges
4. Controllable Demand Credits
5. Voltage Discounts
6. Lighting Rates per Luminaire and Lighting Rates per Unit
7. Siren Service Rate per Horsepower
8. Residential Controlled Air Conditioning and Water Heating Discounts (Energy and Fuel Cost Charges)
9. Commercial and Industrial Controlled Air Conditioning Credits
10. Standby Service Rider
11. Supplemental Service Rider
12. Tier 1 Energy Controlled Service Rider
13. Tier 1 Peak Controlled Short Notice Rider
14. Area Development Rider
15. Fixed Charges for Low Wattage Unmetered Devices

The RES Adjustment Factor does not apply to:

1. Fuel Clause Rider
2. Conservation Improvement Program Rider
3. Off Season Load Rider
4. Revenue Decoupling Mechanism Rider
5. Competitive Response Rider
6. City Requested Facilities Surcharge Rider
7. Windsource Program Rider
8. WAPA Bill Credit Program Rider
9. Mercury Cost Recovery Rider
10. Environmental Improvement Rider
11. Business Incentive and Sustainability Rider
12. State Energy Policy Rate Rider
13. Renewable Development Fund Rider
14. Transmission Cost Recovery Rider
15. Renewable Energy Standard Rider
16. Net Energy Billing Service
17. Late Payment Charge
18. Any currently applicable Interim Rate Surcharge Rider
19. Low Income Program Surcharge
20. Low Income Discounts

This RES adjustment shall be calculated before city surcharge and sales tax.

(Continued on Sheet No. 5-147)

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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

RENEWABLE ENERGY STANDARD RIDER (Continued)

Section No. 5
12th Revised Sheet No. 147

DETERMINATION OF RES ADJUSTMENT FACTOR

The Renewable Energy Standard ("RES") Adjustment Factor shall be the RES annual forecasted revenue requirement as a percentage of "base" revenues. The RES annual forecasted revenue requirement shall be the sum of the Renewable Energy Standard Costs for the forecast period and any residual Tracker balance in the RES Tracker Account.

The RES Adjustment Factor may be adjusted with the approval of the Minnesota Public Utilities Commission (Commission). The RES Factor is:

All Classes	0.497%

RENEWABLE ENERGY STANDARD COSTS

The RES Costs shall be the annual revenue requirements including operation and maintenance (O&M) expenses for Company owned Renewable Energy Project costs and capacity related renewable energy purchased power costs not recoverable through the FCR, that are eligible for recovery under Minnesota Statute Section 216B.1645. A standard model will be used to calculate the total forecasted revenue requirements for each annual period that is determined by the Commission to be eligible for recovery under this Renewable Energy Standard Rider.

RES TRACKER ACCOUNT

For each annual true-up period, a true-up adjustment to the RES Tracker Account (residual Tracker balance) will be calculated reflecting the difference between the RES Adjustment recoveries and the actual expenditures for such period. The true-up adjustment shall be included in calculating the RES Adjustment Factor effective with the start of the next annual recovery period.

The RES Adjustment Factor includes a true-up of actuals as available for the previous recovery period and forecast information for the remainder of the recovery period. The Final true-up adjustment for a previous recovery period will be determined by September 1 of the following year, at which time the Company will record a Final adjustment to the RES Tracker Account.

All costs appropriately charged to the RES Tracker Account shall be eligible for recovery through this rider.

PROVISION OF FORECAST DATA

To assist commercial and industrial customers in budgeting and managing their energy costs, the Company will annually make available on September 1st a 24-month forecast of the RES Adjustment Factor applicable to demand billed C&I customers under this Rider. The forecast period begins January 1st of the following year. This forecast will be provided only to customers who have signed a protective agreement with the Company.

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Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

VOLUNTARY RENEWABLE*CONNECT PILOT PROGRAM RIDER
Section No. 5
Original Sheet No. 149

AVAILABILITY N

The Voluntary Renewable*Connect™ ("R*C") Pilot program will be available, subject to capacity made available within the program, to any customer who elects to participate in the program that would otherwise receive service under a rate schedule that is subject to the adjustments provided for in the Fuel Clause Rider.

DEFINITIONS

The following definitions apply:

"Applicable Retail Electric Usage" means the measured retail electric usage of the Customer on the account(s) during the monthly billing cycle for the Customer's premises identified in the Service Agreement as being associated with the Customer's subscription to the R*C Service.

"R*C Adjustment" means the product resulting from the multiplication of the R*C Price by the Subscription Level.

"R*C Price" means the price as shown in the Rate section below.

"R*C Resources" for this pilot program means portions of renewable sources applicable to the R*C Service.

"R*C Service" means the service offered under this Voluntary Renewable*Connect Pilot Program Rider.

"Service Agreement" means the tariffed service agreement associated with the R*C Service which the Customer signs.

"Subscription Level" means the Customer's allocated share set forth in the Service Agreement, in kWh, of the energy from the R*C Resources. The Subscription Level is a blend of renewable resources.

RIDER

Customer may elect to receive R*C Service. The following types of R*C Service are available ("R*C Service Type") in the following billing methods ("R*C Billing Method"):

R*C Service Types	R*C Billing Methods
Month-to-Month	100 kWh Blocks
5 Years	Entire Monthly Usage
10 Years	Single Event Usage
Single Event	

Each billing month the R*C Price associated with the R*C Service Type chosen by the Customer will be applied to the Subscription Level chosen by the Customer, the product of the R*C Price and Subscription Level being the R*C Adjustment. Customers receiving R*C Service shall not be subject to the Minnesota Electric Fuel Clause Rider for the portion of its Applicable Retail Electric Usage that is less than or equal to the Customer's Subscription Level. All usage shall be subject to any other applicable adjustments and surcharges, including city surcharge or sales tax. The cost to the Customer for participating in the R*C Service will appear on the Customer's retail electric bill.

DETERMINATION OF R*C PRICE

The R*C Price shall be calculated as follows: for the month-to-month and single event R*C Service Type, pricing will be based on the partially levelized delivered cost of the R*C Resources, adjusted for capacity credits and neutrality charges, plus recoverable program expenses. For the 5-year and 10-year R*C Service Types, pricing shall be based on the actual delivered cost of the R*C Resources, adjusted for capacity credits and neutrality charges, plus recoverable program expenses. Recoverable program expenses include renewable energy purchases, marketing, and other costs approved by the Minnesota Public Utilities Commission ("Commission"). The R*C Price for the month-to-month R*C Service Type may be revised annually with approval of the Commission. N

(Continued on Sheet No. 5-150)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

VOLUNTARY RENEWABLE*CONNECT PILOT PROGRAM Section No. 5
RIDER (Continued) 3rd Revised Sheet No. 150

RATE
The R*C Price for the pilot phase R*C Resources of each R*C Service Type shall be as follows based on year of production, unless otherwise provided for in this tariff:

Month-To-Month R*C or Single Event R*C Service Type	
Year number	$/kWh
2 (2018)	$0.03577
3 (2019)	$0.03599

DL
LN

5-Year and 10-Year R*C Service Type

Year	5-Year Contract ($/kWh)	10-Year Contract ($/kWh)
2017	$0.03243	$0.03193
2018	$0.03280	$0.03230
2019	$0.03317	$0.03267
2020	$0.03330	$0.03280
2021	$0.03345	$0.03295
2022	$0.03361	$0.03349
2023	$0.03429	$0.03404
2024	$0.03497	$0.03460
2025	$0.03569	$0.03519
2026	$0.03642	$0.03580

NEUTRALITY CHARGE
The R*C Price includes a neutrality charge to mitigate the impact of the R*C Pilot program on non-participating customers. The standard neutrality charge is as follows:

Year number	$/kWh
2 (2018)	$0.00477
3 (2019)	$0.00483

DL
LN

Customers receiving service under the Company's Business Incentive and Sustainability Rider, Competitive Response Rider, Residential Electric Vehicle Service (Rate Code A08), or Residential Electric Vehicle Pilot Service (Rate Code A80, A81) shall not be subject to the neutrality charge portion of the R*C Price.

TRACKER ACCOUNT
Due to the variability of renewable resources, the Renewable*Connect program tracker account may have an excess or shortage of supply in any given hour or month. The Company will balance Renewable*Connect program usage at the end of the program year in accordance with the expected resource blend. As a result, the program may require more or less of a share of the expected program allocation. Energy produced by the R*C Resources that is not associated with any R*C Service subscription and therefore not allocated to an R*C Customer will be sold to all customers at the delivered cost through the Fuel Clause Adjustment. The Company will maintain accounting of the monthly balance of total R*C Resources production, total program usage, total revenues collected under the program and the expenses associated with offering the R*C Service, including the renewable energy purchases, marketing and other costs for this program. The Company may petition the Commission annually to true up the marketing and administrative cost tracker balance and apply the resulting true-up factors to the Month-To-Month R*C Price.

(Continued on Sheet No. 5-151)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

VOLUNTARY RENEWABLE*CONNECT PILOT PROGRAM Section No. 5
RIDER (Continued) 2nd Revised Sheet No. 150

RATE
The R*C Price for the pilot phase R*C Resources of each R*C Service Type shall be as follows based on year of production, unless otherwise provided for in this tariff:

Month-To-Month R*C or Single Event R*C Service Type	
Year number	$/kWh
1 (2017)	$0.03555
2 (2018)	$0.03577

5-Year and 10-Year R*C Service Type

Year	5-Year Contract ($/kWh)	10-Year Contract ($/kWh)
2017	$0.03243	$0.03193
2018	$0.03280	$0.03230
2019	$0.03317	$0.03267
2020	$0.03330	$0.03280
2021	$0.03345	$0.03295
2022	$0.03361	$0.03349
2023	$0.03429	$0.03404
2024	$0.03497	$0.03460
2025	$0.03569	$0.03519
2026	$0.03642	$0.03580

NEUTRALITY CHARGE
The R*C Price includes a neutrality charge to mitigate the impact of the R*C Pilot program on non-participating customers. The standard neutrality charge is as follows:

Year number	$/kWh
1 (2017)	$0.00472
2 (2018)	$0.00477

Customers receiving service under the Company's Business Incentive and Sustainability Rider, Competitive Response Rider, Residential Electric Vehicle Service (Rate Code A08), or Residential Electric Vehicle Pilot Service (Rate Code A80, A81) shall not be subject to the neutrality charge portion of the R*C Price. N N

TRACKER ACCOUNT
Due to the variability of renewable resources, the Renewable*Connect program tracker account may have an excess or shortage of supply in any given hour or month. The Company will balance Renewable*Connect program usage at the end of the program year in accordance with the expected resource blend. As a result, the program may require more or less of a share of the expected program allocation. Energy produced by the R*C Resources that is not associated with any R*C Service subscription and therefore not allocated to an R*C Customer will be sold to all customers at the delivered cost through the Fuel Clause Adjustment. The Company will maintain accounting of the monthly balance of total R*C Resources production, total program usage, total revenues collected under the program and the expenses associated with offering the R*C Service, including the renewable energy purchases, marketing and other costs for this program. The Company may petition the Commission annually to true up the marketing and administrative cost tracker balance and apply the resulting true-up factors to the Month-To-Month R*C Price.

(Continued on Sheet No. 5-151)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

VOLUNTARY RENEWABLE*CONNECT PILOT PROGRAM Section No. 5
RIDER (Continued) 1st Revised Sheet No. 150

RATE
The R*C Price for the pilot phase R*C Resources of each R*C Service Type shall be as follows based on year of production, unless otherwise provided for in this tariff:

Month-To-Month R*C or Single Event R*C Service Type	
Year number	$/kWh
1 (2017)	$0.03555
2 (2018)	$0.03577

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T
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5-Year and 10-Year R*C Service Type T

Year	5-Year Contract ($/kWh)	10-Year Contract ($/kWh)
2017	$0.03243	$0.03193
2018	$0.03280	$0.03230
2019	$0.03317	$0.03267
2020	$0.03330	$0.03280
2021	$0.03345	$0.03295
2022	$0.03361	$0.03349
2023	$0.03429	$0.03404
2024	$0.03497	$0.03460
2025	$0.03569	$0.03519
2026	$0.03642	$0.03580

NEUTRALITY CHARGE
The R*C Price includes a neutrality charge to mitigate the impact of the R*C Pilot program on non-participating customers. The standard neutrality charge is as follows: T

Year number	$/kWh
1 (2017)	$0.00472
2 (2018)	$0.00477

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Customers receiving service under the Company's Business Incentive and Sustainability Rider, Competitive Response Rider, or Residential Electric Vehicle Service (Rate Code A08) shall not be subject to the neutrality charge portion of the R*C Price.

TRACKER ACCOUNT
Due to the variability of renewable resources, the Renewable*Connect program tracker account may have an excess or shortage of supply in any given hour or month. The Company will balance Renewable*Connect program usage at the end of the program year in accordance with the expected resource blend. As a result, the program may require more or less of a share of the expected program allocation. Energy produced by the R*C Resources that is not associated with any R*C Service subscription and therefore not allocated to an R*C Customer will be sold to all customers at the delivered cost through the Fuel Clause Adjustment. The Company will maintain accounting of the monthly balance of total R*C Resources production, total program usage, total revenues collected under the program and the expenses associated with offering the R*C Service, including the renewable energy purchases, marketing and other costs for this program. The Company may petition the Commission annually to true up the marketing and administrative cost tracker balance and apply the resulting true-up factors to the Month-To-Month R*C Price.

(Continued on Sheet No. 5-151)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

VOLUNTARY RENEWABLE*CONNECT PILOT PROGRAM Section No. 5
RIDER (Continued) 1st Revised Sheet No. 151

TERMS AND CONDITIONS OF SERVICE

1. Any Customer enrolling in this R*C Service shall execute the Service Agreement with the Company. The effective date of such service, and the Customer's Subscription Level, will be set forth in the Service Agreement. A Customer's ability to continue receiving this R*C Service terminates upon the termination of the Service Agreement.

2. A Customer may elect to subscribe by: (i) purchasing a specified number of 100 kWh blocks; (ii) the Customer's entire Applicable Retail Electric Usage; or (iii) the Customer's entire Retail Electric Usage for a special event; provided, however, that in no event shall the customer's total Subscription Level exceed 10% of the total expected average output of the available R*C Resources.

2a. Limited Exception to Subscription Level. Customers who subscribe to the first tranche of resources approved for the Renewable*Connect Pilot Program may purchase a total Subscription Level from the first tranche without limitation. N N N

3. Unless otherwise agreed to by the Company, for a Customer electing to receive the R*C Service by the 100 kWh Blocks R*C Billing Method, the Subscription Level shall be set so that when combined with other distributed generation resources serving the premises designated in the Service Agreement the subscription size does not exceed one hundred (100) percent of the previous annual (12-month) consumption of electric energy by Customer at Premises. If twelve (12) months of historical electric energy consumption data is not available for a particular Customer Premise, the Company will calculate the estimated annual electric energy consumption as follows: if there is less than twelve (12) months but four (4) months or more of consumption history, the average monthly consumption is multiplied by twelve (12) to figure the yearly consumption. In cases where there is less than four (4) months of consumption history, home usage is estimated based on the historical average energy use of homes of a similar size. Homes are assumed to have central A/C, electric appliances, and natural gas water and space heating. For commercial properties and all properties over 4,500 square feet with less than four (4) months of consumption history, the Customer must submit an energy audit (HERS Rating or similar) or load calculations for the property stating the estimated annual consumption. Load calculations must be documented and sent to the Renewable*Connect Program Manager for approval. The compliance check by the Company with this 100% rule will be performed once at the beginning of a subscription and later only if the Customer changes his or her subscription size or relocates to a new premise. In the event a customer's Applicable Retail Electric Usage in a given billing month results in the partial consumption of a 100 kWh Block, the charge on that partial block will be prorated accordingly.

4. For a Customer electing to receive its entire Applicable Retail Electric Usage pursuant to the R*C Service, Xcel Energy reserves the right to provide system energy in any given billing month for any portion of the Customer's Applicable Retail Electric Usage that exceeds its monthly average usage (calculated as the actual or estimated 12-month annual electric energy consumption described in paragraph 3, divided by 12).

(Continued on Sheet No. 5-152)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

VOLUNTARY RENEWABLE*CONNECT PILOT PROGRAM Section No. 5
RIDER (Continued) 1st Revised Sheet No. 152

TERMS AND CONDITIONS OF SERVICE (Continued)

5. A Customer's subscription period becomes effective on the first day of Customer's billing period immediately following the Company counter-signing the Service Agreement (but not before January 1, 2017). Subscription periods are month-to-month, 5 years and 10 years, or are for a designated Special Event. Any termination by the Customer ahead of the 5 year, 10 year or Special Event term shall be provided by notice by the Customer to the Company at least 30 days prior to the Termination Date. The Termination Date is the last day of the billing month following 30 days from Company receipt of the termination notice provided by the Customer. Month-to-month subscriptions shall continue until terminated by the customer, and shall end on the last day of the billing month following 30 days from Company receipt of the termination notice provided by the Customer. A Customer that terminates a 5-Year or 10-Year R*C Service prior to the completion of that 5-Year or 10-Year term shall be subject to an Early Termination Fee. The Early Termination Fee shall be equal to the customer's actual R*C Service usage for the 12-month billing period ending on the Termination Date multiplied by a per MWh amount of $10 (R*C Early Termination Fee Rate). If the Customer does not have at least 12 billing months of R*C Service usage, the anticipated 12-month R*C Service usage will be calculated as follows:
   a. For Customers choosing the 100 kWh Blocks R*C Billing Method, the number of 100 kWh Blocks subscribed will be multiplied by twelve (12).
   b. For Customers choosing the Entire Monthly Usage R*C Billing Method, the estimated annual (12-month) usage for the Customer using the methodology described in paragraph 3.

   This anticipated 12-month R*C Service usage will then be multiplied by the R*C Early Termination Fee Rate to determine the value of the Early Termination Fee.

6. Xcel Energy may cancel this R*C Service and any Service Agreement applicable to the R*C Service on written order from the Commission based on good cause shown. Additionally, Xcel Energy may, upon reasonable notice to a Customer, cancel any Service Agreement applicable to the R*C Service to assure that the Service Agreement does not extend beyond the term of this R*C Pilot Program. The term of this R*C Pilot Program ends on December 31, 2026. N N N N

7. The Company will submit reports to the Commission each April 1, or as otherwise ordered in relation to the tracker accounting.

8. For customers on time of day tariffs, their usage met by R*C Service and any excess usage not met by R*C Service shall both be assigned to the on-peak and off-peak periods in proportion to the Customer's total billing period on-peak and off-peak usage.

9. Xcel Energy may, in its discretion, allow customers to subscribe to the R*C Program on a limited basis for the energy used by a single event or series of events without making a long-term purchase commitment.

10. The discounts under Residential Controlled Air Conditioning and Water Heating Rider and Commercial and Industrial Controlled Air Conditioning Riders are not applicable to the charges under this Rider.

(Continued on Sheet No. 5-153)

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Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

VOLUNTARY RENEWABLE*CONNECT PILOT PROGRAM Section No. 5
RIDER (Continued) Original Sheet No. 153

TERMS AND CONDITIONS OF SERVICE (Continued)

11. This Rider is provided to satisfy the conditions of Minn. Stat. §216B.169, subd. 2 related to renewable and high-efficiency energy rate options. The sales arrangements of renewable energy from the Renewable*Connect program supplies are such that the power supply is sold only once to retail customers.

12. The R*C Service shall only apply to the Applicable Retail Electric Usage of a Customer in excess of other renewable or other energy self-supplied by the Customer or supplied to the Customer by a different entity.

13. Any customer taking service under this Rider shall execute a Renewable*Connect Service Agreement. The effective date of service under this Rider will be set forth in the Service Agreement.

14. All R*C Resources are located in Minnesota. The Company shall assign to Customer, or retire on Customer's behalf, all renewable energy credits (RECs) associated with the Customer's Subscription Level for which the Customer has paid to the Company the applicable R*C Price. RECs assigned to Customer or retired on the Customer's behalf will not also be claimed by the Company as its renewable energy for other purposes.

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President, Northern States Power Company, a Minnesota corporation
Docket No. E002/M-15-985 Order Date: 02-27-17

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

VOLUNTARY RENEWABLE*CONNECT GOVERNMENT PILOT PROGRAM RIDER
Section No. 5
Original Sheet No. 154

AVAILABILITY

The Voluntary Renewable*Connect™ Government ("R*CG") Pilot Program will be available, subject to capacity made available within the program, to any political subdivision or agency customer that: (i) elects to participate in the program; (ii) would otherwise receive service under a rate schedule that is subject to the adjustments provided for in the Minnesota Electric Fuel Clause Rider; and (iii) has the equivalent of an Investment Grade Credit Rating or, if such rating is unavailable, has satisfactory creditworthiness as determined by Northern States Power Company in its reasonably exercised discretion. For purposes of this Rider, a political subdivision or agency means a regional, territorial, or local authority, such as a county or municipality (including a municipal corporation) that is created or recognized by statute or other authority to exercise sovereign powers and that has governing officers appointed by officials of a recognized political subdivision or that are publicly elected. As used in this Pilot Program, a political subdivision or agency includes the Minnesota Department of Administration and those State of Minnesota agencies it assists in administering. Investment Grade Credit Rating, for the purposes of this Rider, means a senior unsecured bond rating (unenhanced by third party support) assigned by Standard & Poors Rating Group (or its successor) of BBB- or higher and/or Moody's Investor Service Inc. (or its successor) of Baa3 or higher; provided, however, that if any senior unsecured bond rating (unenhanced by third party support) is exactly equivalent to BBB-/Baa3, the rated entity shall not be on credit watch by such rating agency, and, provided further, that if the ratings of S&P and Moody's are not equivalent, the lower rating shall apply.

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DEFINITIONS

The following definitions apply:

(i) "Applicable Retail Electric Usage" means the measured retail electric usage of the Customer on the account(s) during the monthly billing cycle for the Customer's premises identified in the Service Agreement as being associated with the Customer's subscription to the R*CG Service.

(ii) "R*CG Adjustment" means the product resulting from the multiplication of the R*CG Price by the R*CG Energy.

(iii) "R*CG Energy" means the electric power, in kWh, from the R*CG Resources associated with the Customer's Subscription Level.

(iv) "R*CG Price" means the price as shown in the Rate section below.

(v) "R*CG Resources" for this pilot program means portions of renewable sources applicable to the R*CG Service.

(vi) "R*CG Service" means the service offered under this Voluntary Renewable*Connect-Government Pilot Program Rider.

(vii) "Service Agreement" means the tariffed service agreement associated with the R*CG Service which the Customer signs.

(viii) "Subscription Level" means the Customer's allocated share set forth in the Service Agreement, in MW, of the capacity from the R*CG Resources. The Subscription Level is a blend of renewable resources.

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(Continued on Sheet No. 5-155)

Northern States Power Company, a Minnesota corporation
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MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

VOLUNTARY RENEWABLE*CONNECT GOVERNMENT PILOT PROGRAM RIDER (Continued)

Section No. 5
Original Sheet No. 155

RIDER

Customer may elect to receive R*CG Service. Under the R*CG Service, the Customer shall subscribe for a fixed amount of the capacity of the R*CG Resources. Each billing month, the R*CG Price will be applied to the Customer's R*CG Energy, the product being the R*CG Adjustment.

If the Customer's Applicable Retail Electric Usage is less than the R*CG Energy in any given billing month, then:

1. The Company will bill the Customer for the Customer's Applicable Retail Electric Usage based on the R*CG Price for that billing month;
2. The kWh surplus shall be carried over and applied to a subsequent billing month for the Customer.
3. Any such surplus may be carried over up to the day before the yearly anniversary of the Customer's Subscription Term as defined in the Service Agreement. If there is a positive kWh carry-over balance at the end of that day, the Customer shall incur a charge on its retail bill for that balance in kWh multiplied by the then-current R*CG Price along with a credit for the balance in kWh multiplied by the Net Resources Cost (defined as the resource cost less the current capacity credit). The accumulated Customer surplus then will be reduced to zero.

Customer receiving R*CG Service shall only be subject to the Minnesota Electric Fuel Clause Rider for the portion of its Applicable Retail Electric Usage that is greater than the Customer's R*CG Energy plus any applicable applied kWh surplus. All usage shall be subject to any other applicable adjustments and surcharges, including city surcharge or sales tax. The cost to the Customer for participating in the R*CG Service will appear on the Customer's retail electric bill.

DETERMINATION OF R*CG PRICE

The R*CG Price is based on the actual delivered cost of the R*CG Resources adjusted for capacity credits and neutrality charges, plus recoverable program expenses. Recoverable program expenses include renewable energy purchases, marketing, and other costs approved by the Minnesota Public Utilities Commission ("Commission").

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(Continued on Sheet No. 5-156)

Date Filed: 11-12-15 By: Christopher B. Clark Effective Date: 02-27-17
President, Northern States Power Company, a Minnesota corporation
Docket No. E002/M-15-985 Order Date: 02-27-17

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

VOLUNTARY RENEWABLE*CONNECT GOVERNMENT PILOT PROGRAM RIDER (Continued)

Section No. 5
Original Sheet No. 156

RATE

The R*CG Price for the pilot phase R*CG Resources shall be as follows based on year of production, unless otherwise provided for in this tariff:

Year	R*CG Price ($/kWh)
2017	$0.03093
2018	$0.03130
2019	$0.03167
2020	$0.03230
2021	$0.03295
2022	$0.03349
2023	$0.03404
2024	$0.03460
2025	$0.03519
2026	$0.03580
2027	$0.03617
2028	$0.03680
2029	$0.03745
2030	$0.03813
2031	$0.03881
2032	$0.03951
2033	$0.04025
2034	$0.04100
2035	$0.04176
2036	$0.04224

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RENEWABLE*CONNECT GOVERNMENT RESOURCES

The Renewable*Connect Government program will be supplied by R*CG Resources, which produce renewable energy as set forth in Minn. Stat. § 216B.169 (as the same may be amended or revised from time to time). The Customer's share of the output of the R*CG Resources is the "R*CG Energy".

The Company shall not be liable to the Customer in the event that the R*CG Energy is greater than or less than the Customer's Applicable Retail Electric Usage. The Customer assumes all production risk of the R*CG Resources.

To the extent the Company is not required to pay the operator of the R*CG Service because R*CG Resources are unavailable, then on a pro-rata basis the R*CG Energy level of the Customer shall be reduced while such resources are unavailable.

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(Continued on Sheet No. 5-157)

Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
MINNESOTA ELECTRIC RATE BOOK - MPUC NO. 2

VOLUNTARY RENEWABLE*CONNECT GOVERNMENT PILOT PROGRAM RIDER (Continued)

Section No. 5
Original Sheet No. 157

TRACKER ACCOUNT

Customers enrolled in the R*CG Service subscribe to a fixed amount of the capacity of the R*CG Resources, which is the Customer's Subscription Level. The R*CG Resources are variable in nature and may produce more or less energy than the Customer's Applicable Retail Electric Usage. The Company shall apply the R*CG Price to the Customer's Applicable Retail Electric Usage up to the level of the R*CG Energy plus any applied kWh surplus from previous months. If the Customer's Applicable Retail Electric Usage in a given billing month is greater than the R*CG Energy plus unused kWh surplus, then to that extent the Customer's electric usage will be subject to the Minnesota Electric Fuel Clause Rider. The Company will balance the usage of R*CG Service Customers at the end of the program month and year with the actual output of the R*CG Resources over the same periods in accordance with the expected resource blend. Energy produced by the R*CG Resources that is not associated with any R*CG Service subscription and therefore not allocated to an R*CG Customer will be sold to all customers at the delivered cost through the Fuel Clause Adjustment.

The Company will maintain accounting of the monthly balance of total program production, total program usage, total revenues collected under the program and the expenses associated with offering the R*CG Service, including the renewable energy purchases, marketing and other costs for this program.

TERMS AND CONDITIONS OF SERVICE

1. Any Customer enrolling in this R*CG Service shall execute the Service Agreement with the Company. The effective date of such service, and the Customer's Subscription Level, will be set forth in the Service Agreement. A Customer's ability to continue receiving this R*CG Service terminates upon the termination of the Service Agreement.

2. Unless otherwise agreed to by the Company, a Customer's Subscription Level initially shall be set so that when combined with other distributed generation resources serving the premises designated in the Service Agreement the subscription size does not exceed one hundred (100) percent of the previous annual (12-month) consumption of electric energy by Customer at Premises to which the subscription is attributed (using a conversion factor based on expected production from the R*CG Resources). If twelve (12) months of historical electric energy consumption data is not available for a particular Customer premise, the Company will calculate the estimated annual electric energy consumption as follows: if there is less than twelve (12) months but four (4) months or more of consumption history, the average monthly consumption is multiplied by twelve (12) to figure the yearly consumption. In cases where there is less than four (4) months of consumption history, for commercial properties and all properties over 4,500 square feet with less than four (4) months of consumption history, the Customer must submit an energy audit (HERS Rating or similar) or load calculations for the property stating the estimated annual consumption. Load calculations must be documented and sent to the Renewable*Connect Government Program Manager for approval. The compliance check by the Company with this 100% rule will be performed once at the beginning of a subscription and later only if the Customer changes the Premise(s) associated with the Customer's Subscription Level.

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(Continued on Sheet No. 5-158)

Date Filed: 11-12-15 By: Christopher B. Clark Effective Date: 02-27-17
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PILOT PROGRAM RIDER (Continued) Original Sheet No. 158

3. Subscription periods become effective on the first day of Customer's billing period immediately following the Company counter-signing the Service Agreement (but not before January 1, 2017), and shall expire on December 31, 2035. Customers that terminate R*CG Service prior to the termination date in the Service Agreement shall be subject to an early termination fee (the "Early Termination Fee"). The Early Termination Fee shall be equal to the Subscription Level in kW multiplied by $20/kW. N

4. A Customer may assign all or part of its Subscription Level to one or more other accounts associated with other premises where it receives retail electric service from the Company and which otherwise qualify under this program under a process which the Company establishes for this.

5. Xcel Energy may cancel this R*CG Service and any Service Agreement applicable to the R*CG Service on written order from the Commission based on good cause shown.

6. The Company will submit reports to the Commission each April 1, for the prior calendar year, or as otherwise ordered in relation to the tracker accounting.

7. For Customers on time of day tariffs, their usage met by R*CG Service and any excess usage not met by R*CG Service shall both be assigned to the on-peak and off-peak periods in proportion to the Customer's total billing period on-peak and off-peak usage.

8. The discounts under Residential Controlled Air Conditioning and Water Heating Rider and Commercial and Industrial Controlled Air Conditioning Riders are not applicable to the charges under this Rider.

9. This R*CG Service shall only apply to the Applicable Retail Electric Usage of a Customer in excess of net metering or other renewable energy supplied by or for the Customer for the premises designated in the Service Agreement.

10. All R*CG Resources are located in Minnesota.

11. The Company shall assign to Customer, or retire on Customer's behalf, all renewable energy credits (RECs) associated with the Customer's R*CG Energy for which the Customer has paid to the Company the applicable R*CG Price. RECs assigned to Customer or retired on the Customer's behalf will not also be claimed by the Company as its renewable energy for other purposes. N

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Northern States Power Company, a Minnesota corporation

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Minnesota Retail Electric Fuel Cost Charges Table ($/kWh)

June 2018-June 2019	FUEL COST CHARGE					
	Residential	C&I Non-Demand	C&I Demand			Outdoor Lighting
			Non-TOD	TOD		
				On-Peak	Off-Peak	
June 2018	$0.02919	$0.02956	$0.02864	$0.03581	$0.02342	$0.02288
July	$0.02807	$0.02843	$0.02754	$0.03444	$0.02252	$0.02201
August	$0.02280	$0.02309	$0.02238	$0.02798	$0.01829	$0.01788
September	$0.03080	$0.03119	$0.03022	$0.03779	$0.02471	$0.02414
October	$0.02737	$0.02772	$0.02686	$0.03358	$0.02196	$0.02146
November	$0.02602	$0.02635	$0.02553	$0.03192	$0.02088	$0.02040
December	$0.02776	$0.02812	$0.02724	$0.03406	$0.02227	$0.02176
January 2019	$0.02702	$0.02736	$0.02651	$0.03315	$0.02168	$0.02118
February	$0.02003	$0.02029	$0.01966	$0.02458	$0.01607	$0.01571
March	$0.02661	$0.02695	$0.02612	$0.03265	$0.02135	$0.02087
April	$0.02642	$0.02676	$0.02593	$0.03242	$0.02120	$0.02072
May	$0.02947	$0.02985	$0.02892	$0.03616	$0.02365	$0.02311
June	$0.02416	$0.02447	$0.02371	$0.02964	$0.01938	$0.01894

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US Department of Energy Energy Information Administration Form EIA-861	ANNUAL ELECTRIC POWER INDUSTRY REPORT	Form Approved OMB No. 1905-0129 Approved Expires 03/31/2020

SCHEDULE 1. IDENTIFICATION

SURVEY CONTACTS: Persons to contact with question about this form

RESPONSE DUE DATE: Please submit by April 30th following the close of calendar year

Contact Beth Osman
Title: Senior Financial Analyst-External R
Phone: (612) 215-4641 FAX: Email: beth.a.osman@xcelenergy.com

REPORT FOR: Northern States Power Co - Minnesota 13781
REPORTING PERIOD: 2018

Supervisor Jolene Stephens
Title: Manager, External Reporting
Phone: (612) 215-5378 FAX: (612) 330-6335 Email: jolene.j.stephens@xcelenergy.com

Logged By / Date:
Logged In: ☐ Receipt Date (mm/dd/yyyy):

1	Legal Name of Industry Participant	Northern States Power Co - Minnesota	**Submission Status/Date:**	Submitted	05/03/2019
2	Current Address of Principal Business Office	414 Nicollet Mall Minneapolis MN 55401 0000			
3	Preparer's Legal Name Operator (if different than line 1)				
4	Current Address of Preparer's Office (if different than line 2)				
5	Respondent Type (Check One)	☐ Federal ☐ Political Subdivision ☐ Municipal Marketing Authority ☐ Cooperative ☐ Independent Power Producer or Qualifying Facility	☐ State ☐ Municipal ☒ Investor-Owned ☐ Retail Power Marketer (or Energy Service Provider) ☐ Community Choice Aggregator	☐ Transmission ☐ Behind the Meter ☐ Wholesale Power Marketer ☐ DSM Administrator	

For questions or additional information about the Form EIA-861 contact the Survey Manager: Fax: (202) 287 - 1938 Email: EIA-861@eia.gov
Stephen Scott Phone: (202) 586-5140 Email: stephen.scott@eia.gov

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US Department of Energy Energy Information Administration Form EIA-861	ANNUAL ELECTRIC POWER INDUSTRY REPORT	Form Approved OMB No. 1905-0129 Approved Expires 03/31/2020

REPORT FOR: Northern States Power Co - Minnesota 13781

REPORT PERIOD ENDING: 2018

SCHEDULE 2. PART A. GENERAL INFORMATION

LINE NO.		
1	Regional North American Electric Reliability Council (Not applicable for power marketers)	[ ] TRE (formerly ERCOT) [ ] NPCC [ ] SPP [ ] FRCC [ ] RFC (formerly ECAR, MAIN. MAAC) [ ] WECC [x] MRO [ ] SERC
2	Name of RTO or ISO	[ ] California ISO [ ] Southwest Power Pool [ ] Electric Reliability Council of Texas [X] Midwest ISO [ ] PJM Interconnection [ ] ISO New England [ ] New York ISO [ ] None
3	(For EIA Use Only) Identify the North American Electric Reliability Council where you are physically located	MRO
4	Did Your Company Operate Generating Plants(s)?	[x] Yes [ ] No
5	Identify The Activities Your Company Was Engaged In During The Year (Check appropriate activities)	[x] Generation from company owned plant [ ] Buying distribution on other electrical system [x] Transmission [x] Wholesale power marketing [x] Buying transmission services on other electrical system [ ] Retail power marketing [x] Distribution using owned/leased electric wires [x] Bundled Services (electricity plus other services such as gas, water, etc. in addition to electric service))
6	Highest Hourly Electrical Peak System Demand	Summer (Megawatts) 7,609.0 Prior Year 7,371.0 Winter (Megawatts) 4,713.0 Prior Year 5,379.0
7	Did Your Company Operate Alternative-Fueled Vehicles During the Year?	[x] Yes [ ] No
	Does Your Company Plan to Operate Such Vehicles During the Coming Year?	[x] Yes [ ] No
	If "Yes", Please Provide Additional Contact Information	Name: Victoria Earnest Title: Fleet Systems Analyst Telephone: 612 - 630 - 4457 Fax: 612 - 573 - 9427 Email: victoria.j.earnest@xcelenergy.com

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US Department of Energy Energy Information Administration Form EIA-861	ANNUAL ELECTRIC POWER INDUSTRY REPORT	Form Approved OMB No. 1905-0129 Approved Expires 03/31/2020

REPORT FOR: Northern States Power Co - Minnesota 13781

REPORT PERIOD ENDING: 2018

SCHEDULE 2. PART B. ENERGY SOURCES AND DISPOSITION

	SOURCE OF ENERGY	MEGAWATTHOURS		DISPOSITION OF ENERGY	MEGAWATTHOURS
1	Net Generation	37,100,627	11	Sales to Ultimate Consumers	34,908,071
2	Purchases from Electricity Suppliers	12,972,506	12	Sales For Resale	14,024,754
3	Exchanged Received (In)		13	Energy Furnished Without Charge	380
4	Exchanged Delivered (Out)		14	Energy Consumed By Respondent Without Charge	52,248
5	Exchanged Net				
6	Wheeled Received (In)				
7	Wheeled Delivered (Out)		15	Total Energy Losses (positive number)	1,087,680
8	Wheeled Net				
9	Transmission by Others Losses (Negative Number)				
10	Total Sources (sum of lines 1, 2, 5, 8 & 9)	50,073,133	16	Total Disposition (sum of lines 11, 12, 13, 14, & 15)	50,073,133

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US Department of Energy Energy Information Administration Form EIA-861	ANNUAL ELECTRIC POWER INDUSTRY REPORT	Form Approved OMB No. 1905-0129 Approved Expires 03/31/2020

REPORT FOR: Northern States Power Co - Minnesota 13781

REPORT PERIOD ENDING: 2018

SCHEDULE 2. PART C. ELECTRIC OPERATING REVENUE

LINE NO.	TYPE OF OPERATING REVENUE		(THOUSAND DOLLARS to the nearest 0.1)
1	Electrical Operating Revenue From Sales to Ultimate Customers (Schedule 4: Parts A, B, and D)	$	3,773,915.5
2	Revenue From Unbundled (Delivery) Customers (Schedule 4: Part C)	$	
3	Electric Operating Revenue from Sales for Resale	$	515,277.0
4	Electric Credits/Other Adjustments	$	-2,879.3
5	Revenue from Transmission	$	285,383.0
6	Other Electric Operating Revenue	$	-76,236.3
7	Total Electric Operating Revenue (sum of lines 1, 2, 3, 4, 5 and 6)	$	4,495,459.9

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US Department of Energy Energy Information Administration Form EIA-861	ANNUAL ELECTRIC POWER INDUSTRY REPORT	Form Approved OMB No. 1905-0129 Approved Expires 03/31/2020

REPORT FOR: Northern States Power Co - Minnesota 13781

REPORT PERIOD ENDING: 2018

SCHEDULE 3. PART A.
DISTRIBUTION SYSTEM RELIABILITY DATA

INSTRUCTIONS: For the purpose of this schedule, a distribution circuit is any circuit with a voltage of 34kV or below that emanate from a substation and that serves end use customers.

State/Territory **MN**

1	Total Number of Distribution Circuits	1,045.0
2	Number of Distribution Circuits that employ voltage/VAR optimization (VVO)	

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US Department of Energy Energy Information Administration Form EIA-861	ANNUAL ELECTRIC POWER INDUSTRY REPORT	Form Approved OMB No. 1905-0129 Approved Expires 03/31/2020

REPORT FOR: Northern States Power Co - Minnesota 13781

REPORT PERIOD ENDING: 2018

SCHEDULE 3. PART A.
DISTRIBUTION SYSTEM RELIABILITY DATA

INSTRUCTIONS: For the purpose of this schedule, a distribution circuit is any circuit with a voltage of 34kV or below that emanate from a substation and that serves end use customers.

State/Territory ND

1	Total Number of Distribution Circuits	63.0
2	Number of Distribution Circuits that employ voltage/VAR optimization (VVO)	

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REPORT FOR: Northern States Power Co - Minnesota 13781

REPORT PERIOD ENDING: 2018

SCHEDULE 3. PART A.
DISTRIBUTION SYSTEM RELIABILITY DATA

INSTRUCTIONS: For the purpose of this schedule, a distribution circuit is any circuit with a voltage of 34kV or below that emanate from a substation and that serves end use customers.

State/Territory SD

1	Total Number of Distribution Circuits	70.0
2	Number of Distribution Circuits that employ voltage/VAR optimization (VVO)	

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REPORT FOR: Northern States Power Co - Minnesota 13781

REPORT PERIOD ENDING: 2018

SCHEDULE 3. PART B.
DISTRIBUTION SYSTEM RELIABILITY DATA

Who is required to complete this schedule?

This schedule collects System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) statistics. If your organization does not compute these indexes, answer 'no' to Question 1 and then skip to Schedule 4A. You do not have to complete any other part of this schedule 3B or 3C.

Should you complete Part B or Part C?

If your organization computes the SAIFI and SAIDI indexes and determines Major Event Days using the IEEE 1366-2003 or the IEEE 1366-2012 standard, answer 'YES' to Questions 1 and 2, and complete Part B. Then skip to Schedule 4A. (You do not complete Schedule 3, Part C.)

If your organization does not use the IEEE 1366-2003 or the IEEE 1366-2012 standard but calculates SAIDI and SAIFI indexes via other method, answer 'yes' to question 1 and 'no' to question 2 and complete Part C. Then go to Schedule 4A.

1	Do you calculate SAIDI and SAIFI by any method? If Yes, go to Question 2. If No, go to Schedule 4, Part A.	[x] Yes	[ ] No
2	Do you calculate SAIDI and SAIFI and determine Major Event Days using the IEEE1366-2003 standard or IEEEE-2012 standard? If Yes, complete Part B. If No, go to complete Part C.	[x] Yes	[ ] No

Part B: SAIDI and SAIFI in accordance with IEEE 1366-2003 standard or IEEE 1366-2012 standard

		State MN
3a.	SAIDI value including Major Event days	124.950
3b.	SAIDI value excluding Major Event days	95.020
4	SAIDI value including Major Event days minus loss of supply	118.780
5a.	SAIFI value including Major Event days	0.950
5b.	SAIFI value excluding Major Event days	0.880
6.	SAIFI value including Major Event days minus loss of supply	0.890
7.	Total number of customers used in these calculations	1,265,163.0
8.	What is the highest voltage that you consider part of the distribution system, as opposed to the supply system? (kV)	34.5
9.	Do you receive information about a customer outage in advance of a customer reporting it?	[x] Yes [ ] No

Thank You for completing this part. Skip Part C and go directly to Schedule 4 Part A.

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US Department of Energy Energy Information Administration Form EIA-861	ANNUAL ELECTRIC POWER INDUSTRY REPORT	Form Approved OMB No. 1905-0129 Approved Expires 03/31/2020

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REPORT PERIOD ENDING: 2018

SCHEDULE 3. PART B.
DISTRIBUTION SYSTEM RELIABILITY DATA

Who is required to complete this schedule?

This schedule collects System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) statistics. If your organization does not compute these indexes, answer 'no' to Question 1 and then skip to Schedule 4A. You do not have to complete any other part of this schedule 3B or 3C.

Should you complete Part B or Part C?

If your organization computes the SAIFI and SAIDI indexes and determines Major Event Days using the IEEE 1366-2003 or the IEEE 1366-2012 standard, answer 'YES' to Questions 1 and 2, and complete Part B. Then skip to Schedule 4A. (You do not complete Schedule 3, Part C.)

If your organization does not use the IEEE 1366-2003 or the IEEE 1366-2012 standard but calculates SAIDI and SAIFI indexes via other method, answer 'yes' to question 1 and 'no' to question 2 and complete Part C. Then go to Schedule 4A.

1	Do you calculate SAIDI and SAIFI by any method? If Yes, go to Question 2. If No, go to Schedule 4, Part A.	[x] Yes	[ ] No
2	Do you calculate SAIDI and SAIFI and determine Major Event Days using the IEEE1366-2003 standard or IEEEE-2012 standard? If Yes, complete Part B. If No, go to complete Part C.	[x] Yes	[ ] No

Part B: SAIDI and SAIFI in accordance with IEEE 1366-2003 standard or IEEE 1366-2012 standard

		State	SD
3a.	SAIDI value including Major Event days		76.520
3b.	SAIDI value excluding Major Event days		58.570
4	SAIDI value including Major Event days minus loss of supply		66.670
5a.	SAIFI value including Major Event days		0.680
5b.	SAIFI value excluding Major Event days		0.480
6.	SAIFI value including Major Event days minus loss of supply		0.540
7.	Total number of customers used in these calculations		92,713.0
8.	What is the highest voltage that you consider part of the distribution system, as opposed to the supply system? (kV)		34.5
9.	Do you receive information about a customer outage in advance of a customer reporting it?	[x] Yes	[ ] No

Thank You for completing this part. Skip Part C and go directly to Schedule 4 Part A.

7610.0600 F

US Department of Energy Energy Information Administration Form EIA-861	ANNUAL ELECTRIC POWER INDUSTRY REPORT	Form Approved OMB No. 1905-0129 Approved Expires 03/31/2020

REPORT FOR: Northern States Power Co - Minnesota 13781

REPORT PERIOD ENDING: 2018

SCHEDULE 3. PART B.
DISTRIBUTION SYSTEM RELIABILITY DATA

Who is required to complete this schedule?

This schedule collects System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) statistics. If your organization does not compute these indexes, answer 'no' to Question 1 and then skip to Schedule 4A. You do not have to complete any other part of this schedule 3B or 3C.

Should you complete Part B or Part C?

If your organization computes the SAIFI and SAIDI indexes and determines Major Event Days using the IEEE 1366-2003 or the IEEE 1366-2012 standard, answer 'YES' to Questions 1 and 2, and complete Part B. Then skip to Schedule 4A. (You do not complete Schedule 3, Part C.)

If your organization does not use the IEEE 1366-2003 or the IEEE 1366-2012 standard but calculates SAIDI and SAIFI indexes via other method, answer 'yes' to question 1 and 'no' to question 2 and complete Part C. Then go to Schedule 4A.

1	Do you calculate SAIDI and SAIFI by any method? If Yes, go to Question 2. If No, go to Schedule 4, Part A.	[x] Yes	[ ] No
2	Do you calculate SAIDI and SAIFI and determine Major Event Days using the IEEE1366-2003 standard or IEEEE-2012 standard? If Yes, complete Part B. If No, go to complete Part C.	[x] Yes	[ ] No

Part B: SAIDI and SAIFI in accordance with IEEE 1366-2003 standard or IEEE 1366-2012 standard

		State ND
3a.	SAIDI value including Major Event days	68.190
3b.	SAIDI value excluding Major Event days	52.360
4	SAIDI value including Major Event days minus loss of supply	61.890
5a.	SAIFI value including Major Event days	0.560
5b.	SAIFI value excluding Major Event days	0.490
6.	SAIFI value including Major Event days minus loss of supply	0.500
7.	Total number of customers used in these calculations	92,389.0
8.	What is the highest voltage that you consider part of the distribution system, as opposed to the supply system? (kV)	34.5
9.	Do you receive information about a customer outage in advance of a customer reporting it?	[x] Yes [ ] No

Thank You for completing this part. Skip Part C and go directly to Schedule 4 Part A.

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Part C: SAIDI and SAIFI calculated by other methods

	State			
10a. SAIDI value including Major Events				
10b. SAIDI value excluding Major Events				
11a. SAIFI value including Major Events				
11b. SAIFI value excluding Major Events				
12. Total number of customers used in these calculations				
13. Do you include inactive accounts?	☐ Yes	☐ No		
14. How do you define momentary interruptions	☐ Less than 1 min.	☐ Less than 5 min.	☐ Other	
15. What is the highest voltage that you consider part of the distribution system, as opposed to the supply system?	kv			
16. Is information about customer outages recorded automatically?	☐ Yes	☐ No		

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SCHEDULE 4. PART A. SALES TO ULTIMATE CUSTOMERS. FULL SERVICE - ENERGY AND DELIVERY SERVICE (BUNDLED)

	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
State MN **Balancing Authority**	56669				
Revenue (thousand dollars)	1,259,859.4	1,412,579.2	661,416.1	2,474.8	3,336,329.5
Megawatthours	8,905,592	13,390,272	8,127,676	25,832	30,449,372
Number of Customers	1,149,958	139,539	506	1	1,290,004
Are your rates decoupled?	[x] Yes [ ] No	[x] Yes [ ] No	[ ] Yes [x] No	[ ] Yes [x] No	
If the answer is YES, is the revenue adjustment automatic or does it require a rate-making proceeding?	[N] automatic	[N] automatic	[N] automatic	[N] automatic	
	[N] proceeding	[N] proceeding	[N] proceeding	[N] proceeding	
Cents/Kwh	14.147	10.549	8.138	9.580	10.957
State ND **Balancing Authority**	56669				
Revenue (thousand dollars)	82,604.4	101,127.4	26,819.8		210,551.6
Megawatthours	794,324	1,098,791	371,963		2,265,078
Number of Customers	80,998	13,191	23		94,212
Are your rates decoupled?	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No	
If the answer is YES, is the revenue adjustment automatic or does it require a rate-making proceeding?	[N] automatic	[N] automatic	[N] automatic	[N] automatic	
	[N] proceeding	[N] proceeding	[N] proceeding	[N] proceeding	
Cents/Kwh	10.399	9.204	7.210		9.296

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SCHEDULE 4. PART A. SALES TO ULTIMATE CUSTOMERS. FULL SERVICE - ENERGY AND DELIVERY SERVICE (BUNDLED)

	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
State SD **Balancing Authority**	56669				
Revenue (thousand dollars)	95,263.1	102,067.0	29,704.3		227,034.4
Megawatthours	776,420	1,039,733	377,468		2,193,621
Number of Customers	82,144	12,160	24		94,328
Are your rates decoupled?	☐ Yes ☒ No	☐ Yes ☒ No	☐ Yes ☒ No	☐ Yes ☒ No	
If the answer is YES, is the revenue adjustment automatic or does it require a rate-making proceeding?	[N] automatic	[N] automatic	[N] automatic	[N] automatic	
	[N] proceeding	[N] proceeding	[N] proceeding	[N] proceeding	
Cents/Kwh	12.270	9.817	7.869		10.350
State					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Are your rates decoupled?					
If the answer is YES, is the revenue adjustment automatic or does it require a rate-making proceeding?					
Cents/Kwh					
Total					
Revenue (thousand dollars)	1,437,726.9	1,615,773.6	717,940.2	2,474.8	3,773,915.5
Megawatthours	10,476,336	15,528,796	8,877,107	25,832	34,908,071
Number of Customers	1,313,100	164,890	553	1	1,478,544

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SCHEDULE 4. PART B. SALES TO ULTIMATE CUSTOMERS. ENERGY -- ONLY SERVICE (WITHOUT DELIVERY SERVICE)

	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
State	**Balancing Authority**				
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					
State					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					
Total					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					

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SCHEDULE 4. PART C. SALES TO ULTIMATE CUSTOMERS. DELIVERY -- ONLY SERVICE (AND OTHER RELATED CHARGES)

	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
State **Balancing Authority**					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					
State					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					

Total
Revenue (thousand dollars)
Megawatthours
Number of Customers

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SCHEDULE 4. PART D. BUNDLED SERVICE BY RETAIL ENERGY PROVIDERS AND POWER MARKETERS

	RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANSPORTATION (d)	TOTAL (e)
State	**Balancing Authority**				
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					
State					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					
Cents/Kwh					
Total					
Revenue (thousand dollars)					
Megawatthours					
Number of Customers					

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SCHEDULE 5. MERGERS and/or ACQUISITIONS

Mergers and/or acquisitions during the reporting month

If Yes, Provide:

Date of Merger or Acquisition

Company merged with or acquired

Name of new parent company

Address

City

State, Zip

New Contact Name

Telephone No.

Email address

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SCHEDULE 6. PART A. ENERGY EFFICIENCY PROGRAMS
Adjusted Gross Energy and Demand Savings -- Energy Efficiency

If you have a non utility DSM administrator that reports your DSM activity for you please select them from the list

State/Territory **MN** **Balancing Authority** **56669**

		RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANS (d)	Total (e)
	Reporting Year Incremental Annual Savings					
1	Energy Savings (MWh)	185,418.428	379,316.999	67,278.587	0.000	632,014.014
2	Peak Demand Savings (MW)	30.807	62.249	7.698	0.000	100.754
	Increment Life Cycle Savings					
3	Energy Savings (MWh)	1232501.215	5,967,875.992	1,128,873.154	0.000	8,329,250.361
4	Peake Demand Savings (MW)	30.807	62.249	7.698	0.000	100.754
	Reporting Year Incremental Costs					
5	Customer Incentives	14,312.040	39,190.754	4,765.265	0.000	58,268.059
6	All other costs	10,267.469	26,350.916	3,307.063	0.000	39,925.448
	Incremental Life Sycle Costs					
7	Customer Incentives	14,312.040	39,190.754	4,765.265	0.000	58,268.059
8	All other costs	10,267.469	26,350.916	3,307.063	0.000	39,925.448
	Weighted Average Life for Portfolio (Years) - Use Spreadsheet to Calculate					
9	Weighted Average Life	6.647	15.733	16.779		39.000

Please provide website address to your energy efficiency program reports:

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SCHEDULE 6. PART A. ENERGY EFFICIENCY PROGRAMS
Adjusted Gross Energy and Demand Savings -- Energy Efficiency

State/Territory **SD** **Balancing Authority** **56669**

		RESIDENTIAL (a)	COMMERCIAL (b)	INDUSTRIAL (c)	TRANS (d)	Total (e)
	Reporting Year Incremental Annual Savings					
1	Energy Savings (MWh)	2,426.884	3,332.874			5,759.758
2	Peak Demand Savings (MW)	0.258	0.469			0.727
	Increment Life Cycle Savings					
3	Energy Savings (MWh)	12768.236	56,069.636			68,837.872
4	Peake Demand Savings (MW)	0.258	0.469			0.727
	Reporting Year Incremental Costs					
5	Customer Incentives	71.587	331.051			402.638
6	All other costs	68.959	71.494			140.453
	Incremental Life Sycle Costs					
7	Customer Incentives	71.587	331.051			402.638
8	All other costs	68.959	71.494			140.453
	Weighted Average Life for Portfolio (Years) - Use Spreadsheet to Calculate					
9	Weighted Average Life	5.261	16.823			22.000

Please provide website address to your energy efficiency program reports:

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SCHEDULE 6. PART A. ENERGY EFFICIENCY PROGRAMS

DMS Administration only. List all utilities that you provide service for.

State	Utility Name

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Schedule 6. Part B. Yearly Energy and Demand Savings - Demand Response

Reporting Year Savings

State/Territory **MN** **Balancing Authority** **56669**

		(a) Residential	(b) Commercial	(c) Industrial	(d) Transportation	(e) Total
1	Number of Customers Enrolled	424,571	18,503	218		443,292
2	Energy Savings (Mwh)	655.000	434.494	92.690		1,182.184
3	Potential Peak Demand Savings (MW)	274.546	326.567	94.045		695.158
4	Actual Peak Demand Savings (MW)	0.000	0.000	0.000		0.000

Schedule 6. Part B. Program Cost -- Demand Response (Thousand Dollars)

Reporting Year Costs

5	Customer Incentives	28,450.910	25,642.093	1,252.901		55,345.904
6	All other costs	6,414.000	2,064.255	525.103		9,003.358

7 If you have a demand side management (DMS) program for grid-interactive water heaters (as defined by DOE), how many grid interactive water heaters were added to your program this year?

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Schedule 6. Part B. Yearly Energy and Demand Savings - Demand Response

Reporting Year Savings

State/Territory **ND** **Balancing Authority** **56669**

		(a) Residential	(b) Commercial	(c) Industrial	(d) Transportation	(e) Total
1	Number of Customers Enrolled	12,397	695	11		13,103
2	Energy Savings (Mwh)	16.426	15.000	0.000		31.426
3	Potential Peak Demand Savings (MW)	7.365	15.000	46.000		68.365
4	Actual Peak Demand Savings (MW)	0.000	0.000	0.000		0.000

Schedule 6. Part B. Program Cost -- Demand Response (Thousand Dollars)

Reporting Year Costs

5	Customer Incentives	871.474	1,053.600	2,458.400		4,383.474
6	All other costs	23.160	27.792	64.848		115.800
7	If you have a demand side management (DMS) program for grid-interactive water heaters (as defined by DOE), how many grid interactive water heaters were added to your program this year?					

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Schedule 6. Part B. Yearly Energy and Demand Savings - Demand Response

Reporting Year Savings

State/Territory SD	Balancing Authority 56669	(a) Residential	(b) Commercial	(c) Industrial	(d) Transportation	(e) Total
1	Number of Customers Enrolled	20,057	685	3		20,745
2	Energy Savings (Mwh)	22.118	16.050	0.000		38.168
3	Potential Peak Demand Savings (MW)	10.844	16.050	6.010		32.904
4	Actual Peak Demand Savings (MW)	0.000	0.000	0.000		0.000

Schedule 6. Part B. Program Cost -- Demand Response (Thousand Dollars)

Reporting Year Costs

5	Customer Incentives	1,521.316	910.695	384.610		2,816.621
6	All other costs	185.090	48.725	3.876		237.691
7	If you have a demand side management (DMS) program for grid-interactive water heaters (as defined by DOE), how many grid interactive water heaters were added to your program this year?					

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SCHEDULE 6. PART C. DYNAMIC PRICING PROGRAMS

Number of Customers

INSTRUCTIONS: Report the number of customers participating in dynamic pricing programs, e.g. Time-of-Use-Pricing, Real-Time-Pricing, Variable Peak Pricing, Critical Peak Pricing Programs.

State/Territory SD Balancing Authority 56669

		Residential (a)	Commercial (b)	Industrial (c)	Transportatio (d)	Total (e)
1	Number of Customers enrolled in dynamic pricing programs, by customer class	9	675	0		684

Types of Dynamic Pricing Programs

INSTRUCTIONS: For each customer class, mark the types of dynamic pricing programs in which the customers are participating.

		Residential (a)	Commercial (b)	Industrial (c)	Transportatio (d)
2	Time-of-Use Pricing	[x] Yes [ ] No	[x] Yes [ ] No	[x] Yes [ ] No	[ ] Yes [x] No
3	Real-Time Pricing	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No
4	Variable Peak Pricing	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No
5	Critical Peak Pricing	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No
6	Critical Peak Rebate	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No

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SCHEDULE 6. PART C. DYNAMIC PRICING PROGRAMS

Number of Customers

INSTRUCTIONS: Report the number of customers participating in dynamic pricing programs, e.g. Time-of-Use-Pricing, Real-Time-Pricing, Variable Peak Pricing, Critical Peak Pricing Programs.

State/Territory MN Balancing Authority 56669

		Residential (a)	Commercial (b)	Industrial (c)	Transportatio (d)	Total (e)
1	Number of Customers enrolled in dynamic pricing programs, by customer class	1,021	15,647	26	1	16,695

Types of Dynamic Pricing Programs

INSTRUCTIONS: For each customer class, mark the types of dynamic pricing programs in which the customers are participating.

		Residential (a)	Commercial (b)	Industrial (c)	Transportatio (d)
2	Time-of-Use Pricing	[x] Yes [ ] No	[x] Yes [ ] No	[x] Yes [ ] No	[x] Yes [ ] No
3	Real-Time Pricing	[ ] Yes [x] No	[x] Yes [ ] No	[x] Yes [ ] No	[ ] Yes [x] No
4	Variable Peak Pricing	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No
5	Critical Peak Pricing	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No
6	Critical Peak Rebate	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No

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SCHEDULE 6. PART C. DYNAMIC PRICING PROGRAMS

Number of Customers

INSTRUCTIONS: Report the number of customers participating in dynamic pricing programs, e.g. Time-of-Use-Pricing, Real-Time-Pricing, Variable Peak Pricing, Critical Peak Pricing Programs.

State/Territory **ND** **Balancing Authority** **56669**

		Residential (a)	Commercial (b)	Industrial (c)	Transportatio (d)	Total (e)
1	Number of Customers enrolled in dynamic pricing programs, by customer class	35	831			866

Types of Dynamic Pricing Programs

INSTRUCTIONS: For each customer class, mark the types of dynamic pricing programs in which the customers are participating.

		Residential (a)	Commercial (b)	Industrial (c)	Transportatio (d)
2	Time-of-Use Pricing	[x] Yes [ ] No	[x] Yes [ ] No	[x] Yes [ ] No	[ ] Yes [x] No
3	Real-Time Pricing	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No
4	Variable Peak Pricing	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No
5	Critical Peak Pricing	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No
6	Critical Peak Rebate	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No	[ ] Yes [x] No

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SCHEDULE 6. PART D. ADVANCED METERING

Only customers from schedule 4A and 4C need to be reported on this schedule.
AMR- data transmitted one-way, to the utility.
AMI- data transmitted in both directions, to the utility and customer

State MN Balancing Authority 56669

		Residential (a)	Commercial (b)	Industrial (c)	Transportation (d)	Total (e)
1	Number of AMR Meters	1,170,629	127,918	11,451	15	1,310,013
2	Number of AMI Meters					
3	Number of AMI Meters with home area network (HAN) gateway enabled					
4	Number of non AMR/AMI Meters	22	1,596	278	1	1,897
5	Total Number of Meters (All Types), line 1+2+4	1,170,651	129,514	11,729	16	1,311,910
6	Energy Served Through AMI					
7	Number of Customers able to access daily energy usage through a webportal or other electronic means					0
8	Number of customers with direct load control	391,361	13,916	1,395		406,672

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SCHEDULE 6. PART D. ADVANCED METERING

Only customers from schedule 4A and 4C need to be reported on this schedule.
AMR- data transmitted one-way, to the utility.
AMI- data transmitted in both directions, to the utility and customer

State ND **Balancing Authority 56669**

		Residential (a)	Commercial (b)	Industrial (c)	Transportation (d)	Total (e)
1	Number of AMR Meters	82,526	13,001	542		96,069
2	Number of AMI Meters					
3	Number of AMI Meters with home area network (HAN) gateway enabled					
4	Number of non AMR/AMI Meters	0	33	4		37
5	Total Number of Meters (All Types), line 1+2+4	82,526	13,034	546		96,106
6	Energy Served Through AMI					
7	Number of Customers able to access daily energy usage through a webportal or other electronic means					0
8	Number of customers with direct load control	12,359	516	20		12,895

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SCHEDULE 6. PART D. ADVANCED METERING

Only customers from schedule 4A and 4C need to be reported on this schedule.
AMR- data transmitted one-way, to the utility.
AMI- data transmitted in both directions, to the utility and customer

State SD Balancing Authority 56669

		Residential (a)	Commercial (b)	Industrial (c)	Transportation (d)	Total (e)
1	Number of AMR Meters	83,892	12,093	398		96,383
2	Number of AMI Meters					0
3	Number of AMI Meters with home area network (HAN) gateway enabled					
4	Number of non AMR/AMI Meters	0	2	0		2
5	Total Number of Meters (All Types), line 1+2+4	83,892	12,095	398		96,385
6	Energy Served Through AMI					
7	Number of Customers able to access daily energy usage through a webportal or other electronic means					0
8	Number of customers with direct load control	19,771	514	32		20,317

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SCHEDULE 7. PART A. NET METERING

Net Metering programs allow customers to sell excess power they generated back to the electrical grid to offset consumption. Provide the information about programs by State balancing authority, customer class, and technology for all net metering applications.

State	MN	Balancing Authority	56669	Residential (a)	Commercial (b)	Industrial (c)	Transportation (d)	Total (e)
	Net Metering Installed Capacity (MW)			19.087	16.966	8.121		44.174
	Net Metering Installations			2,595	632	168		3,395
	Storage Installed Capacity (MW)							
	Storage Installations							
Photovoltaic	Virtual NM Installed Capacity (1 MW and greater)							
	Virtual NM Customers (1 MW and greater)							
	Virtual NM Installed Capacity (less than 1MW)							
	Virtual NM Customers (less than 1MW)							
	If Available, Enter the Electric Energy Sold Back to the Utility (MWh)							0.000
	Installed Net Metering Capacity (MW)							0.000
Wind	Number of Net Metering Customers							0
	If Available, Enter the Electric Energy Sold Back to the Utility (MWh)							0.000
	Installed Net Metering Capacity (MW)							0.000
Other	Number of Net Metering Customers							0
	If Available, Enter the Electric Energy Sold Back to the Utility (MWh)							0.000
	Installed Net Metering Capacity (MW)			19.087	16.966	8.121	0.000	44.174
Total	Number of Net Metering Customers			2,595	632	168	0	3,395
	If Available, Enter the Electric Energy Sold Back to the Utility (MWh)			0.000	0.000	0.000	0.000	0.000
	Net Metering Installed Capacity (MW)			19.087	16.966	8.121	0	44.174
Grand Total All States	**Net Metering Installations/customers**			2595	632	168	0	3395
	If Available, Enter the Electric Energy Sold Back to the Utility (MWh)			0	0	0	0	0

7610.0600 F

US Department of Energy Energy Information Administration Form EIA-861	ANNUAL ELECTRIC POWER INDUSTRY REPORT	Form Approved OMB No. 1905-0129 Approved Expires 03/31/2020

REPORT FOR Northern States Power Co - Minnesota

REPORT PERIOD ENDING:

SCHEDULE 7. PART B. NON NET-METERED DISTRIBUTED GENERATORS

If your company owns and/or operates a distribution system, please report information on known distributed generation (grid connected/synchronized) capacity on the system. Such capacity must be utility or customer-owned

NUMBER AND CAPACITY

State	**Balancing Authority**	< 1MW

1. Number of generators	3. Capacity that consists of backup-only units
2. Total combined capacity (MW)	4. Capacity owned by respondent

Capacity by Technology and Sector (MW)

	Residential	**Commercial**	**Industrial**	**Transportation**	**Direct Connected**	**Total**
5. Internal combustion						
6. Combustion turbine(s)						
7. Steam turbine(s)						
8. Fuel Cell(s)						
9. Hydroelectric						
10, Photovoltaic						
11. Storage						
12. Wind turbine(s)						
13. Other						
14. Total						

7610.0600 F

US Department of Energy Energy Information Administration Form EIA-861	ANNUAL ELECTRIC POWER INDUSTRY REPORT	Form Approved OMB No. 1905-0129 Approved Expires 03/31/2020

REPORT FOR: Northern States Power Co - Minnesota 13781

REPORT PERIOD ENDING: 2018

SCHEDULE 8. DISTRIBUTION SYSTEM INFORMATION

If your company owns a distribution system, please identify the names of the counties (parish, etc.) by State in which the electric wire/equipment are located.

LINE NO.	STATE (US Postal Abbreviation) (a)	COUNTY (Parish, Etc.) (b)	LINE NO.	STATE (US Postal Abbreviation) (a)	COUNTY (Parish, Etc.) (b)
1	MN - Anoka		21	MN - Lyon	
2	MN - Benton		22	MN - McLeod	
3	MN - Blue Earth		23	MN - Meeker	
4	MN - Brown		24	MN - Mower	
5	MN - Carver		25	MN - Murray	
6	MN - Chippewa		26	MN - Nicollet	
7	MN - Chisago		27	MN - Nobles	
8	MN - Clay		28	MN - Norman	
9	MN - Dakota		29	MN - Olmsted	
10	MN - Dodge		30	MN - Pine	
11	MN - Douglas		31	MN - Pipestone	
12	MN - Faribault		32	MN - Polk	
13	MN - Freeborn		33	MN - Pope	
14	MN - Goodhue		34	MN - Ramsey	
15	MN - Hennepin		35	MN - Redwood	
16	MN - Houston		36	MN - Renville	
17	MN - Kandiyohi		37	MN - Rice	
18	MN - Lac Qui Parle		38	MN - Rock	
19	MN - Le Sueur		39	MN - Scott	
20	MN - Lincoln		40	MN - Sherburne	

7610.0600 F

US Department of Energy Energy Information Administration Form EIA-861	ANNUAL ELECTRIC POWER INDUSTRY REPORT	Form Approved OMB No. 1905-0129 Approved Expires 03/31/2020

REPORT FOR: Northern States Power Co - Minnesota 13781

REPORT PERIOD ENDING: 2018

SCHEDULE 8. DISTRIBUTION SYSTEM INFORMATION

If your company owns a distribution system, please identify the names of the counties (parish, etc.) by State in which the electric wire/equipment are located.

LINE NO.	STATE (US Postal Abbreviation) (a)	COUNTY (Parish, Etc.) (b)	LINE NO.	STATE (US Postal Abbreviation) (a)	COUNTY (Parish, Etc.) (b)
41	MN - Sibley		61	SD - Lincoln	
42	MN - Stearns		62	SD - McCook	
43	MN - Steele		63	SD - Miner	
44	MN - Todd		64	SD - Minnehaha	
45	MN - Wabasha		65	SD - Moody	
46	MN - Waseca		66	SD - Sanborn	
47	MN - Washington		67	SD - Turner	
48	MN - Watonwan				
49	MN - Wilkin				
50	MN - Winona				
51	MN - Wright				
52	MN - Yellow Medicine				
53	ND - Cass				
54	ND - Grand Forks				
55	ND - McHenry				
56	ND - Traill				
57	ND - Ward				
58	SD - Hanson				
59	SD - Hutchinson				
60	SD - Lake				

7610.0600 F

US Department of Energy Energy Information Administration Form EIA-861	ANNUAL ELECTRIC POWER INDUSTRY REPORT	Form Approved OMB No. 1905-0129 Approved Expires 03/31/2020

REPORT FOR: Northern States Power Co - Minnesota 13781

REPORT PERIOD ENDING: 2018

SCHEDULE 9. COMMENTS

SCHEDULE	PART	LINE NO.	COLUMN	NOTES
(a)	(b)	(c)	(d)	(e)

7610.0600 F

US Department of Energy Energy Information Administration Form EIA-861	ANNUAL ELECTRIC POWER INDUSTRY REPORT	Form Approved OMB No. 1905-0129 Approved Expires 03/31/2020

REPORT FOR: Northern States Power Co - Minnesota 13781

REPORT PERIOD ENDING: 2018

EIA861 ERROR LOG

Part		State	BA ID	Error No.	Error Description/Override Comment	Type	Override
6	D	MN	56669	6045	Commercial Meter counts (Line 5) cannot be less than Commercial Customers (4A+4C). Advanced Meters (AMR/AMI) or non-AMR/AMI - "Standard Meters" (Line 4) maybe be missing. Please provide revised data. The difference between meter count data by customer class on Schedule 6 of the Form 861 and customer count data by customer class on Schedule 4 of the Form 861 is due to reporting differences between the metering departments and the department that handles the customer count information. The metering departments have their information disaggregated with more detail by customer class (which also would encompass premise locations), whereas the department that handles customer count has the information only available by residential and C&I. In preparation of the Form 861, we do our best to split out commercial and industrial customer count data from the `C&I? bucket, but due to the fact that this customer count reporting is designed for our billing and FERC reporting and the metering data is at a much different level of detail, there are differences between the two.	W	
6	D	SD	0	6111	The number of Industrial customers with direct load control on line 8 cannot be greater than number of Industrial customers on 4A plus 4C. Please provide revised data. The difference between meter count data by customer class on Schedule 6 of the Form 861 and customer count data by customer class on Schedule 4 of the Form 861 is due to reporting differences between the metering departments and the department that handles the customer count information. The metering departments have their information disaggregated with more detail by customer class (which also would encompass premise locations), whereas the department that handles customer count has the information only available by residential and C&I. In preparation of the Form 861, we do our best to split out commercial and industrial customer count data from the `C&I? bucket, but due to the fact that this customer count reporting is designed for our billing and FERC reporting and the metering data is at a much different level of detail, there are differences between the two.	W	
6	D	MN	0	6111	The number of Industrial customers with direct load control on line 8 cannot be greater than number of Industrial customers on 4A plus 4C. Please provide revised data. The difference between meter count data by customer class on Schedule 6 of the Form 861 and customer count data by customer class on Schedule 4 of the Form 861 is due to reporting differences between the metering departments and the department that handles the customer count information. The metering departments have their information disaggregated with more detail by customer class (which also would encompass premise locations), whereas the department that handles customer count has the information only available by residential and C&I. In preparation of the Form 861, we do our best to split out commercial and industrial customer count data from the `C&I? bucket, but due to the fact that this customer count reporting is designed for our billing and FERC reporting and the metering data is at a much different level of detail, there are differences between the two.	W	

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION

INSTRUCTIONS

These worksheet tabs correspond closely to the tables in the forecast instructions received by the utility.
The forecast instructions pertain to the data to be entered in each of the worksheet tabs.
PLEASE DO NOT CHANGE THE **NAME** OR **ORDER** OF ANY OF THE WORKSHEET TABS OR CHANGE THE NAME OF THIS WORKBOOK.

In general, the following color scheme is used on each worksheet:
Cells shown with a light green background correspond to headings for sections, columns, row, or individual fields on each worksheet tab.
Cells shown with a light yellow background require data to be entered by the utility.
Cells shown with a light brown background generally correspond to fields that are calculated from the data entered, or correspond to fields that are informational and not to be modified by the utility.

Each worksheet tab contains a section labeled "Comments" below the main data entry area.
You may enter any comments in that section to provide an explaination or clarification on the data entered; OR why data IS NOT being entered on the worksheet tab (for example: cells left blank).

Cells with automatic calculations (typically totals) are provided on some worksheets to assist with the accuracy of the data provided by the utility. It is recognized that there may be circumstances in which the data entered by the utility is more appropriate or accurate than the value in the corresponding automatically-calculated cell. If the value in the automatically-calculated cell does not match the value that your utility entered, please provide an explanation in the Comments area at the bottom of the worksheet tab.

Please complete the required worksheet tabs and save the completed workbook to your local computer.
Then attach the completed workbook to an email message, include your contact information, and send it to the following email address:
rule7610.reports@state.mn.us

If you have any questions please contact:
Anne Sell
MN Department of Commerce
rule7610.reports@state.mn.us
(651) 539-1851

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT - FORECAST SECTION

7610.0120 REGISTRATION

ENTITY ID#	85
REPORT YEAR	2018

RILS ID#	

UTILITY DETAILS	
UTILITY NAME	Xcel Energy
STREET ADDRESS	414 Nicollet Mall
CITY	Minneapolis
STATE	MN
ZIP CODE	55401
TELEPHONE	612-330-5500
	Scroll down to see allowable UTILITY TYPES
* UTILITY TYPE	PRIVATE

CONTACT INFORMATION	
CONTACT NAME	Jim G. Erickson
CONTACT TITLE	Regulatory Administrator
CONTACT STREET ADDRESS	414 Nicollet Mall
CITY	Minneapolis
STATE	MN
ZIP CODE	55401
TELEPHONE	612-330-5821
CONTACT E-MAIL	regulatory.records@xcelenergy.com

COMMENTS

PREPARER INFORMATION	(do not type "Same as Above")
PERSON PREPARING FORMS	Jim G. Erickson
PREPARER'S TITLE	Regulatory Administrator
DATE	7/1/2019
PREPARER'S EMAIL ADDRESS	jim.g.erickson@xcelenergy.com

ALLOWABLE UTILITY TYPES

Code

Private
Public
Co-op

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item A. SYSTEM FORECAST OF ANNUAL ELECTRIC CONSUMPTION BY ULTIMATE CONSUMERS

Provide actual data for your entire system for the past year, your estimate for the present year and all future forecast years.
Please remember that the number of customers *should reflect the* ***number of customers*** *at year's end,* ***not the number of meters*** .

			FARM	NON-FARM RESIDENTIAL	COMMERCIAL	MINING *	INDUSTRIAL	STREET & HIGHWAY LIGHTING	OTHER	SYSTEM TOTALS	Calculated System Totals
Past Year	2018	No. of Customers	NA	1,536,955	197,854	NA	684	6703	2,630	1,744,826	1,744,826
		MWH	NA	12,434,988	18,293,536	NA	10,905,955	157,682	103,874	41,896,034	41,896,034
Present Year	2019	No. of Customers	NA	1,547,758	198,048	NA	672	6717	2,646	1,755,841	1,755,841
		MWH	NA	11,942,905	18,038,023	NA	10,330,543	143655.4094	100,165	40,555,291	40,555,291
1st Forecast Year	2020	No. of Customers	NA	1,558,697	199,068	NA	669	6842	2,644	1,767,920	1,767,920
		MWH	NA	11,985,316	18,014,457	NA	10,361,957	145080.1597	100,228	40,607,039	40,607,039
2nd Forecast Year	2021	No. of Customers	NA	1,569,632	200,148	NA	666	6970	2,643	1,780,059	1,780,059
		MWH	NA	11,983,172	17,866,313	NA	10,222,132	146280.825	100,268	40,318,165	40,318,165
3rd Forecast Year	2022	No. of Customers	NA	1,580,700	201,208	NA	665	7097	2,640	1,792,310	1,792,310
		MWH	NA	12,061,607	17,797,968	NA	10,176,075	147534.9319	100,359	40,283,544	40,283,544
4th Forecast Year	2023	No. of Customers	NA	1,591,407	202,249	NA	661	7210	2,638	1,804,165	1,804,165
		MWH	NA	12,157,892	17,671,921	NA	10,072,026	148708.587	100,372	40,150,920	40,150,920
5th Forecast Year	2024	No. of Customers	NA	1,601,803	203,275	NA	660	7322	2,635	1,815,695	1,815,695
		MWH	NA	12,261,830	17,594,660	NA	10,064,492	149913.4386	100,386	40,171,281	40,171,281
6th Forecast Year	2025	No. of Customers	NA	1,611,985	204,284	NA	657	7431	2,635	1,826,992	1,826,992
		MWH	NA	12,262,809	17,465,133	NA	10,030,437	150935.2908	100,390	40,009,704	40,009,704
7th Forecast Year	2026	No. of Customers	NA	1,622,287	205,270	NA	656	7538	2,632	1,838,383	1,838,383
		MWH	NA	12,312,077	17,412,745	NA	10,046,935	152017.7383	100,457	40,024,232	40,024,232
8th Forecast Year	2027	No. of Customers	NA	1,632,517	206,227	NA	655	7644	2,630	1,849,673	1,849,673
		MWH	NA	12,372,901	17,465,722	NA	10,121,723	153079.8681	100,454	40,213,881	40,213,881
9th Forecast Year	2028	No. of Customers	NA	1,642,629	207,148	NA	653	7744	2,627	1,860,801	1,860,801
		MWH	NA	12,535,991	17,673,405	NA	10,294,362	154207.4711	100,457	40,758,422	40,758,422
10th Forecast Year	2029	No. of Customers	NA	1,651,718	208,046	NA	651	7842	2,626	1,870,883	1,870,883
		MWH	NA	12,462,524	17,621,591	NA	10,304,757	155138.5235	100,454	40,644,464	40,644,464
11th Forecast Year	2030	No. of Customers	NA	1,660,922	208,925	NA	650	7936	2,623	1,881,056	1,881,056
		MWH	NA	12,448,614	17,692,261	NA	10,386,909	156128.1351	100,517	40,784,429	40,784,429
12th Forecast Year	2031	No. of Customers	NA	1,670,942	209,781	NA	647	8028	2,621	1,892,019	1,892,019
		MWH	NA	12,449,720	17,694,527	NA	10,414,625	157092.1712	100,510	40,816,475	40,816,475
13th Forecast Year	2032	No. of Customers	NA	1,681,204	210,621	NA	647	8116	2,618	1,903,206	1,903,206
		MWH	NA	12,619,658	17,847,807	NA	10,536,100	158123.6264	100,511	41,262,200	41,262,200
14th Forecast Year	2033	No. of Customers	NA	1,691,977	211,445	NA	645	8202	2,617	1,914,886	1,914,886
		MWH	NA	12,710,020	17,891,801	NA	10,595,363	158952.593	100,508	41,456,643	41,456,643

* MINING needs to be reported as a separate category only if annual sales are greater than 1,000 GWH. Otherwise, include MINING in the INDUSTRIAL category.

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item A. MINNESOTA-ONLY FORECAST OF ANNUAL ELECTRIC CONSUMPTION BY ULTIMATE CONSUMERS

Provide actual data for your Minnesota service area only, for the past year, your best estimate for the present year and all future forecast years.
Please remember that the number of customers should reflect the ***actual number of customers*** the utility has in that category at year's end, ***not the number of meters*** .

			FARM	NON-FARM RESIDENTIAL	COMMERCIAL	MINING *	INDUSTRIAL	STREET & HIGHWAY LIGHTING	OTHER	MN-ONLY TOTALS	Calculated MN-Only Totals
Past Year	2018	No. of Customers	NA	1,154,330	132,981	NA	511	5207	2,039	1,295,068	1,295,068
		MWH	NA	8,905,592	13,225,312	NA	8,127,676	113,974	76,819	30,449,373	30,449,373
Present Year	2019	No. of Customers	NA	1,162,246	133,069	NA	500	5232	2,047	1,303,094	1,303,094
		MWH	NA	8,549,795	13,033,694	NA	7,596,799	98755.20742	73,873	29,352,916	29,352,916
1st Forecast Year	2020	No. of Customers	NA	1,170,594	133,617	NA	496	5342	2,048	1,312,097	1,312,097
		MWH	NA	8,580,360	13,009,693	NA	7,621,983	99779.33861	73,901	29,385,717	29,385,717
2nd Forecast Year	2021	No. of Customers	NA	1,178,991	134,235	NA	493	5455	2,048	1,321,222	1,321,222
		MWH	NA	8,582,413	12,880,831	NA	7,492,870	100738.2331	73,958	29,130,810	29,130,810
3rd Forecast Year	2022	No. of Customers	NA	1,187,544	134,842	NA	490	5566	2,048	1,330,490	1,330,490
		MWH	NA	8,645,744	12,823,852	NA	7,451,720	101673.0095	74,040	29,097,030	29,097,030
4th Forecast Year	2023	No. of Customers	NA	1,195,742	135,438	NA	486	5664	2,048	1,339,378	1,339,378
		MWH	NA	8,719,027	12,704,464	NA	7,350,305	102526.8213	74,043	28,950,367	28,950,367
5th Forecast Year	2024	No. of Customers	NA	1,203,592	136,023	NA	484	5761	2,048	1,347,908	1,347,908
		MWH	NA	8,794,994	12,624,021	NA	7,337,448	103325.206	74,020	28,933,808	28,933,808
6th Forecast Year	2025	No. of Customers	NA	1,211,250	136,597	NA	481	5855	2,049	1,356,232	1,356,232
		MWH	NA	8,803,159	12,515,616	NA	7,315,019	104106.1487	74,041	28,811,941	28,811,941
7th Forecast Year	2026	No. of Customers	NA	1,219,069	137,159	NA	479	5947	2,049	1,364,703	1,364,703
		MWH	NA	8,845,220	12,475,960	NA	7,337,342	104867.4499	74,098	28,837,488	28,837,488
8th Forecast Year	2027	No. of Customers	NA	1,226,941	137,711	NA	477	6037	2,049	1,373,215	1,373,215
		MWH	NA	8,895,092	12,536,567	NA	7,415,682	105608.0914	74,084	29,027,034	29,027,034
9th Forecast Year	2028	No. of Customers	NA	1,234,690	138,250	NA	474	6123	2,049	1,381,586	1,381,586
		MWH	NA	9,036,101	12,740,176	NA	7,583,928	106324.3488	74,048	29,540,578	29,540,578
10th Forecast Year	2029	No. of Customers	NA	1,241,548	138,778	NA	472	6206	2,049	1,389,053	1,389,053
		MWH	NA	8,964,190	12,692,816	NA	7,604,160	107016.1623	74,061	29,442,242	29,442,242
11th Forecast Year	2030	No. of Customers	NA	1,248,568	139,294	NA	470	6286	2,049	1,396,667	1,396,667
		MWH	NA	8,940,379	12,756,096	NA	7,689,234	107683.1893	74,112	29,567,504	29,567,504
12th Forecast Year	2031	No. of Customers	NA	1,256,323	139,798	NA	467	6363	2,049	1,405,000	1,405,000
		MWH	NA	8,929,843	12,740,474	NA	7,716,456	108324.4846	74,093	29,569,190	29,569,190
13th Forecast Year	2032	No. of Customers	NA	1,264,195	140,289	NA	465	6437	2,049	1,413,435	1,413,435
		MWH	NA	9,077,282	12,864,085	NA	7,829,084	108940.0421	74,055	29,953,445	29,953,445
14th Forecast Year	2033	No. of Customers	NA	1,272,602	140,769	NA	463	6508	2,049	1,422,391	1,422,391
		MWH	NA	9,169,642	12,906,129	NA	7,897,299	109532.5882	74,065	30,156,668	30,156,668

* MINING needs to be reported as a separate category only if annual sales are greater than 1,000 GWH. Otherwise, include MINING in the INDUSTRIAL category.

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

PUBLIC DOCUMENT - NOT PUBLIC (OR PRIVILEGED)
DATA HAS BEEN EXCISED

7610.0310 Item B. FORECAST OF ANNUAL SYSTEM CONSUMPTION AND GENERATION DATA (Express in MWH)

NOTE: (Column 1 + Column 2) = (Column 3 + Column 5) - (Column 4 + Column 6)

It is recognized that there may be circumstances in which the data entered by the utility is more appropriate or accurate than the value in the corresponding automatically-calculated cell. If the value in the automatically-calculated cell does not match the value that your utility entered, please provide an explanation in the Comments area at the bottom of the worksheet tab.

		Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	CALCULATED
		CONSUMPTION BY ULTIMATE CONSUMERS IN MINNESOTA MWH [7610.0310 B(1)]	CONSUMPTION BY ULTIMATE CONSUMERS OUTSIDE OF MINNESOTA MWH [7610.0310 B(2)]	RECEIVED FROM OTHER UTILITIES MWH [7610.0310 B(3)]	DELIVERED FOR RESALE MWH [7610.0310 B(4)]	TOTAL ANNUAL NET GENERATION MWH [7610.0310 B(5)]	TRANSMISSION LINE SUBSTATION AND DISTRIBUTION LOSSES MWH [7610.0310 B(6)]	TOTAL WINTER CONSUMPTION MWH [7610.0310 B(7)]	TOTAL SUMMER CONSUMPTION MWH [7610.0310 B(7)]	(GENERATION + RECEIVED) MINUS (RESALE + LOSSES) MINUS (CONSUMPTION) SHOULD EQUAL ZERO
				[TRADE SECRET DATA BEGINS						
Past Year	2018	30,449,373	11,446,661			39,923,909	3,091,456	19,898,550	21,997,484	0
Present Year	2019	29,352,916	11,202,375			36,624,555	3,167,790	19,538,273	21,017,018	0
1st Forecast Year	2020	29,385,717	11,221,322			38,296,862	3,173,676	19,621,722	20,985,317	0
2nd Forecast Year	2021	29,130,810	11,187,355			37,258,715	3,149,511	19,422,459	20,895,706	0
3rd Forecast Year	2022	29,097,030	11,186,514			37,595,824	3,146,689	19,404,758	20,878,786	0
4th Forecast Year	2023	28,950,367	11,200,553			38,613,171	3,136,475	19,339,502	20,811,418	0
5th Forecast Year	2024	28,933,808	11,237,473			37,098,272	3,139,909	19,411,224	20,760,058	0
6th Forecast Year	2025	28,811,941	11,197,764			38,561,145	3,125,444	19,272,714	20,736,991	0
7th Forecast Year	2026	28,837,488	11,186,744			38,579,947	3,126,313	19,278,780	20,745,452	0
8th Forecast Year	2027	29,027,034	11,186,847			37,356,187	3,140,575	19,370,617	20,843,263	0
9th Forecast Year	2028	29,540,578	11,217,844			37,162,324	3,183,763	19,694,912	21,063,510	0
10th Forecast Year	2029	29,442,242	11,202,222			36,564,217	3,172,830	19,579,080	21,065,384	0
11th Forecast Year	2030	29,567,504	11,216,925			36,746,696	3,183,129	19,647,074	21,137,354	0
12th Forecast Year	2031	29,569,190	11,247,285			37,484,504	3,185,237	19,662,702	21,153,772	0
13th Forecast Year	2032	29,953,445	11,308,754			37,952,071	3,220,712	19,939,747	21,322,453	0
14th Forecast Year	2033	30,156,668	11,299,975			38,158,838	3,233,036	19,971,422	21,485,221	0

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COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item C. PEAK DEMAND BY ULTIMATE CONSUMERS AT THE TIME OF ANNUAL SYSTEM PEAK (in MW)

		FARM	NON-FARM RESIDENTIAL	COMMERCIAL	MINING	INDUSTRIAL	STREET & HIGHWAY LIGHTING	OTHER	SYSTEM TOTALS	Calculated System Totals
Last Year Peak Day	2018	NA	2,875	3,831	NA	2,219	-	20	8,944	8944.0

7610.0310 Item D. PEAK DEMAND BY MONTH FOR THE LAST CALENDAR YEAR (in MW)

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
Last Year	2018	6,536	6,267	5,717	5,675	8,246	8,944	8,835	8,527	7,500	5,738	6,058	6,104

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

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7610.0310 Item E. PART 1: FIRM PURCHASES (Express in MegaWatts)

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Past Year	2018	Summer							
		Winter							
Present Year	2019	Summer							
		Winter							
1st Forecast Year	2020	Summer							
		Winter							
2nd Forecast Year	2021	Summer							
		Winter							
3rd Forecast Year	2022	Summer							
		Winter							
4th Forecast Year	2023	Summer							
		Winter							
5th Forecast Year	2024	Summer							
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6th Forecast Year	2025	Summer							
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9th Forecast Year	2028	Summer							
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NAME OF OTHER UTILITY =>				
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Present Year	2019	Summer		
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1st Forecast Year	2020	Summer		
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MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

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7610.0310 Item E. PART 2: FIRM SALES (Express in MegaWatts)

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		Winter								
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Present Year	2019	Summer	
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1st Forecast Year	2020	Summer	
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3rd Forecast Year	2022	Summer	
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COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

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7610.0310 Item F. PART 1: PARTICIPATION PURCHASES (Express in MegaWatts)

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NAME OF OTHER UTILITY =>										
Past Year	2018	Summer								
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Present Year	2019	Summer								
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1st Forecast Year	2020	Summer								
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7610.0310 Item F. PART 1: PARTICI

NAME OF OTHER UTILITY =>						
Past Year	2018	Summer				
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Present Year	2019	Summer				
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1st Forecast Year	2020	Summer				
		Winter				
2nd Forecast Year	2021	Summer				
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MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

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7610.0310 Item F. PART 2: PARTICIPATION SALES (Express in MegaWatts)

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Present Year	2019	Summer						
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12th Forecast Year	2031	Summer						
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13th Forecast Year	2032	Summer						
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		Winter						

COMMENTS

The sales values on this worksheet are accounted for in column 4 of the Load & Gen Cap worksheet.

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7610.0310 Item F. PART 2: PARTICIP DATA HAS BEEN EXCISED

NAME OF OTHER UTILITY =>				
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Present Year	2019	Summer		
		Winter		
1st Forecast Year	2020	Summer		
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2nd Forecast Year	2021	Summer		
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14th Forecast Year	2033	Summer		
		Winter		

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The sales values on th

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

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7610.0310 Item G. LOAD AND GENERATION CAPACITY (Express in MW)

			Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	Column 9	Column 10	Column 11	Column 12
			Generation Zonal Resource Credits (ZRCs)	Demand Response ZRCs	ZRC Purchases	ZRC Sales	Total ZRCs [1 + 2 + 3 - 4]	Forecasted Non-Coincident Peak Demand for NSP System	Energy Efficiency Adjustment to Base Demand Forecast	Adjusted Forecasted Non-Coincident Summer Peak Demand for NSP System [6 7]	Coincidence Factor with MISO Peak Demand	Forecasted Demand Coincident with MISO Peak [Summer: 8 x 9] [Winter: 6 x 9]	Firm Purchases	Firm Sales
			[PROTECTED DATA BEGINS											
Past Year	2018	Summer												
		Winter												
Present Year	2019	Summer												
		Winter												
1st Forecast Year	2020	Summer												
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14th Forecast Year	2033	Summer												
		Winter												

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7610.0310 Item G. LOAD AND GENERATI

			Column 13	Column 14	Column 14
			Total Load Serving Obligation [10 - 11 + 12]	Capacity Obligation (Column 13 plus planning reserves: 8.4% in 2018, and 7.9% in 2019 and beyond)	Total System Surplus/Deficit [5 - 14]
Past Year	2018	Summer			
		Winter			
Present Year	2019	Summer			
		Winter			
1st Forecast Year	2020	Summer			
		Winter			
2nd Forecast Year	2021	Summer			
		Winter			
3rd Forecast Year	2022	Summer			
		Winter			
4th Forecast Year	2023	Summer			
		Winter			
5th Forecast Year	2024	Summer			
		Winter			
6th Forecast Year	2025	Summer			
		Winter			
7th Forecast Year	2026	Summer			
		Winter			
8th Forecast Year	2027	Summer			
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9th Forecast Year	2028	Summer			
		Winter			
10th Forecast Year	2029	Summer			
		Winter			
11th Forecast Year	2030	Summer			
		Winter			
12th Forecast Year	2031	Summer			
		Winter			
13th Forecast Year	2032	Summer			
		Winter			
14th Forecast Year	2033	Summer			
		Winter			

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MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continue

7610.0310 Item H. ADDITIONS AND RETIREMENTS (Express in MW)

		ADDITIONS	RETIREMENTS
Past Year	2018		
Present Year	2019	654	76
1st Forecast Year	2020	222	76
2nd Forecast Year	2021	181	2
3rd Forecast Year	2022	4	8
4th Forecast Year	2023	451	50
5th Forecast Year	2024	4	847
6th Forecast Year	2025	4	1,165
7th Forecast Year	2026	4	211
8th Forecast Year	2027	1,053	1,185
9th Forecast Year	2028	4	36
10th Forecast Year	2029	4	15
11th Forecast Year	2030	646	610
12th Forecast Year	2031	204	47
13th Forecast Year	2032	325	273
14th Forecast Year	2033	848	508

COMMENTS

Additions and Retirements are expressed in anticipated UCAP values based on 18-765 Dakota Range III Strategist data

Note: Addition year reflect the first summer with accredited generation

Year of Addition:		MW
2019	Black Dog 6 (230 MW)	216
2019	Calpine MEC2 (375 MW)	358
2019	Solar - CSG	80
2020	Wind (1300 MW)	201
2020	Solar - CSG	21
2021	Manitoba Hydro (125 MW)	122
2021	Solar - CSG	4
2021	Wind (350 MW)	55
2022	Solar - CSG	4
2023	Demand Response (400 MW)	400
2023	Solar - CSG	4
2023	Wind (300 MW)	47
2024	Solar - CSG	4
2025	Solar - CSG	4
2026	Solar - CSG	4
2027	CT's (350 MW)	321
2027	Sherco CC (786 MW)	728
2027	Solar - CSG	4
2028	Solar - CSG	4
2029	Solar - CSG	4
2030	CT's (700 MW)	642
2030	Solar - CSG	4
2031	Solar - CSG	4
2031	CT's (225 MW)	200
2032	Solar - CSG	4
2032	CT's (350 MW)	321
2033	Solar - CSG	4
2033	CC's (900 MW)	844

Note: Retirement year reflect the first summer without accredited generation

First Year Following Retirement:		MW
2019	Granite City	51
2019	Bayfront (Unit 4)	3
2019	Renewable PPAs	22
2020	Manitoba Hydro (75 MW)	73
2020	Renewable PPAs	3
2021	Renewable PPAs	2
2022	Renewable PPAs	8
2023	St. Paul CoGen	24
2023	Renewable PPAs	26
2024	Blue Lake	156
2024	Sherco 2	691
2025	Invenergy	312
2025	Manitoba Hydro (350 MW)	342
2025	Manitoba Hydro (500 MW)	485
2025	Renewable PPAs	26
2026	Wheaton	206
2026	Renewable PPAs	5
2027	Sherco 1	681
2027	Renewable PPAs	16
2027	Chemolite-LSPower	233
2027	Inver Hills	255
2028	Red Wing	16
2028	Wilmarth	16
2028	Renewable PPAs	4
2029	Renewable PPAs	15
2030	Monticello	610
2031	Renewable PPAs	47
2032	Black Dog CC	254
2032	Renewable PPAs	19
2033	Prairie Island 1	508

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

Please use the appropriate code for the fuel type as shown in the list at the bottom of the worksheet.

		FUEL TYPE 1		FUEL TYPE 2		FUEL TYPE 3		FUEL TYPE 4	
		Name of Fuel	Coal	Name of Fuel	NUC	Name of Fuel	REF	Name of Fuel	NG
		Unit of Measure	mmBtu	Unit of Measure	mmBtu	Unit of Measure	mmBtu	Unit of Measure	mmBtu
		QUANTITY OF FUEL USED	NET GWH GENERATED	QUANTITY OF FUEL USED	NET GWH GENERATED	QUANTITY OF FUEL USED	NET GWH GENERATED	QUANTITY OF FUEL USED	NET GWH GENERATED
		[PROTECTED DATA BEGINS							
Past Year	2018								
Present Year	2019								
1st Forecast Year	2020								
2nd Forecast Year	2021								
3rd Forecast Year	2022								
4th Forecast Year	2023								
5th Forecast Year	2024								
6th Forecast Year	2025								
7th Forecast Year	2026								
8th Forecast Year	2027								
9th Forecast Year	2028								
10th Forecast Year	2029								
11th Forecast Year	2030								
12th Forecast Year	2031								
13th Forecast Year	2032								
14th Forecast Year	2033								

LIST OF FUEL TYPES

BIT - Bituminous Coal	LPG - Liquefied Propane Gas	HYD - Hydro (water)
COAL - Coal (general)	NG - Natural Gas	WIND - Wind
DIESEL - Diesel	NUC - Nuclear	WOOD - Wood
FO2 - Fuel Oil #2 (Mid-distillate)	REF - Refuse, Bagasse, Peat, Non-wo	SOLAR - Solar
FO6 - Fuel Oil #6 (Residual fuel oil)	STM - Steam	
LIG - Lignite	SUB - Sub-bituminous coal	

COMMENTS

Energy Production is in GWh not MWh, NG Energy Production and Fuel Consumption includes tolling units.
Data Source: Business as Usual Scenario of the 2020-2034 IRP (filed 7/1/2019) Note, this forecast reflects approved and existing resources, with solar and natural gas additions.

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7610.0430 FUEL REQUIREMEN

		FUEL TYPE 5		FUEL TYPE 6		FUEL TYPE 7		FUEL TYPE 7	
		Name of Fuel	Oil	Name of Fuel	HYD	Name of Fuel	Wind	Name of Fuel	Solar
		Unit of Measure	mmBtu	Unit of Measure	mmBtu	Unit of Measure	mmBtu	Unit of Measure	mmBtu
		QUANTITY OF FUEL USED	NET GWH GENERATED	QUANTITY OF FUEL USED	NET GWH GENERATED	QUANTITY OF FUEL USED	NET GWH GENERATED	QUANTITY OF FUEL USED	NET GWH GENERATED
Past Year	2018								
Present Year	2019								
1st Forecast Year	2020								
2nd Forecast Year	2021								
3rd Forecast Year	2022								
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MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0500 TRANSMISSION LINES

Subpart 1. **Existing transmission lines**. Each utility shall report the following information in regard to each transmission line of 200 kilovolts now in existence:

A. a map showing the location of each line;
B. the design voltage of each line;
C. the size and type of conductor;
D. the approximate location of d.c. terminals or a.c. substations; and
E. the approximate length of each line in Minnesota.

Subpart 2. **Transmission line additions**. Each generating and transmission utility, as defined in part 7610.0100, shall report the information required in subpart 1 for all future transmission lines over 200 kilovolts that the utility plans to build within the next 15 years.

Subpart 3. **Transmission line retirements**. Each generating and transmission utility, as defined in part 7610.0100, shall identify all present transmission lines over 200 kilovolts that the utility plans to retire within the next 15 years.

In Use (enter X for selection)	To Be Built (enter X for selection)	To Be Retired (enter X for selection)	DESIGN VOLTAGE	SIZE OF CONDUCTOR	TYPE OF CONDUCTOR	D.C. OR A.C. (specify)	LOCATION OF D.C. TERMINALS OR A.C. SUBSTATIONS	INDICATE YEAR IF "TO BE BUILT" OR "RETIRED"	LENGTH IN MINNESOTA (miles)
X			500 kV	3-1192 kcmil	ACSR	A.C.	Forbes - Chisago North		139.20
X			500 kV	3-1192 kcmil	ACSR	A.C.	Forbes - Roseau County South		192.70
X			500 kV	3-1192 kcmil	ACSR	A.C.	Riel(Manitoba Hyd) - Roseau Co N		10.20
X			500 kV	3-1192 kcmil	ACSR	A.C.	Roseau Middle - Roseau Co N		0.10
X			500 kV	3-1192 kcmil	ACSR	A.C.	Roseau Middle - Roseau Co S		0.10
X			345 kV	2-795 kcmil	ACSR	A.C.	Adams - Mitchell Co (ITC)		78.60
X			345 kV	2-795 kcmil	ACSR	A.C.	Adams - Pleasant Valley		16.90
X			345 kV	2-795 kcmil	ACSR	A.C.	Arpin (WP&L) - Eau Claire		80.00
X			345 kV	2-795 kcmil	ACSR	A.C.	A.S. King - Chisago County		38.00
X			345 kV	2-795 kcmil	ACSR	A.C.	A.S. King - Eau Claire		63.00
X			345 kV	2-795 kcmil	ACSR	A.C.	A.S. King - Kohlman Lake		12.70
X			345 kV	2-795 kcmil	ACSR	A.C.	A.S. King - Red Rock		25.81
X			345 kV	1192 kcmil	ACSR	A.C.	Benton Co (GRE) - Sherburne Co		20.70
X			345 kV	2-954 kcmil	ACSS/TW	A.C.	Briggs Road - North Rochester		43.50
X			345 kV	2-954 kcmil	ACSS/TW	A.C.	Bison - Alexandria Switching Stat.		77.50
X			345 kV	2-795 kcmil	ACSR	A.C.	Blue Lake - Eden Prairie		5.50
X			345 kV	2-795 kcmil	ACSR	A.C.	Blue Lake - Parkers Lake		14.90
X			345 kV	2-795 kcmil	ACSR	A.C.	Blue Lake - Scott County		27.50
X			345 kV	2-795 kcmil	ACSS	A.C.	Brookings Co - White (WAPA)		0.43
X			345 kV	2-795 kcmil	ACSS	A.C.	Brookings Co - White (WAPA) (2)		0.43
X			345 kV	2-954 kcmil	ACSR	A.C.	Bunker Lake (GRE) - Coon Creek		6.80
X			345 kV	2-795 kcmil	ACSR	A.C.	Byron - North Rochester		13.60
X			345 kV	2-795 kcmil	ACSR	A.C.	Byron - Pleasant Valley		16.30
X			345 kV	2-795 kcmil	ACSR	A.C.	Crandal - Fieldon South		19.70
X			345 kV	2-795 kcmil	ACSR	A.C.	Crandal - Lakefield Gen SW		5.01
X			345 kV	2-795 kcmil	ACSR	A.C.	Chisago Co - Kohlman Lake		37.70
X			345 kV	2-954 kcmil	ACSR	A.C.	Coon Creek - Dickinson (GRE)		26.70
X			345 kV	2-795 kcmil	ACSR	A.C.	Coon Creek - Kohlman Lake		8.30
X			345 kV	2-954 kcmil	ACSR	A.C.	Coon Creek - Sherburne Co (1)		41.40
X			345 kV	2-954 kcmil	ACSR	A.C.	Coon Creek - Sherburne Co (3)		43.40
X			345 kV	2-795 kcmil	ACSR	A.C.	Coon Creek - Terminal		13.70
X			345 kV	2-954 kcmil	ACSR	A.C.	Dickinson (GRE) - Parkers Lake		28.40
X			345 kV	2-954 kcmil	ACSR	A.C.	Elm Creek - Monticello		39.0
X			345 kV	2-954 kcmil	ACSR	A.C.	Elm Creek - Parkers Lake		11.00
X			345 kV	2-795 kcmil	ACSR	A.C.	Eden Prairie - Parkers Lake		9.50

In Use (enter X for selection)	To Be Built (enter X for selection)	To Be Retired (enter X for selection)	DESIGN VOLTAGE	SIZE OF CONDUCTOR	TYPE OF CONDUCTOR	D.C. OR A.C. (specify)	LOCATION OF D.C. TERMINALS OR A.C. SUBSTATIONS	INDICATE YEAR IF "TO BE BUILT" OR "RETIRED"	LENGTH IN MINNESOTA (miles)
X			345 kV	2-795 kcmil	ACSR	A.C.	Fieldon North - Wilmarth		32.10
X			345 kV	2-954 kcmil	ACSR	A.C.	Hampton Corners - Blue Lake		5.83
X			345 kV	2-954 kcmil	ACSS TW	A.C.	Hampton Corners - Chub Lake (GRE)		18.40
X			345 kV	2-795 kcmil	TACSR/VR2	A.C.	Hampton Corners - North Rochester		77.50
X			345 kV	2-954 kcmil	ACSR	A.C.	Hampton Corners - Prairie Island		19.60
X			345 kV	2-954 kcmil	ACSS TW	A.C.	Helena - Chub Lake (GRE)		20.63
X			345 kV	2-954 kcmil	ACSS TW	A.C.	Helena - Cedar Mountain (GRE) (1)		72.97
X			345 kV	2-954 kcmil	ACSS TW	A.C.	Helena - Cedar Mountain (GRE) (2)		72.97
X			345 kV	2-795 kcmil	ACSR	A.C.	Helena - Sheas Lake		54.80
X			345 kV	2-795 kcmil	ACSR	A.C.	Inver Hills - Blue Lake		24.50
X			345 kV	2-795 kcmil	ACSR	A.C.	Kohlman Lake - Terminal		10.30
X			345 kV	2-795 kcmil	ACSR	A.C.	Lakefield Jct - Lakefield Gen SW		18.80
X			345 kV	2-954 kcmil	ACSS/TW	A.C.	Lakefield Jct - Nobles County		35.96
X			345 kV	2-954 kcmil	ACSS/TW	A.C.	Lyon Co - Cedar Mountain (GRE) (1)		49.49
X			345 kV	2-954 kcmil	ACSS/TW	A.C.	Lyon Co - Cedar Mountain (GRE) (2)		49.49
X			345 kV	2-954 kcmil	ACSS	A.C.	Lyon Co - Hazel Creek		24.32
X			345 kV	2-795 kcmil	ACSR	A.C.	Mankato Energy Center - Wilmarth		0.22
X			345 kV	2-954 kcmil	ACSR	A.C.	Monticello - Sherburne Co		5.80
X			345 kV	2-954 kcmil	ACSS/TW	A.C.	Nobles County - Split Rock		5.10
X			345 kV	2-795 kcmil	ACSR	A.C.	North Rochester - Prairie Island		49.50
X			345 kV	2-795 kcmil	ACSR	A.C.	Prairie Island - Red Rock (1)		32.30
X			345 kV	2-795 kcmil	ACSR	A.C.	Prairie Island - Red Rock (2)		32.20
X			345 kV	2-954 kcmil	ACSS/TW	A.C.	Quarry - Alexandria Switching Station		77.50
X			345 kV	2-954 kcmil	ACSS/TW	A.C.	Quarry - Monticello		28.80
X			345 kV	2-795 kcmil	ACSR	A.C.	Red Rock - Inver Hills		8.50
X			345 kV	2-795 kcmil	ACSR	A.C.	Scott County - Helena		27.50
X			345 kV	2-954 kcmil	ACSR	A.C.	Sherburne Co - Bunker Lake (GRE)		36.90
X			345 kV	2-954 kcmil	ACSS/TW	A.C.	Sioux City (WAPA) - Split Rock		5.10
X			345 kV	2-954 kcmil	ACSR	A.C.	Split Rock - White (WAPA)		5.10
X			345 kV	2-795 kcmil	ACSR	A.C.	Sheas Lake - Wilmarth		54.80
X			230 kV	795 kcmil	ACSR	A.C.	Auduban (OTP) - Hubbard		49.90
X			230 kV	795 kcmil	ACSR	A.C.	Lake Park - Sheyenne		43.50
X			230 kV	795 kcmil	ACSR	A.C.	Benton Co (GRE) - Monticello		21.60
X			230 kV	795 kcmil	ACSR	A.C.	Blue Lake - McLeod (GRE)		14.10
X			230 kV	795 kcmil	ACSS	A.C.	Boswell (MP) - Zemple (MP)		7.32
X			230 kV	795 kcmil	ACSS	A.C.	Cass Lake (OTP) - Wilton (MPC)		19.30
X			230 kV	795 kcmil	ACSR	A.C.	Drayton(MPC) - Letellier(Manitoba Hyd)		23.00
X			230 kV	795 kcmil	ACSR	A.C.	Fargo Tap (OTP) - Sheyenne		4.20
X			230 kV	795 kcmil	ACSR	A.C.	Frontier - Maple River		53.60
X			230 kV	795 kcmil	ACSR	A.C.	Frontier - Wahpeton		10.00
X			230 kV	954 kcmil	ACSR	A.C.	Glenborough - Peace Garden		51.50
X			230 kV	954 kcmil	ACSR	A.C.	Grand Forks (WAPA) - Prairie		6.80
X			230 kV	954 kcmil	ACSR	A.C.	Granite Falls (WAPA) - Minn Valley		2.60
X			230 kV	795 kcmil	ACSR	A.C.	Granite Falls (WAPA) - Minn Valley Tap		2.50
X			230 kV	795 kcmil	ACSR	A.C.	McLeod (GRE) - Panther (GRE)		28.50
X			230 kV	2-954 kcmil	ACSR	A.C.	Minn Valley - Hazel Creek		5.10
X			230 kV	795 kcmil	ACSR	A.C.	Minn Valley - Minn Valley Tap		0.20
X			230 kV	795 kcmil	ACSR	A.C.	Minn Valley Tap - Panther (GRE)		30.20
X			230 kV	795 kcmil	ACSR	A.C.	Maple River - Sheyenne		6.60
X			230 kV	795 kcmil	ACSR	A.C.	Paynesville Tran - Willmar		29.70
X			230 kV	954 kcmil	ACSR	A.C.	Peace Garden - Borders Wind Farm		1.00
X			230 kV	954 kcmil	ACSR	A.C.	Peace Garden - Rugby		54.40
X			230 kV	795 kcmil	ACSR	A.C.	Rock Creek - Bear Creek (GRE)		24.40

In Use (enter X for selection)	To Be Built (enter X for selection)	To Be Retired (enter X for selection)	DESIGN VOLTAGE	SIZE OF CONDUCTOR	TYPE OF CONDUCTOR	D.C. OR A.C. (specify)	LOCATION OF D.C. TERMINALS OR A.C. SUBSTATIONS	INDICATE YEAR IF "TO BE BUILT" OR "RETIRED"	LENGTH IN MINNESOTA (miles)
X			230 kV	795 kcmil	ACSR	A.C.	Rock Creek - Rush City (GRE)		8.80
X			230 kV	795 kcmil	ACSR	A.C.	Red Rock - Rush City (GRE)		59.60
X			230 kV	795 kcmil	ACSS	A.C.	Sioux Falls Mun (WAPA) - Split Rock		0.80
X			230 kV	795 kcmil	ACSS	A.C.	Zemple (MP) - Cass Lake (OTP)		44.10
X			345 kV	2-954 kcmil	ACSS	A.C.	Brookings-Big Stone		32
X			345 kV	2-954 kcmil	ACSS	A.C.	Lacrosse-Madison	2018	55
	X		345 kV	Bundled 954 kcmil Hawk	ACSR/T2	A.C.	Huntley - Wilmarth *	2022	40-50

COMMENTS
Huntley - Wilmarth is a MTEP16 Approved Market Efficiency project in which the line mileage is estimated and may change depending on the routing process.

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continu

7610.0600, item A. 24 - HOUR PEAK DAY DEMAND

Each utility shall provide the following information for the last calendar year:

A table of the demand in megawatts by the hour over a 24-hour period for:

1. the 24-hour period during the summer season when the megawatt demand on the system was the greatest; and
2. the 24-hour period during the winter season when the megawatt demand on the system was the greatest.

	DATE OF PEAK DAY DEMAND	DATE OF PEAK DAY DEMAND	
	6/29/18	1/2/18	**<= ENTER DATES**
TIME OF DAY	MW USED ON **SUMMER** PEAK DAY	MW USED ON **WINTER** PEAK DAY	
0100	5676	4831	
0200	5400	4746	
0300	5191	4728	
0400	5077	4726	
0500	5139	4866	
0600	5411	5189	
0700	5937	5715	
0800	6506	6082	
0900	7043	6139	
1000	7498	6154	
1100	7945	6221	
1200	8260	6208	
1300	8519	6183	
1400	8746	6166	
1500	8876	6157	
1600	8918	6156	
1700	8944	6331	
1800	8782	6536	
1900	8528	6455	
2000	8198	6268	
2100	7940	6080	
2200	7727	5831	
2300	7307	5469	
2400	6748	5128	

COMMENTS

REMEMBER TO SEND/UPLOAD THE FOLLOWING ATTACHMENTS:	
DO NOT INSERT THE ATTACHMENT INTO THIS WORKBOOK	
1	Each utility shall report the following information in regard to each transmission line of 200 kilovolts now in existence: a. a map showing the location of each line; b. the design voltage of each line; c. the size and type of conductor; d. the approximate location of d.c. terminals or a.c. substations; and e. the approximate length of each line in Minnesota. (pursuant to MN Rules Chapter 7610.0500 Subpart 1, Existing transmission lines)

When submitting this workbook and attachments, please following the file naming format of:

ELEC_###_2018 Forecast Report (this workbook)
ELEC_###_2018 TL Map

NOTE: ### is your Utility Entity number found in Cell C5 on the Registration Tab

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT - LARGEST CUSTOMER LIST

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

WHEN E-FILING THIS FORM, IT SHOULD BE UPLOADED AS TRADE SECRET

ENTITY ID#	85
REPORT YEAR	2018

UTILITY DETAILS	
UTILITY NAME	Xcel Energy
STREET ADDRESS	414 Nicollet Mall
CITY	Minneapolis
STATE	MN
ZIP CODE	55401
TELEPHONE	612-330-5500

7610.0600 OTHER INFORMATION REPORTED ANNUALLY

PLEASE PROVIDE THE FOLLOWING INFORMATION FOR THOSE CUSTOMERS USING IN EXCESS OF 10,000 MWH. BE SURE TO INCLUDE YOUR LARGE CUSTOMERS LOCATED IN AND OUTSIDE MINNESOTA.

B. LARGEST CUSTOMER LIST - ATTACHMENT ELEC-1

[TRADE SECRET DATA BEGINS

ID#	CUSTOMER NAME	ADDRESS	CITY	STATE	ZIP	2018 MWH

ID#	CUSTOMER NAME	ADDRESS	CITY	STATE	ZIP	2018 MWH

ID#	CUSTOMER NAME	ADDRESS	CITY	STATE	ZIP	2018 MWH

ID#	CUSTOMER NAME	ADDRESS	CITY	STATE	ZIP	2018 MWH

ID#	CUSTOMER NAME	ADDRESS	CITY	STATE	ZIP	2018 MWH

TRADE SECRET DATA ENDS]

COMMENTS
* These include on-site generation. A supplement will be filed in docket 19-11.

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0120 REGISTRATION

ENTITY ID#	85
REPORT YEAR	2018

Number of Power Plants	45

UTILITY DETAILS	
UTILITY NAME	Xcel Energy
STREET ADDRESS	414 Nicollet Mall
CITY	Minneapolis
STATE	MN
ZIP CODE	55401
TELEPHONE	612-330-5500
	Scroll down to see allowable UTILITY TYPES
* UTILITY TYPE	PRIVATE

CONTACT INFORMATION	
CONTACT NAME	Jim G. Erickson
CONTACT TITLE	Regulatory Administrator
CONTACT STREET ADDRESS	414 Nicollet Mall
CITY	Minneapolis
STATE	MN
ZIP CODE	55401
TELEPHONE	612-330-5821
CONTACT EMAIL ADDRESS	regulatory.records@xcelenergy.com

UTILITY OFFICERS	
NAME	TITLE
Benjamin G.S. Fowke III	Chairman of the Board, President, and CEO
Robert C. Frenzel	Executive Vice President and Chief Financial Officer
Kent T. Larson	Executive Vice President and Group President, Operations
Scott M. Wilensky	Executive Vice President and General Counsel
Judy M. Poferl	Senior Vice President, Corporate Secretary and Executive Services
Timothy J. O'Connor	Chief Nuclear Officer
Jeffrey S. Savage	Senior Vice President and Controller
Christopher B. Clark	President, Xcel Energy - Minnesota, South Dakota, North Dakota
Alice K. Jackson	President, Xcel Energy - Colorado
David T. Hudson	President, Xcel Energy - New Mexico, Texas
Mark E. Stoering	President, Xcel Energy - Michigan, Wisconsin
Brett C. Carter	Executive Vice President and Chief Customer and Innovation Officer
Sarah W. Soong	Vice President and Treasurer
Darla Figoli	Senior Vice President, Human Resources & Employee Services, Chief Human Resources Officer
David L Eves	Executive Vice President, Group President - Utilities

PREPARER INFORMATION	(do not type "Same as Above")
PERSON PREPARING FORMS	Jim G. Erickson
PREPARER'S TITLE	Regulatory Administrator
DATE	7/1/2019
PREPARER'S EMAIL ADDRESS	jim.g.erickson@xcelenergy.com

COMMENTS

ALLOWABLE UTILITY TYPES

Code*
Private
Public
Co-op

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0150 FEDERAL OR STATE DATA SUBSTITUTION

FEDERAL AGENCY	FORM NUMBER	FORM TITLE	FILING CYCLE (enter an "X" in the cell) MONTHLY	YEARLY	OTHER
Department of Energy	EIA-411	Coordinated Bulk Power Supply Report		X	
Department of Energy	EIA-457A	Residential Energy Consumption Survey			X
Department of Energy	EIA-860	Annual Electric Generator Report		X	
Department of Energy	EIA-860M	Monthly Update to Annual Electric Generator Report	X		
Department of Energy	EIA-861	Annual Electric Utility Report		X	
Department of Energy	EIA-861M	Monthly Electric Sales & Revenue Report with State Distributions	X		
Department of Energy	EIA-871A/I	Commercial Building Energy Consumption Survey			X
Department of Energy	EIA-923	Power Plant Operations Report		X	
Department of Energy	GC-859	Nuclear Fuel Data			X
Federal Energy Regulatory Commission	FERC 537	Annual Report of 311 Facility Activities		X	
Federal Energy Regulatory Commission	FERC 549B	Peak Day Capacity Report Under Section 284.13		X	
Federal Energy Regulatory Commission	FERC 549B	Quarterly Index of Customers			X
Federal Energy Regulatory Commission	FERC 549D	Quarterly Transportation and Storage Report for Intrastate Natural Gas and Hinshaw Pipelines			X
Federal Energy Regulatory Commission	FERC 576	Report by natural gas pipeline companies for damage or serious service interruptions occurring on the pipeline system		X	
Federal Energy Regulatory Commission	FERC 577	Annual Report of Replacement of Certificated Facilities		X	
Federal Energy Regulatory Commission	Form 1	Annual Report of Major Electric Utilities, Licensees and Others		X	
Federal Energy Regulatory Commission	Form 3Q	Quarterly Report of Major Electric Utilities, Licensees and Others			X
Federal Energy Regulatory Commission	Form 516	Electronic Quarterly Report			X
Federal Energy Regulatory Commission	Form 552	Annual Report of Natural Gas Transactions		X	
Federal Energy Regulatory Commission	Form 561	Interlocking Directorships or Conflict of Interest		X	
Federal Energy Regulatory Commission	Form 566	Twenty Largest Electric Customers		X	
Federal Energy Regulatory Commission	Form 580	Interrogatory on Fuel and Energy Purchases Practices			X
Federal Energy Regulatory Commission	Form 60	Annual Report of Centralized Service Companies		X	
Federal Energy Regulatory Commission	Form 652	Change in Status Report/Changes in Control of Inputs to Electric Power Production (market power test)		X	
Federal Energy Regulatory Commission	Form 652	Triennial Market Power Review			X
Federal Energy Regulatory Commission	Form 714	Annual Electric Control and Planning Area Report		X	
Federal Energy Regulatory Commission	Form 715	Annual Transmission Planning and Evaluation Report		X	
Federal Energy Regulatory Commission	Form 730	Report of Transmission Investment Activity		X	
Federal Energy Regulatory Commission	Form 80	Licensed Hydropower Development Recreation Report			X
Federal Energy Regulatory Commission	Reporting Requirement 582	Annual Charges Report		X	
Federal Energy Regulatory Commission		Interchange Agreement between NSPM/NSPW		X	
Internal Revenue Service	Form 1120	Corporate Income Tax Return		X	
Internal Revenue Service	Form 5500	Annual Return/Report of Employee Benefit Plan		X	
Internal Revenue Service	Form 990	Return of Organization Exempt from Income Tax		X	
Nuclear Regulatory Commission		Annual Nuclear Decommissioning Trust Report			X
Securities Exchange Commission	Form 10-K	Annual Financial Statements		X	
Securities Exchange Commission	Form 10-Q	Quarterly Financial Statements			X
Securities Exchange Commission	Form 11-K	401(k) Benefit Plan		X	
Securities Exchange Commission	Form 3	Initial Disclosures for Statement of Changes in Beneficial Ownership of Securities		X	
Securities Exchange Commission	Form 4	Statement of Changes in Beneficial Ownership of Securities		X	
Securities Exchange Commission	Form 8-K	Disclosure of Interim Events			X
Securities Exchange Commission	Form S	Registration Statements			X
Securities Exchange Commission	Form S	Registration Statements			X
Securities Exchange Commission	Schedule 14A	Proxy Statement		X	
Securities Exchange Commission	Schedule 14A	Proxy Statement		X	
U.S. Department of Commerce	NWPA-830R	Standard Contract for Disposal of Spent Nuclear Fuel and/or High Level Radioactive Waste			X
U.S. Department of Commerce	NWPA-830R	Standard Contract for Disposal of Spent Nuclear Fuel and/or High Level Radioactive Waste			X
U.S. Energy Information Administration	EIA 64A	Annual Report of the Origin of Natural Gas Liquids Production.		X	
U.S. Energy Information Administration	EIA 64A	Annual Report of the Origin of Natural Gas Liquids Production.		X	
U.S. Energy Information Administration	EIA 757	Survey of Natural Gas Processing Plants			X
U.S. Energy Information Administration	EIA 757	Survey of Natural Gas Processing Plants			X
U.S. Energy Information Administration	EIA 886	EIA-886 Alternative Fuel Vehicles		X	
U.S. Energy Information Administration	EIA 886	EIA-886 Alternative Fuel Vehicles		X	
U.S. Energy Information Administration	EIA 923S	EIA 923S - Power Plant Operations Report Supplement to Schedule 8a-f		X	
U.S. Energy Information Administration	EIA 923S	EIA 923S - Power Plant Operations Report Supplement to Schedule 8a-f		X	
U.S. Energy Information Administration	EIA-861M	Monthly Electric Power Industry Report	X		
U.S. Energy Information Administration	EIA-861M	Monthly Electric Sales and Revenue with State Distributions Report	X		
U.S. Energy Information Administration	EIA-861M	Monthly Electric Sales and Revenue with State Distributions Report	X		

COMMENTS

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0600 OTHER INFORMATION REPORTED ANNUALLY

A utility shall provide the following information for the last calendar year:

B. LARGEST CUSTOMER LIST - ATTACHMENT ELEC-1 — **If applicable, the Largest Customer List must be submitted in electronic format. If information is Trade Secret, note it as such.**

See "LargestCustomers" worksheet for data entry.

C. MINNESOTA SERVICE AREA MAP — **The referenced map must be submitted in electronic format.**

See Instructions for details of the information required on the Minnesota Service Area Map.

D. PURCHASES AND SALES FOR RESALE

UTILITY NAME (please spell out acronyms)	INTERCONNECTED UTILITY (please spell out acronyms)	MWH PURCHASED	RESALE ONLY MWH SOLD FOR RESALE
Adams Wind Generations, LLC		52,099	
Agassiz Beach		4,357	
American Electric Power		3,339	
Aurora Distributed Solar, LLC		-34	
Aurora Distributed Solar, LLC		188,886	
Benson Power, LLC		150,262	
Best Power International LLC		1,759	
Big Blue		118,512	
Bisson Windfarm, LLC		4,119	
Boeve Windfarm, LLC		5,346	
BP Energy Company			24,400
Byllesby		13,153	
Cannon Falls Energy Center		114,046	
Carleton College		3,897	
CG Windfarm, LLC		2,298	
Chanarambie Power Partners, LLC		211,136	
Cisco Wind Energy, LLC		23,205	
Citigroup Energy, Inc.		8,400	
City of Ada			6,547
City of Ada			36
City of Kasota			4,239
City of Kasota			34
Covanta Hennepin Energy Resource Co LP		203,431	
Dahlberg Light and Power			5,596
Dahlberg Light and Power			112,537
Dairyland Electric Cooperative Incorpd		17,200	
Danielson Wind Farms, LLC		46,149	
Diamond K Dairy		-43	

Direct Energy Buisness Marketing, LLC			41,600
Dragonfly Solar, LLC		197	
East Ridge		23,978	
ERCOT		-23,200	
ETC Endure Energy, LLC			1,600
Ewington Energy System, LLC		58,779	
Fenton Power Partners I, LLC		645,208	
Fey Windfarm, LLC		5,229	
FPL Energy Mower County, LLC		262,300	
Garwin McNeilus		74,762	
Grant County Wind, LLC		54,123	
Hastings Lock & Dam		13,592	
Hilltop Power, LLC		3,004	
ICE NGX Canada, Inc			41,200
Jeffers Wind Energy Center		159,825	
JJN Windfarm, LLC		4,082	
Kas Brothers Windfarm, LLC		3,178	
K-Brink Windfarm, LLC		5,629	
KODA Energy, LLC		100,021	
Lake Benton Power Partners, LLC		455,115	
Laurentian Energy Authority, LLC		138,398	
LCO Hydro		12,302	
Lincoln Heights Wind Holdings		15,170	
Lower Colorado River Authority		33,600	
LSP Cottage Grove Incorporated		258,522	
Luminant Energy Company LLC			17,600
Manitoba Hydro		1,637,153	
Mankato Energy Center, LLC		486,324	
Marshall Solar		107,319	
Metro Wind, LLC		759	
Midcontinent ISO			6,729,664
Midcontinent ISO			13,097
Midcontinental ISO		-9,181	
Midcontinental ISO		2,769,281	
MinnDakota		494,144	
Miscellaneous		114,676	
Moraine Wind, LLC		307,348	
NAE Lakota Ridge, LLC		6,257	
NAE Lakota Ridge, LLC		22,306	
NAE Shaokatan, LLC		24,951	
NAE Shaokatan Hills, LLC		7,214	
NAE Shaokatan Hills, LLC		30,345	
Natural Gas Exchange Inc.		31,200	

Neshkoro (Neshonoc)		1,767	
NextEra Energy Power Marketing, LLC			24,400
NextEra Energy Power Marketing, LLC			800
North Central Power Company, Inc.			13,868
North Central Power Company, Inc.			12,840
North Community Turbines, LLC		45,340	
North Star Solar		195,387	
North Wind Turbines LLC		43,551	
Northwestern Wisconsin Electric Company			54,876
Northwestern Wisconsin Electric Company			125,520
Northwestern Wisconsin Electric Company			-360
NSP-Wisconsin			6,367,949
NSP-M Solar Gardens		595,562	
Odell Wind Farm, LLC		759,749	
Ohio Power Company			406,681
Olsen Wind Farm		1,975	
Pine Bend		9,496	
Pipestone		22,156	
PJM Interconnection, LLC			20,030
PJM Interconnection, LLC		381,814	
Prairie Rose Wind LLC		623,329	
Rapidan Hydroelectric Facility		18,820	
Ridgewind Power Partners, LLC		80,230	
Rock County Energy		22,889	
Rock Ridge Power Partners, LLC		5,105	
Ruthton Ridge, LLC		40,234	
SAF Hydroelectric LLC		51,374	
Shane's Wind Machine LLC		6,236	
Slayton Solar, LLC		2,622	
South Ridge		3,798	
Southern Minnesota Municipal Power Agy		9,671	
Southwest Power Pool Electric Energy		-58	
Southwest Power Pool Electric Energy		4,500	
St. Cloud		51,166	
St. Olaf College		3	
St. Olaf College		24	
St. Paul Cogeneration		161,318	
TG Windfarm, LLC		4,637	
Tholen		41,484	
Tofteland Windfarm, LLC		4,253	
Uilk Wind Farm, LLC		12,074	
University of Minnesota		2,736	
Valley View Transmission		27,443	

Velva Windfarm, LLC		25,878	
Viking Wind Partners		33,267	
Western Area Power Administration		11,785	
Westridge Windfarm, LLC		2,497	
Windcurrent Farms, LLC		5,759	
Windvest		1,824	
Winona County Wind, LLC		-1	
Winona County Wind, LLC		-31	
WM Renewable Energy, LLC		35,536	
Woodstock Hills, LLC		6,401	
Woodstock Municipal Wind, LLC		957	
Zephyr Wind		112,522	

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0600 OTHER INFORMATION REPORTED ANNUALLY (continued)

A utility shall provide the following information for the last calendar year:

E. RATE SCHEDULES	**The rate schedule and monthly power cost adjustment information must be submitted in electronic format.**

See Instructions for details of the information required on the Rate Schedules and Monthly Power Cost Adjustments.

F. REPORT FORM EIA-861	**A copy of report form EIA-861 filed with the US Department of Energy must be submitted in electronic format.**

A copy of the report form EIA-861 filed with the Energy Information Administration of the US Department of Energy must be submitted.

G. FINANCIAL AND STATISTICAL REPORT	**If applicable, a copy of the Financial and Statistical Report filed with the US Department of Agriculture must be submitted in electronic format.**

For rural electric cooperatives, a copy of the Financial and Statistical Report to the US Department of Agriculture must be submitted.

H. GENERATION DATA

If the utility has Minnesota power plants, enter the fuel requirements and generation data on the Plant1, Plant2, etc. worksheets.

I. ELECTRIC USE BY MINNESOTA RESIDENTIAL SPACE HEATING USERS

See Instructions for details of the information required for residential space heating users.

COLUMN 1 NUMBER OF RESIDENTIAL ELECTRICAL SPACE HEATING CUSTOMERS	COLUMN. 2 NUMBER OF RESIDENTIAL UNITS SERVED WITH ELECTRICAL SPACE HEATING	COLUMN 3 TOTAL MWH USED BY THESE CUSTOMERS AND UNITS
35,430	NA	417,199

COMMENTS

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0600 OTHER INFORMATION REPORTED ANNUALLY (continued)

J. ITS DELIVERIES TO ULTIMATE CONSUMERS BY COUNTY FOR THE LAST CALENDAR YEAR

ENERGY DELIVERED TO ULTIMATE CONSUMERS BY COUNTY IN 2018

COUNTY CODE	COUNTY NAME	MWH DELIVERED	COUNTY CODE	COUNTY NAME	MWH DELIVERED
1	Aitkin		46	Martin	
2	Anoka	982,156	47	Meeker	38,901
3	Becker		48	Mille Lacs	
4	Beltrami		49	Morrison	0
5	Benton	252,631	50	Mower	1,763
6	Big Stone		51	Murray	43,090
7	Blue Earth	683,013	52	Nicollet	99,856
8	Brown	1,915	53	Nobles	
9	Carlton		54	Norman	1,430
10	Carver	503,933	55	Olmstead	42,689
11	Cass		56	Otter Tail	
12	Chippewa	108,937	57	Pennington	
13	Chisago	213,044	58	Pine	
14	Clay	56,878	59	Pipestone	74,060
15	Clearwater		60	Polk	1
16	Cook		61	Pope	79,272
17	Cottonwood		62	Ramsey	4,937,214
18	Crow Wing		63	Red Lake	
19	Dakota	3,270,992	64	Redwood	37,645
20	Dodge	110,741	65	Renville	64,492
21	Douglas	12,200	66	Rice	548,068
22	Faribault	5,229	67	Rock	1,641
23	Fillmore		68	Roseau	
24	Freeborn	9,641	69	St. Louis	
25	Goodhue	378,492	70	Scott	440,350
26	Grant		71	Sherburne	229,982
27	Hennepin	11,872,483	72	Sibley	74,682
28	Houston	33,882	73	Stearns	1,241,305
29	Hubbard		74	Steele	21,837
30	Isanti	14	75	Stevens	
31	Itasca		76	Swift	
32	Jackson		77	Todd	1,723
33	Kanabec		78	Traverse	
34	Kandiyohi	114,513	79	Wabasha	72,140
35	Kittson		80	Wadena	
36	Koochiching		81	Waseca	182,100
37	Lac Qui Parle	838	82	Washington	2,346,800
38	Lake		83	Watonwan	6,760
39	Lake of the Woods		84	Wilkin	1,046
40	Le Sueur	96,570	85	Winona	451,037
41	Lincoln	553	86	Wright	534,785
42	Lyon	39,912	87	Yellow Medicine	25,308
43	McLeod	100,829			
44	Mahnomen			GRAND TOTAL (Entered)	30,449,373
45	Marshall				
				GRAND TOTAL (Calculated)	30449373.08

COMMENTS

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0600 OTHER INFORMATION REPORTED ANNUALLY (continued)

J. ITS DELIVERIES TO ULTIMATE CONSUMERS BY MONTH FOR THE LAST CALENDAR YEAR

See Instructions for details of the information required concerning electricity delivered to ultimate consumers.

Past Year (2018)	Entire System	A Non-Farm Residential	B Residential With Space Heat	C Farm	D Small Commercial & Industrial	E Irrigation	F Large Commercial & Industrial	G Street & Highway Lighting	H Other (Include Municipals)	I Total (Columns A through H)
January	No. of Customers	1,110,459	34,976	n/a	132,345	n/a	505	4,925	2,049	1,285,259
	MWH	757,252	59,488	n/a	1,120,269	n/a	634,598	16,403	5,485	2,593,495
February	No. of Customers	1,111,368	35,081	n/a	132,276	n/a	505	4,957	2,047	1,286,234
	MWH	615,469	50,827	n/a	961,949	n/a	597,145	9,390	5,052	2,239,833
March	No. of Customers	1,112,844	35,174	n/a	132,345	n/a	504	4,969	2,048	1,287,884
	MWH	617,897	38,693	n/a	1,096,398	n/a	665,679	10,381	6,270	2,435,318
April	No. of Customers	1,113,827	35,187	n/a	132,315	n/a	504	4,971	2,046	1,288,850
	MWH	547,242	31,043	n/a	983,347	n/a	637,803	8,283	5,397	2,213,114
May	No. of Customers	1,114,679	35,148	n/a	132,370	n/a	504	4,986	2,044	1,289,731
	MWH	648,186	24,822	n/a	1,117,747	n/a	680,738	7,386	6,352	2,485,231
June	No. of Customers	1,114,542	35,099	n/a	132,319	n/a	505	5,020	2,041	1,289,526
	MWH	865,940	23,826	n/a	1,214,653	n/a	694,955	6,907	7,336	2,813,617
July	No. of Customers	1,114,657	35,176	n/a	132,333	n/a	506	5,027	2,047	1,289,746
	MWH	906,688	23,820	n/a	1,265,909	n/a	765,633	5,082	7,504	2,974,637
August	No. of Customers	1,115,473	35,164	n/a	132,410	n/a	505	5,066	2,046	1,290,664
	MWH	944,258	26,453	n/a	1,261,861	n/a	774,244	6,747	7,673	3,021,236
September	No. of Customers	1,115,525	35,137	n/a	132,393	n/a	506	5,085	2,048	1,290,694
	MWH	681,802	19,997	n/a	1,093,413	n/a	723,431	9,608	8,192	2,536,443
October	No. of Customers	1,117,187	35,273	n/a	132,573	n/a	505	5,142	2,046	1,292,726
	MWH	584,463	27,765	n/a	1,024,315	n/a	672,424	8,270	6,190	2,323,427
November	No. of Customers	1,117,863	35,326	n/a	132,792	n/a	506	5,186	2,041	1,293,714
	MWH	620,981	44,212	n/a	989,176	n/a	628,510	12,698	5,395	2,300,971
December	No. of Customers	1,118,900	35,430	n/a	132,981	n/a	511	5,207	2,039	1,295,068
	MWH	698,216	46,254	n/a	1,096,275	n/a	652,517	12,819	5,971	2,512,052
	Total MWH	8,488,393	417,199	#VALUE!	13,225,312	#VALUE!	8,127,676	113,974	76,819	30,449,373

COMMENTS

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0600 OTHER INFORMATION REPORTED ANNUALLY (continued)

ELECTRICITY DELIVERED TO ULTIMATE CONSUMERS IN MINNESOTA SERVICE AREA IN LAST CALENDAR YEAR

See Instructions for details of the information required concerning electricity delivered to ultimate consumers.
Exclude station use, distribution losses, and unaccounted for energy losses from this table altogether.

Classification of Energy Delivered to Ultimate Consumers (include energy used during the year for irrigation and drainage pumping)	This column reports the number of farms, residences, commercial establishments, etc., and not the number of meters, where different. Number of Customers at End of Year	This column total should equal the grand total in the worksheet labeled "ElectricityByCounty" which provides deliveries by county. Megawatt hours (round to nearest MWH)	This column total will be used for the Alternative Energy Assessment and should NOT include revenues from sales for resale (Minnesota Statutes, Section 216B.62, Subd. 5). Revenue ($)
Farm	NA	NA	NA
Non-Farm Residential	1,154,330	8,905,592	1,259,859,426
Commercial	132,981	13,225,312	1,381,657,732
Industrial	511	8,127,676	661,416,078
Street & Highway Lighting	5,207	113,974	24,029,120
All other	2,039	76,819	8,674,796
Entered Total	1,295,068	30,449,373	3,335,637,152
CALCULATED TOTAL	1,295,068	30,449,373	3,335,637,152

COMMENTS

REMEMBER TO SEND/UPLOAD THE FOLLOWING ATTACHMENTS:	
DO NOT INSERT THE ATTACHMENT INTO THIS WORKBOOK	
1	If applicable, the Largest Customer List (Attachment ELEC-1), if the separate LargestCustomers workbook was not used (pursuant to MN Rules Chapter 7610.0600 B)
2	Minnesota Service Area Map (pursuant to MN Rules Chapter 7610.0600 C)
3	Rate Schedules and Monthly Power Cost Adjustments (pursuant to MN Rules Chapter 7610.0600 E)
4	Report form EIA-861 filed with US Department of Energy (pursuant to MN Rules Chapter 7610.0600 F)
5	If applicable, for rural electric cooperatives, the Financial and Statistical Report filed with US Department of Agriculture (pursuant to MN Rules Chapter 7610.0600 G)

When submitting this workbook and attachments, please following the file naming format of:

ELEC_###_2018 Annual Report (this workbook)
ELEC_###_2018 Largest Customer List
ELEC_###_2018 MN Service Area Map
ELEC_###_2018 Rate Schedules
ELEC_###_2018 Monthly Power Cost Adjustments
ELEC_###_2018 USDOE EIA-861
ELEC_###_2018 USDOA Financial and Statistical Report

NOTE: ### is your Utility Entity number found in Cell C5 on the Registration Tab

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2018

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME		PLANT ID	(leave this cell blank)
STREET ADDRESS			
CITY			
STATE		NUMBER OF UNITS	
ZIP CODE			
COUNTY			
CONTACT PERSON			
TELEPHONE			

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
				PLANT TOTAL	0	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
PLANT TOTAL	0.0	0.0				

D. UNIT FUEL USED

	PRIMARY FUEL USE					SECONDARY FUEL USE			
Unit ID #	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)		Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading	Code	Code Definition
*** Unit Status**	USE	In-use	**** Unit Type**	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
***** Energy Source**	BIT	Bituminous Coal		WI	Wind
& Fuel Type	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	****** Unit of Measure**	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate = (percentage)
$$\frac{\text{Hours Unit Failed to be Available X 100}}{\text{Hours Unit Called Upon to Produce}}$$
Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability = (percentage)
100 - Maintenance percentage - Forced Outage percentage
Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage)
$$\frac{\text{Total Annual MWH of Production X 100}}{\text{Accredited Capacity Rating (MW) of the Unit X 8,760}}$$

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2018

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	United Hospital	**PLANT ID**	85083
STREET ADDRESS			
CITY	St. Paul		
STATE	MN	**NUMBER OF UNITS**	3
ZIP CODE	55102		
COUNTY	Ramsey		
CONTACT PERSON	Will Mills		
TELEPHONE	303-571-7418		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	OTHER	IC	1992	F02		Sold
2	OTHER	IC	1992	F02		Sold
3	OTHER	IC	1992	F02		Sold
				Plant Total	0.00	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	4.80	4.80				Sold
2	4.80	4.80				Sold
3	4.80	4.80				Sold
Plant Total	14.40	14.40				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	FO2		GAL					
2	FO2		GAL					
3	FO2		GAL					

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2018

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Grand Meadow Generating Statior	**PLANT ID**	85084
STREET ADDRESS			
CITY	Dexter		
STATE	MN	**NUMBER OF UNITS**	1
ZIP CODE	55926		
COUNTY	Mower		
CONTACT PERSON	Will Mills		
TELEPHONE	303-571-7418		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
GMWF01-67	USE	WI	2010	WIND	270,861.75	Up to 100 Megawatts from 67 GE wind turbines
				Plant Total	270,861.75	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
GMWF01-67	16.00	16.00	30.77	100.00	0.00	Up to 100 Megawatts from 67 GE wind turbines
Plant Total	16.00	16.00				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
GMWF01-67	WIND							

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2018

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Alliant Tech Systems	**PLANT ID**	85080
STREET ADDRESS			
CITY	Hopkins		
STATE	MN	**NUMBER OF UNITS**	1
ZIP CODE	55343		
COUNTY	Hennepin		
CONTACT PERSON	Will Mills		
TELEPHONE	303-571-7418		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	OTHER	IC	1993	FO2		Sold
				Plant Total	0.00	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	1.60	1.60				Sold
Plant Total	1.60	1.60				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	FO2		GAL					

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2018

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Bay Front Generating Station	**PLANT ID**	85004
STREET ADDRESS			
CITY	Ashland		
STATE	WI	**NUMBER OF UNITS**	3
ZIP CODE	54806		
COUNTY	Ashland		
CONTACT PERSON	Will Mills		
TELEPHONE	303-571-7418		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
4	USE	ST	1948	COAL	29.57	Uses more wood than coal
5	USE	ST	1950		87,501.33	Uses more wood than coal
6	USE	ST	1956		79,383.38	Uses more wood than coal
				Plant Total	166,914.28	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
4	15.00	15.00	34.03	99.50	0.13	Total plant, no individual stats
5	18.00	18.00				
6	23.00	23.00				
Plant Total	56.00	56.00				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
4-6	COAL	882.71	TONS	8,419				
	WOOD	245,724.70	TONS					
	NG	35,466.00	MCF					
	Other-Tires	3,342.50	TONS					

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2018

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Lake Wissota Hydro Generating Station	**PLANT ID**	85074
STREET ADDRESS	6425 164th St		
CITY	Chippewa Falls		
STATE	WI	**NUMBER OF UNITS**	6
ZIP CODE	54729		
COUNTY	Chippewa		
CONTACT PERSON	Will Mills		
TELEPHONE	303-571-7418		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1917	HYD	9,864.00	
2	USE	HC	1917	HYD	12,390.00	
3	USE	HC	1917	HYD	21,213.00	
4	USE	HC	1917	HYD	12,173.00	
5	USE	HC	1917	HYD	11,579.00	
6	USE	HC	1917	HYD	9,164.00	
				Plant Total	76,383.00	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	3.00	3.00	29.63	66.39	2.83	
2	3.10	3.10	35.36	100.00	22.24	
3	3.00	3.00	62.09	83.09	0.30	
4	3.00	3.00	35.63	87.64	0.41	
5	2.90	2.90	33.89	100.00	0.31	
6	3.00	3.00	26.15	100.00	0.47	
Plant Total	18.00	18.00				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	HYD							
2	HYD							
3	HYD							
4	HYD							
5	HYD							
6	HYD							

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2018

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	White River Hydro Generating Station	**PLANT ID**	85072
STREET ADDRESS			
CITY	Ashland		
STATE	WI	**NUMBER OF UNITS**	2
ZIP CODE	54806		
COUNTY	Ashland		
CONTACT PERSON	Will Mills		
TELEPHONE	303-571-7418		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1907	HYD	3,234.00	
2	USE	HC	1907	HYD	1,522.00	
				Plant Total	4,756.00	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	0.20	0.20	123.06	90.19	9.50	
2	0.20	0.20	57.91	67.51	34.14	
Plant Total	0.40	0.40				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	HYD							
2	HYD							

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2018

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Wheaton Generating Station	**PLANT ID**	85071
STREET ADDRESS			
CITY	Wheaton		
STATE	WI	**NUMBER OF UNITS**	6
ZIP CODE	54729		
COUNTY	Chippewa		
CONTACT PERSON	Will Mills		
TELEPHONE	303-571-7418		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	GT	1973	FO2	4,869.90	
2	USE	GT	1973	FO2	7,807.70	
3	USE	GT	1973	FO2	4,732.90	
4	USE	GT	1973	FO2	5,624.50	
5	RET	GT	1973	FO2	(535.90)	Retired
6	USE	GT	1973	FO2	491.30	
				Plant Total	22,990.40	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	44.00	56.00	0.99	89.83	14.73	
2	55.00	70.00	1.27	90.58	45.77	
3	44.00	56.00	0.96	84.33	65.86	
4	47.00	61.00	1.05	90.47	30.64	
5	0.00	0.00	0.00	0.00	0.00	Retired
6	48.00	70.00	0.08	88.74	94.30	
Plant Total	238.00	313.00				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
1-6	FO2	107,241.10	GAL		NG	433,505.10	MCF	

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2018

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Thornapple Hydro Generating Statior	**PLANT ID**	85063
STREET ADDRESS			
CITY	Ladysmith		
STATE	WI	**NUMBER OF UNITS**	2
ZIP CODE	54848		
COUNTY	Rusk		
CONTACT PERSON	Will Mills		
TELEPHONE	303-571-7418		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1929	HYD	4,559.00	
2	USE	HC	1929	HYD	5,048.00	
				Plant Total	9,607.00	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	0.40	0.40	65.05	92.90	7.27	
2	0.40	0.40	64.03	100.00	0.00	
Plant Total	0.80	0.80				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	HYD							
2	HYD							

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2018

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Trego Hydro Generating Station	**PLANT ID**	85065
STREET ADDRESS			
CITY	Trego		
STATE	WI	**NUMBER OF UNITS**	2
ZIP CODE	54888		
COUNTY	Washburn		
CONTACT PERSON	Will Mills		
TELEPHONE	303-571-7418		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1927	HYD	6,052.00	
2	USE	HC	1927	HYD	3,301.00	
				Plant Total	9,353.00	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	0.40	0.40	76.76	99.54	0.30	
2	0.30	0.30	62.80	99.63	0.01	
Plant Total	0.70	0.70				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	HYD							
2	HYD							

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2018

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Superior Falls Hydro Generating Statior	**PLANT ID**	85062
STREET ADDRESS			
CITY	Ironwood		
STATE	MI	**NUMBER OF UNITS**	2
ZIP CODE	49938		
COUNTY	Gogebic		
CONTACT PERSON	Will Mills		
TELEPHONE	303-571-7418		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1917	HYD	6,474.00	
2	USE	HC	1917	HYD	5,976.00	
				Plant Total	12,450.00	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	0.50	0.50	92.38	95.71	4.36	
2	0.50	0.60	97.46	97.02	2.95	
Plant Total	1.00	1.10				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	HYD							
2	HYD							

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2018

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	St. Croix Falls Hydro Generating Statior	**PLANT ID**	85060
STREET ADDRESS			
CITY	St. Croix Falls		
STATE	WI	**NUMBER OF UNITS**	8
ZIP CODE	54024		
COUNTY	Polk		
CONTACT PERSON	Will Mills		
TELEPHONE	303-571-7418		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1905	HYD	10,833.00	
2	USE	HC	1905	HYD	9,979.00	
3	USE	HC	1905	HYD	12,326.00	
4	USE	HC	1905	HYD	11,674.00	
5	USE	HC	1910	HYD	8,658.00	
6	USE	HC	1910	HYD	14,060.00	
7	USE	HC	1923	HYD	24,091.00	
8	USE	HC	1923	HYD	22,203.00	
				Plant Total	113,824.00	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	1.80	1.40	41.22	74.01	0.32	
2	1.80	1.40	37.97	65.61	22.98	
3	1.90	1.50	43.97	57.44	14.60	
4	1.90	1.50	41.65	62.84	0.30	
5	2.00	1.60	29.07	74.82	0.00	
6	1.90	1.50	48.64	65.84	0.00	
7	2.00	1.60	80.89	96.08	0.00	
8	1.90	1.50	74.55	94.44	0.00	
Plant Total	15.20	12.00				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	HYD							
2	HYD							
3	HYD							
4	HYD							
5	HYD							
6	HYD							
7	HYD							
8	HYD							

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2018

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Riverdale Hydro Generating Statior	**PLANT ID**	85053
STREET ADDRESS			
CITY			
STATE	WI	**NUMBER OF UNITS**	2
ZIP CODE			
COUNTY			
CONTACT PERSON	Will Mills		
TELEPHONE	303-571-7418		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1905	HYD	1,172.00	
2	USE	HC	1905	HYD	1,316.00	
				Plant Total	2,488.00	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	0.20	0.20	44.60	93.13	9.18	
2	0.10	0.10	50.08	87.24	13.96	
Plant Total	0.30	0.30				

D. UNIT FUEL USED

	PRIMARY FUEL USE				SECONDARY FUEL USE			
Unit ID #	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	HYD							
2	HYD							

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2018

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Saxon Falls Hydro Generating Statior	**PLANT ID**	85057
STREET ADDRESS			
CITY	Saxon		
STATE	WI	**NUMBER OF UNITS**	2
ZIP CODE	54559		
COUNTY	Iron		
CONTACT PERSON	Will Mills		
TELEPHONE	303-571-7418		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1913	HYD	6,087.00	
2	USE	HC	1913	HYD	5,571.00	
				Plant Total	11,658.00	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	0.50	0.50	115.81	98.95	0.08	
2	0.50	0.60	90.85	95.66	4.02	
Plant Total	1.00	1.10				

D. UNIT FUEL USED

	PRIMARY FUEL USE				SECONDARY FUEL USE			
Unit ID #	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	HYD							
2	HYD							

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2018

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Big Falls Hydro Generating Statior	**PLANT ID**	85006
STREET ADDRESS			
CITY	Big Falls		
STATE	WI	**NUMBER OF UNITS**	3
ZIP CODE	54926		
COUNTY	Rusk		
CONTACT PERSON	Will Mills		
TELEPHONE	303-571-7418		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1922	HYD	16,172.00	
2	USE	HC	1922	HYD	11,917.00	
3	USE	HC	1925	HYD	15,334.00	
				Plant Total	43,423.00	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	1.10	1.00	61.54	98.52	0.00	
2	1.10	1.00	45.35	95.81	3.89	
3	1.10	1.00	70.02	98.52	0.00	
Plant Total	3.30	3.00				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	HYD							
2	HYD							
3	HYD							

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2018

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Angus Anson Generating Statior	**PLANT ID**	85076
STREET ADDRESS			
CITY	Sioux Falls		
STATE	SD	**NUMBER OF UNITS**	3
ZIP CODE			
COUNTY	Minnehaha		
CONTACT PERSON	Will Mills		
TELEPHONE	303-571-7418		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
2	USE	GT	1994	NG	16,942.57	
3	USE	GT	1994	NG	1,877.94	
4	USE	GT	2005	NG	101,476.94	
				Plant Total	120,297.45	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
2	90.00	109.00	1.77	87.56	0.00	
3	90.00	109.00	0.20	35.51	98.07	
4	147.00	168.00	6.90	70.46	19.93	
Plant Total	327.00	386.00				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
2-4	NG	1,325,454.00	MCF		FO2	107,221.40	GAL	

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2018

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Nobles Wind Farm	**PLANT ID**	85085
STREET ADDRESS			
CITY	Reading		
STATE	MN	**NUMBER OF UNITS**	2
ZIP CODE			
COUNTY	Nobles		
CONTACT PERSON	Will Mills		
TELEPHONE	303-571-7418		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
NWF1-134	USE	WI	2010	WIND	651,204.15	Up to 201 Megawatts from 134 GE wind turbines
				Plant Total	651,204.15	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
NWF01-134	32.00	32.00	37.17	100.00	0.00	Up to 201 Megawatts from 134 GE wind turbines
Plant Total	32.00	32.00				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
NWF01-67	WIND							
NWF68-134								

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2018

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Menomonie Hydro Generating Statior	**PLANT ID**	85043
STREET ADDRESS			
CITY	Menomonie		
STATE	WI	**NUMBER OF UNITS**	2
ZIP CODE	54751		
COUNTY	Dunn		
CONTACT PERSON	Will Mills		
TELEPHONE	303-571-7418		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1958	HYD	14,513.00	
2	USE	HC	1958	HYD	12,212.00	
				Plant Total	26,725.00	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	1.10	1.20	61.36	100.00	0.00	
2	1.10	1.20	51.63	100.00	0.00	
Plant Total	2.20	2.40				

D. UNIT FUEL USED

	PRIMARY FUEL USE				SECONDARY FUEL USE			
Unit ID #	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	HYD							
2	HYD							

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2018

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Ladysmith Hydro Generating Statior	**PLANT ID**	85039
STREET ADDRESS			
CITY	Ladysmith		
STATE	WI	**NUMBER OF UNITS**	3
ZIP CODE	54848		
COUNTY	Rusk		
CONTACT PERSON	Will Mills		
TELEPHONE	303-571-7418		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1940	HYD	3,862.00	
2	USE	HC	1940	HYD	5,052.00	
3	USE	HC	1983	HYD	4,094.00	
				Plant Total	13,008.00	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	0.30	0.30	48.99	100.00	0.00	
2	0.30	0.20	64.08	100.00	0.00	
3	0.40	0.30	42.49	100.00	0.00	
Plant Total	1.00	0.80				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	HYD							
2	HYD							
3	HYD							

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2018

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Jim Falls Hydro Generating Statior	**PLANT ID**	85035
STREET ADDRESS			
CITY	Jim Falls		
STATE	WI	**NUMBER OF UNITS**	3
ZIP CODE	54748		
COUNTY	Chippewa		
CONTACT PERSON	Will Mills		
TELEPHONE	303-571-7418		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1988	HYD	72,799.00	
2	USE	HC	1988	HYD	73,769.00	
3	USE	HC	1986	HYD	1,409.97	
				Plant Total	147,977.97	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	12.30	12.30	28.08	100.00	0.00	
2	12.50	12.50	28.45	99.71	0.60	
3	0.20	0.20	26.83	34.27	0.00	
Plant Total	25.00	25.00				

D. UNIT FUEL USED

	PRIMARY FUEL USE				SECONDARY FUEL USE			
Unit ID #	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	HYD							
2	HYD							
3	HYD							

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2018

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Holcombe Hydro Generating Statior	**PLANT ID**	85032
STREET ADDRESS			
CITY	Holcombe		
STATE	WI	**NUMBER OF UNITS**	3
ZIP CODE	54745		
COUNTY	Chippewa		
CONTACT PERSON	Will Mills		
TELEPHONE	303-571-7418		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1950	HYD	30,858.00	
2	USE	HC	1950	HYD	42,074.00	
3	USE	HC	1950	HYD	37,895.00	
				Plant Total	110,827.00	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	7.30	7.30	29.85	78.61	0.00	
2	7.30	7.30	40.70	96.00	8.82	
3	7.30	7.30	36.66	97.20	0.00	
Plant Total	21.90	21.90				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	HYD							
2								
3								

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2018

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	French Island Generating Statior	**PLANT ID**	85021
STREET ADDRESS			
CITY	LaCrosse		
STATE	WI	**NUMBER OF UNITS**	4
ZIP CODE			
COUNTY	LaCrosse		
CONTACT PERSON	Will Mills		
TELEPHONE	303-571-7418		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	ST	1969	WOOD	21,632.57	
2	USE	ST	1969	NG	33,061.22	
3	USE	GT	1974	FO2	(34.10)	
4	USE	GT	1974	FO2	(409.60)	
				Plant Total	54,250.09	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	9.00	9.00	27.43	67.85	31.52	
2	7.00	7.00	53.92	79.20	6.80	
3	61.00	81.00	0.00	95.92	98.22	
4	61.00	81.00	-0.06	99.62	72.38	
Plant Total	138.00	178.00				

D. UNIT FUEL USED

	PRIMARY FUEL USE				SECONDARY FUEL USE			
Unit ID #	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
1-2	WOOD	59,132.00	TONS		REF	52,950.50	TONS	
1-2	NG	4,321.00	MCF					
3-4	FO2	82,896.00	GAL					

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2018

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Hayward Hydro Generating Statior	**PLANT ID**	85028
STREET ADDRESS			
CITY	Hayward		
STATE	WI	**NUMBER OF UNITS**	1
ZIP CODE	54843		
COUNTY	Sawyer		
CONTACT PERSON	Will Mills		
TELEPHONE	303-571-7418		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1925	HYD	(31.48)	
				Plant Total	(31.48)	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	0.20	0.20	-1.80	0.00	100.00	
Plant Total	0.20	0.20				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	HYD							

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2018

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Flambeau	**PLANT ID**	85020
STREET ADDRESS			
CITY	Park Falls		
STATE	WI	**NUMBER OF UNITS**	1
ZIP CODE			
COUNTY	Price		
CONTACT PERSON	Will Mills		
TELEPHONE	303-571-7418		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	RET	GT	1969	NG		Retired
				Plant Total	0.00	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	12.00	16.00				
Plant Total	12.00	16.00				

D. UNIT FUEL USED

	PRIMARY FUEL USE				SECONDARY FUEL USE			
Unit ID #	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	NG		MCF		FO2		GAL	

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2018

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Dells Hydro Generating Station	**PLANT ID**	85017
STREET ADDRESS			
CITY	Eau Claire		
STATE	WI	**NUMBER OF UNITS**	7
ZIP CODE			
COUNTY	Eau Claire		
CONTACT PERSON	Will Mills		
TELEPHONE	303-571-7418		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1923	HYD	14,306.00	
2	USE	HC	1924	HYD	13,059.00	
3	USE	HC	1930	HYD	13,488.00	
4	USE	HC	1930	HYD	8,015.00	
5	USE	HC	1930	HYD	5,342.00	
6	RET	HC	1916	HYD		Retired
7	RET	HC	1907	HYD		Retired
				Plant Total	54,210.00	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	1.90	1.90	56.31	88.19	9.24	
2	1.50	1.50	57.34	100.00	0.00	
3	1.50	1.50	59.22	100.00	0.00	
4	1.50	1.50	35.19	100.00	0.00	
5	0.90	0.90	38.11	96.79	3.23	
6	0.00	0.00				Retired
7	0.00	0.00				Retired
Plant Total	7.30	7.30				

D. UNIT FUEL USED

	PRIMARY FUEL USE				SECONDARY FUEL USE			
Unit ID #	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	HYD							
2	HYD							
3	HYD							
4	HYD							
5	HYD							
6								
7								

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2018

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Black Dog Generating Station	**PLANT ID**	85008
STREET ADDRESS			
CITY	Burnsville		
STATE	MN	**NUMBER OF UNITS**	5
ZIP CODE			
COUNTY	Dakota		
CONTACT PERSON	Will Mills		
TELEPHONE	303-571-7418		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
2	USE	CS	1954	NG	245,348.72	
3	RET	ST	1955	SUB		Retired
4	RET	ST	1960	SUB		Retired
5	USE	CS	2002	NG	551,363.00	
6	USE	GT	2018	NG	167,365.78	
				Plant Total	964,077.50	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
2	117.00	117.00	23.94		1.10	
3	79.00	79.00				Retired
4	153.00	153.00				Retired
5	165.00	181.00	34.77	61.69	1.10	
6	212.00	228.00	12.45	92.06	9.90	
Plant Total	726.00	758.00				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
2	NG	93,534.00	MCF					
5	NG	3,680,108.00	MCF					
6	NG	1,663,167.00	MCF					

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2018

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Cedar Falls Hydro Generating Statior	**PLANT ID**	85010
STREET ADDRESS			
CITY	Menonomie		
STATE	WI	**NUMBER OF UNITS**	3
ZIP CODE			
COUNTY	Dunn		
CONTACT PERSON	Will Mills		
TELEPHONE	303-571-7418		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1910	HYD	13,496.00	
2	USE	HC	1911	HYD	11,450.00	
3	USE	HC	1915	HYD	11,788.00	
				Plant Total	36,734.00	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	1.30	1.20	59.26	74.18	0.00	
2	1.10	1.10	56.83	100.00	0.00	
3	1.20	1.10	57.59	100.00	0.00	
Plant Total	3.60	3.40				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	HYD							
2	HYD							
3	HYD							

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2018

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Chippewa Falls Hydro Generating Statior	**PLANT ID**	85013
STREET ADDRESS	25 Court St		
CITY	Chippewa Falls		
STATE	WI	**NUMBER OF UNITS**	6
ZIP CODE	54729		
COUNTY	Chippewa		
CONTACT PERSON	Will Mills		
TELEPHONE	303-571-7418		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1928	HYD	9,864.00	
2	USE	HC	1928	HYD	12,390.00	
3	USE	HC	1928	HYD	21,213.00	
4	USE	HC	1928	HYD	12,173.00	
5	USE	HC	1928	HYD	11,579.00	
6	USE	HC	1928	HYD	9,164.00	
				Plant Total	76,383.00	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	1.90	1.90	29.63	91.08	2.83	
2	2.10	2.10	35.36	87.34	22.24	
3	2.00	2.00	62.09	99.79	0.30	
4	2.00	2.00	35.63	99.79	0.41	
5	2.00	2.00	33.89	99.79	0.31	
6	2.10	2.10	26.15	99.79	0.47	
Plant Total	12.10	12.10				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	HYD							
2								
3								
4								
5								
6								

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2018

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Cornell Hydro Generating Statior	**PLANT ID**	85015
STREET ADDRESS			
CITY	Cornell		
STATE	WI	**NUMBER OF UNITS**	4
ZIP CODE			
COUNTY	Chippewa		
CONTACT PERSON	Will Mills		
TELEPHONE	303-571-7418		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1976	HYD	30,694.00	
2	USE	HC	1976	HYD	31,479.00	
3	USE	HC	1976	HYD	32,239.00	
4	USE	HC	1976	HYD	3,899.00	
				Plant Total	98,311.00	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	6.20	6.20	34.02	100.00	0.00	
2	6.40	6.40	33.58	99.63	0.00	
3	6.90	6.90	32.28	99.92	0.00	
4	0.40	0.40	63.58	98.61	1.65	
Plant Total	19.90	19.90				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	HYD							
2	HYD							
3	HYD							
4	HYD							

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2018

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Apple River Hydro Generating Statior	**PLANT ID**	85022
STREET ADDRESS			
CITY	Somerset		
STATE	WI	**NUMBER OF UNITS**	4
ZIP CODE	54025		
COUNTY	St. Croix		
CONTACT PERSON	Will Mills		
TELEPHONE	303-571-7418		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1900	HYD	2,545.00	
2	RET	HC	1900	HYD		
3	USE	HC	1900	HYD	4,183.00	
4	USE	HC	1900	HYD	5,237.00	
				Plant Total	11,965.00	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	0.40	0.05	29.05	54.24	16.47	
2	0.00	0.00				Retired
3	0.50	0.60	43.41	93.69	5.59	
4	0.50	0.60	54.35	92.61	8.28	
Plant Total	1.40	1.25				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	HYD							
2	HYD							
3	HYD							
4	HYD							

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2018

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Hennepin Island Hydro Generating Statior	**PLANT ID**	85029
STREET ADDRESS			
CITY	Minneapolis		
STATE	MN	**NUMBER OF UNITS**	5
ZIP CODE			
COUNTY	Hennepin		
CONTACT PERSON	Will Mills		
TELEPHONE	303-571-7418		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	HC	1954	HYD	12,367.00	
2	USE	HC	1954	HYD	10,917.00	
3	USE	HC	1954	HYD	16,137.00	
4	USE	HC	1954	HYD	14,638.00	
5	USE	HC	1955	HYD	7,091.00	
				Plant Total	61,150.00	

C. UNIT CAPABILITY DATA

	CAPACITY (MEGAWATTS)					
Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	1.20	1.40	50.42	73.21	0.00	
2	1.20	1.40	44.51	63.63	0.00	
3	1.20	1.40	65.79	94.18	0.00	
4	1.20	1.40	59.68	94.20	0.00	
5	1.30	1.50	29.98	54.11	54.88	
Plant Total	6.10	7.10				

D. UNIT FUEL USED

	PRIMARY FUEL USE				SECONDARY FUEL USE			
Unit ID #	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	HYD							
2	HYD							
3	HYD							
4	HYD							
5	HYD							

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2018

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	High Bridge Generating Station	**PLANT ID**	85031
STREET ADDRESS			
CITY	St. Paul		
STATE	MN	**NUMBER OF UNITS**	3
ZIP CODE			
COUNTY	Ramsey		
CONTACT PERSON	Will Mills		
TELEPHONE	303-571-7418		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
4	RET	ST	1944			Retired
5	RET	ST	1956	SUB		Retired
6	RET	ST	1959	SUB		Retired
7	USE	CS	2008	NG	820,283.51	
8	USE	CS	2008	NG	674,026.00	
9	USE	CS	2008	NG	837,187.00	
				Plant Total	2,331,496.51	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
4	0.00	0.00				Retired
5	0.00	0.00				Retired
6	0.00	0.00				Retired
7	152.00	185.00	50.62	80.75	0.37	
8	152.00	185.00	41.59	77.84	2.11	
9	226.00	236.00	40.50	80.74	0.32	
Plant Total	530.00	606.00				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
4								
5	SUB		TONS		NG		MCF	
6	SUB		TONS		NG		MCF	
7	NG	8,654,582.37	MCF					
8	NG	6,402,455.00	MCF					
9	NG	1,358.57	MCF					

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2018

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Key City	**PLANT ID**	85037
STREET ADDRESS			
CITY	Mankato		
STATE	MN	**NUMBER OF UNITS**	4
ZIP CODE			
COUNTY	Blue Earth		
CONTACT PERSON	Will Mills		
TELEPHONE	303-571-7418		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	RET	GT	1969			Retired
2	RET	GT	1969	NG		All units retired in 2015
3	RET	GT	1969	NG		All units retired in 2015
4	RET	GT	1969	NG		All units retired in 2015
				Plant Total	0.00	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	0.00	0.00				Retired
2	8.00	9.00				Retired
3	13.00	16.00				Retired
4	13.00	16.00				Retired
Plant Total	34.00	41.00				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	NG		MCF					
2	NG		MCF					
3	NG		MCF					
4	NG		MCF					

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2018

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Inver Hills	**PLANT ID**	85034
STREET ADDRESS			
CITY	Inver Grove Heights		
STATE	MN	**NUMBER OF UNITS**	8
ZIP CODE			
COUNTY	Dakota		
CONTACT PERSON	Will Mills		
TELEPHONE	303-571-7418		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1-6	USE	GT	1972	NG	14,143.00	
7-8	STB		1994			
				Plant Total	14,143.00	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	47.00	62.00	0.69	97.22	9.81	
2	47.00	62.00	0.27	95.61	73.98	
3	47.00	62.00	0.24	82.28	0.00	
4	47.00	62.00	0.43	81.76	31.48	
5	47.00	61.00	0.49	88.18	77.71	
6	47.00	62.00	0.49	99.24	0.00	
7	1.80	1.80	0.00	0.00	0.00	
8	1.80	1.80	0.00	0.00	0.00	
Plant Total	285.60	374.60				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
1-6	NG	241,179.00	MCF		FO2	178,849.00	GAL	

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2018

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Granite City	**PLANT ID**	85025
STREET ADDRESS			
CITY	Saint Cloud		
STATE	MN	**NUMBER OF UNITS**	4
ZIP CODE			
COUNTY	Sherburne		
CONTACT PERSON	Will Mills		
TELEPHONE	303-571-7418		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1-4	USE	GT	1969	NG	(554.00)	
				Plant Total	(554.00)	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	13.00	16.00	-0.10	85.86	99.68	
2	13.00	16.00	-0.09	77.79	99.80	
3	13.00	16.00	-0.10	85.86	99.68	
4	13.00	16.00	-0.10	85.03	99.71	
Plant Total	52.00	64.00				

D. UNIT FUEL USED

	PRIMARY FUEL USE				SECONDARY FUEL USE			
Unit ID #	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
1-4	NG	4,551.00	MCF		FO2	2,986.00	GAL	

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2018

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Blue Lake	**PLANT ID**	85009
STREET ADDRESS			
CITY	Shakopee		
STATE	MN	**NUMBER OF UNITS**	6
ZIP CODE			
COUNTY	Scott		
CONTACT PERSON	Will Mills		
TELEPHONE	303-571-7418		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1-4	USE	GT	1974	FO2	(451.00)	
7-8	USE	GT	2005	FO2	105,730.00	
				Plant Total	105,279.00	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	39.00	50.00	-0.04	47.28	99.89	
2	39.00	50.00	-0.05	55.11	99.87	
3	36.00	46.00	0.00	91.67	96.43	
4	39.00	48.00	-0.02	91.70	91.17	
7	150.00	174.00	2.91	83.26	47.00	
8	150.00	177.00	3.96	81.78	54.69	
Plant Total	453.00	545.00				

D. UNIT FUEL USED

	PRIMARY FUEL USE				SECONDARY FUEL USE			
Unit ID #	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
1-4, 7-8	FO2	113,779.00	GAL		NG	1,049,313.00	mcf	

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2018

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Riverside Generating Station	**PLANT ID**	85055
STREET ADDRESS			
CITY	Minneapolis		
STATE	MN	**NUMBER OF UNITS**	5
ZIP CODE			
COUNTY	Hennepin		
CONTACT PERSON	Will Mills		
TELEPHONE	303-571-7418		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
7	RET	ST	1987	SUB		Retired
8	RET	ST	1964	SUB		Retired
7A	USE	CS	2008	NG	901,917.00	
9	USE	CS	2008	NG	882,127.00	
10	USE	CS	2008	NG	849,224.00	
				Plant Total	2,633,268.00	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
7	0.00	0.00				Retired
8	0.00	0.00				Retired
7A	160.00	158.00	64.35	90.07	1.60	
9	147.00	171.00	58.89	88.68	2.88	
10	147.00	171.00	56.69	86.94	4.92	
Plant Total	454.00	500.00				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
7	SUB		TONS		NG		MCF	
8	SUB		TONS		FO2		GAL	
7A	NG	0.00	MCF					
9	NG	8,917,543.00	MCF					
10	NG	8,556,205.00	MCF		FO2	335.00	GAL	

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2018

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Monticello Nuclear Generating Statior	**PLANT ID**	85046
STREET ADDRESS			
CITY	Monticello		
STATE	MN	**NUMBER OF UNITS**	1
ZIP CODE	55362		
COUNTY	Wright		
CONTACT PERSON	Will Mills		
TELEPHONE	303-571-7418		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	NC	1971	NUC	5,618,024.00	
				Plant Total	5,618,024.00	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	617.00	646.00	99.28	99.21	0.00	
Plant Total	617.00	646.00				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	NUC		MBTU					

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2018

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Prairie Island Nuclear Generating Statior	**PLANT ID**	85051
STREET ADDRESS			
CITY	Welch		
STATE	MN	**NUMBER OF UNITS**	2
ZIP CODE			
COUNTY	Goodhue		
CONTACT PERSON	Will Mills		
TELEPHONE	303-571-7418		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	NC	1973	NUC	4,190,471.00	
2	USE	NC	1974	NUC	4,792,834.00	
				Plant Total	8,983,305.00	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	521.00	546.00	87.61	90.46	0.00	
2	519.00	546.00	100.21	100.00	0.00	
Plant Total	1,040.00	1,092.00				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	NUC		MBTU					
2	NUC		MBTU					

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2018

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Red Wing Generating Station	**PLANT ID**	85052
STREET ADDRESS			
CITY	Red Wing		
STATE	MN	**NUMBER OF UNITS**	2
ZIP CODE	55066		
COUNTY	Goodhue		
CONTACT PERSON	Will Mills		
TELEPHONE	303-571-7418		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1-2	USE	ST	1949	REF	133,810.00	
				Plant Total	133,810.00	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	9.00	9.00	89.75	90.58	1.48	
2	9.00	9.00	64.16	61.06	36.87	
Plant Total	18.00	18.00				

D. UNIT FUEL USED

	PRIMARY FUEL USE				SECONDARY FUEL USE			
Unit ID #	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	REF	124,765.24	TONS		NG	12,267.70	MCF	
2	REF	84,991.53	TONS		NG	13,957.50	MCF	

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2018

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
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A. PLANT DATA

PLANT NAME	Allen S. King Generating Statior	**PLANT ID**	85038
STREET ADDRESS			
CITY	Bayport		
STATE	MN	**NUMBER OF UNITS**	1
ZIP CODE			
COUNTY	Washington		
CONTACT PERSON	Will Mills		
TELEPHONE	303-571-7418		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	ST	1968	SUB	2,698,691.00	
				Plant Total	2,698,691.00	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	511.00	511.00	60.29	70.97	13.20	
Plant Total	511.00	511.00				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	SUB	1,501,255.00	TONS	8,796	NG	53,400.00	MCF	

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2018

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
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A. PLANT DATA

PLANT NAME	Sherburne County (Sherco) Generating Statior	**PLANT ID**	85058
STREET ADDRESS			
CITY	Becker		
STATE	MN	**NUMBER OF UNITS**	3
ZIP CODE	55308		
COUNTY	Sherburne		
CONTACT PERSON	Will Mills		
TELEPHONE	303-571-7418		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	ST	1976	SUB	2,853,704.00	
2	USE	ST	1977	SUB	4,354,996.00	
3	USE	ST	1987	SUB	5,238,565.00	
				Plant Total	12,447,265.00	

C. UNIT CAPABILITY DATA

	CAPACITY (MEGAWATTS)					
Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	680.00	680.00	47.91	69.56	5.54	
2	682.00	682.00	72.90	97.82	2.18	
3	876.00	876.00	68.27	93.21	6.79	
Plant Total	2,238.00	2,238.00				

D. UNIT FUEL USED

	PRIMARY FUEL USE				SECONDARY FUEL USE			
Unit ID #	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	SUB	1,756,925.00	TONS	8,651	FO2	222,586.48	GAL	
2	SUB	2,657,125.00	TONS	8,643	FO2	210,584.73	GAL	
3	SUB	3,113,242.00	TONS	8,555	FO2	683,419.80	GAL	

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2018

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A. PLANT DATA

PLANT NAME	Wilmarth Generating Station	**PLANT ID**	85073
STREET ADDRESS			
CITY	Mankato		
STATE	MN	**NUMBER OF UNITS**	2
ZIP CODE			
COUNTY	Blue Earth		
CONTACT PERSON	Will Mills		
TELEPHONE	303-571-7418		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	ST	1948	REF	60,441.54	
2	USE	ST	1951	REF	39,995.11	
				Plant Total	100,436.65	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	9.00	9.00	76.66	86.4	1.7	
2	9.00	9.00	50.73	64.7	3.5	
Plant Total	18.00	18.00				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	REF	99,880.26	TONS		NG	27,445.00	MCF	
2	REF	68,160.86	TONS		NG	15,457.50	MCF	

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2018

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A. PLANT DATA

PLANT NAME	Pleasant Valley Wind Farm	**PLANT ID**	85086
STREET ADDRESS	228 Industrila Park Dr		
CITY	Dexter		
STATE	MN	**NUMBER OF UNITS**	1
ZIP CODE	55926		
COUNTY	Mower		
CONTACT PERSON	Chriss Hogg		
TELEPHONE	612-321-3291		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
PVWF01-100	USE	WI	2015	WIND	756,650.32	Up to 200 megawatts from 100 wind turbines
				Plant Total	756,650.32	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
PVWF01-100	29.40	29.40	44.07	100.0	0.0	Up to 200 megawatts from 100 wind turbines
Plant Total	29.40	29.40				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
PVWF01-100	WIND		0		WIND		0	

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2018

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A. PLANT DATA

PLANT NAME	Border Wind Farm	**PLANT ID**	85087
STREET ADDRESS	5190 107th St NE		
CITY	Rolla		
STATE	ND	**NUMBER OF UNITS**	1
ZIP CODE	58367		
COUNTY	Rollette		
CONTACT PERSON	Jayme Orrock		
TELEPHONE	612-321-3275		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
BWF01-75	USE	WI	2015	WIND	609,517.15	Up to 150 megawatts from 75 wind turbines
				Plant Total	609,517.15	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
BWF01-75	22.10	22.10	47.01	100.0	0.0	Up to 150 megawatts from 75 wind turbines
Plant Total	22.10	22.10				

D. UNIT FUEL USED

	PRIMARY FUEL USE				SECONDARY FUEL USE			
Unit ID #	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
BWF01-75	WIND		0		WIND		0	

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2018

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A. PLANT DATA

PLANT NAME	Courtenay Wind Farm	**PLANT ID**	85088
STREET ADDRESS	1401 Hwy 9 SE		
CITY	Courtenay		
STATE	ND	**NUMBER OF UNITS**	1
ZIP CODE	58426		
COUNTY	Stutsman		
CONTACT PERSON	Jayme Orrock		
TELEPHONE	612-321-3275		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
CWF01-100	USE	WI	2016	WIND	714,237.32	Up to 200 megawatts from 100 wind turbines
				Plant Total	714,237.32	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
CWF01-100	30.40	30.40	41.81	100.0	0.0	Up to 200 megawatts from 100 wind turbines
Plant Total	30.40	30.40				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
CWF01-100	WIND		0		WIND		0	

2302 Great N. Drive
Fargo, ND 58102
(701) 241-8632
dave.sederquist@xcelenergy.com

July 2, 2018

—Via Electronic Filing & Federal Express—

Darrell Nitschke, Executive Secretary
North Dakota Public Service Commission
600 East Boulevard, Dept. 408
Bismarck, ND 58505

RE: NORTHERN STATES POWER COMPANY
BIENNIAL TEN-YEAR PLAN

Dear Mr. Nitschke:

In accordance with Section 49-22-04 of the North Dakota Century Code, Northern States Power Company, doing business as Xcel Energy, hereby submits 10 copies of its Annual Ten-Year Plan for Major Generation and Transmission Facilities in the state of North Dakota. The information contained in the report is in compliance with the rules and regulations of the North Dakota Public Service Commission, as well as the provisions of the Settlement Agreement in Case No. PU-10-657.

In compliance with section 69-06-02-02, notice of the filing has been given to each state agency and officer entitled to notice as designated in section 69-06-01-05. A service list is attached.

Please feel free to contact me at dave.sederquist@xcelenergy.com or (701) 241-8632 if you have any questions regarding this report.

Sincerely,

David H. Sederquist

DAVID H. SEDERQUIST
SR. REGULATORY CONSULTANT
XCEL ENERGY

Enclosures
c: Service List (WITHOUT ENCLOSURES)

CERTIFICATE OF SERVICE

I, Carl Cronin, hereby certify that I have this day served notice of the foregoing document on the attached list of persons by delivery by hand or by causing to be placed in the U.S. mail at Minneapolis, Minnesota.

TEN-YEAR PLAN FOR MAJOR GENERATION AND TRANSMISSION FACILITIES IN THE STATE OF NORTH DAKOTA

Dated this 2nd day of July 2018

/s/

_____

Carl Cronin
Regulatory Administrator

Northern States Power Company d/b/a Xcel Energy
2018 North Dakota Ten-Year Plan
Service List – Notice of Filing

Darrell Nitschke
Executive Secretary
North Dakota Public Service Commission
600 East Boulevard Ave., Dept. 408
Bismarck, ND 58505

Aeronautics Commission
PO Box 5020
Bismarck, ND 58502

Attorney General
State Capitol Building, 1st Floor
600 East Boulevard Ave., Dept. 125
Bismarck, ND 58505

Department of Agriculture
State Capitol Building, 6th Floor
600 East Boulevard Ave., Dept. 602
Bismarck, ND 58505-0020

Department of Health
State Capitol Building
2nd Floor Judicial Wing
600 East Boulevard Ave.
Bismarck, ND 58505-0200

Department of Human Services
State Capitol, Judicial Wing
600 East Boulevard Ave., Dept 325
Bismarck, ND 58505-0250

ND Department of Labor & Human Rights
State Capitol, 13th Floor
600 East Boulevard Ave.
Bismarck, ND 58505-0340

Department of Commerce
Division of Economic Development & Finance
Century Center
1600 East Century Ave., Suite 2
PO Box 2057
Bismarck, ND 58502-2057

Energy Development Impact Office
1707 N. 9th St
PO Box 5523
Bismarck, ND 58506-5523

Game & Fish Department
100 North Bismarck Expressway
Bismarck, ND 58501-5095

North Dakota Industrial Commission
Geological Survey
1016 East Calgary Ave.
Bismarck, ND 58503

Governor's Office
State Capitol Building, 1st Floor
600 East Boulevard Ave., Dept 101
Bismarck, ND 58505-0001

Department of Transportation
608 East Boulevard Ave.
Bismarck, ND 58505-0700

State Historical Society of North Dakota
Heritage Center, Capitol Grounds
612 East Boulevard Ave.
Bismarck, ND 58505-0830

Indian Affairs Commission
State Capitol, 1st Floor Judicial Wing – Rm 117
600 East Boulevard Ave.
Bismarck, ND 58505-0300

Job Service of North Dakota
1000 East Divide
PO Box 5507
Bismarck, ND 58506-5507

State Land Department
1707 N. 9th St.
PO Box 5523
Bismarck, ND 58506-5523

Parks and Recreation Department
1600 East Century Ave., Suite 3
Bismarck, ND 58503-0649

Soil Conservation Committee
2718 Gateway Ave., Ste. 104
Bismarck, ND 58503-0585

State Water Commission
900 East Boulevard Ave., Dept. 770
State Office Building
Bismarck, ND 58505-0850

United States Department of Defense
Minot Air Force Base
201 Summit Drive
Minot, ND 58701

United States Fish and Wildlife Service
3425 Miriam Avenue
Bismarck, ND 58501

United States Army Corps of Engineers
1513 South 12th Street
Bismarck, ND 58504

Federal Aviation Administration
Bismarck Airports District Office, BIS-ADO-600
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TEN-YEAR PLAN FOR MAJOR GENERATION AND TRANSMISSION FACILITIES

TO THE

NORTH DAKOTA PUBLIC SERVICE COMMISSION

SUBMITTED BY NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION JULY 2, 2018

Northern States Power Company
2018 North Dakota Ten-Year Plan

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STATE OF NORTH DAKOTA
BEFORE THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE 2018 TEN-YEAR PLAN OF NORTHERN STATES POWER COMPANY, DOING BUSINESS AS XCEL ENERGY

TEN-YEAR PLAN

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy with operations in North Dakota, (Xcel Energy or the Company) is pleased to submit our biennial Ten-Year Plan to the North Dakota Public Service Commission (Commission) in compliance with Section 49-22-04 of the North Dakota Century Code.

The NSP-Minnesota operating company (NSPM) has service territory in North Dakota, South Dakota, and Minnesota. NSP-Wisconsin (NSPW) has service territory in Wisconsin and Michigan. The Company operates the NSPM and NSPW generation and transmission as the NSP System. We presently serve approximately 92,000 retail electric customers in North Dakota around Fargo, Grand Forks, and Minot, and 54,000 natural gas customers in the Fargo and Grand Forks areas. The Company owns just over 430 miles of transmission lines and 20 substations (69kV and above) in North Dakota.

This Ten-Year Plan contains expanded information in compliance with the Settlement Agreement in Case No. PU-07-776 and Order points in Case Nos. PU-08-907 and PU-08-908 including:

- A summary of the major generation and transmission investments and purchase agreements we plan to pursue over the next 5 years; and
- A schedule of anticipated future applications for Advance Determination of Prudence (ADP) (Appendix B).
- A report of reductions in energy production at its base load generation units due to the existence of wind generation, and the impacts and costs of cycling coal plant production to accommodate off-peak wind generation (Appendix C).

I. ELECTRIC GENERATION FACILITIES

A. Existing Facilities

In this section, we describe the general location, size, and type of all facilities in North Dakota to be owned or operated by Xcel Energy during the next ten years, as well as those facilities to be removed from service during the ten-year period.

1. Border Winds Wind Facility.

The company owns and operates the 150 MW Border Winds wind facility near Rolla, North Dakota. The facility is comprised of 75 Vestas V100 2.0 MW turbines with variable pitch blades. The Border Winds footprint spans nearly 25,000 acres in the northeastern part of Rolette County. The plant went into service in December, 2015.

2. Courtenay Wind Facility.

The company owns and operates the 200 MW Courtenay wind facility north of Jamestown, North Dakota. The facility is comprised of 100 Vestas V100 2.0 MW turbines with variable pitch blades. The Courtenay facility spans nearly 25,000 acres in northeastern Stutsman County. The plant went into service in December, 2016.

3. Purchases of Power Produced in North Dakota.

In its previously filed 2016 Ten-year Plan, the Company reported that it had a Transmission Service Agreement (TSA) known as the "Stanton Displacement Agreement" in which 188 MW was supplied from Great River Energy's Stanton Unit, located in the vicinity of Stanton, North Dakota, for NSP's North Dakota loads. However, Great River Energy (GRE) retired the Stanton unit in 2017, and the TSA was terminated on October 22, 2017. FERC accepted the termination of the TSA in Docket No. ER17-2344-000.

Xcel Energy also has a twenty-year power purchase agreement (PPA), through January 18, 2026, with Acciona Wind Energy USA for energy supplied from its 11.88 MW Velva Windfarm located in McHenry County, North Dakota.

See Appendix A for a listing of *all* generating plants owned and operated by Xcel Energy that serve the Company's Upper Midwest (NSP) System.

B. Proposed Facilities – Next Five Years

In this section, we provide the locations of the preferred sites for all electric generating facilities tentatively planned to be constructed in North Dakota within the next five years. In addition, we provide brief summaries of key generation additions contemplated within the larger NSP System, per the terms of the Settlement in Case No. PU-07-776.

We note that the Company filed its 2016-2030 Upper Midwest Resource Plan (IRP) with the Minnesota Public Utilities Commission (MPUC) (Docket No. E002/RP-15-21) on January 2, 2015, and filed a substantive supplement on January 29, 2016. Copies of the plan and supplement were also filed with the North Dakota Commission (Case No. PU-15-019). The MPUC approved the IRP in October 2016.

The Company plans to file its next IRP on February 1, 2019. Our resource plan modeling includes a planning scenario based on meeting North Dakota requirements – specifically, the exclusion of environmental externalities, as required by N.D.C.C.§49-02-23, and removing energy-related mandates imposed on the Company by other states.

We propose to continue to fulfill our future NSP System electric generating resource needs through multiple resource acquisition processes including competitive bidding, Company ownership, PPAs, and demand side management.[1] This multi-pronged and flexible approach to resource acquisitions facilitates multiple generation technologies and locations.

North Dakota Generation

1. *Foxtail Wind.*

The Company is pursuing the addition of 1,850 MW of wind on its NSP System as a result of a comprehensive RFP issued in September 2016. As part of this portfolio, the Company is constructing a 150 MW wind facility in Dickey County on a 20,000 acre site about 20 miles west of Ellendale, North Dakota. It is anticipated that commercial operations will commence by September 2019.

[1] While the Company has included proposed resources in its Resource Plan, at this point there are no specific plans with sufficient information for listing in the Anticipated ADP Petitions table in Appendix B.

2. Clean Energy #1Wind.

As part of its 1,850 MW wind portfolio proposal, the Company has entered into a PPA with Allete Clean Energy (ACE) for the purchase of power from a 100 MW wind facility being constructed in Dickey County on a 20,000 acre site about 20 miles west of Ellendale, North Dakota. It is anticipated that commercial operations will commence by September 2019.

Other NSP System Generation

3. Other Projects in the 1,850 MW Wind Portfolio.

The Company solicited several wind projects through an RFP issued in September 2016. As a result, the Company is pursuing multiple wind resources as Power Purchase Agreements, Build-Own-Transfer agreements, and Company self-build projects, totaling 1,850 MW. In addition to the two projects in North Dakota, there are seven other sites located in South Dakota, and Minnesota. ADP's were filed for these projects with the Commission on March 29, 2017 in Case No. PU-17-120 and October 10, 2017 in Case No. PU-17-372. We submitted supplemental filings on May 18, 2018 and March 23, 2018, in each respective docket, that address the impacts of the Tax Cuts and Jobs Act (TCJA) on the costs of the propose wind projects. The dockets are still pending. Below is the list of wind projects located outside of North Dakota with commercial operation dates indicated.

Wind Farm	**Size**	**Location**	**COD**
Blazing Star I Wind Farm	200 MW	Hendricks, MN	2019
Blazing Star II Wind Farm	200 MW	Hendricks, MN	2020
Freeborn Wind Farm	200 MW	Glenville, MN	2020
Crowned Ridge Wind Farm	300 MW	Watertown, SD	2019
Crowned Ridge Purchase Agreement	300 MW	Watertown, SD	2019
Lake Benton Wind Farm	100 MW	Lake Benton, MN	2019
Dakota Range Wind Farm	300 MW	Watertown, SD	2021

4. Mankato Energy Center Unit 2.

In 2015, the Minnesota Commission approved a proposal made by the Calpine Corporation for the expansion of the Mankato Energy Center (MEC). The Company subsequently filed an ADP Application with the North Dakota Commission for 345 MW of capacity and associated energy to be added to the NSP System through a 20-year PPA with MEC in Case No. PU-15-96. On March 23, 2016, the Commission

dismissed our application without prejudice. Commercial operation is anticipated for 2nd Quarter 2019.

C. Proposed Facilities – Next 10 Years

At this time, specific plans for additional electric generation facilities in the State of North Dakota over the next 10 years include the 150 MW Foxtail wind energy facility and the 100 MW Clean Energy #1 PPA as previously discussed.

Additionally, on March 9, 2016, the Commission approved the First Revised Negotiated Agreement between the Company and Commission Advocacy Staff that included a commitment by the Company to build generation in North Dakota. Specifically, the terms of the agreement are as follows:

> *By the end of 2025, [the Company] will build or have located in eastern North Dakota a natural gas-fired electric generation facility with a capacity of at least 200 MW. The combustion turbine will be treated as an [Xcel Energy] System resource and its costs will be allocated to all states and customers served by the [Xcel Energy] System. If the combustion turbine is not in-service by December 31, 2025, [the Company] will refund to its North Dakota customers 50 percent of the revenues collected from North Dakota customers that exceed the revenues that would have been collected from January 1, 2016 through December 31, 2025 if North Dakota customers had paid an adjusted system average cost for fuel, and energy and associated capacity, for the six biomass PPAs identified in the Negotiated Agreement.* [2]

The Commission's March 9, 2016 Order also outlined the need for a long-term Resource Treatment Framework (RTF) to appropriately address resource energy policy differences in the states within the NSP System, which the Company was required to file with the Commission by January 1, 2017.[3] The Company filed its RTF proposal on December 31, 2016, consistent with the terms of the Negotiated Agreement. The RTF docket is still pending before the commission.

See Appendix B for a schedule of the pending and future ADP requests by the Company for generation resources.

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[2] *N. States Power Co. 2013 Elec. Rate Increase Application et al.*, Case Nos. PU-12-813, PU-13-706, PU-13-707, PU-13-708, PU-13-742, PU-13-743, PU-13-194, PU-13-195, ORDER APPROVING SETTLEMENT at 4 (N.D. P.S.C. Mar. 9, 2016).
[3] Id.

II. ELECTRIC TRANSMISSION FACILITIES

A. Existing Facilities

Our existing electric transmission line facilities in North Dakota are listed in Table 1 below. We have no plans to retire any electric transmission facilities in North Dakota within the next 10 years.

Table 1. NSP North Dakota Transmission Lines

Line Description	Line Number	kV	Line Mileage
Bison-Alexandria SS (MRES)	0955	345	135.7
Total 345 kV			**135.7**
Letellier-Drayton	912	230	28.7
Prairie-Grand Forks (WAPA)	916	230	6.8
Maple River-Wahpeton (MPC)	910	230	3.6
Maple River-Sheyenne	911	230	6.6
Sheyenne-Fargo(WAPA)	915	230	4.3
Sheyenne-Lake Park (MPC)	911	230	1.4
Audubon (OTP)-Hubbard (MP)	909	230	38.3
Glenboro (MHEB)-Peace Garden	920	230	2.0
Peace Garden-Rugby (OTP)	920	230	54.4
Total 230 kV			**146.1**
Maple River-Red River	839	115	5.6
Maple River-Cass County	839	115	2.7
Cass County Tap-Moderow (MPC)	839	115	1.9
Moderow (MPC)-Sheyenne	839	115	1.5
Cass County-Sheyenne	866	115	3.5
Mallard-Souris	860	115	5.3
Souris-Velva	850	115	19.6
Velva-McHenry	850	115	5.2
McHenry-Neal	850	115	0.2
Prairie-Nordic1	5510	115	2
Prairie-Nordic2	5511	115	1.98
Total 115 kV			**49.48**

Ada-Ada (MPC)	757	69	3.1
Gateway-Grand Forks Steam	746	69	0.9
Gateway-Prairie	746	69	5.5
Grand Forks (WAPA)-Central	786	69	4.6
Central-Sugar Hills	786	69	0.8
Sugar Hills-Park	786	69	0.8
Prairie-Emerado	772	69	13.3
Prarie-Thompson	733	69	8.5
Thompson-Reynolds	773	69	7
Reynolds-South	773	69	10
South-Hillsboro Tap	773	69	8.6
Hillsboro Tap-Hillsboro	773	69	1.9
Hillsboro-Trail County	773	69	1
Trail County-Elm River	773	69	9.3
South-Mayville (MPC)	768	69	12
Mayville (MPC)-Mayville	768	69	1.2
Mayville-Hatton	768	69	14.8
Elk Valley-Larimore	776	69	1.7
Total 69 kV			**105.0**

B. Proposed Facilities – Next Five Years

In this section, we provide a brief description of significant transmission developments planned by the Company on its NSP System in North Dakota, which includes updates on previously proposed facilities.

1. Fargo Load Serving

NSPM's yearly planning assessments have indicated that the existing Fargo area 115 kV system and the 230-115 kV transformers are deficient in the ability to serve the load during double contingency conditions. NSPM performed the "Fargo Load Serving Study" to identify transmission plan to address these load serving deficiencies in this area, and determined that a five mile 115 kV line from Maple River substation to Red River substation would be the least cost option.

The facilities include building five miles of new 115 kV line from Maple River substation to Red River substation, and substation work at Maple River and Red River to accommodate the new line. The Commission approved our application for Red River-Maple River 2nd 115 kV line. The expected in-service date is by the end of 2019.

2. Minot Load Serving Plan

A joint study with Basin Electric Power Cooperative, Western Area Power Administration, and Central Power Electric Cooperative has been completed for the Minot Area. NSP is proposing to construct a new 20 mile 230 kV from GRE's existing McHenry substation to a new propose NSP 230/115 kV substation called Magic City. The new 230 kV will help offload the existing 115 kV lines in the area and provide additional transformation capacity and voltage support to the Minot area. The expected in-service date is the end of 2018.

C. Proposed Facilities – Next 10 Years

Xcel Energy participated in a large regional Multi Value Project (MVP) study with Midcontinent Independent System Operator (MISO) to determine what large regional transmission build-outs would be necessary to increase the overall reliability and efficiency of the transmission system. The costs of these projects are being shared to beneficiaries across the entire MISO North/Central footprint. These projects qualify for MVP cost treatment based on their contributions to increased reliability, economic benefits, or supporting compliance with one or more of the states' renewable requirements.

In addition to the MISO MVP process, Xcel Energy participates in transmission planning with a larger group of utilities called the Minnesota Transmission Owners (MTO). The MTO consists of all of the investor-owned, cooperative, and municipal utilities that own transmission facilities 100 kV and above in Minnesota. Several MTO members (e.g., Xcel Energy, Great River Energy, Otter Tail Power, etc.) also own significant transmission facilities in North Dakota.

III. NATURAL GAS PIPELINE FACILITIES

A. Existing Facilities

We operate an 11.9 mile intrastate natural gas pipeline facility in the state of North Dakota, from an interconnection with Williston Basin Interstate Pipeline Company near Mapleton, North Dakota, to our natural gas distribution system in Fargo, North Dakota. The Commission granted a Certificate of Public Convenience and Necessity and Corridor Certificate for this facility in Case No. PU-400-89-426. We have no plans to retire any intrastate natural gas pipeline facilities in North Dakota within the next 10 years.

B. Proposed Facilities - Next Five Years

At this time we do not have plans to construct any new intrastate natural gas pipeline transmission facilities in North Dakota within the next five years.

C. Proposed Facilities - Next 10 Years

At this time we do not have formal plans to construct any new intrastate natural gas pipeline transmission facilities in North Dakota within the next 10 years. However, we are continually reviewing the potential for serving additional gas retail demand in eastern North Dakota. We will inform the Commission if these projects become viable.

IV. REGIONAL COORDINATION

All major transmission planning performed by the Company is now coordinated through MISO on a regional basis. MISO issues its annual transmission expansion plan MTEP after coordinated planning and stakeholder review.

As a result of complying with the Federal Energy Regulatory Commission Order No. 890 rules, MISO has also implemented Sub-Regional Planning Meetings as part of their annual MTEP development process. We participate in the Western Region meetings. These Sub-Regional Planning meetings provide forums for stakeholder input and coordination of plans and we actively participate in each one. This joint planning is intended to maximize use of existing facilities and minimize the amount of new facilities. More information regarding this joint planning is available at the following link:

https://www.misoenergy.org/planning/transmission-studies-and-reports/#nt=%2Freport-study-analysistype%3AMTEP&t=10&p=0&s=&sd=

Another example of coordination by the utilities is the formalization of the MTO organization, as noted above. In addition to the biennial transmission planning work of the MTO, the MTO utilities also coordinate their transmission planning activities with MISO's MTEP process.

The Company participates in all MISO targeted planning studies, which are studies that happen outside the normal MTEP process. MISO has performed three targeted studies in the last two years.

The first targeted study was the Renewable Integration Impact Assessment. The primary purpose of the Renewable Integration Impact Assessment (RIIA) is to methodically find system integration inflection points driven by increasing levels of renewable generation. Industry studies have shown that the complexity for renewable integration escalates non-linearly with increasing penetrations of renewables. Over certain ranges of renewable penetration, complexity is constant when spare capacity and flexibility exist, but at specific penetration levels when they are depleted, complexity rises dramatically. These are system inflection points, where the underlying infrastructure and/or system operations need to be modified to reliably achieve the next tranche of renewable deployment. This study aims to find those inflection points, and examine potential solutions to mitigate them. This study is available at the following link:

https://cdn.misoenergy.org/20170927%20PAC%20Item%2003i%20Renewable%20Integration%20Impact%20Assessment%20Assumptions%20Document89950.pdf

The second study was the Southwest Power Pool Coordinated System Plan. This study was performed to examine if any potential transmission projects between the two markets had mutual benefits. The study examined seven unique transmission projects for the regional planning process. MISO and SPP staff worked together with stakeholders from both markets to determine benefits through a collaborated effort. The transmission options were tested using Adjusted Production Cost (APC) benefits. No projects met the criteria for selection. The Southwest Power Pool Coordinated System Plan is available at the following link:

https://cdn.misoenergy.org/MTEP17%20Book%203%20Policy%20Landscape106028.pdf

Finally, MISO performed the Footprint Diversity Study. This studies focus was on the transfer rights between MISO North and MISO South using MISO operated facilities. The primary focus was on potential ways to increase the interface capability using economic drivers. Thirty Five transmission projects were analyzed for potential benefits and none passed the minimum 1.25 Benefit/Cost ratio needed to move on in the next phase of the analysis. The Footprint Diversity Study is available at the following link:

https://cdn.misoenergy.org/MTEP17%20Book%201%20Transmission%20Studies106030.pdf

V. ENVIRONMENTAL PROTECTION

Specific environmental information and efforts to involve land-use planning agencies will be provided to the Commission in future regulatory filings pertaining to specific facilities identified for construction.

VI. DEMAND PROJECTIONS

The NSP System integrates electric generation and transmission to serve customers in North Dakota, South Dakota, Minnesota, Wisconsin, and Michigan. The North Dakota portion of the NSP System's 25-year historical native energy requirements and non-coincident peak demand are shown in Table 2. We produce long-range "median" NSP System forecasts of native energy requirements, summer peak, and winter peak demand. For planning purposes, we also develop a bandwidth to supplement our median forecasts. These scenarios are intended to describe uncertainty in a business-as-usual context: a relatively narrow range of U.S. economic growth with no fundamental change in the relationship between the regional and national economies. Table 3 shows the long-range system forecast of native energy requirements, summer peak, and winter peak demand for the NSP System. Table 4 shows the North Dakota portion of the NSP System forecast.

The forecast for the NSP System is based on forecasts of state jurisdictional sales by major customer class: residential (with and without space heating), small commercial and industrial, and large commercial and industrial. Each customer class is modeled independently for the five states in the NSP System. The native energy requirements are determined by applying a loss factor on total sales.

The NSP System peak is apportioned to state jurisdictions based on their native energy requirements and respective load factors. Consequently, the summer and winter "coincident peak loads" provided in Table 4 represent the North Dakota jurisdiction customer demand at time of the NSP System seasonal peak demand. This coincident peak demand is appropriate for generating capacity requirement forecasting.

"Non-coincident" peak demand is also used in evaluating transmission capacity requirements. This is because the transmission system must be able to supply the full local customer demand at all times. Due to load diversity caused primarily by weather variations among states within the NSP System, peak customer demands in our North Dakota service area can be higher than it is during the hour in which the total system peak demand occurs. These local "non-coincident" peak demands are also factored in

to the determination of the need for transmission improvements required for load serving functions.

Table 2. Historical Energy and Peak Load Requirements
North Dakota portion of NSP System (1989 – 2017)

Year	Energy (GWh)	Annual Growth	Non-Coincident Peak Load (MW)	Annual Growth
1989	1,844		374	
1990	1,904	3.3%	399	6.7%
1991	1,925	1.1%	373	-6.5%
1992	1,883	-2.2%	376	0.8%
1993	1,771	-5.9%	333	-11.4%
1994	1,796	1.4%	360	8.1%
1995	1,916	6.7%	362	0.6%
1996	1,984	3.5%	382	5.5%
1997	1,911	-3.7%	351	-8.1%
1998	1,958	2.5%	352	0.3%
1999	1,950	-0.4%	363	3.1%
2000	2,053	5.3%	370	1.9%
2001	2,048	-0.2%	384	3.9%
2002	2,119	3.5%	403	4.8%
2003	2,171	2.4%	395	-2.0%
2004	2,158	-0.6%	403	2.2%
2005	2,289	6.1%	426	5.7%
2006	2,353	2.8%	439	3.0%
2007	2,378	1.1%	463	5.5%
2008	2,478	4.2%	427	-7.8%
2009	2,379	-4.0%	427	0.0%
2010	2,422	1.8%	445	4.2%
2011	2,441	0.8%	449	0.9%
2012	2,419	-0.9%	468	4.2%
2013	2,479	2.5%	453	-3.2%
2014	2,491	0.5%	444	-2.0%
2015	2,418	-2.9%	456	2.7%
2016	2,379	-1.6%	436	-4.4%
2017	2,348	-1.3%	423	-3.0%

Table 3. Forecast of NSP System Energy and Peak Load Requirements (2018 - 2036)

Year	Energy (GWh)	Summer Peak Load (MW)	Winter Peak Load (MW)
2018	43,773	9,060	6,316
2019	43,427	9,004	6,289
2020	43,473	9,015	6,265
2021	43,257	9,050	6,269
2022	43,279	9,110	6,291
2023	43,198	9,144	6,290
2024	43,265	9,188	6,292
2025	43,186	9,222	6,301
2026	43,330	9,283	6,338
2027	43,703	9,391	6,431
2028	44,495	9,525	6,520
2029	44,592	9,600	6,581
2030	44,938	9,691	6,663
2031	45,302	9,780	6,765
2032	46,259	9,962	6,930
2033	47,005	10,203	7,092
2034	47,977	10,432	7,253
2035	49,008	10,654	7,453
2036	50,394	10,912	7,681
Average Annual Growth Rate, 2018-2036			
% Growth:	**0.8%**	**1.0%**	**1.1%**

Notes:

1) Peak Load is *coincident* to the NSP System peak.
2) Winter Peak = MISO Winter Peak season, 2016 is 2016 - 2017 winter peak.
3) Peak Load is the Base Peak (uninterrupted)

Table 4. Forecast of Energy and Peak Load Requirements
North Dakota portion of NSP System (2018 – 2036)

Year	Energy (GWh)	Summer Peak Load (MW)	Winter Peak Load (MW)
2018	2,405	377	390
2019	2,399	377	387
2020	2,391	375	384
2021	2,378	376	385
2022	2,375	377	385
2023	2,376	380	386
2024	2,380	381	386
2025	2,373	383	386
2026	2,373	383	387
2027	2,370	384	389
2028	2,381	385	389
2029	2,390	385	389
2030	2,404	386	389
2031	2,426	387	388
2032	2,458	387	388
2033	2,483	388	388
2034	2,515	389	388
2035	2,554	390	388
2036	2,607	390	388
Average Annual Growth Rates, 2018-2036			
% Growth:	**0.4%**	**0.2%**	**0.0%**

Notes:
1). Peak Load is *coincident* to the Xcel Energy system peak.
2). Winter Peak = MISO Winter Peak season, 2018 is 2018 - 2019 winter peak.
3.) Peak Load forecast growth from 2028 - 2036 is based on average summer and winter ND peak growth rates from 2018 through 2027.

APPENDIX A
List of Xcel Energy Upper Midwest Generating Plants

Resource	Fuel	Capacity		Location
Sherburne County	Coal	2,238	MW	Becker, MN
Prairie Island	Nuclear	1,100	MW	Red Wing, MN
Monticello	Nuclear	671	MW	Monticello, MN
High Bridge	Natural Gas CC	530	MW	St. Paul, MN
Allen S. King	Coal	511	MW	Oak Park Heights, MN
Riverside	Natural Gas CC	454	MW	Minneapolis, MN
Wheaton	Natural Gas, Fuel Oil	430	MW	Wheaton, WI
Angus Anson	Natural Gas CT	327	MW	Sioux Falls, SD
Black Dog	Gas, Coal	282	MW	Burnsville, MN
Nobles	Wind	201	MW	Worthington, MN
Courtenay Wind Farm	Wind	200	MW	Courtenay, ND
Pleasant Valley Farm	Wind	200	MW	Austin, MN
Border Winds	Wind	150	MW	Rolla, ND
French Island	Wood, Refuse	140	MW	La Crosse, WI
Grand Meadow	Wind	100	MW	Dexter, MN
Jim Falls	Hydro	60	MW	Chippewa River, WI
Bay Front	Coal, Wood, Nat Gas	56	MW	Ashland, WI
Wissota	Hydro	40	MW	Chippewa River, WI
Holcombe	Hydro	35	MW	Chippewa River, WI
Cornell	Hydro	33	MW	Chippewa River, WI
St. Croix Falls	Hydro	26	MW	St. Croix River, WI
Chippewa Falls	Hydro	24	MW	Chippewa River, WI
Red Wing	Refuse	18	MW	Red Wing, MN
Wilmarth	Refuse	18	MW	Mankato, MN
Flambeau	Natural Gas, Fuel Oil	17	MW	Park Falls, WI
Hennepin Island	Hydro	14	MW	Minneapolis, MN
Dells	Hydro	13	MW	Chippewa River, WI
Big Falls	Hydro	9	MW	Flambeau River, WI
Cedar Falls	Hydro	7	MW	Red Cedar River, WI
Menomonie	Hydro	5	MW	Red Cedar River, WI
Apple River	Hydro	3	MW	Apple River, WI
Ladysmith	Hydro	3	MW	Flambeau River
Superior Falls	Hydro	2	MW	Montreal River, WI
Thornapple	Hydro	2	MW	Flambeau River, WI
Trego	Hydro	2	MW	Namekagon River, WI
Riverdale	Hydro	1	MW	Apple River, WI
Saxon	Hydro	1	MW	Montreal River, WI
White River	Hydro	1	MW	White River, WI
Hayward	Hydro	0	MW	Namekagon River, WI
	Total	7,924		

APPENDIX B
Schedule of ADP Filings

Pending ADP Petitions

Project	Date Filed	Case No.
1,550 MW Wind Generation	3/29/2017	PU-17-120
Biomass PPA Terminations	6/30/2017	PU-17-270, 271, 322
300 MW Dakota Range Wind	10/10/2017	PU-17-372

Anticipated ADP Petitions

Project	Estimated Date
North Dakota CT	Completion by 2026

APPENDIX C
Report on the Effect of Wind Generation on Baseload Plants

In the Commission's orders on the Company's applications for Advance Determination of Prudence for the Nobles and Merricourt Wind Projects dated August 12, 2009 in Case Nos. PU-08-907 and PU-08-908, the Commission included the following order points:

2. NSP will report to the extent possible, as part of its annual 10-year plan, all reductions in the energy produced at its base load generation units that would not have occurred except for the existence of wind generation. The report will include the time of the event, length of the event, base load plant affected and the amount of energy not produced at the base load plant during the event.
3. NSP will report, as part of its next 10-year plan, on the impacts and costs associated with taking coal plant production up and down to accommodate wind resources during off peak hours.

Order Point 2

In response to order point 2, we performed an analysis of the NSP system performance over 8,760 hours from the first hour on April 1, 2017 through the last hour on March 31, 2018. To establish a criteria as to what would constitute reductions in energy production, we looked at the set points for each unit established in our Energy Management System. Units have an economic maximum and an economic minimum set point that comprise the normal dispatch range. For the purposes of this study, we assumed that any time a unit was not operating at its economic maximum, it was "backed down". We then attributed the cause of the reduced baseload production each hour to load, wind, market dispatch, or some combination based on the net energy position for the NSP system over the hour.

As an example, let's assume load is 500 MWs, wind is 100 MWs and Sherco Unit 1 is the only baseload resource online with a maximum capability of 680 MWs. By itself, the NSP system would only need 400 MWs from Sherco to serve load. If the unit were in fact dispatched to 400 MWs by MISO, we would attribute 180 MWs of backed down generation to our load (680 – 500), and 100 MWs to the wind. If MISO backed the unit down further to 300 MWs, the additional 100 MW reduction would be attributed to market dispatch. There are also times when baseload units remain loaded above the level necessary to serve the NSP system load net of wind generation due to the market wide demand for energy.

It is important to note that the cause of reductions in baseload energy production cannot be determined with certainty given the regional dispatch of generation in MISO. Wind generation may play a role in MISO market dispatch decisions, but the

Company does not have enough information to determine definitively the cause of these decisions. Nevertheless, the analysis described above provides a reasonable framework for assessing the impact of wind on the NSP system.

The results show that the total amount of energy that was not produced that could have been produced during the study period if no baseload generation was backed down was 2,514,261 MWhs. Wind production contributed to 1,295,715 MWh or 51.5% of MWhs backed down. Changes in customer load accounted for 45,063 MWh or 1.8% of the MWhs backed down. MISO Market Dispatch was responsible for 1,173,484 MWh or 46.7% of the MWhs backed down. There were many hours where baseload generation was backed down for a combination of market dispatch, wind production and customer loads.

Out of the 365 days evaluated, there were 328 cycles in which wind generation contributed to backing down base load generation. We define a cycle as the period of time over which the base load generation was backed down. As an example, on April 6, 2017, base load generation was backed down for three consecutive hours in part due to wind generation. This was considered a cycle. On May 16, 2017, base load generation was backed down for one hour in part due to wind generation. This was also counted as one cycle.

Order Point 3

The Company complied with Order Point 3 in its 2010 ten-year plan.

10-YEAR PLAN FOR MAJOR GENERATION AND TRANSMISSION FACILITIES

TO THE

SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

SUBMITTED BY NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION JULY 2018

Northern States Power Company d/b/a Xcel Energy
2018 South Dakota Ten-Year Plan
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Northern States Power Company, doing business as Xcel Energy (Xcel Energy or the Company), submits its 10-year plan to the South Dakota Public Utilities Commission as required by S.D. Admin. R. § § 20:10:21:02 to 20:10:21:21 and SDCL § 49-41B-3.[1]

These administrative rules and legislative provision require every utility that owns or operates, or plans within the next ten years to own or operate, energy conversion facilities to develop and submit a 10-year plan that contains the following:

(1) A description of the general location, size, and type of energy conversion facilities or transmission facilities of two hundred fifty kilovolts or more to be owned or operated by the utility during the ensuing ten years, as well as those facilities to be removed from service during the planning period;

(2) A description of the efforts by the utility to coordinate the plan with other utilities so as to provide a coordinated regional plan for meeting the utility needs of the region;

(3) A statement of the projected demand for the service rendered by the utility for the ensuing ten years and the underlying assumptions for the projection, with such information being as geographically specific as possible and a description of the manner and extent to which the utility will meet the projected demand; and

(4) Any other relevant information as may be requested by the commission.

We present the information required for our 10-year plan in sequence as provided in §§ 20:10:21:04 to 20:10:21:18 inclusive, and additionally provide any further information required by SDCL 49-41B03 along with the closest related administrative rule requirement.

BIENNIAL REPORT

20:10:21:04 EXISTING ENERGY CONVERSION FACILITIES

This section outlines the Company's electric generation facilities. We provide the details required by S.D. Admin. R. § § 20:10:21:04 for Company generating facilities located in South Dakota, and provide a list of the other generating facilities that comprise the NSP System that serves our South Dakota customers.[2]

Xcel Energy has one existing energy conversion facility in South Dakota. The table below provides the required information on this facility.

[1] The rules incorporate and put into effect the requirements outlined under S.D. Codified Laws § 49-41B-3

[2] The NSP System is comprised of electric generating plants and transmission facilities located and serving customers in the states of Michigan, Minnesota, North Dakota, South Dakota, and Wisconsin.

South Dakota Electric Generating Facilities

Table 1. Angus C. Anson Plant

1	Location	Minnehaha County, South Dakota	
2	Type Nameplate Capacity	Simple Cycle Combustion Turbine 119.7 MW (unit 2) 119.7 MW (unit 3) 166.3 MW (unit 4)	
3	Net Capacity	2016 Summer	 90 MW (unit 2) 90 MW (unit 3) 147 MW (unit 4)
		Winter	109 MW (unit 2) 109 MW (unit 3) 168 MW (unit 4)
		2017 Summer	 90 MW (unit 2) 90 MW (unit 3) 147 MW (unit 4)
		Winter	109 MW (unit 2) 109 MW (unit 3) 168 MW (unit 4)
	Annual Production	2016: 2017:	65,698 MWh (total) 70,125 MWh (total)
4	Water Source and Annual Consumption	Ground Water 2016: 2017:	 7,482,510 gal 5,578,546 gal
5	Fuel Type Source Annual Consumption	Natural Gas Northern Natural Gas Co.[3] 2016: 805,279.64 MMBtu 2017: 845,279.92 MMBtu	Fuel Oil 2016: 103,380 gal 2017: 21,542 gal
6	Projected Retirement Date	Unit 2 & 3: Unit 4:	2026 2035

We provide a list of our other NSP System generating facilities and Power Purchase Agreements (PPA) as Appendix A to this report.

[3] The natural gas fuel is purchased from independent third party suppliers and delivered through the Northern Natural Gas interstate pipeline system.

20:10:21:05 PROPOSED ENERGY CONVERSION FACILITIES

This rule requires utilities to provide the specific electric generating facilities that have been proposed but are not yet in commercial operation in the 10-year period of the biennial report. In addition to providing the details for each of these planned facilities as required by S.D. Admin. R. § § 20:10:21:04, we note that the Company's Resource Plan proposes additional changes to its generation resources and mix. We provide a high level summary of our resource planning process and the procedural timeline for the proceeding in our Minnesota jurisdiction below.

Table 2

		Fox Tail Wind Farm	Blazing Star I Wind Farm
1	Location	**Ellendale, ND**	**Hendricks, MN**
2	Why Selected	**Competitive RFP bid**	**Competitive RFP bid**
3	Type Nameplate Capacity	**Wind** **150 MW**	**Wind** **200 MW**
4	Estimated Production	**[TRADE SECRET BEGINS… [redacted] …TRADE SECRET ENDS]**	**[TRADE SECRET BEGINS… [redacted] …TRADE SECRET ENDS]**
5	Water Source	**NA**	**NA**
6	Fuel Type	**Wind**	**Wind**
7	Disposal Plans	**Not Applicable**	**Not Applicable**
8	Associated Facilities	**Montana-Dakota 230 kW Ellendale Tatanka Line**	**Brookings-Lyon 345 kW line**
9	Operating life with SD Fuels	**Not Applicable**	**Not Applicable**
10	Projected End of Life	**2044**	**2044**
11	Estimated Cost	**[TRADE SECRET BEGINS… [redacted] …TRADE SECRET ENDS]**	**[TRADE SECRET BEGINS… [redacted] …TRADE SECRET ENDS]**
12	Projected In-Service Date	**2019**	**2019**

Table 3

		Blazing Star II Wind Farm	Freeborn Wind Farm
1	Location	Hendricks, MN	Glenville, MN
2	Why Selected	Competitive RFP bid	Competitive RFP bid
3	Type Nameplate Capacity	Wind 200 MW	Wind 200 MW
4	Estimated Production	**[TRADE SECRET BEGINS…** [redacted] **TRADE SECRET ENDS]**	**[TRADE SECRET BEGINS…** [redacted] **TRADE SECRET ENDS]**
5	Water Source	NA	NA
6	Fuel Type	Wind	Wind
7	Disposal Plans	Not Applicable	Not Applicable
8	Associated Facilities	Brookings-Lyon 345 kW line	Glenworth 161 kV Substation
9	Operating life with SD Fuels	Not Applicable	Not Applicable
10	Projected End of Life	2045	2045
11	Estimated Cost	**[TRADE SECRET BEGINS…** [redacted] **…TRADE SECRET ENDS]**	**[TRADE SECRET BEGINS…** [redacted] **…TRADE SECRET ENDS]**
12	Projected In-Service Date	2020	2020

Table 4

		Crowned Ridge Wind Farm	Crowned Ridge Purchase Agreement
1	Location	Watertown, SD	Watertown, SD
2	Why Selected	Competitive RFP bid	Competitive RFP bid
3	Type Nameplate Capacity	Wind 300 MW	Wind 300 MW
4	Estimated Production	**[TRADE SECRET BEGINS… [redacted] …TRADE SECRET ENDS]**	**[TRADE SECRET BEGINS… [redacted] …TRADE SECRET ENDS]**
5	Water Source	NA	NA
6	Fuel Type	Wind	Wind
7	Disposal Plans	Not Applicable	Not Applicable
8	Associated Facilities	Otter Tail Power's Big Stone South Substation	Otter Tail Power's Big Stone South Substation
9	Operating life with SD Fuels	Not Applicable	Not Applicable
10	Projected End of Life	2044	2044
11	Estimated Cost	**[TRADE SECRET BEGINS… [redacted] …TRADE SECRET ENDS]**	**[TRADE SECRET BEGINS… [redacted] …TRADE SECRET ENDS]**
12	Projected In-Service Date	2019	2019

Table 5

		Lake Benton Wind Farm	Clean Energy #1 Purchase Agreement
1	Location	Lake Benton, MN	Glen Ullin, ND
2	Why Selected	Competitive RFP bid	Competitive RFP bid
3	Type Nameplate Capacity	Wind 100 MW	Wind 100 MW
4	Estimated Production	**[TRADE SECRET BEGINS… [redacted] …TRADE SECRET ENDS]**	**[TRADE SECRET BEGINS… [redacted] …TRADE SECRET ENDS]**
5	Water Source	NA	NA
6	Fuel Type	Wind	Wind
7	Disposal Plans	Not Applicable	Not Applicable
8	Associated Facilities	Buffalo Ridge and Chamarambie Substations	Square Butte substation
9	Operating life with SD Fuels	Not Applicable	Not Applicable
10	Projected End of Life	2044	2044
11	Estimated Cost	**[TRADE SECRET BEGINS… [redacted] …TRADE SECRET ENDS]**	**[TRADE SECRET BEGINS… [redacted] …TRADE SECRET ENDS]**
12	Projected In-Service Date	2019	2019

Table 6

		Dakota Range I & II Wind Farm	Mankato Energy Center 2, Purchase Power Agreement
1	Location	Watertown, SD	Mankato, MN
2	Why Selected	Competitive RFP bid	Competitive RFP bid
3	Type Nameplate Capacity	Wind 300 MW	Combined Cycle 345 MW
4	Estimated Production	**[TRADE SECRET BEGINS… [redacted] …TRADE SECRET ENDS]**	**[TRADE SECRET BEGINS… [redacted] TRADE SECRET ENDS]**
5	Water Source	NA	NA
6	Fuel Type	Wind	Natural Gas
7	Disposal Plans	Not Applicable	Not Applicable
8	Associated Facilities	Big Stone South-Ellendale 345kV Line	Not Applicable
9	Operating life with SD Fuels	Not Applicable	Not Applicable
10	Projected End of Life	2046	2038
11	Estimated Cost	**[TRADE SECRET BEGINS… [redacted] …TRADE SECRET ENDS]**	**[TRADE SECRET BEGINS… [redacted] …TRADE SECRET ENDS]**
12	Projected In-Service Date	2021	2019

Resource Planning Overview

Resource Planning is a complex and integrated process of planning for the capacity, energy, and emission requirements of the electric system. The process incorporates a number of key assumptions or industry projections that helps to inform a common vision of what the future planning environment may look like. This ongoing planning process requires utilities to examine and establish a long-term proposal for management, operation, and expansion or contraction of their generating and demand management resources to meet customer needs.

Traditionally the primary focus of resource planning has been to identify the least-cost approach to provide reliable service and meet growing demand. While these goals remain critical to the resource planning process, we have broadened the scope of planning considerations by incorporating new generation technologies, increasing renewable energy, reducing emission profiles, and evaluating the retirement of large baseload facilities, thereby positioning the NSP System for the future.

The planning landscape underlying the Resource Plan greatly informs the planning efforts. We believe that proactive leadership in the face of evolving industry, new and proposed environmental regulation, customer expectations, emerging technologies, and changes to the NSP System will allow us to affirmatively address these trends rather than being shaped by them. Our planning also calls for sufficient flexibility to allow us to adjust and react as we gain more clarity on the planning landscape.

The criteria we apply as as we evaluate and propose our preferred plan in relation to a reference plan is its ability to: (1) maintain or improve the adequacy and reliability of utility service; (2) keep customers' bills and our rates as low as practicable, given regulatory and other constraints; (3) minimize adverse socioeconomic effects and adverse effects upon the environment; (4) enhance the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations; and (5) limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control.

The Company filed the 2016-2030 Upper Midwest Resource Plan (IRP) on January 2, 2015, and filed a substantive supplement on January 29, 2016. The Minnesota Public Utilities Commission approved the IRP in October 2016. The approved plan was developed to address the planning landscape in which it was developed – and based on five key considerations:

- The solid foundation that has resulted from our investment cycle;
- Innovative use of renewable energy to drive down emissions and preserve flexibility;
- Strategic flexibility;
- Cost effectiveness; and
- A plan to address the future of Sherco Units 1 and 2.

The preferred plan for our Upper Midwest customers builds on our strong foundation of environmental performance, while continuing to reliably meet our customers' electricity needs in a cost-effective mannerThe Company plans to file its next IRP onFebruary 1, 2019.

20:10:21:06 EXISTING TRANSMISSION FACILITIES

This rule requires utilities to provide a description of its existing transmission facilities. Similar to the information we provided about our electric generating facilities, we provide the details required by S.D. Admin. R. § § 20:10:21:04 for Company transmission facilities located in South Dakota, and provide information about other transmission facilities that comprise the NSP System that serves our South Dakota customers as Appendix B.

South Dakota Transmission Facilities

Listed below are our existing transmission facilities operating at 115 kV or above in South Dakota. They are all located in the eastern portion of the state. As noted

above, a map showing the location of our transmission lines is included as Appendix B. Currently none of these facilities are projected to be removed from service.

A. Type 115 kV – AC

1. Lawrence Substation in Sioux Falls to the Lincoln County Substation south of Sioux Falls – 11 miles.
2. Lincoln County Substation south of Sioux Falls to the Louise Substation (southwest side of Sioux Falls) – 3 miles.
3. Louise Substation (southwest corner of Sioux Falls) to the Cherry Creek Substation (west side of Sioux Falls) – 7 miles.
4. Cherry Creek Substation to the Grant Substation west of Sioux Falls – 24 miles.
5. Grant Substation west of Sioux Falls to Northwestern Energy (Northwestern) at Mitchell – 24 miles to Wolf Creek Interconnection owned by Xcel Energy; the remainder is owned by Northwestern.
6. Lawrence Substation in Sioux Falls to the Western Area Power Administration (WAPA) Substation in Sioux Falls – 1 mile.
7. Lawrence Substation in Sioux Falls to the Split Rock Substation approximately 5 miles northeast of Sioux Falls (circuit #1) – 2 miles.
8. Split Rock Substation to the Pathfinder Substation to the Pipestone Substation in Pipestone, Minnesota. Approximately 35.5 miles of this line are in the state of South Dakota – 44.5 miles total.
9. Lawrence Substation in Sioux Falls to the Split Rock Substation approximately 5 miles northeast of Sioux Falls (circuit #2). Approximately 1 mile of this line is double-circuited with the Split Rock-Magnolia 161 kV line; 2.2 miles total.
10. Split Rock Substation to the West Sioux Falls Substation – 17.3 miles.
11. West Sioux Falls Substation to the Cherry Creek Substation – 3.5 miles.
12. Split Rock Substation to Renner Substation – 8.7 miles.
13. Renner Substation to Cherry Creek-7.8 miles.
14. Split Rock to Angus C. Anson generating plant – 0.28 miles.
15. Split Rock to Angus C. Anson generating plant # 2 – 0.43 miles.
16. Brookings County to Yankee #1 – 3.7 miles of this line is in South Dakota; 13 miles total.
17. Brookings County to Yankee #2 – 6.5 miles of this line is in South Dakota; 13 miles total.
18. West Sioux Falls to Falls Substation-3.6 miles
19. Falls Substation to Split Rock Substation-8.25 miles

B. Type 161 kV – AC

1. Split Rock Substation approximately 5 miles northeast of Sioux Falls to ITC Midwest, LLC (ITC Midwest) interconnection near Luverne, Minnesota.[4] Approximately 1 mile of this line is double-circuited with the second Lawrence- Split Rock 115 kV line. Approximately 11 miles of this line are in the state of South Dakota - 20 miles total.

C. Type 230 kV – AC

1. Split Rock Substation to the WAPA Sioux Falls Substation – 1 mile.

D. Type 345 kV – AC

1. Split Rock Substation northeast of Sioux Falls to the WAPA's 345 kV line to Watertown. This is a 5.1 mile line with 2.5 miles double circuit but one circuit is not energized.
2. Split Rock Substation northeast of Sioux Falls to the WAPA's 345 kV line to Sioux City. This is a double-circuit line – 5.1 miles with the Split Rock-Nobles line.
3. Split Rock-Nobles County-Lakefield Junction. 345 kV line approximately 10 miles of this line are in the state of South Dakota – 90.8 miles total. 5.1 miles are double circuit with the Split Rock-Sioux City line.
4. Brookings County-White 345 kV line #1. This is a 0.4 mile line.
5. Brookings County-White 345 kV line #2. This is a 0.4 mile line.
6. A 230 mile, 345 kV line between Brookings, South Dakota, and the southeast Twin Cities, plus a related 30 mile, 345 kV line between Marshall, Minnesota, and Granite Falls, Minnesota (Brookings Project).
7. Big Stone South to Brookings Co Substation is a 72 mile long line with the ownership split evenly between Xcel Energy and Otter Tail Power Company.

As noted above, a map of our total NSP System transmission facilities is provided as Appendix B to this report.

20:10:21:07 PROPOSED TRANSMISSION FACILITIES

This rule requires utilities to provide the specific transmission facilities that have been proposed but are not yet in operation in the 10-year period of the biennial report.

There are no transmission facilities proposed in the 10-year period. The transmission system is analyzed on an annual basis and any future projects will included when necessary.

[4] In early 2008, ITC Midwest purchased all of the high voltage electric transmission facilities of Interstate Power and Light Company (Alliant Energy) in Iowa, Minnesota and Illinois.

20:10:21:08 COORDINATION OF PLANS

This rule requires utilities to describe how their plans coordinate with other utilities serving the region.

Xcel Energy is a member of the Midwest Reliability Organization (MRO). The purpose of the MRO is to ensure the reliability and security of the bulk power system covering the states of Wisconsin, Iowa, Minnesota, Nebraska, and most of South Dakota as well as the Canadian provinces of Saskatchewan and Manitoba. As such, the members of the non-profit organization meet to discuss reliability and security issues. There are numerous committees that develop standards, guidelines, and reporting procedures for everything from load shedding to vegetation management. More information about the organization can be found at: http://www.midwestreliability.org.

The Company is also a participant in the Minnesota Transmission Assessment & Compliance Team (MN-TACT) along with several other utilities covering Minnesota, Western Wisconsin and parts of North Dakota and South Dakota. The purpose of this analysis is to develop an understanding of the transmission system topology, behavior and operation. This analysis is performed to meet NERC Transmission Planning Standards TPL-001.

All major transmission planning performed by the Company is now coordinated through the MISO on a regional basis, consistent with the Federal Energy Regulatory Commission (FERC) Orders (a) dated May 19, 2000 (FERC Docket No. EC00-60-000) authorizing the transfer of functional control of our high voltage transmission system to the MISO; (b) dated December 20, 2001[5] finding the MISO to be the first FERC-approved regional transmission organization (RTO); and dated February 15, 2007 (Order No. 890), requiring RTOs and their member utilities to use coordinated regional planning.[6] MISO issues an annual MTEP after coordinated planning and stakeholder review. Prior to 2007, these plans were issued biennially. The current MTEP 2017 series of projects was approved by the MISO Board of Directors in December of 2017 and is available at the MISO website at www.misoenergy.org.

[5] FERC Docket Nos. RT01-87-000, RT01-001, ER02-106-000 and ER02-108-000.
[6] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 FR 12266 (March 15, 2007), FERC Stats. & Regs. ¶ 31,241 (2007) (Order No. 890), *order on reh'g*, 73 Fed. Reg. 2984 (Jan. 16, 2008), FERC Stats. & Regs. ¶ 31,261 (2008) (Order No. 890-A); *order on reh'g* 123 FERC ¶ 61,299 (Order No. 890B) (June 23, 2008). MISO's Order No. 890 regional transmission planning process was conditionally accepted for filing in *Midwest Independent Transmission System Operator, Inc.*, 123 FERC ¶ 61,164 (May 15, 2008).

As a result of complying with the FERC Order No. 890 rules, MISO has implemented its own Sub-Regional Planning Meetings. We participate in the Western Region meetings. This group provides a forum for stakeholder input and coordination of plans and we actively participate in this. This joint planning is intended to maximize use of existing facilities and minimize the amount of new facilities.

Another example of this coordination by the utilities is the formalization of the Minnesota Transmission Owners (MTO) organization. The MTO consists of all transmission owning utilities in Minnesota. The MTO was formed to submit coordinated biennial transmission planning reports to the Minnesota Commission as required by Minn. Stat. § 216B.2425. Some MTO utilities also serve eastern North Dakota and eastern South Dakota. The MTO group is presently developing coordinated short-term regional plans and longer term vision plans for the bulk transmission needs throughout the upper Midwest and the transmission required to meet the various states' Renewable Energy Standards. The MTO group also performs an annual 10-year assessment of the members' utility systems for compliance with the North American Electric Reliability Corporation Transmission Planning (TPL) standards. The MTO utilities also coordinate their planning with the CapX2020 planning processes and the MTEP processes.

We also participate in Interconnection-wide transmission planning, currently being facilitated under the Eastern Interconnection Planning Collaborative (EIPC) effort, funded by the Department of Energy. The EIPC effort is focused on a high level look at the transmission needs east of the Rocky Mountains (excluding parts of Texas).

In addition, as noted previously, the Company prepares Integrated Resource Plans for the NSP System and submits a copy of those plans to the Commission consistent with the Commission's requirements in Docket No. EL08-028 and the Settlement Stipulation and Commission Order in Docket No. EL09-009.

20:10:21:09 SINGLE REGIONAL PLANS

This rule requires utilities to state whether the facilities it has proposed comprise all or part of a single regional plan. As described in the previous sections, the Company serves its South Dakota customers from an integrated NSP System that serves portions of Michigan, Minnesota, North Dakota, South Dakota, and Wisconsin. We periodically evaluate our customers' needs and federal and state requirements, and develop Integrated Resource Plans that look 15 years into the future to ensure we continue to meet our reliability requirements and customer needs. We additionally continue to work with MISO and other coordinated regional utility groups to evaluate

potential transmission needs in the future and to develop coordinated regional plans as required to meet those needs.

20:10:21:10 SUBMISSION OF REGIONAL PLANS

This rule requires utilities proposing facilities that comprise all or part of a regional plan to submit the plan(s). As noted previously, we submit our Integrated Resource Plans to the Commission as they are developed.

Regional transmission plans, by virtue of their geographic coverage, involve a collaborative effort of multiple utilities. As the CapX2020 effort has shown, we and the other utilities in this region are actively analyzing and developing coordinated regional plans. This analysis includes the active participation of the MTO and the MISO planning efforts. This effort is part of the MTEP regional planning process. As specific plans for additional facilities are developed, they will be submitted with subsequent 10-year plans. The MTEP is subject to review and approval by MISO's independent Board of Directors. Proposals to construct specific MTEP approved facilities in South Dakota would be submitted for Commission approval as required.

20:10:21:11 UTILITY RELATIONSHIPS

This rule requires utilities to describe any relationship of the utility to other utilities and regional associates, power pools, and networks.

Northern States Power Company-Minnesota (NSPM) is an operating company subsidiary of Xcel Energy Inc., a public utility holding company, and we are affiliated with three other regulated public utilities: Northern States Power Company-Wisconsin (NSPW), Public Service Company of Colorado, and Southwestern Public Service Company. NSPM is a member of MISO, the first FERC-approved RTO. As an RTO, MISO provides regional tariff administration services and operates a Day-ahead and Real-time regional wholesale energy market pursuant to its Open Access Transmission, Energy and Operating Reserve Markets Tariff. MISO implemented a regional planning reserve market in 2009, pursuant to Module E of the Open Access Transmission, Energy and Operating Reserve Markets Tariff. MISO is also the Regional Reliability Coordinator for the NSPM and NSPW integrated electric generation and transmission system (NSP System).

Outside of MISO, NSPM serves a small amount of retail load in Berthold, ND. For that, NSPM is also a transmission customer and market participant under Southwest Power Pool's Open Access Transmission Tariff.

We are also a member of the MRO, which is the Regional Entity responsible for enforcement of mandatory electric reliability standards adopted by the North American Electric Reliability Corporation.

20:10:21:12 EFFORTS TO MINIMIZE ADVERSE EFFECTS

This rule requires utilities to describe in detail its methodology used and efforts to identify, minimize, or avoid adverse environmental, social, economic, health, public safety, and historic or aesthetic preservation effects.

The Company uses a multi-step effort to minimize adverse effects resulting from siting, constructing, operating and maintaining large electric generating plants and high voltage transmission lines. These efforts relate to long-range planning and coordination, environmental site and route analysis, and to ensure the effects of construction and operation practices are minimized.

High voltage transmission facility plans are coordinated with MISO, other area power suppliers and load serving entities in order to develop, whenever possible, joint use facilities. Coordination with others can reduce the number of facilities by providing for joint ownership and operation of facilities.

Once the need for generation or transmission is identified, an initial site or route search is begun by defining a broad study area to locate the facility. A broad range of information about the physical, biological and cultural environment within the study area is then collected. As information on such factors as land use, air and water quality, plants and animals, transportation and social services, and local and regional employment becomes available, various siting criteria are used to define preferred and alternate routes and sites. We prefer to develop a project with the cooperative assistance of state and local agency officials, neighboring transmission utilities (such as Northwestern, WAPA, Missouri River Energy Services and ITC Midwest), and affected landowners in order to assure the widest possible considerations of information, concerns and options. It is our policy to ensure compliance with all local, state and federal regulatory requirements in the development and location of proposed projects.

Because of the detail involved in a major generation or transmission project, we continue to refine site and route engineering once permits have been granted. This allows us to adjust for new developments that may arise during construction, such as the need for changes in locations, land use or construction techniques, and allows any concerns to be addressed and mitigated without undue delay and expense. We are committed to working with affected landowners to mitigate environmental and land use problems which may arise as a result of construction and maintenance activities.

We discuss our other efforts to respond to the evolving utility landscape in our 2016-2030 Upper Midwest Integrated Resource Plan in Docket No. EL09-009.[7] For ease of reference, we provide the public version our January 29, 2016 Supplement as Appendix C to this 10-year plan.

20:10:21:13 LOAD MANAGEMENT EFFORTS

This rule requires utilities to describe its efforts toward efficient load management.

The Company's load management efforts in South Dakota reduce peak demands, especially during the summer months, which can help delay or avoid more expensive electric generation and purchased power needs.

On January 1, 2012 we launched a demand side management (DSM) program in South Dakota, approved in the Order in Docket No. EL11-013. The DSM portfolio includes load management, energy efficiency, and consumer education programs aimed at both residential and commercial customers.

Commercial programs in the DSM portfolio include:

- Lighting Efficiency (conservation)
- Business Saver's Switch (load management)
- Peak and Energy Control (load management)

Residential programs in the DSM portfolio include:

- Residential Home Lighting (conservation)
- Residential Saver's Switch (load management)
- Consumer Education

Since their launch, these programs have reduced peak demand by about 13.8 MW and have conserved almost 30 GWh. It is forecasted that in the next two years (2017-2019) the programs will achieve an additional 2.6 MW in peak reduction and 10 GWh.

We additionally provide details regarding the Company's load management and conservation efforts in our Resource Plan.

20:10:21:14 LIST OF REPORTS RELATED TO PROPOSED FACILITIES

This rule requires utilities to provide a list of all reports or studies filed or proposed to be filed with federal or other state agencies relating to the proposed facilities.

[7] *See* January 29, 2016 Supplement.

A. Electric Generation Facilities

Table 7. Electric Generation Facilities Reporting

Project Name	SD Docket No.	MN Docket No.	ND Case No.
Fox Tail Wind Farm	N/A	E002/M-16-777	PU-17-120
Blazing Star I Wind Farm	N/A	E002/M-16-777	PU-17-120
Blazing Star II Wind Farm	N/A	E002/M-16-777	PU-17-120
Freeborn Wind Farm	N/A	E002/M-16-777	PU-17-120
Crowned Ridge Wind Farm/PPA	EL-18-019	E002/M-16-777	PU-17-120
Lake Benton Wind Farm	N/A	E002/M-16-777	PU-17-120
Clean Energy #1 Purchase Agreement	N/A	E002/M-16-777	PU-17-120
Dakota Range I & II Wind Farm	EL-18-003	E002/M-17-694	PU-17-372
Mankato Energy Center 2/Purchase Agreement	N/A	E002/CN-12-1240	PU-15-096

B. Transmission Facilities

Minnesota Transmission Assessment and Compliance Team 2014 Transmission Assessment: December 2016

MTEP16 Report: December 2016

Minnesota Transmission Assessment and Compliance Team 2017 Transmission Assessment: February 2018

MTEP17 Report: December 2017

20:10:21:15 CHANGES IN STATUS OF FACILITIES

This rule requires utilities to list changes in the status of the utility's facilities during the past two years, or since submission of its most recent 10-year plan.

There have been no changes in the status of Xcel Energy's facilities in South Dakota in the past two years.

20:10:21:16 PROJECTED ELECTRIC DEMAND

This rule requires utilities to provide its projected customer demand for the 10-year period, in South Dakota and outside of South Dakota. Additionally, SDCL § 49-41B-3 requires utilities to describe the underlying assumptions for their projections, with

such information being as geographically specific as possible – and a description of the manner and extent to which the utility will meet the projected demand.

As we have described, our South Dakota customers are served by the integrated NSP System, which is how we plan for and meet the needs of NSP System customers – including our South Dakota customers.

We produce long-range "median" forecasts of native energy requirements, summer peak, and winter peak demand. For planning purposes, we also develop a bandwidth (called semi-high and semi-low scenarios) to supplement our "median" forecasts. These two scenarios are intended to describe uncertainty in a business-as-usual context: a relatively narrow range of US economic growth with no basic change in the relationship between the regional and national economies. Tables 10, 12, and 12 below show the long-range system forecast of native energy requirements, summer peak, and winter peak demand for the NSP System. While this is how we plan and meet the needs of the NSP System, in compliance with Rule 20:10:21:16, we provide a forecast of our native energy requirements and peak demand for the State of South Dakota jurisdiction in Table 9 below.

The forecast for the NSP System is based on forecasts of jurisdictional sales by major customer class: residential with and without space heating, small commercial and industrial, and large commercial and industrial. Each customer class is modeled independently for the five states included in the NSP System. The native energy requirements are determined by applying a loss factor on total sales. The NSP System peak is apportioned to jurisdictions based on the native energy requirements by state and the load factor by state. Consequently, the summer and winter "peak loads" provided in Table 9 represent the South Dakota jurisdiction customer demand at time of total System seasonal peak demand. This "coincident" demand is appropriate for generating capacity requirement forecasting.

It is important to note, however, that a "non-coincident" peak demand must be used in evaluating transmission capacity requirements. This is because the transmission system must be able to supply the full local customer demand at all times. Due to load diversity caused by weather variations within the multi-state NSP System, peak customer demands in our South Dakota service areas can be as much as ten percent higher than the demands registered during the hour in which the total System peak demand occurs. It is these local "non-coincident" peak demands that determine the need for transmission improvements required for load serving functions.

We have described in our current Resource Plan how we propose to meet our customers' needs, federal and state policy requirements and objectives, and transition to the future, which we summarize below.

While forecasts are always subject to change, we expect to have sufficient capacity to meet our customers' needs through 2024. However, our current forecast indicates that beginning in 2025 our capacity position shifts from a surplus of nearly 500 MW to a deficit of over 2,200 MW by 2030. Much of this shift is due to the retirement of approximately 800 MW of peaking plants, as well as the expiration of nearly 1,700 MW of hydro and natural gas PPAs during the period, including the expiration of our existing 850 MW PPA with Manitoba Hydro in 2025.

Our plan proposes to address the capacity deficit through a combination of renewable resource additions in the early years, and the addition of natural gas CT and CC units. In summary, our proposed resource additions are:

- 1,400 MW of large solar additions, including 400 MW by 2020,
- 1,800 MW of additional wind, including 800 MW by 2020,
- A 786 MW CC addition at the Sherco site in 2026 to replace the capacity of Sherco Unit 1 before it ceases operation,
- A 230 MW CT located in North Dakota by the end of 2025, and
- Over 1,800 MW of additional CT capacity.

The early renewable energy additions we have proposed as part of our plan will allow us to capitalize on favorable market pricing associated with the recently extended Federal Investment Tax Credit and Production Tax Credit incentives, reducing the cost impacts of our proposed plan. Locating the proposed 786 MW Combined Cycle Unit at Sherco will allow us to cost-effectively address the transmission issues identified by the MISO Attachment Y2 Study, ensure the stability and reliability of our transmission system, mitigate impacts to the local community and our employees, and potentially provide improved access to natural gas supplies for communities in central Minnesota.

20:10:21:17 CHANGES IN ELECTRIC ENERGY

This rule requires utilities to show the increase or decrease in projected electric energy demand and allocation by volume and percentage for each year relative to the prior year.

We provide this information in Table 9 for our South Dakota service area for each year below.

Table 9. Forecast of Electric Energy Requirements & Peak Demand
State of SD

	Summer Peak (MW)	Winter Peak (MW)	Energy (GWh)	Change In Energy (GWh)	% Change In Energy
2016	450	322	2,194		
2017	452	328	2,210	15	0.7%
2018	455	329	2,220	10	0.4%
2019	460	332	2,238	19	0.8%
2020	460	335	2,265	27	1.2%
2021	467	339	2,282	17	0.8%
2022	469	338	2,297	15	0.7%
2023	480	346	2,320	23	1.0%
2024	480	348	2,351	31	1.4%
2025	486	350	2,372	21	0.9%
2026	490	353	2,392	20	0.8%
2027	494	356	2,421	29	1.2%
2028	498	359	2,460	38	1.6%
2029	502	362	2,489	30	1.2%
2030	506	365	2,525	36	1.4%
2031	510	368	2,569	44	1.7%
2032	514	372	2,618	49	1.9%
2033	518	375	2,661	43	1.6%
2034	522	378	2,700	38	1.4%
Avg Annual Growth Rate 2016-2034 % growth:	**0.8%**	**0.8%**	**1.1%**		

1) Peak Load is ***coincident*** to the Xcel Energy system peak.
2) Winter Peak = MISO Winter Peak season, 2016 is –2016-2017 winter peak.
3) Peak Load forecast growth from 2026 - 2034 is based on average summer and winter SD peak growth rates from 2016 through 2025.

Table 10. NSP System Net Energy Requirements (MWh)

Year	Semi-Low (MWh)	Median (MWh)	Semi-High (GWh)
2016	43,989,457	45,064,055	46,262,752
2017	43,874,591	45,128,687	46,504,791
2018	43,656,152	45,062,182	46,585,860
2019	43,871,450	45,423,138	47,077,374
2020	43,947,404	45,616,130	47,400,653
2021	43,807,807	45,609,740	47,500,028
2022	43,845,079	45,766,856	47,779,829
2023	43,781,135	45,820,537	47,939,528
2024	43,805,327	45,966,956	48,192,850
2025	43,788,823	46,045,426	48,391,874
2026	43,751,308	46,128,476	48,571,673
2027	43,929,165	46,407,695	48,948,504
2028	44,242,272	46,844,261	49,511,025
2029	44,027,234	46,758,471	49,518,562
2030	44,393,402	47,238,280	50,133,084
2031	44,755,403	47,709,648	50,705,610
2032	45,195,700	48,267,360	51,421,776
2033	45,468,045	48,695,026	51,968,640
2034	45,700,827	49,048,008	52,466,651
Avg Annual Growth Rate 2016-2034 % growth:	**0.2%**	**0.4%**	**0.7%**

1) Semi-Low and Semi-High Scenarios reflect an 80%/20% Confidence Level NSP System Net Energy Requirements have been adjusted for DSM

Table 11. NSP System Net Summer Peak (MW)

Year	Semi-Low (MW)	Median (MW)	Semi-High (MW)
2016	8,229	8,507	8,860
2017	8,218	8,598	9,033
2018	8,190	8,633	9,136
2019	8,168	8,680	9,247
2020	8,131	8,701	9,327
2021	8,123	8,736	9,401
2022	8,084	8,758	9,470
2023	8,074	8,793	9,564
2024	8,028	8,786	9,604
2025	7,990	8,801	9,652
2026	7,961	8,798	9,698
2027	7,927	8,813	9,767
2028	7,909	8,820	9,815
2029	7,894	8,851	9,898
2030	7,917	8,913	9,978
2031	7,950	8,991	10,108
2032	7,993	9,066	10,219
2033	8,048	9,151	10,324
2034	8,086	9,234	10,451
Avg Annual Growth Rate 2016-2034 % growth:	**-0.1%**	**0.4%**	**0.9%**

1) Semi-Low and Semi-High Scenarios reflect an 80%/20% Confidence Level Net Peak Demand Adjusted for DSM

Table 12. NSP System Net Winter Peak (MW)

Year	Semi-Low (MW)	Median (MW)	Semi-High (MW)
2016	6,172	6,425	6,751
2017	6,131	6,474	6,846
2018	6,068	6,489	6,923
2019	6,058	6,529	7,009
2020	6,005	6,535	7,072
2021	5,989	6,569	7,153
2022	5,946	6,576	7,208
2023	5,932	6,606	7,257
2024	5,877	6,589	7,303
2025	5,832	6,596	7,341
2026	5,808	6,588	7,387
2027	5,798	6,608	7,438
2028	5,749	6,620	7,465
2029	5,767	6,658	7,584
2030	5,776	6,705	7,638
2031	5,826	6,785	7,752
2032	5,869	6,845	7,841
2033	5,895	6,912	7,946
2034	5,920	6,964	8,017
Avg Annual Growth Rate 2016-2034 % growth:	**-0.2%**	**0.4%**	**0.9%**

1) Winter Peak = Winter Peak season, 2015, is 2015-2016 winter peak.
2) Semi-Low and Semi-High Scenarios reflect an 80%/20% Confidence Level
3) Peak Adjusted for DSM

20:10:21:18 MAP OF SERVICE AREA

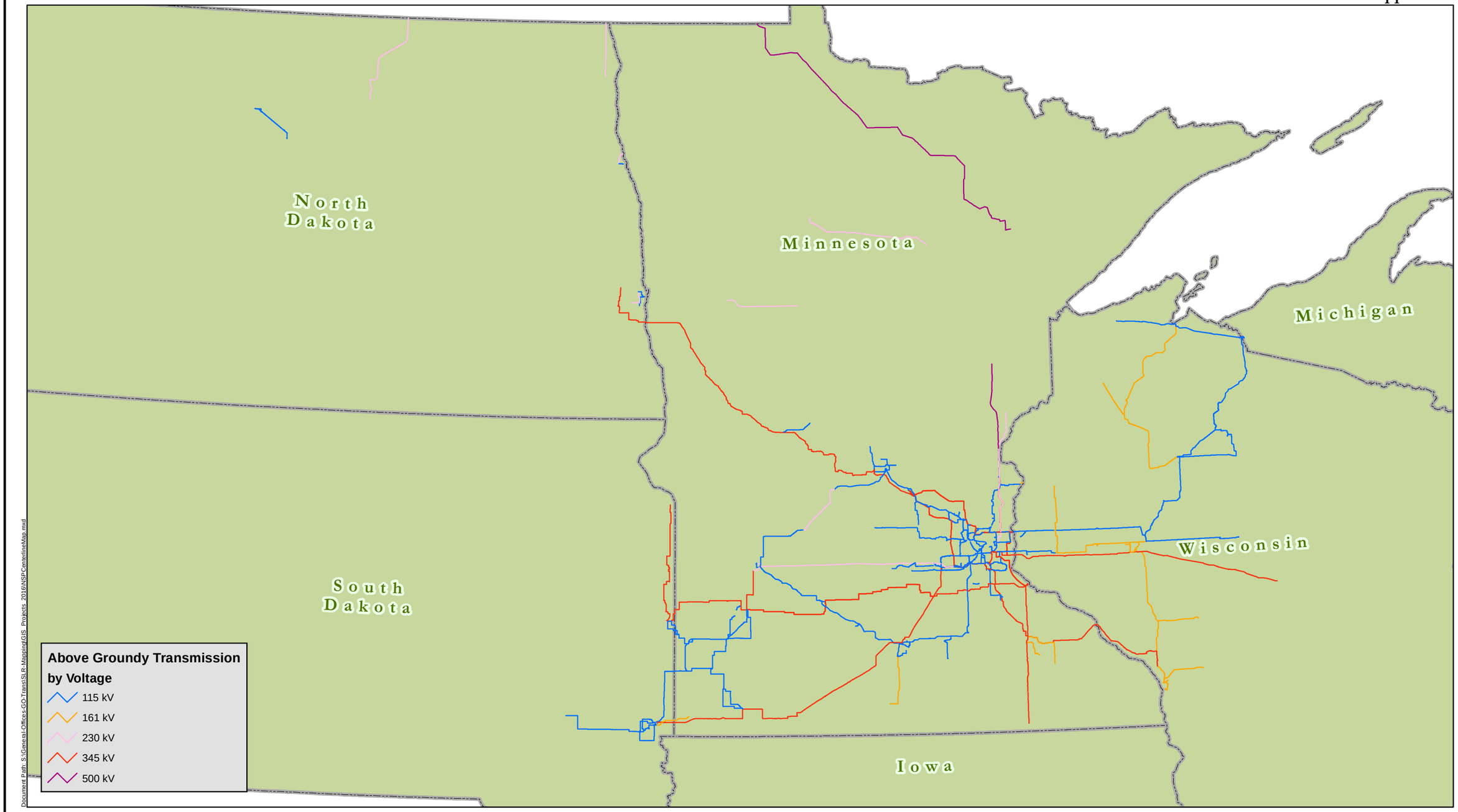
This rule requires utilities to provide a map or maps showing the specific geographic location of the utility's service area or areas.

We provide this information as Appendix D to this report.

NSP System Generating Resource Summary

Plant	Own/PPA	Type	Fuel
A.S. King	Owned	Thermal	Coal
Sherco 1, 2, 3	Owned	Thermal	Coal
Monticello	Owned	Thermal	Nuclear
Prairie Island 1, 2	Owned	Thermal	Nuclear
Black Dog 5/2	Owned	Combined Cycle	Natural Gas
High Bridge	Owned	Combined Cycle	Natural Gas
Riverside	Owned	Combined Cycle	Natural Gas
Cogentrix - Cottage Grove	PPA	Combined Cycle	Natural Gas
Calpine MEC 1	PPA	Combined Cycle	Natural Gas
Blue Lake 7, 8	Owned	Combustion Turbine	Natural Gas
Flambeau	Owned	Combustion Turbine	Natural Gas
Granite City 1-4	Owned	Combustion Turbine	Natural Gas
Inver Hills 1-6	Owned	Combustion Turbine	Natural Gas
Wheaton 1-4	Owned	Combustion Turbine	Natural Gas
Invenergy - Cannon Falls 1, 2	PPA	Combustion Turbine	Natural Gas
Bayfront 4	Owned	Thermal	Natural Gas
Blue Lake 1-4	Owned	Combustion Turbine	Oil
French Island 3, 4	Owned	Combustion Turbine	Oil
Wheaton 5, 6	Owned	Combustion Turbine	Oil
Bayfront 5, 6	Owned	Thermal	Biomass
French Island 1, 2	Owned	Thermal	Biomass
Red Wing 1, 2	Owned	Thermal	Biomass
Wilmarth 1, 2	Owned	Thermal	Biomass
Laurentian	PPA	Thermal	Biomass
KODA/Rahr	PPA	Thermal	Biomass
Fibrominn	PPA	Thermal	Biomass
St. Paul CoGen	PPA	Thermal	Biomass
MN Methane	PPA	Thermal	Biomass
Pine Bend	PPA	Thermal	Biomass
Hennepin Energy Recovery	PPA	Thermal	Biomass
Wind PPA's (1430 MW, nameplate)	PPA	Wind	Wind
Border Winds Wind Farm	Owned	Wind	Wind
Courtenay Wind Farm	Owned	Wind	Wind
Grand Meadow Wind Farm	Owned	Wind	Wind
Nobles Wind Farm	Owned	Wind	Wind
Pleasant Valley Wind Farm	Owned	Wind	Wind
Small Hydro PPA's (40 MW, nameplate)	PPA	Hydro	Hydro
MN Hydro - Owned	Owned	Hydro	Hydro
WI Hydro - Owned	Owned	Hydro	Hydro
Manitoba Hydro - PPA's (2)	PPA	Hydro	Hydro
Manitoba Hydro - Diversity Exchange	PPA	Hydro	Hydro

Appendix B



NSPM and NSPW Overhead Centerlines: 115 kV and Over

Updated: June 2018

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January 29, 2016

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—Via Electronic Filing —

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101-2147

RE: SUPPLEMENT – CURRENT PREFERRED PLAN
2016-2030 UPPER MIDWEST RESOURCE PLAN
DOCKET NO. E002/RP-15-21

Dear Mr. Wolf:

Northern States Power Company, doing business as Xcel Energy, submits the enclosed Supplement to its 2016-2030 Upper Midwest Resource Plan to the Minnesota Public Utilities Commission as required by its January 6, 2016 ORDER REQUIRING SUPPLEMENTAL FILING in the above-referenced docket.

This Supplement provides the detailed analysis supporting the proposal we outlined in our October 2, 2015 Reply Comments, as well as the information required in the Commission's January 6 Order. It also provides a detailed discussion of Prairie Island and our support for operating the plant through the end of each unit's respective current licensed life.

Our plan consists of the following:

- Accelerating our transition away from coal by ceasing coal operations at our Sherco Units 1 and 2 in the 2020s,
- Adding 1,400 megawatts of large solar to our system, including 400 megawatts by 2020,
- Adding 1,800 megawatts of wind, including 800 megawatts by 2020,
- Adding natural gas generation in the 2020s,
- Operating our carbon-free nuclear fleet through their existing plant licenses, and
- Continuing our commitment to increased energy efficiency and seeking out new technologies that will advance customer-driven solutions.

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Collaboration has been the hallmark of this proceeding. We developed the changes to our initial plan with input from stakeholders and believe our plan offers an energy vision that will benefit our customers, communities, and the states we serve. Together, the actions outlined in our Current Preferred Plan will result in a significant transformation in our generation fleet, including a nearly 60 percent reduction in our carbon emissions by 2030 without significantly impacting customer costs, reliability, Company employees, or the communities we serve. In fact, due to recent extensions to federal tax credits for solar and wind generation, the cost of our Current Preferred Plan is even lower than we anticipated in our October Reply Comments.

Request for Protection of Trade Secret Information

The Company recognizes and supports the need for transparency in review of our Resource Plan. Non-Public data included in this filing is limited to certain portions of the Supplement and four attachments as discussed below. We have identified the Trade Secret and other Non-Public information pursuant to Minn. Rule 7829.0500.

1. Forecasted Capital and O&M Costs

Section V of the Supplement contains forecasted cost details. This information is Trade Secret information as defined by Minn. Stat. §13.37(1)(b), because it derives independent economic value from not being generally known or readily ascertainable by others who could obtain a financial advantage from its use. The disclosure of this information could adversely impact contract negotiations, potentially increasing costs for these services for our customers. Thus, the Company maintains this information as a trade secret.

2. Attachment D – Grid Primer and Study Summary Report

Attachment D is a summary of the technical studies analyses the Company conducted to examine the technical impacts of potentially retiring Sherco Units 1 and 2. It is marked as Non-Public, as it contains Critical Electrical Infrastructure Information (CEII) including a summary of the results of the Midcontinent Independent System Operator Attachment Y2 Study and the Xcel Energy Transmission Reliability Study provided as Attachments D1, D2 and D3. Attachment D also discusses the Company's analysis of its Black Start Plan, which specifies the process of restoring the grid to full operation without relying on the external transmission network following a full- or partial-black out. Portions of this analysis are also CEII and marked as Trade Secret for the same security purposes noted in parts 3 and 4 below.

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3. Technical Study Reports

- *Attachment D1 - System Support Resource Attachment Y2 Study – The Sherburne County Generating Plant ("Sherco") Units 1 & 2 (Final Report of Midcontinent Independent System Operator (MISO) – August 28, 2015)*
- *Attachment D2 - Sherco 1 Replacement Power Study – Phase 1 (Siemens Power Technologies International - January 22, 2016)*
- *Attachment D3 - Sherco 1 and 2 Replacement Power Study – Phase 2 (Siemens Power Technologies International - January 22, 2016)*

Attachment D1 is marked as Non-Public in its entirety and is provided with critical infrastructure and highly-sensitive information redacted. Attachment D1 contains information regarding the MISO area grid, including specific information about the Xcel Energy and other transmission owner systems as it relates to the potential retirement of Xcel Energy's Sherburne County Generating Plant (Sherco) Units 1 and 2. While MISO has redacted all critical infrastructure and highly-sensitive information from the report, Xcel Energy maintains that the balance of the information is "security information" as defined by Minn. Stat. § 13.37, subd. 1(a).

Attachments D2 and D3 are marked as Non-Public in their entirety and contain CEII and highly-sensitive information redacted for the same reasons noted for Attachment D1. Xcel Energy maintains that the balance of the information is "security information" as defined by Minn. Stat. § 13.37, subd. 1(a). The reports by Siemens Power Technologies International resulted from studying the effects of potential retirement of one or both Sherco Units on the transmission system, and technical implications and upgrade costs associated with replacement of one or both Units at alternate locations on the NSP System. We believe that the information could potentially be used to determine vulnerabilities in the grid or in disrupting electric service to our customers, in the event Sherco Units 1 and or 2 were not in service. The public disclosure or use of this information creates an unacceptable risk, because those who want to disrupt the electrical grid may learn which facilities to target to create the greatest disruption. For this reason, pursuant to Minn. Stat. § 13.37, subd. 2, we have excised this data from the study results provided with this filing.

We take seriously our responsibility to maintain the security of the information and systems involved in the delivery of safe, reliable energy to our customers. A key tenet of our security program is limiting the extent to which sensitive information is accessed or shared. This is designed to help prevent key information about our system and the grid from being accessible. While we are not providing full Attachment Y2 and Siemens study reports available with this filing, we are open to

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discussing the specifics of the reports with parties to this docket who have signed a supplementary Non-Disclosure Agreement, provided that the information would remain adequately protected. Alternatively, the Company will make the full study reports available for inspection by Xcel Energy regulators who have fulfilled MISO's CEII requirements and will also consider making them available to certain other parties to the proceeding who have fulfilled MISO's CEII requirements and Xcel Energy's supplementary non-disclosure requirements.

We have electronically filed this document with the Commission, and copies have been served on the parties on the attached service list. Interested parties will be able to obtain copies from our web site at:

http://www.xcelenergy.com/Company/Rates_&_Regulations/Resource_Plans.

Please contact me at (612) 215-4663 or Aakash.Chandarana@xcelenergy.com if you have any questions regarding this filing.

/s/

AAKASH H. CHANDARANA
REGIONAL VICE-PRESIDENT
RATES AND REGULATORY AFFAIRS

Enclosures
c: Service List

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SUPPLEMENT TO XCEL ENERGY'S 2016-2030 UPPER MIDWEST RESOURCE PLAN

DOCKET NO. E002/RP-15-21

JANUARY 29, 2016

2016-2030 Upper Midwest Resource Plan – Supplement
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ATTACHMENT B – Updated Strategist Modeling and Outputs

ATTACHMENT C – Resource Plan Comparisons

ATTACHMENT D – Examining the Grid Impacts of Retiring Sherco Units 1 and/or 2

ATTACHMENT D1 – System Support Resource Attachment Y2 Study

ATTACHMENT D2 – Sherco 1 Replacement Power Study

ATTACHMENT D3 – Sherco 1 and 2 Replacement Power Study

ATTACHMENT E – Estimated Rate Impacts

ATTACHMENT F – Demand Response, Grid Efficiency, and Distributed Energy Resources as Alternative Resources

ATTACHMENT G – Socioeconomic Study Summary

ATTACHMENT G1 – Economic Impacts of Sherco Plant Alternatives

ATTACHMENT H – Preliminary Assessment of CO_2 Markets under the Clean Power Plan

2016-2030 Upper Midwest Resource Plan – Supplement
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I. EXECUTIVE SUMMARY

Partnerships with communities, customers, and stakeholders have helped to make Minnesota a leader in energy policy - collaboration has been the hallmark of this proceeding. As our industry enters an era of increasing responsiveness to evolving expectations – from those of individual customers, to federal and state carbon emissions goals – these partnerships will become even more important to charting a path that provides certainty in uncertain times.

The Commission noted in its January 6, 2016 Order that resource planning is a collaborative and iterative process and that a full understanding of the relevant facts requires exposure to the views of engaged and knowledgeable stakeholders. The Commission also explained that the process of analyzing future energy needs and preparing to meet them is not a static process, and that strategies for meeting future needs evolve in response to changing conditions. We agree. Through significant collaboration with our stakeholders, our Current Preferred Plan has evolved from a plan that would achieve a 40 percent carbon dioxide emissions reduction from 2005 levels to one that achieves a nearly 60 percent reduction in the same timeframe.

After filing our initial resource plan in January 2015, we engaged in informal discussions and conducted several technical workshops to receive feedback from our stakeholders. We listened carefully to this feedback, we reviewed and analyzed the comments filed in this docket, and we shared an updated vision of our energy future that resulted from this collaboration in our October 2, 2015 Reply Comments.

As described in those Reply Comments, we envision an energy future that transitions our generation fleet such that we will achieve a dramatic reduction in carbon and by 2030, our energy mix will be 63 percent carbon-free. Taking action to transition our fleet now mitigates the costs and risks of retiring a significant proportion of our baseload generation in the same time period. It will also mitigate environmental regulatory risks that could affect the economic viability of our older coal units, and provides certainty to our customers and stakeholders throughout the planning period. Our proposal to achieve this vision will benefit our customers, states, and the communities we serve in a variety of ways. It will benefit our customers by providing for a cost-effective transition to the cleaner energy future they want, while preserving the reliable and safe service they expect. As discussed further below, we can accomplish this transition for just a fraction of a percent more in incremental cost over earlier plans.

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Our Current Preferred Plan will also benefit our states by advancing both federal and state energy policies and by being nearly certain to comply with the final Clean Power Plan rules. Finally, our Current Preferred Plan will benefit our communities. It allows adequate time to transition our workforce during this fleet evolution, and provides for new investments and the creation of new jobs in current and future host communities. For these reasons, we believe that our Current Preferred Plan charts the right path forward for our Company and stakeholders.

Our Current Preferred Plan consists of the following course of action:

- Accelerating our transition away from coal by ceasing operation of our Sherco Units 1 and 2 in the 2020s,
- Adding 1,400 megawatts of large solar to our system, including 400 megawatts by 2020,
- Adding 1,800 megawatts of wind, including 800 megawatts by 2020,
- Adding natural gas generation in the 2020s,
- Operating our carbon-free nuclear fleet through their existing plant licenses, and
- Continuing our commitment to increased energy efficiency and seeking out new technologies that will advance customer-driven solutions.

As we make this transition, maintaining the reliability of the system is critical. Our reliability studies confirm that, before ceasing coal operations at the second Sherco unit in 2026, we must take measures to maintain reliability. Our operational analysis confirms that the most cost-effective way to stabilize the transmission system and meet our customers' load requirements is to build a combined cycle plant at the existing Sherco site. By locating the plant at Sherco, we are able to use existing infrastructure and interconnection rights, which will result in significantly lower costs as compared to locating it elsewhere. We can also use our existing water allocation to wet-cool the plant, further improving cost and performance. Finally, we believe that the impacts on the Becker community should be properly considered in this proceeding, and the siting of a combined cycle at Sherco will promote economic development for the community. We also propose to add a combustion turbine near one of our load centers in North Dakota. This will balance the interests of the states that we serve and maintain the benefits of an integrated system for all of our customers, while also addressing the reliability concerns of the North Dakota commission, which wants the Company to build cost-effective and dispatchable generation in their state.

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We recognize that site-specific generation is not typically a part of traditional resource planning analysis. However, the plan components we are proposing will have wide-ranging impacts on our system and region, making a locational analysis imperative to ensuring continued reliability and maximizing customer benefits. For these reasons, and those discussed later in this Supplement, we believe that a locational analysis is appropriate and in the public interest.

Our ownership of these assets, along with a balanced portfolio of the renewable generation we propose to add to the system, is a critical component of our vision, because it results in a balanced generation portfolio that will minimize customer costs and mitigate risk. The specific benefits of ownership include investment in our communities, continued use of our interconnection rights at Sherco, long-term value for our customers arising from the asset life of owned resources, increased diversity in our generation portfolio, and a demonstration of our commitment to being a leading provider of cleaner and greener energy. Our ability to secure these benefits for our customers is a critical component of our Current Preferred Plan and, we believe, an important factor in the public interest analysis.

Finally, because our nuclear fleet comprises more than half of the Company's carbon-free generation, it is a cornerstone to our carbon-reduction goals. We continue, therefore, to support operating our nuclear fleet through the end of each plant's respective current licensed life. In October, we acknowledged our projected increase in the capital costs necessary to run the Prairie Island nuclear plant to the end of its current licensed life. At the hearing on December 3, 2015, the Commission sought additional information on the increased capital forecast, and we have since studied the Prairie Island numbers in greater depth. Two key conclusions emerged from this study. First, the lower fixed operating and maintenance costs we have experienced relative to our 2008 modeling projections more than offset the increased capital projections – by more than $950 million. Second, even with the increased capital costs (the bulk of which occur in 2021 and beyond), Prairie Island has been, and continues to be, a cost-effective resource.

We recognize however, that stakeholders would like to better understand the implications of our updated forecast, as well as the potential for future updates. To help promote a better understanding of these costs, we are including a detailed discussion of Prairie Island in this Supplement. We believe that this information supports our continued operation of the plant, including the near-term investments we must make to safely and reliably operate our plants over the next few years. We acknowledge, however, that it is impossible to perfectly forecast costs for the

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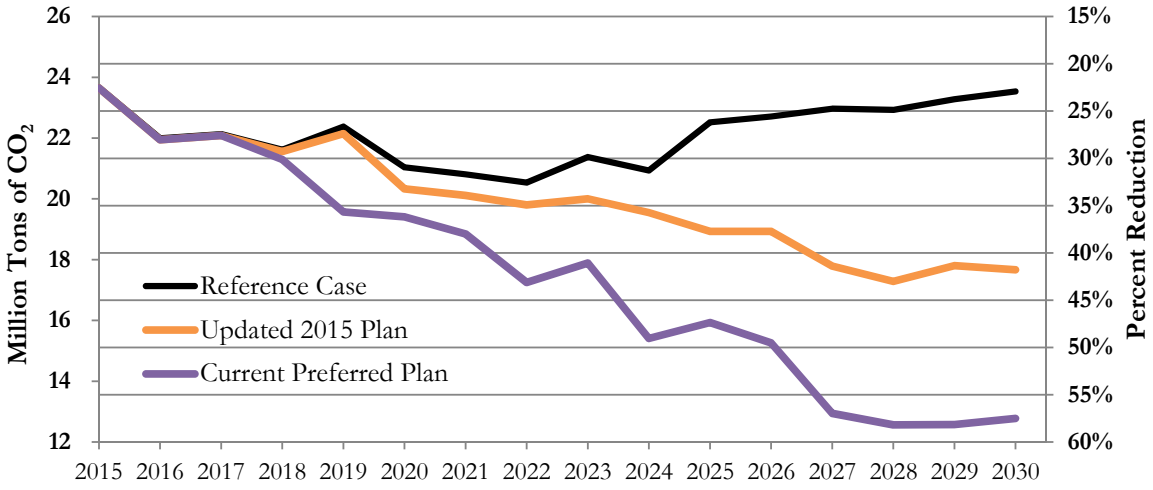
remaining 19 years of the plant's licensed life and recognize that stakeholders may want to explore alternatives based on that uncertainty. We therefore provide some preliminary analysis relating to an alternative path for Prairie Island (an "off-ramp") sometime in the mid-2020s. We recognize that there are other alternatives, but our analysis confirms that any near-term retirement would be significantly more costly than one in the mid-2020s or beyond. We agree that it makes sense to continue a dialogue regarding the future of Prairie Island. If the Commission wishes to further explore alternatives to operating Prairie Island through its current licenses, we are committed to doing the work necessary to advance this discussion, and anticipate that it could be completed within 18 months. At the same time, we believe that this Supplement demonstrates that the continued operation of Prairie Island is cost-effective and in the public interest in the near term, such that our continuing dialogue should not impede approval of our Current Preferred Plan.

Together, these actions will result in a significant transformation in our generation fleet, including a nearly 60 percent reduction in carbon emissions by 2030. The following graph shows the dramatically reduced carbon emissions that would result from our Current Preferred Plan, as compared to both our Updated 2015 Plan and Reference Case:



While the Updated 2015 Plan would have achieved substantial progress toward federal and state energy goals, the Current Preferred Plan – which grew out of the 2015 Plan through hard work and collaboration with stakeholders – does more. It

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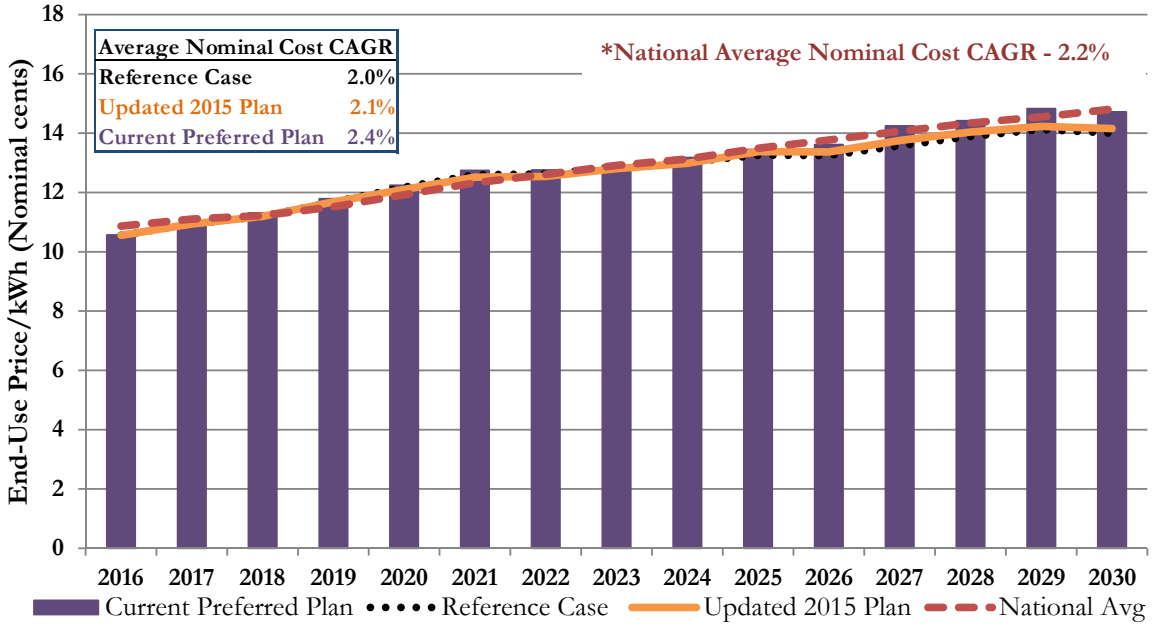
moves Minnesota significantly closer to achieving its goal of 80 percent carbon reduction by 2050, and it is the only scenario that is nearly certain to be compliant with the Clean Power Plan.

Our Current Preferred Plan achieves these goals without significantly impacting customer costs, reliability, our employees, or the communities we serve. In fact, due to recent extensions to federal tax incentives for solar and wind generation, the cost of our Current Preferred Plan is even lower than we anticipated in our October Reply Comments. We can now offer a plan that achieves 50 percent more carbon reduction than our Updated 2015 Plan for a nominal customer cost of less than one-half of one percent Compound Annual Growth Rate (CAGR) over that plan. The opportunity to achieve such significant reductions in our carbon emissions for a nominal increase in customer cost is one of the principal benefits of our Current Preferred Plan, which is reflected in the Strategist modeling discussed in detail later in this supplement.

As we would expect, the trajectory of our Current Preferred Plan deviates from our Reference Case and Updated 2015 Plan mostly in the out years of the planning period, after we complete the transition away from coal operations at Sherco Units 1 and 2. The following graph shows the relative cost growth of our Current Preferred Plan, Updated 2015 Plan, and Reference Case, in comparison to the national average:



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*National energy cost forecast from Energy Information Administration (EIA) Annual Energy Outlook 2015, Table Energy Supply, Disposition, Prices and Emissions. End use prices, all sector average.

As shown above, the cost of the three plans are comparable and roughly consistent with the expected national average increase in energy prices over the planning period.

Our Current Preferred Plan is in the public interest. It builds on our strong foundation of environmental performance, and ensures we will continue to reliably meet our customers' electricity needs in a cost-effective manner. It puts the Company on a path to transform its fleet in a planful, coordinated way that ensures we will meet our obligations under the Clean Power Plan and the most stringent of our state renewable energy and carbon reduction requirements. Implementation of our plan will put Minnesota at the forefront to lead the nation in clean energy, and at the same time, acknowledges and constructively addresses the unique policy preferences of the NSP System states. It provides our customers, employees, and communities with certainty while also maintaining flexibility to adjust and respond to changes along the way. Our Current Preferred Plan maintains a balanced diversity of energy sources and provides investment opportunities that will benefit the economies and communities in the states we serve. Finally, it promotes an orderly, gradual transition of our generation fleet and thus avoids a scenario where the Company may have to retire and replace five baseload generating facilities in the early 2030s.

To be sure, the process for approving this Resource Plan has taken longer than anticipated, and our Current Preferred Plan charts a path that is longer still. We believe, however, that a fleet transformation of this magnitude and scope requires a deliberate process, and that our Current Preferred Plan is a direct result of our deep engagement with stakeholders throughout this process. We have completed an extensive analysis since our October Reply, as well as in response to the Commission's January 6, 2016 Order. We are therefore appreciative of this opportunity to share our analysis and additional information in support of our Current Preferred Plan and look forward to engaging with our stakeholders to continue the constructive dialogue that brought us this far.

II. BACKGROUND

The Company submitted its 2016-2030 Upper Midwest Resource Plan on January 2, 2015, as required by the Commission's May 23, 2014 Order in the Competitive Acquisition Process (CAP) proceeding, which was an outcome from our last

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Resource Plan.[1] The Commission made determinations in that proceeding in December 2014, which, due to the timing, we were unable to incorporate into our Initial Filing.

On January 16, 2015, the Commission issued a NOTICE requiring the Company to supplement its Resource Plan with a revised Preferred Plan that incorporated the CAP resource decisions. On March 16, 2015, we submitted a Supplement incorporating the CAP resources, the 187 MW Solar RFP Portfolio the Commission approved in February 2015 in Docket No. E002/M-14-162, an acceleration of small solar additions to reflect the Community Solar Gardens proceeding, and additional modeling and discussion that resulted from our stakeholder engagement.[2]

Parties commented on the completeness of our Resource Plan on April 3, 2015, and as part of our April 17, 2015 Reply to those Comments, we submitted a detailed five-year rate analysis of our updated Preferred Plan. On July 2, 2015, parties commented on our Preferred Plan.

On October 2, 2015, we replied to parties' comments, in part committing to maintain a goal of 1.5 percent Demand Side Management (DSM) through the planning period and find ways to stimulate greater demand response with our customers – and in addition, outlined a Revised Proposal that would transition our system from coal generation, advance the acquisition of significant levels of renewable generation, recognize nuclear energy as a critical carbon-free baseload resource, and confirm our commitment to energy efficiency efforts. We also proposed to supplement the record with a detailed analysis supporting our Revised Proposal on January 29, 2016.

On January 6, 2016, the Commission approved our request to submit a Supplement on January 29, 2016, and set forth several informational requirements for the Supplement.[3] The Commission's Order additionally set a 30-day period within which the Minnesota Department of Commerce (Department) is to submit a letter to the Commission recommending a comment period and whether any additional information is needed. After reviewing the Department's recommendation and recommendations from any other party, the Executive Secretary is authorized to set a Reply Comment period.

[1] Docket No. E002/M-12-1240.
[2] Docket No. E002/M-14-162.
[3] *See* ORDER REQUIRING SUPPLEMENTAL FILING, Docket No. E002/RP-15-21 (January 6, 2016).

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We note that in this Supplement, we have updated the naming of our scenarios from our past filings to properly reflect our Current Preferred Plan for which we seek regulatory approval as follows:

January 2, 2015 Initial Filing	March 16, 2015 Supplement	October 2, 2015 Reply Comments	January 29, 2016 Supplement
Reference Case	Reference Case	Reference Case	Reference Case
Preferred Plan	Updated Preferred Plan	Preferred Plan	Updated 2015 Plan
N/A	N/A	Revised Proposal	Current Preferred Plan

The Updated 2015 Plan in this Supplement is named as such because we allowed our updated modeling for this scenario to select Production Tax Credit (PTC)- and Investment Tax Credit (ITC)-priced renewable resources, as a result of the December 2015 extension of these Federal tax incentives. Implementing this change allows for improved comparability of our Current Preferred Plan and our previous filings in this proceeding.

III. CURRENT PREFERRED PLAN

Our Current Preferred Plan proposes a bold energy vision that is centered around four principles:

First, accelerate the transition from coal energy to lower- and zero-carbon resources. Specifically we propose to:

- Achieve a reduction of in carbon dioxide (CO_2) emissions of nearly 60 percent (from 2005 levels) by 2030,
- Cease coal generation at Sherco Unit 2 in 2023 and Sherco Unit 1 in 2026, and
- Advance the addition of substantial renewable generation (1,200 MW by 2020).

Second, preserve regional system reliability. The preservation of system stability will be critical as we make the transition from coal energy to renewables, and we will preserve it by adding natural gas to our system and by continuing to operate our carbon-free nuclear fleet. We therefore propose to:

- Reaffirm our commitment to nuclear energy through the current licenses of our existing units,
- Add a combustion turbine (CT) in North Dakota by the end of 2025, and

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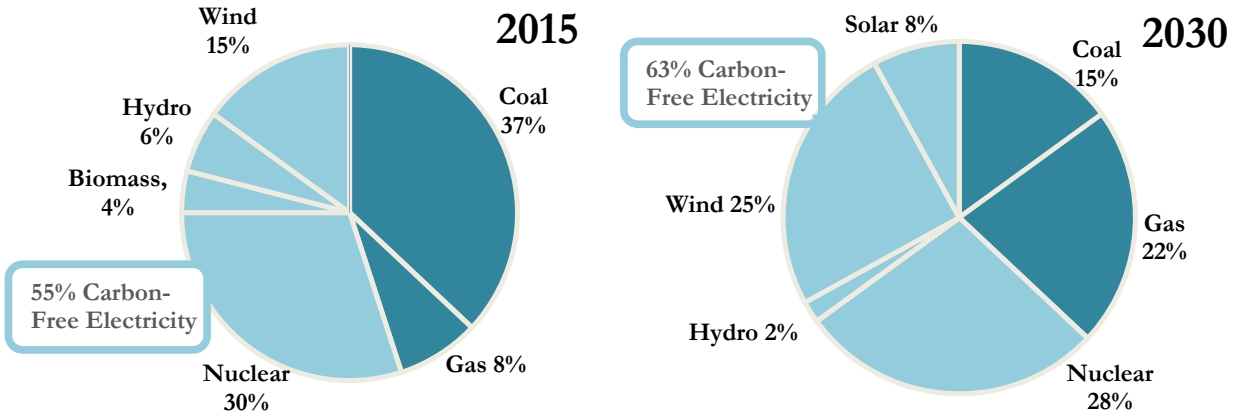
- Replace Sherco generation onsite with a combined cycle (CC) no later than 2026.

Third, pursue energy efficiency gains and grid modernization. We will continue our commitment to energy efficiency and new technologies and look to capitalize on these efforts rather than seeking to replace coal capacity megawatt for megawatt. We believe that modernizing the grid will further enable customer-driven solutions.

Fourth, ensure customer benefits. We will work with our state Commissions, the Minnesota Pollution Control Agency (MPCA) along with its counterpart environmental agencies in our other states, and our stakeholders to ensure our customers get the full benefit of our proposal. Specifically, we will work to maximize the benefits of complying with the Clean Power Plan (CPP) State Plans for our customers and communities.

In short, our vision for the future is cleaner at an affordable price. While our Current Preferred Plan includes slight variations in the timing and siting of our resource additions as compared to the proposal we outlined in our October 2 Reply, the resulting 2030 energy mix is the same. Likewise, the primary resource changes – ceasing coal operations at Sherco Units 1 and 2 and more than doubling the renewable resources on our system – remain unchanged. Figure 1 below provides a side-by-side comparison of our energy mix in 2015 and 2030.

Figure 1: 2015 Energy Mix Compared to Current Preferred Plan in 2030



Our Current Preferred Plan dramatically changes the NSP System energy mix at the end of the planning period. Coal *reduces* from 37 to 15 percent; natural gas *increases*

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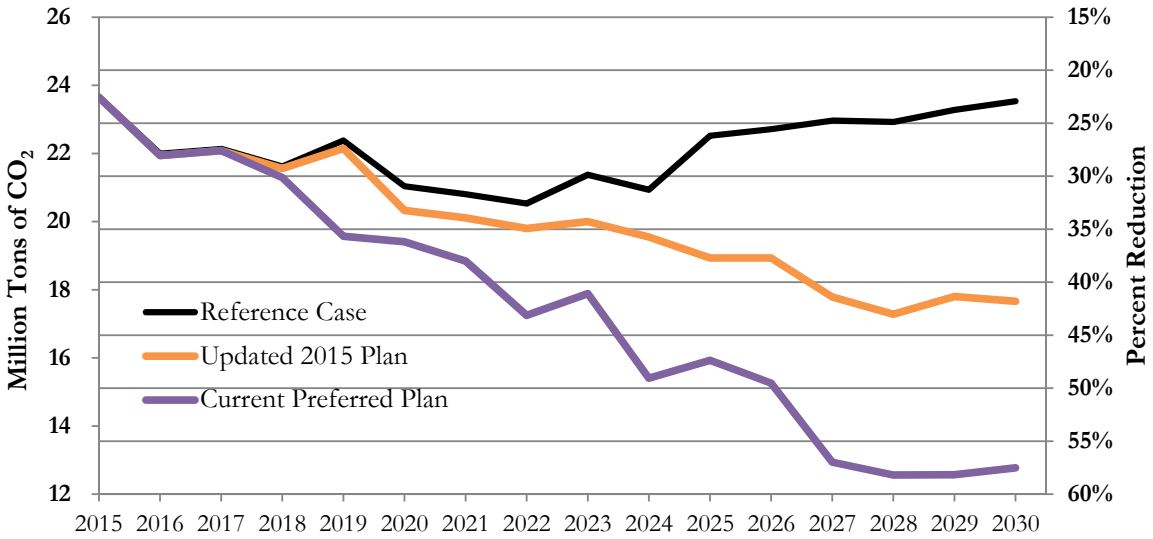
from 8 percent to 22 percent; solar, which makes up less than 1 percent of our energy mix in 2015, *increases* to 8 percent by 2030; wind *increases* from 15 to 25 percent; biomass and hydro *drop* to zero and two percent, respectively (due to contract expirations), while nuclear remains relatively constant at around 30 percent.

While our Updated 2015 Plan would have reduced our 2030 CO_2 emissions 40 percent from 2005 levels, our Current Preferred Plan puts us on an even greater CO_2 reduction trajectory. It will reduce CO_2 emissions by nearly 60 percent from 2005 levels by 2030, and it will move us significantly closer to achieving Minnesota's policy objective of an 80 percent reduction by 2050.

Figure 2: Projected Carbon Reduction from 2005 Levels



As discussed in greater detail below, we will achieve this dramatic reduction for just a fraction of a percent in incremental cost over our Updated 2015 Plan. Figure 2 below compares the projected CO_2 reduction of our Current Preferred Plan to our Updated 2015 Plan and the Reference Case.

It is also important to note that – given what we now know about the final CPP rules – the Reference Case would clearly not comply with the CO_2 reductions required of the Company under Minnesota's state plan to implement the CPP, nor may the Updated 2015 Plan. Further, we believe additional environmental compliance regulations will continue to place pressure on coal operations at Sherco. It is possible that installation of Selective Catalytic Reduction (SCR) equipment for tighter nitrogen oxide (NOx) control might be required near the end of the planning

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period.[4] We believe the actions we are proposing to take with our Current Preferred Plan positions us well to serve our customers into the future, and reduces the risk of potential future increased costs to maintain environmental compliance.

IV. MINIMUM SYSTEM NEEDS & EXPANSION PLAN

In this section, we discuss our strategy and proposal to address the future capacity deficit that results from our proposal to cease coal operations at Sherco Units 1 and 2, combined with a number of other large changes in our generating resources.

A. Load & Resources Analysis and Future Capacity Deficits

We provide in Table 1 below an updated Load and Resources (L&R) analysis that reflects our excess/deficit capacity position for the planning period, starting with the approved and existing resource additions reflected in our March 2015 Supplement. It also addresses the impact of the resource changes we propose as part of our Current Preferred Plan and summarizes our resulting capacity position through the planning period. Consistent with our January 2015 initial filing and all subsequent filings, we have used the same fall 2014 load forecast in this analysis, and maintained the same available resources to the Strategist model.

[4] In January 2016, the Eighth Circuit issued an opinion that upheld EPA's approval of the Minnesota regional haze plan, which did not require installation of SCRs on Sherco Units 1 and 2. The next regulatory developments that could include a requirement to install SCRs on these units will occur in the early 2020s, with installation potentially required in the late 2020s. The ozone standard, if made more stringent in 2020, might drive SCR installation in the 2027-2032 timeframe. The next round of regional haze planning is expected to occur in the early 2020s (EPA has announced plans to delay the 2018 deadline by 2-3 years), which could drive SCR installation in the late 2020s. We estimate that the capital cost for the installation of an SCR is approximately $250 million per unit in 2015 dollars.

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Table 1: Updated Load and Resources (MW UCAP[5])

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Forecasted Load	9,442	9,525	9,597	9,649	9,674	9,694	9,754	9,748	9,766	9,798	9,868	9,962	10,136	10,151	10,251
MISO System Coincident	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
Coincident Load	8,970	9,048	9,117	9,167	9,190	9,209	9,266	9,261	9,278	9,308	9,375	9,464	9,629	9,644	9,739
MISO Planning Reserve	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%
Obligation	9,607	9,691	9,764	9,818	9,843	9,863	9,924	9,919	9,937	9,969	10,041	10,136	10,313	10,328	10,430
Existing/Approved Resources	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Load Management	1,009	1,021	1,033	1,044	1,056	1,067	1,078	1,090	1,101	1,103	1,098	1,094	1,089	1,085	1,080
Coal	2,372	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395
Nuclear	1,648	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643	1,643
Natural Gas	3,451	3,476	3,476	3,465	3,465	3,465	3,465	3,465	3,137	2,824	2,298	2,047	1,812	1,812	1,812
Black Dog 6	0	0	0	208	208	208	208	208	208	208	208	208	208	208	208
Calpine MEC2	0	0	0	278	278	278	278	278	278	278	278	278	278	278	278
Biomass/RDF/Hydro/ Wind	1,341	1,339	1,316	1,279	1,205	1,437	1,430	1,383	1,310	461	451	407	318	300	299
Solar [1][3]	25	33	137	143	149	156	164	174	187	202	220	242	268	300	338
Aurora [3]	0	0	70	69	69	69	68	68	68	67	67	67	66	66	66
Community Solar Garden - Additions [2][3]	20	36	53	72	94	103	103	102	102	101	101	100	100	99	98
Resources – Existing & Approved	9,866	9,942	10,122	10,597	10,562	10,821	10,833	10,806	10,427	9,282	8,758	8,479	8,177	8,186	8,218
Capacity Excess/ Deficit March 16, 2015 Filing	**260**	**251**	**358**	**779**	**719**	**958**	**909**	**887**	**490**	**-687**	**-1,282**	**-1,657**	**-2,136**	**-2,143**	**-2,212**

(1) Solar includes 2014 Solar RFP (Docket No. E002/M-14-162)

(2) Solar Additions represent the revised solar implementation due to Community Solar Gardens.

(3) Solar resources may be accredited up to 1 year earlier than forecasted based on changes to MISO's Business Practices for 2016/2017. This recent proposal has not been incorporated into the current L&R.

Current Preferred Plan – Existing Resource Changes	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Sherco 2 Cease Coal Operation	0	0	0	0	0	0	0	-667	-667	-667	-667	-667	-667	-667	-667
Sherco 1 Cease Coal Operation	0	0	0	0	0	0	0	0	0	0	-694	-694	-694	-694	-694
Proposed Coal Changes	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**-667**	**-667**	**-667**	**-1,361**	**-1,361**	**-1,361**	**-1,361**	**-1,361**
Capacity Excess/Deficit Jan 29, 2016	**260**	**251**	**358**	**779**	**719**	**958**	**909**	**220**	**-177**	**-1,354**	**-2,643**	**-3,017**	**-3,497**	**-3,503**	**-3,573**

The "Capacity Excess/Deficit March 16, 2015 Filing" line in Table 1 represents our updated capacity position before adding any of the resource changes proposed in our Current Preferred Plan. Consistent with our March 2015 Supplement and our October 2015 Reply, it shows we expect to have sufficient capacity to meet our customers' needs through 2024. However, beginning in 2025 our capacity position shifts from a surplus of nearly 500 MW to a deficit of over 2,200 MW by 2030. Much of this shift is due to the retirement of approximately 800 MW of peaking plants, as well as the expiration of nearly 1,700 MW of hydro and natural gas Power

[5] MISO Unforced Capacity values, summer ratings.

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Purchase Agreements (PPAs) during the period, including the expiration of our existing 850 MW PPA with Manitoba Hydro in 2025.

The "Capacity Excess/Deficit Jan 29, 2016" line represents our position after applying the changes to existing resources that are part of our Current Preferred Plan.[6]

B. Current Preferred Plan Expansion Plan

Our Current Preferred Plan proposes to address the capacity deficit through a combination of renewable resource additions in the early years, and the addition of natural gas CT and CC units. In summary, our proposed resource additions are:

- 1,400 MW of large solar additions, including 400 MW by 2020,
- 1,800 MW of additional wind, including 800 MW by 2020,
- A 786 MW CC addition at the Sherco site in 2026 to replace the capacity of Sherco Unit 1 before it ceases operation,
- A 230 MW CT located in North Dakota by the end of 2025, and
- Over 1,800 MW of additional CT capacity.

The early renewable energy additions in our Current Preferred Plan will allow us to capitalize on favorable market pricing associated with the recently extended Federal ITC and PTC tax incentives, reducing the cost impacts of our Current Preferred Plan.

Our modeling results, described in more detail below, consistently show the addition of a CC in 2027.[7] We propose to locate the CC at Sherco because it will allow us to cost-effectively address the transmission issues identified by the Midcontinent Independent System Operator (MISO) Attachment Y2 Study, ensure the stability and reliability of our transmission system, mitigate impacts to the local community and our employees, and potentially provide improved access to natural gas supplies for communities in central Minnesota.

[6] Unit retirements typically occur during a period of the three to nine months following the summer peak (months October-May). Commercial operation of replacement generation would commence between the months of October and March to maintain adequate capacity resources to meet MISO obligations.
[7] 2027 represents the year the CC resource is needed to address a capacity deficit; our Current Proposed Plan proposes that a replacement CC unit go in-service at Sherco such that there will be no gap in MISO capacity accreditation.

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In order to balance the perspectives of the stakeholders in the states we serve and maintain the benefits of an integrated system for all of our customers, we also propose to add a CT near our North Dakota load. This would address the reliability concerns of the North Dakota commission, while preserving the objective of both the North Dakota and Minnesota commissions for the Company to develop cost-effective generation proposals.

We show the resource additions we propose with our Current Preferred Plan in Table 2 below.

Table 2: Current Preferred Plan Expansion Plan[8] (MW ICAP[9])

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Large Solar	-	-	-	-	200	-	200	100	100	200	100	100	-	400	-	-	1,400
Wind	-	-	-	-	800	-	-	400	-	-	400	200	-	-	-	-	1,800
CT	-	-	-	-	-	-	-	-	-	-	460	690	230	230	-	230	1,840
Fargo CT	-	-	-	-	-	-	-	-	-	-	230	-	-	-	-	-	230
Sherco CC	-	-	-	-	-	-	-	-	-	-	-	-	786	-	-	-	786

Note: Resources are shown in their first full year of operation and will go into service the year prior.

We note that, with respect to solar, only the utility-scale resource additions proposed as part of our Current Preferred Plan are identified in this Expansion Plan. All small solar and previously-approved large solar resources are included as available resources in the L&R in Table 1 above. We discuss an update to our *small* solar forecast in Attachment B to this Supplement. To the extent small-scale solar additions out- or under-pace our updated small solar forecast, we will make corresponding adjustments to our large solar acquisition plan.

For reference, we provide updated Renewable Energy Standard and Solar Energy Standard compliance information, as well as the Expansion Plans for the Reference Case and Updated 2015 Plan in Attachment C.

V. RESOURCE PLANNING ANALYSIS

We provide as Attachment B details regarding our revised modeling assumptions, the scenarios and sensitivities analyzed, potential alternatives, an economic analysis,

[8] We clarify that we do not show the small solar additions, the 187 MW Solar RFP, or the competitive acquisition process resources in our Expansion Plan. These are included as existing/approved resources in the Updated L&R (Table 1).
[9] MISO Installed Capacity values.

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a discussion on our treatment of dump energy, and a methodology for our long-term rate impact projections – which we also summarize below.

We analyzed and compared five key scenarios in our analysis. We summarize the assumptions underlying these scenarios in Table 3 below.

Table 3: Summary of Scenarios Analyzed

Scenario Name	Description
Current Preferred Plan	• Ceases operation of a total of 1,400 MW of capacity and associated energy at Sherco Unit 2 in 2023 and Unit 1 in 2026 • Adds 1,800 MW of wind • Adds 1,400 MW of large solar • Includes 700 MW of small solar • All renewable costs updated for Federal ITC/PTC extension • Includes goal of 50 percent ownership of renewables • Adds Company-owned Fargo CT by 2025 and Sherco CC in 2027
Current Preferred Plan – All Generics	Same resource changes as Current Preferred Plan, with all generic thermal replacements
Reference Case	• Continues operation of Sherco Units 1 and 2 through the end of the planning period • Adds 400 MW of wind • Includes 400 MW of small solar additions • Includes 287 MW of large solar additions
Updated 2015 Plan	• Continues operation of Sherco Units 1 and 2 through the planning period • Adds 1,800 MW of wind • Adds 1,400 MW of large solar • Includes 700 MW of small solar • Updated for Federal ITC/PTC extension
North Dakota Plan	No additional renewables beyond currently committed 750 MW of wind; no assumptions changes.

We additionally considered the following alternative scenarios, which we discuss in Attachment B:

- A scenario that converts a Sherco Unit to a Gas Boiler, and
- A scenario that relies only on renewables.

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We also discuss Demand Response, Distributed Energy Resources, and Grid Modernization as Alternative Resources in Attachment F.

We evaluate these scenarios holistically by analyzing their environmental performance, strategic flexibility, and cost using a "Run Key" to summarize and compare key Strategist modeling metrics. The Run Key below includes the results of the Present Value Revenue Requirements (PVRR) and Present Value of Societal Costs (PVSC) analysis for each of our key scenarios to provide a reference point, but it also identifies key policy outcome metrics such as the reduction in CO_2 emissions from 2005 levels and the amount of renewable energy added to the NSP System under each scenario. We note that the PVRR and PVSC results are the result of the Strategist model, which extends beyond the planning period to 2053.

Table 4: Run Key[10]

	PVSC Results ($M)	PVRR Results ($M)	2030 Coal Gen vs. Ref Case	2030 Gas Burn (Bcf)	2030 Percent CO_2 Reduction	Total Expansion Plan Renewable Additions (MW)	CPP Compliant?
Current Preferred Plan	$51,293	$45,606	-59%	83	58%	3,200	Yes
Current Preferred Plan, All Generics	$51,280	$45,582	-59%	84	57%	3,200	Yes
Updated 2015 Plan	$51,458	$45,302	-16%	32	42%	3,200	Uncertain
Reference Case	$52,422	$45,605	-	58	23%	400	No
North Dakota Plan	$52,620	$45,473	+3%	68	19%	0	No

The comprehensive Run Key analysis shows that our Current Preferred Plan has the strongest performance in terms of CO_2 reductions and renewable energy additions to the NSP System. The amount of renewable energy additions in our Updated 2015 Plan and Current Preferred Plans are consistent, but the timing and ownership assumptions have shifted. Our Current Preferred Plan continues to provide the best value for our customers – achieving a balance between multiple objectives including reasonable costs, dramatic emissions reductions, anticipated compliance with the CPP, and sustained reliability on our system.

[10] In this Run Key Table, the PVRR Results, change in coal generation in 2030 as compared to the Reference Case (2030 Coal Gen vs. Ref Case), amount of gas burned at our plants in 2030 in Billions of cubic feet (2030 Gas Burn (Bcf)), and the percent reduction of CO_2 from 2005 levels (2030 Percent CO_2 Reduction) are all considered under a cost sensitivity that excludes regulatory costs and CO_2 externalities in the dispatch (Sensitivity T, explained in detail in Attachment B). Under this sensitivity, there will be a tendency to overestimate CO_2 emissions, as coal would be 'priced' at a lower cost and the likelihood of dispatching the resource more frequently would therefore be increased.

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A. Modeling Approach

This resource planning process begins the transformation of our generating fleet and signals a step change. It is additionally important to the states in the Upper Midwest Region in terms of alignment and compliance with the requirements of the CPP.

Over the last 20 years, resource plans have traditionally centered on meeting the needs of a growing system, or replacing smaller generators that have reached the end of their lives. In this Resource Plan, we are proposing to cease operation of 1,400 MW of coal generation at Sherco Units 1 and 2, which represents over 30 percent of our baseload generating capacity within the short 2023-2026 timeframe. Because these resources are concentrated in a single geographic area and proximate to other baseload generation, it is important to consider the location of replacement generation. This is a departure from traditional resource planning. In this instance however, the location of new or replacement generation requires additional consideration due to the potential impact to the system of removing such large important assets.

In considering the replacement of key components of an existing system, such as Sherco Units 1 and 2, the analysis must take into account a number of additional considerations that cannot always be captured in economic modeling or analysis terms. These other considerations are both technical and policy-based and include the security and reliability of the combined operation of the generation fleet and the transmission system.

We therefore conducted both traditional "generic" and location-specific Strategist modeling to inform the Current Preferred Plan we propose. We provide an optimized capacity Expansion Plan that considered only generic capacity alternatives as Table 5 below.

Table 5: Generic Unit Expansion Plan (MW ICAP)

Current Preferred Plan - All Generic	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Large Solar	-	-	-	-	200	-	200	100	100	200	100	100	-	400	-	-	1,400
Wind	-	-	-	-	800	-	-	400	-	-	400	200	-	-	-	-	1,800
CT	-	-	-	-	-	-	-	-	-	-	690	690	230	460	-	-	2,070
CC	-	-	-	-	-	-	-	-	-	-	-	-	778	-	-	-	778

These analyses resulted in the same conclusions in terms of the size and type of expansion resources and nearly identical in their timing. Both the site-specific and

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generic modeling shows a need for CT capacity in the 2025 timeframe and a CC addition in 2027.[11]

However, as part of the determination to cease coal operations at Sherco Units 1 and 2, we believe it is important and appropriate to also consider the impacts to the transmission system, the local community, state and federal policies, customer and community preferences and cost impacts. We have undertaken numerous studies to better understand these and other implications of our Current Preferred Plan. We believe our plan addresses these issues through our proposal to locate a CT in North Dakota by the end of 2025 and to locate a CC at the Sherco site in 2026 in order meet the capacity deficit resulting from ceasing coal operations at the second Unit.

Table 6 below outlines our capacity surplus/deficit position after applying the proposed resource additions of our Current Preferred Plan.

Table 6: Capacity Position with Current Preferred Plan Expansion Plan (MW UCAP)

Current Preferred Plan Proposed Additions	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Large Solar	0	0	0	0	0	209	261	314	418	471	523	523	732	732	732
Wind	0	0	0	0	0	118	178	178	178	266	266	266	266	266	266
North Dakota CT	0	0	0	0	0	0	0	0	0	219	219	219	219	219	219
Sherco CC	0	0	0	0	0	0	0	0	0	0	0	763	763	763	763
CT	0	0	0	0	0	0	0	0	0	439	1,097	1,316	1,535	1,535	1,755
Total Plan Additions	**0**	**0**	**0**	**0**	**0**	**328**	**439**	**491**	**596**	**1,365**	**2,105**	**3,087**	**3,516**	**3,516**	**3,735**
Revised Proposal Capacity Excess/ Deficit	**260**	**251**	**358**	**779**	**719**	**1,286**	**1,348**	**1,379**	**419**	**11**	**156**	**70**	**19**	**12**	**162**

As shown above, our resulting capacity position is a surplus through the planning period. In 2025 and beyond, our position reflects the expiration of significant capacity resource PPAs and peaking retirements we discussed above, resulting in our more narrow capacity position in the out-years of the planning period. Because

[11] The Department noted in its November 6, 2015 Comments that the Updated 2015 Plan we filed in our initial January 2015 filing and March 2015 Supplement did not include the addition of a CC resource prior to 2030. We note that at the time of those filings, we had not proposed to cease operation of any major generating units in the planning period like we now propose with Sherco Units 1 and 2. Ceasing coal operations of Sherco Units 1 and 2 results in the loss of nearly 1,400 MW of high-capacity-factor generation, which drives our need to add a CC resource prior to 2030. The model selects a natural gas CC unit in 2027 as a cost-effective resource addition to fill this gap. In addition to the favorable economics of adding a CC instead of a CT, at the time the second Sherco Unit ceases coal operation, we must also consider the technical system benefits the Sherco Units provide through their spinning mass to help maintain system reliability. We would not expect a simple-cycle CT to be online very often – nor would that be cost-effective as compared to a CC.

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these changes will occur in the out-years, we can continue to monitor our position over time and through the course of upcoming resource planning cycles. Addressing any potential necessary resource additions to meet capacity needs in the mid to late 2020s will be analyzed in our next Resource Plan filing, which we expect to occur by 2018.

B. Locational Analysis

As we have discussed, Resource Plans typically do not analyze location-specific alternatives. However, we believe that our Current Preferred Plan – as well as state and federal policies – present unique challenges that are not easily addressed through a traditional resource planning framework. Sherco Units 1 and 2 are critical components of our energy supply and the Upper Midwest grid. In addition to the energy and capacity they provide to customers, the sheer mass and operating characteristics of these Units provide important system benefits that impact customer reliability. For these reasons, and because the maintenance of system reliability is critical to serving the public interest, a location-specific analysis is essential. With respect to the CT needed in 2025, our North Dakota regulators have stated a preference, and the Company has agreed, to have dispatchable generation located close to our largest load centers in North Dakota, which we discuss in part 3 below.

In order to examine various aspects of the technical and policy-based issues associated with Sherco Units 1 and 2, we undertook several studies to understand the impacts of ceasing coal operations at Sherco Units 1 and 2. The studies we conducted to examine the implications of potentially ceasing coal operations at Sherco Units 1 and 2 are as follows: (1) a MISO Attachment Y2 Study, which assessed grid implications if Units were no longer operating; (2) an Xcel Energy Transmission Reliability Study, which assessed grid implications of replacing all or a portion of the Units' capacity at other locations on the NSP System; (3) a Black Start Plan Analysis that assessed the implications associated with altering our system restoration path and would be necessary because the Units currently play an essential role in the event of a major system outage; and (4) a socioeconomic analysis conducted by the Leeds School of Business at the University of Colorado Boulder and the Labovitz School of Business and Economics at the University of Minnesota Duluth.

We discuss each of these location-specific resources below.

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1. On-Site Combined Cycle Unit at Sherco

First, we are proposing to construct a 786 MW (ICAP) natural gas CC onsite at the current Sherco site. Because we are not replacing all of the MWs that result from ceasing coal operations at Units 1 and 2 with the CC unit, there will be additional interconnection injection capabilities at the site, which we are proposing to partially utilize by also constructing photovoltaic (PV) solar generation on existing property.[12]

As outlined in Attachment B, our updated modeling for this Supplement includes several options for a CC: (1) at the site of the current Sherco 1 and 2 Units, (2) at a generic brownfield site, and (3) at a generic greenfield site. We developed the option of onsite replacement to incorporate into our Strategist modeling an economic analysis of locating generation at the Sherco site. We believe there are significant benefits associated with siting the CC at the Sherco site, which we discuss below.

a. Benefits of Onsite Generation at Sherco

There are number of benefits to locating a replacement CC at the Sherco site. Importantly, our Strategist demonstrates that the addition of a CC unit onsite at Sherco is part of a least-cost capacity expansion plan. However, not all relevant factors are easily converted to an economic basis for inclusion in Strategist. For instance, there are benefits to using existing infrastructure and an existing brownfield site that do not easily reduce to economic terms, including the fact that the transmission grid has been studied, designed, engineered and operated for decades to provide a high degree of reliability and resiliency for customers by incorporating significant generation injection at the Sherco site. Similarly, it is important to consider that our host community of Becker, Minnesota and the greater Sherburne County area has come to depend on local employment opportunities, property taxes, and other economic benefits associated with the existing units. We discuss these factors below.

Use of Existing Infrastructure. As an existing brownfield generation site, the Sherco site offers a number of advantages over new greenfield sites, both in terms of operations and cost. For example, we can use our existing interconnection rights and existing substation and transmission outlet capacity once Units 1 and 2 cease

[12] We have identified two areas on the existing Sherco site for solar development. One location would be atop the closed and capped ash ponds 1 and 2 and the second would be on open land on the north side of the Mississippi River between the Sherco plant and the Monticello plant.

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coal operations. The existing Sherco site also comprises sufficient available land to site a CC unit and is already permitted for a large industrial generating facility. Further, existing water and wastewater treatment facilities can support the proposed CC unit, and existing facility staff, administration, warehousing, and maintenance facilities can likewise be utilized. Finally, the site's water allocation is sufficient for cooling approximately 2,300 MW of generation (the current combined installed capacity of Sherco Units 1, 2 and 3), which means that once Units 1 and 2 cease coal operations, an allocation equivalent to approximately 1,400 MW will become available. Consequently, portions of the Unit 2 cooling system can be reused by the new CC facility, allowing the replacement CC at the Sherco site to be wet-cooled, improving both performance and cost.

The System is Designed to Reliably Operate with Significant Generation Injection at Sherco. From the technical studies conducted by MISO and the Company we concluded that we can avoid anticipated impacts on the electric transmission system and related costs by replacing generation at Sherco. In contrast, siting replacement thermal generation at other locations on the NSP System have disadvantages compared to siting a CC at Sherco, including a significant level of uncertainty with regard to final costs and performance. The *Xcel Energy Transmission Reliability Study* confirmed that the existing transmission system with significant generation injection at Sherco works well, and plays a significant role in providing reliable service for NSP System customers and other customers in our portion of the MISO region. It also concluded that there are transmission upgrade costs and other trade-offs associated with replacing Sherco Units 1 and 2 at an alternative location, such as increased energy losses the farther the replacement generation is located from the Twin Cities load center.

Unlike an onsite CC that will have injection capability and interconnection rights, replacement generation at other locations will be subject to the MISO generator interconnection process, and may incur additional network upgrade costs beyond those we have identified. The MISO interconnection queue has changed significantly since these technical studies were initiated in early 2015. Since March 2015, requests to add nearly 10,000 MW of wind have entered the queue in the Iowa, Minnesota, North Dakota, and South Dakota area.[13] Nearly 70 percent, or 7,000 MW have paid all required study deposits and achieved milestones, qualifying them to participate in MISO's upcoming interconnection studies. This significant

[13] MISO Generator Interconnection Queue is located at: https://www.misoenergy.org/Planning/GeneratorInterconnection/Pages/InterconnectionQueue.aspx.

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number of projects that have entered MISO's interconnection queue creates uncertainty with respect to the identified transmission impacts and associated interconnection costs. Replacement generation at the Sherco site, as we have proposed, has the added benefit of not being impacted by this uncertainty.

Locating a CC at the Sherco Site Avoids Significant Transmission Costs. Our technical studies each identified costs associated with siting replacement generation at locations other than Sherco. We summarize the study results below and provide a full summary of the studies and our conclusions as Attachment D.

MISO Y2 Study. MISO concluded that retirement of Sherco Unit 1 and Sherco Unit 2 would result in violations of applicable planning criteria that would require transmission upgrades and the need for Units to be designated as System Support Resources (SSR). Assuming a future Attachment Y study would have similar results, MISO would require that the identified violations be mitigated to its satisfaction prior to retirement of Sherco Units 1 and 2, if replacement generation is not located at Sherco. Specifically, the MISO Y2 study identified significant thermal and voltage violations in the Twin Cities if Sherco Units 1 and 2 are retired. The voltage violations impact our Monticello Nuclear Plant's operation and Nuclear Regulatory Commission (NRC) requirements. Both the thermal and voltage violations would need to be addressed through transmission investment in the Sherco area, regardless of the location of any replacement generation at an alternative site before the units could cease operation. Additional transmission upgrades that may be necessary due to the location of replacement generation, were not within the scope of the MISO Y2 study, but were studied in the Xcel Energy Transmission Reliability Study we discuss below. We provide this study report as Attachment D1.

Xcel Energy Transmission Reliability Study. Our study, conducted in conjunction with Siemens Power Technologies International, involved a full thermal analysis, full voltage analysis, and transient stability analysis. As noted above, it confirmed that the existing transmission system with significant generation injection at Sherco works well, and that there are transmission upgrade costs and other trade-offs associated with replacing Sherco Units 1 and 2 at an alternative location. We provide these study reports as Attachments D2 and D3.

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Black Start Plan Analysis. Our analysis of our current Black Start Plan examined impacts if our current Sherco Units 1 and 2 target units cease coal operations.[14] Our analysis concluded that our proposal to construct a natural gas CC unit at the Sherco site would provide for use of the current and most efficient restoration path. Altering the restoration path away from the Sherco site will require the addition of various equipment and/or facilities and results in a longer restoration period, which is of greatest concern in winter/cold months. We have included the approximate costs of altering our restoration path as part of the costs associated with siting the 2027 CC at alternative locations.

If replacement generation is not sited at Sherco, we must mitigate the reliability issues our technical studies identified. For example, the Monticello Plant cannot operate if its voltage is outside the permissible range. As discussed further in Attachment D, we have determined that the best option to address these issues is to convert Sherco Unit 1 or Unit 2 to a Synchronous Condenser (SC). Importantly, SCs provide not only the required continuous range of voltage support, but are also a rotating mass that helps hold the grid electrically together following a disturbance such as a major fault. These additional costs stem from transmission upgrades and the need for additional equipment onsite at Sherco and other locations on the NSP System. We refer to these costs as "leave-behind" costs, which are therefore appropriately added to the cost of any combined cycle generator at an alternative location. The total leave-behind costs are shown below in Table 7.

[14] A Black Start Plan specifies the process of restoring the grid to full operation without relying on the external transmission network following a full or partial black out. Black Start Plans are required by the North American Electric Reliability Corporation (NERC), developed in concert with neighboring utilities, and are subject to review and approval by MISO.

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Table 7: Leave-Behind Costs – PVRR
($Millions – 2015)

Cost Components	PVRR
	[TRADE SECRET BEGINS…
Installation of Synchronous Condenser	
O&M for Synchronous Condenser	
Upgrade Brainerd - Riverton 115 kV Line	
Rebuild Helena - Scott County 345 kV Line	
Installation of Additional Capacitors	
New Blackstart Path	
	…TRADE SECRET END]
Total	**$150**

Retiring Sherco Units 1 and 2 would have negative impacts on employment, GDP, and disposable personal income in Sherburne County. We understand the Commission has previously expressed interest in understanding the socioeconomic impacts on the Becker area, so therefore commissioned a socioeconomic study. We summarize the study below and provide a full summary and the study itself as Attachments G and G1, respectively. This Study assessed impacts on employment, Gross Domestic Product (GDP), and disposable personal income on the locations impacted by a change in operating expenditures, capital expenditures, property taxes, and electricity rates resulting from Unit retirement and replacement at an alternative location. The scenarios analyzed in the Study, included various potential Unit retirement dates and a scenario that included the replacement of the two Sherco Units with one CC at the Sherco site and one CC located in Dakota County. The Study found that all early retirement scenarios, when compared to a baseline where the Units continued operations through the planning period, result in moderately slower growth in the Minnesota economy. The closure of the Units showed negative impacts on employment, GDP, and disposable personal income in Sherburne County. However, if the generation is replaced elsewhere in Minnesota, those impacts are partially offset by positive economic impacts in the replacement location – mitigating on an overall state-level, the negative impacts. While the Study did not model a scenario that directly reflects our Current Preferred Plan, our proposed 2023 and 2026 dates fall within the range of scenarios analyzed.

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As we stated in our October 2, 2015 Reply, ceasing coal operations at Sherco Units 1 and 2 will impact our employees and their families, the City of Becker and surrounding area, and Liberty Paper, which relies on steam from the Units for its operations. Charting a path certain for these stakeholders particularly, will provide an 8-10 year transition period, and with our proposal to site replacement generation onsite, will promote economic development, and reaffirm our commitment to central Minnesota. We are committed to mitigating impacts on our employees by working closely with our International Brotherhood of Electrical Workers union local to successfully manage the transition. Finally, our proposed onsite CC will provide additional options to continue to supply steam to Liberty Paper, who is a valued Xcel Energy customer, an important employer in the Becker area, and a critical part of Minnesota's recycling industry.

b. Costs of Onsite CC

Generating Equipment. We developed the costs for the onsite CC generation based on the installation of a 2x1 CC wet-cooled facility in 2026, which would begin commercial operation prior to the second Sherco Unit ceasing coal operations. The summer-rated capacity of the CC facility would be approximately 763 MW UCAP (786 MW ICAP). We developed our initial capital cost estimates for the onsite Sherco CC by adjusting the cost of the generic CC used in the modeling throughout this proceeding for the site-specific benefits associated with utilizing existing infrastructure. Because of the site's available water allocation, the replacement CC at the Sherco site is to be wet-cooled, improving both performance and cost. We expect the initial capital cost of the generic CC to be approximately **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** higher than our proposed onsite CC at Sherco.[15]

Because we have not obtained formal estimates for the turbine equipment or performed detailed engineering, we have developed delta cost estimates in order to compare the unique attributes of locating a CC onsite and at alternative locations. The ultimate project pricing will vary based on the final design definition, equipment price negotiations, contractual commercial terms, and other factors.

[15] 2015 dollars on a PVRR basis. We use the same Fixed Operating and Maintenance (Fixed O&M) costs and on-going capital costs as the generic CC alternative.

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Natural Gas Infrastructure. Our proposed CC unit at Sherco will be fueled entirely by natural gas. Even though the community of Becker enjoys the benefits of heating their homes and commercial businesses with natural gas from Xcel Energy, there is not currently adequate pressure and capacity with the existing natural gas infrastructure to serve a new CC unit.

Therefore we performed a high-level cost analysis of bringing new natural gas infrastructure to serve the proposed CC unit at Sherco, so as to estimate a gas demand charge, which we estimate to be approximately **[TRADE SECRET BEGINS… … TRADE SECRET ENDS]** to the Sherco site. We based this estimate on our experience in designing, engineering, and constructing competitive natural gas infrastructure, which we do through the use of a competitive bidding process for each component or phase of the construction process. We also benchmarked the costs of some of our past significant, similar construction projects within the industry to ensure that our estimates are in-line with other contractors. We will leverage our knowledge, expertise, and competitive advantage to minimize costs for our customers. We note that we are also assessing opportunities arising from the new natural gas infrastructure that may afford numerous adjacent Minnesota communities along the proposed route greater access to a natural gas supply.

In determining the cost to construct the natural gas infrastructure, there are two primary aspects to consider: (1) the cost of the facilities from the source of supply to the new market (in this case, Sherco); and (2) the costs from the source of the supply, to ensure the new infrastructure has adequate pressure and capacity. We evaluated several alternatives to determine the best way to source the new supply to Sherco.

The associated capital cost estimates incorporated into our modeling are indicative. The cost estimates we provide for this analysis are based on current system constraints and associated capital construction project costs required to alleviate those constraints, which are subject to change. We believe however, they are reasonable and appropriate for planning purposes.

Transmission Infrastructure. As discussed above, because the new CC unit can use existing transmission interconnection rights, there will not be any associated network upgrade costs. Generators located at other locations would have to go through the MISO generator interconnection process in order to obtain

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interconnection rights, and may additionally incur transmission upgrade costs. We estimate onsite substation modifications to cost approximately **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]**. We note that we are proposing a 786 MW CC unit, which is below the current 1,400 MW capacity and associated energy output of Sherco Units 1 and 2. We also intend to locate a portion of the proposed solar resource additions at the Sherco site.

We outline the cost deltas from a generic CC on a PVRR basis below.[16] This approach allows us to show the site-specific costs associated with locating a CC at the Sherco site and to compare the site-specific costs of onsite replacement to alternative site locations.

Table 8: Site-Specific Cost Comparison – Onsite CC Replacement ($Millions – 2015 dollars)

[TRADE SECRET BEGINS…

PVRR Delta from Generic Unit	
Site Specific PVRR Costs	
Transmission Facilities[17]	
Gas Demand Charge	
…TRADE SECRET ENDS]	
Total	***$155***

2. Alternatives to Retirement and Onsite Replacement

We considered several alternatives to our proposed partial replacement of the Sherco Units with an onsite CC generating unit. In addition to examining another brownfield site and a greenfield site, we explored alternatives such as all renewables and alternative resource such as Distributed Energy Resources, Demand Response, and grid efficiencies. We discuss the brownfield and greenfield alternatives below and the renewables and alternative resources in Attachments B and F, respectively.

[16] All costs have been discounted to 2015 dollars. Actual costs will be influenced by the year in which they are incurred. Therefore, in order to compare these estimates with future expenditures, these estimates must be escalated.
[17] The substation modification costs noted above are included in the delta from the generic unit.

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Our Current Preferred Plan does not propose to replace all of the Sherco Units 1 and 2 capacity with gas-fired generation. As explained in our October Reply, we are committed to reducing the CO_2 emissions of the NSP System and advancing the acquisition of significant levels of renewable generation. Thus, we plan to acquire significant amounts of wind and solar resources to help meet our future energy and capacity needs. Below we discuss alternatives to replacing the Sherco Units with an onsite CC, in conjunction with additional renewable generation.

a. Offsite Brownfield CC

The Offsite Brownfield CC alternative included in our updated modeling is based on representative costs associated with locating a CC at the existing Black Dog site in Burnsville, Minnesota. Black Dog coal-fired Units 3 and 4 were suspended in early 2015, and the coal and ash storage and handling areas are currently being remediated and closed. When this work is complete, there will be sufficient land area protected from the 100-year flood plain to construct a 2x1 CC facility and 345 kV switchyard. The Twin Cities 345 kV ring is nearby – approximately just one-half mile from the plant site – and could be used as the transmission outlet from the new facility, making this site an appropriate proxy for an off-site brownfield CC.

Current information indicates that a new 345 kV substation would be required to accommodate the installation of this CC Unit. However, as noted above, additional transmission upgrade and interconnection costs could be incurred through the MISO generator interconnection process. Gas costs for this facility are based on anticipated demand charges for use of the Northern Natural Gas (NNG) system. The site has significant water allocations and would be able to support a wet-cooled CC facility through conversion of the existing Black Dog facility from a once-through cooling system to a cooling tower system.

Similar to the onsite Sherco alternative, locating generation on a brownfield site results in savings related to transmission upgrades, gas infrastructure, and other existing infrastructure such as land, access to water supplies, and existing maintenance facilities and facility staff.[18] As we did for the onsite CC alternative, we have adjusted the generic CC cost to incorporate the advantages of a brownfield location. However, this analysis must include the costs to mitigate the loss of

[18] While the Brownfield site is located near existing transmission facilities, the availability of interconnection capacity is uncertain until the MISO interconnection process is complete.

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generation at the Sherco site. Table 9 below summarizes the cost deltas from a Generic CC in the representative Offsite Brownfield CC alternative:

Table 9: Site-Specific Cost Comparison – Offsite Brownfield Alternative ($Millions – 2015 dollars)

	Brownfield Alternative	Sherco CC
	[TRADE SECRET BEGINS…	
PVRR Delta from Generic Unit		
Site Specific PVRR Costs		
Leave-Behind Costs		
345 kV Interconnection Facilities		
Annual Gas Demand Charge		
		…TRADE SECRET ENDS]
Total	***$221***	***$155***
PVRR Delta from Sherco Site	**$66**	

The Offsite Brownfield CC results in approximately $66 million in additional costs as compared to siting the CC at Sherco. In addition, locating the replacement CC offsite results in greater risk of additional transmission expense and reliability impacts, and does not consider the important economic benefits of replacing generation at the Sherco site, nor the potential of expanding access to natural gas supplies to residents of central Minnesota.

b. Offsite Greenfield CC

We also included an Offsite Greenfield CC alternative in our updated modeling. The Greenfield site is based on a location in Western Minnesota near existing transmission and interstate natural gas lines. Water resources are limited, and it is expected that such a facility would have to be dry-cooled to minimize water use. We have evaluated the costs for transmission interconnection and upgrades and natural gas infrastructure, and included those costs in our analysis. As noted above, additional transmission upgrade and interconnection costs could be incurred through the MISO generator interconnection process. Gas costs for this facility assume construction of new infrastructure. Table 10 below summarizes the costs included in the representative Offsite Greenfield alternative:

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Table 10: Site-Specific Cost Comparison – Offsite Greenfield Alternative ($Millions – 2015 dollars)

	Greenfield Alternative	Sherco CC
	[TRADE SECRET BEGINS…	
PVRR Delta from Generic Unit		
Site Specific PVRR Costs		
Leave-Behind Costs		
345 kV Interconnection Facilities		
Annual Gas Demand Charge		
		…TRADE SECRET ENDS]
Total	***$172***	***$155***
PVRR Delta from Sherco Site	**$17**	

The Offsite Greenfield CC results in approximately $17 million in additional costs as compared to siting the CC at Sherco. The Offsite Greenfield alternative is a CC located along the Brookings 345 kV line, so will use available transmission outlet capability that could otherwise be used for renewables in the wind-rich western and southwestern areas of Minnesota, which may increase transmission upgrade costs for those types of facilities during the planning period. These costs are difficult to quantify, but could be significant. As with the offsite brownfield alternative, locating the replacement CC offsite results in greater risk of additional transmission expense and reliability impacts, and does not consider the important economic benefits of replacing generation at the Sherco site, nor the potential of expanding access to natural gas supplies to residents of central Minnesota.

c. Conclusion

The addition of a CC at the Sherco site is a critical part of our proposal to cease coal operations of Sherco Units 1 and 2 and ensure reliability at a reasonable cost to ratepayers. By locating a CC at Sherco, we eliminate the need to address the issues identified in the MISO Y2 Study, avoid the costs associated with locating the CC offsite, support economic development in the Becker area, and mitigate reliability risks and implications stemming from the shutdown of two of the largest baseload generating units in the Upper Midwest. Our Strategist analysis, transmission studies, and socioeconomic studies support this proposal, and we believe it best advances the interest of our customers, as well as the Becker economy and our employees.

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3. North Dakota Combustion Turbine

a. Policy Considerations

Our regulators in North Dakota have stated that they believe it would be in the best interest of our customers to have cost-effective, dispatchable generation located in North Dakota and close to major load centers in that state. In an effort to balance the interests of the states that we serve and to maintain the benefits of an integrated system for all of our customers, the Company set out to find CT options that address the reliability concerns of the North Dakota commission, while preserving the Company's desire to develop cost-effective generation alternatives. To that end, we embarked on a review of possible generation sites located reasonably close to Company load centers in North Dakota that could also satisfy traditional resource planning criteria. We discuss the results of that review below.

b. Alternative Sites

In our review, we identified two potential areas where a CT could be located that satisfies the common desires of Minnesota and North Dakota commissions for a selection of a cost-competitive and reliable generation resource. The two locations include an area west of Fargo (Fargo CT) and a location in the south-central portion of North Dakota (South Central CT). These two sites appear to satisfy the traditional resource planning criteria, while also aligning policies regarding energy security, reliability, and energy policy objectives.

Recognizing that the Company is the largest utility in North Dakota, and that the Company does not yet have any dispatchable generation (either owned or in the form of a PPA) in that state, we decided to start the search for potential generation sites with a focus on North Dakota. While a formal project development and engineering estimate has yet to begin, it appears that both sites have adequate access to natural gas supplies and transmission injection capacity as well as available land and workforce.[19]

We also looked at alternative locations in Minnesota and Wisconsin. The potential site in Minnesota included the development of a second CT at our existing Black

[19] While generators at both sites would be required to go through the MISO generation interconnection process, a CT has an advantage over a CC as it is a peaking resource and will only be studied on-peak where we believe significantly more transmission capacity exists in the locations considered for the alternative CTs.

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Dog site. Consistent with the Black Dog 6 CT that was recently approved by the Minnesota and North Dakota commissions, the Black Dog 7 site takes advantage of an already owned brownfield location with access to transmission and an existing workforce.

While we also identified a possible site for a CT in Wisconsin, we did not perform any additional development work on that site at this time due to the need for more robust transmission studies. While all of the sites in Minnesota also appear to satisfy traditional resource planning criteria, they obviously do not address the concerns about the lack of dispatchable generation near the Company's North Dakota load.

Table 11 below contains a summary table of the key resource planning characteristics of the three locations investigated by the Company.

Table 11: Summary of CT Alternatives

	Fargo	South Central	Black Dog 7
Generator	Generic 230 MW Dual-Fuel CT[20]	Generic 230 MW Gas-Fired CT	Generic 230 MW Gas-Fired CT
Gas Supply	Lateral Gas Pipeline	Lateral Gas Pipeline	Demand Charges on NNG
Transmission	345 kV Interconnection Facilities	345 kV Interconnection Facilities and 230 kV Line Upgrades	345 kV Interconnection Facilities

Since both the Minnesota and North Dakota commissions have a keen interest in determining if the proposed CT alternatives are cost-effective and reliable when compared with other alternatives, we have performed an initial analysis of the three sites identified by the Company. While we have not obtained formal estimates on the turbine equipment or performed detailed engineering on the projects, as with the analysis of CC site alternatives above, we developed delta cost estimates from the generic CT unit used in the modeling. The deltas show the site-specific cost differences for each location based on the unique factors of the generator site, including transmission access, gas supply costs, and operation and maintenance costs. We summarize this cost comparison in Table 12 below.

[20] We are proposing oil back-up at the Fargo site to allow for the unit to have firm accreditation year-round, similar to the Company's Angus Anson Units 2 and 3 in South Dakota.

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Table 12: Site-Specific Cost Comparison – CT Alternatives ($Millions – 2015 dollars)

	Fargo	South Central	Black Dog 7
	[TRADE SECRET BEGINS…		
PVRR Delta from Generic Unit			
Site-Specific PVRR Costs			
Transmission			
Annual Gas Demand Charge			
		…TRADE SECRET ENDS]	
Total	***$79***	***$106***	***$85***
PVRR Delta from Fargo Site		**$27**	**$6**

This preliminary cost analysis shows that the Fargo CT site is cost competitive to the Black Dog 7 CT project, while the South Central North Dakota CT site is somewhat higher in cost.

4. Conclusion

The impact to our customers, reliability, the transmission system, the local community, and state and federal policies are all appropriately considered as part of the determination to cease coal operations at Sherco Units 1 and 2. We have undertaken numerous studies to better understand the implications of our Sherco proposal and believe our Current Preferred Plan addresses these issues in a cost-effective manner. For these reasons, we believe our location-specific expansion plan is in the public interest.

C. Ownership of New Resources

We propose to own the Sherco and North Dakota natural gas plants, along with a portion of the renewable generation additions contemplated by our Expansion Plan. Our ownership of these assets is a critical component of our vision, as it will result in a balanced generation portfolio that will minimize customer costs and mitigate risk of future cost increases. We discuss the specific benefits of ownership in greater detail below and explain how our customers will realize these benefits.

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1. Proposed CC at Sherco Site and CT in North Dakota

By owning the CC that we propose to add at the Sherco site, we are able to use our existing site and interconnection rights, we will continue to employ current Sherco-based Xcel Energy employees, we will preserve options to continue to supply a large customer with steam, and we will avoid additional cost and risks associated with modifying our Black Start Plan. Our ownership of the CC allows the Company to secure these important benefits for our customers, and we believe it is in the public interest.

Ownership of a CT in North Dakota provides important options to be able to expand generation onsite in the future to serve our customers in the Red River Valley region. Expansion options could include a partnership with another utility or converting the facility to a CC. If a third-party owns the CT, these options may not be available or may be more expensive and difficult to implement. In addition, the North Dakota commission has expressed a preference for an ownership model to a PPA model. Thus, ownership best allows us to provide reliable service to our customers in the region.

2. Proposed Renewable Resources

An important and significant component of our proposed plan is the accelerated acquisition of renewable resources. Table 13 below, shows our proposed renewable resource additions during the planning period.

Table 13: Proposed Renewable Additions (MW ICAP)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Large Solar	-	-	-	-	200	-	200	100	100	200	100	100	-	400	-	-	1,400
Wind	-	-	-	-	800	-	-	400	-	-	400	200	-	-	-	-	1,800

As discussed below, we propose that approximately half of the renewable additions be Company-owned resources, which we have assumed in the Strategist modeling supporting our Current Preferred Plan. A balance between PPA and Company-owned resources ensures that our customers obtain the benefits of each ownership structure, and that the cost and risks are appropriately balanced. Table 14 below shows the renewable additions that we propose to own.

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Table 14: Proposed Owned Renewable Additions (MW ICAP)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Large Solar	-	-	-	-	100	-	100	50	50	100	50	50	-	200	-	-	700
Wind	-	-	-	-	400	-	-	200	-	-	200	200	-	-	-	-	1,000

Table 15 below summarizes our current portfolio of wind resources, which contains approximately two-thirds purchased wind resources and one-third owned resources.[21]

Table 15: Current Wind Generation by Asset Type (MW)

Asset Type	Capacity Type	MW	Percent of Total
Owned	Nameplate	851.5	33%
PPA	Contracted*	1,759.9	67%

** Since we contract for a specific amount of energy, we do not maintain nameplate capacities in our records.*

Our solar portfolio, which primarily includes the Aurora project and the 187 MW resulting from our 2014 RFP is exclusively PPAs and third-party providers.

While we will also continue to acquire renewable resources through PPAs and third-party providers, concentrated efforts to improve the balance of our portfolio through expanded ownership of renewable resources is appropriate and necessary to minimize customer costs and balance risks. In this way, we believe our plan will capitalize on the strengths of each structure while ensuring that resources are acquired at reasonable costs for our customers.

Understanding the customer impacts of utility ownership versus purchased power is important to assessing the benefits of a balanced portfolio. While utility participation in competitive bidding may on its face be a means for such comparison, we have found that it is difficult to obtain an accurate assessment of the full economic and life-cycle costs and other benefits solely through this perspective. We believe a framework that allows the relative costs and benefits of our future acquisition of renewable resources to be assessed is a more reasonable and appropriate approach.

[21] Includes the most recently-approved Odell, Courtenay, Pleasant Valley, and Border Winds projects.

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Given similar access to suppliers, sites, and transmission, we also believe it is reasonable to assume that the capital costs of renewable development will be very similar between a utility-owned project and third-party development; thus, customer impacts will stem from the respective cost recovery mechanisms of the projects rather than development costs. Key issues affecting customer costs include differences regarding contract versus asset life and balance sheet impacts. We discuss each of these issues below.

3. Contract vs. Asset Life

Asset life affects the comparative costs of utility-owned versus purchased wind energy. A PPA is for a specific term that is likely shorter than the useful life of the facility. After the expiration of a PPA, the Company must return to the marketplace to procure replacement renewable energy. The market price of this replacement renewable energy will be based on a number of factors, including:

- Costs for new wind and solar generating facilities,
- Costs of capital,
- Market prices for electricity,
- The value of embedded environmental attributes, including Renewable Energy Credits (RECs) and Emission Rate Credits (ERCs) under the CPP, and
- PTC and ITC status and values.

Under utility ownership, by contrast, the asset remains in the utility portfolio until it is retired. Customers benefit when the actual useful life of the asset exceeds a comparable PPA's term, as they will continue to receive the capacity and energy for a longer period of time, lowering lifecycle costs. While we have modeled a 25-year life for both utility-owned and PPA renewable resources, there is the potential that the 25-year PPAs may not be widely available and also that utility-owned assets will exceed a 25-year life.

Based on our 2013 Wind RFP and 2014 Solar RFP, wind projects typically have PPA terms of 15 to 20 years with an asset life of 25-30 years, and solar projects typically have PPA terms of 20 to 25 years with an asset life of 25-30 years. While utility-owned assets may require refurbishment to extend their useful life, we would expect such costs to be lower than the market price of replacement renewable energy that would be required when a PPA expires. Life extension options for utility assets have traditionally offered cost-savings benefits for customers.

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The tradeoff for these long-term benefits is that relative to a PPA, utility-owned assets generally have higher costs in the early years when the rate base value is highest. For wind resources, direct pass-through to customers of the PTC will help offset this impact. Although there is no guarantee that ownership will provide significant present value savings compared to a PPA, it is certain that by using only PPAs to meet renewable resource needs, customers lose the opportunity for overall longer-term savings from the value of depreciating plant.

Figures 3 and 4 below illustrate the potential benefits provided by Company ownership of wind and solar resources. Customers could obtain significant benefits as shown by the shaded areas in the below figures.

Figure 3: Benefit Provided by Ownership
Illustrative 200 MW Wind Resource

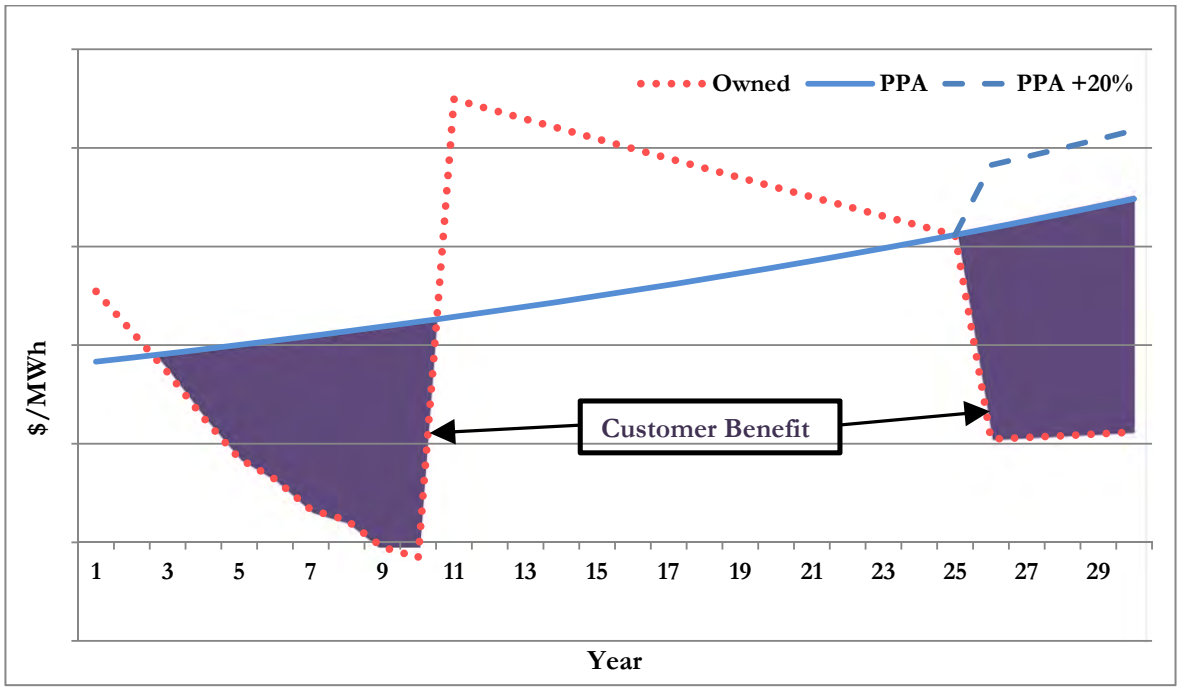

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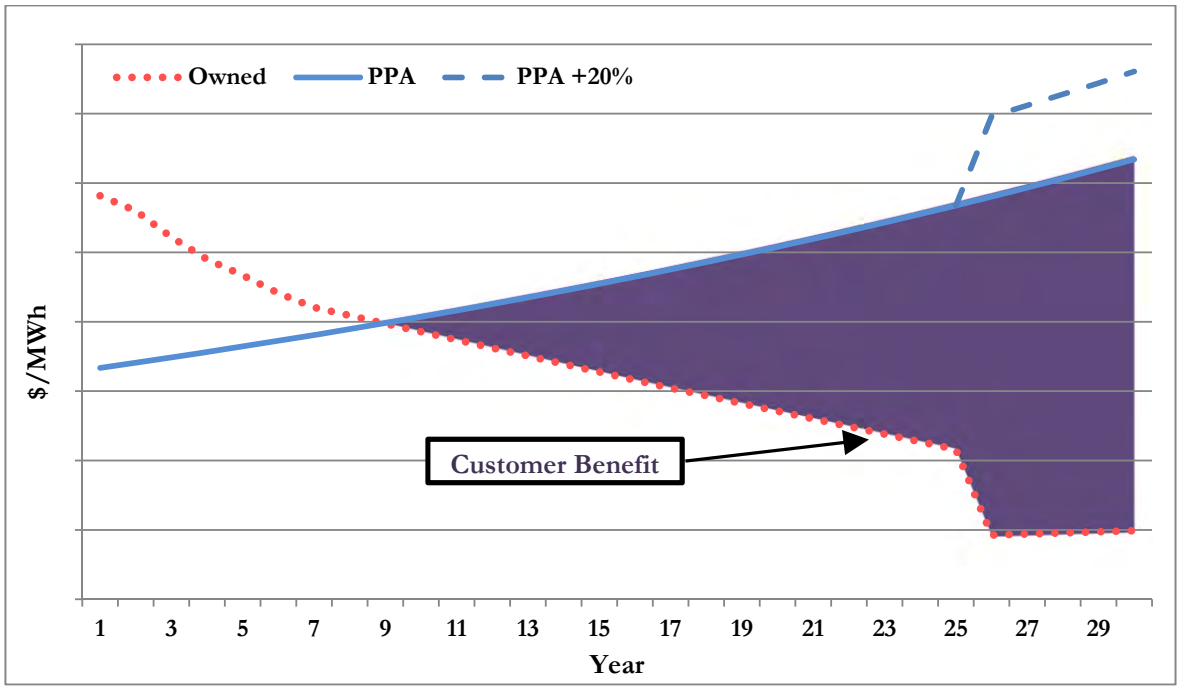
Figure 4: Benefit Provided by Ownership
Illustrative 50 MW Solar Resource



The cost per MWh for the PPA and utility-owned resources were derived from the wind and solar resources included in our modeling which assume a 25-year life. The utility-owned wind resource costs show additional reductions in the first 10 years due to the PTC while the PPA wind costs spread the benefits over the PPA term. The solar resources include the benefits of the ITC. These benefits are not achieved under a PPA structure, as the PPA must either be renegotiated or replaced when the contract term expires. In addition, ownership may help smooth rate impacts as the renewable resources procured in the near term will experience several years of depreciation prior to our projected procurement of significant additional resources in the mid-2020s.

4. Balance Sheet Impacts

Debt accounts for approximately half of the Company's total capital structure. The cost of debt is highly dependent on the credit profile of the utility, and higher-cost debt results in higher costs for customers. Generally speaking, companies with higher percentages of debt in their capital structure are considered riskier and pay higher rates for this debt, due to concerns that the company may be over-leveraged.

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PPAs are obligations the utility must pay that are viewed as additional debt on the utility's balance sheets – affecting the credit profile of the utility, which in turn affects costs to customers. Credit rating agencies also consider off balance sheet obligations in their risk assessment to determine credit ratings. These agencies impute additional debt to a utility's balance sheets based on the size, type, and terms of PPAs, thus increasing the financial leverage and risk of a company and also its cost of debt.

Likewise, auditors scrutinize PPAs to evaluate the effects of imputed debt and the lease-like characteristics of PPAs to ensure fair representation of obligations and creditworthiness on financial statements. Imputed debt and lease accounting effects have the potential to add significant debt-like obligations to the balance sheet used to determine the credit rating for the Company. In contrast to a PPA, owned projects are financed through both equity and debt which allows us to maintain our capital structure.

These issues highlight some of the implications of PPAs. Imputed debt has the potential to raise costs for customers in one of two ways: (1) through higher debt costs, as already described; and (2) through additional equity costs, as the utility may require additional equity in its capital structure to compensate for the additional debt-like obligations associated with the PPAs. Because these impacts affect the overall capital structure and capital costs, the costs of financing other utility infrastructure requirements are higher than they otherwise would be. While wind and solar PPAs are viewed more favorably than more traditional PPAs due to their energy-based payment structure, they nonetheless have imputed debt implications for the utility that will, over time, raise costs for customers.

Finally, we believe there are additional factors to consider when determining an appropriate balance between owned and purchased assets:

Potential unknown valuable attributes. If and when new value is attached to attributes of renewable resources (such as renewable energy credits were in the past), ownership of resources ensures that customers benefit from those attributes. If the resource is purchased through a PPA, those attributes may not accrue to customers. In the Silent REC Docket, the Commission was presented with this issue.[22] Under a PPA structure, there is uncertainty and risk associated with the allocation of any new valuable attribute that was not anticipated by the PPA. If the resource is utility-

[22] *See* Docket No. E002/M-08-440.

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owned, however, our Commissions will have increased control over how the value associated with any attribute is allocated.

Increased diversity in supply portfolio. Our proposed portfolio reflects an appropriate resource mix that achieves compliance with regulatory requirements, such as the CPP, and state policy objectives. Investors would be appropriately concerned if a utility's owned assets did not include the renewable assets required to achieve compliance. Thus, the financial health of the utility can be affected both by the aggregate mix of resources used to supply customers and the Company's mix of owned resources.

Complement to Xcel Energy's overall business plan. A key component of our overall business plan is environmental leadership. We believe that a balanced, clean energy portfolio is in the long-term best interests of our customers. Ownership of renewable resources is one means of demonstrating this commitment for our customers, regulators, and shareholders. We believe we must increase our investment in owned renewable resources to help maintain our financial health, minimize risks through a balanced portfolio, and reduce costs for our customers.

D. Proposed Acquisition Process

In this section, we describe our plan to acquire the replacement generation resources that will be necessary to address the capacity deficit created by our proposal to cease coal operations at Sherco Units 1 and 2.

Consistent with the Commission's January 6, 2016 Order, we will not submit a Sherco conversion plan proposal pursuant to Minn. Stat. § 216B.1692 (Emissions Reduction Statute) any earlier than one month following the Order in this Resource Plan proceeding. We expect that our proposal will take a similar approach to our 2002 Metro Emissions Reduction Project (MERP) petition under the Emissions Reduction Statute.[23] Following an overview and summary of the proposed projects, we will present further details including projected book life, capacity, capital cost, annualized emissions reductions, and proposed project schedule for the proposed thermal and renewable projects. We will address the benefits of our proposal, along with costs, customer impacts, and an analysis of alternatives. Our proposal will also contain a suggested procedural schedule, which we intend to develop in consultation with appropriate state agencies.

[23] Docket No. E002/M-02-633.

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Also similar to our approach in 2002, we intend to submit a cost recovery petition within 60 days of our proposal. The Emissions Reduction Statute gives the Commission the authority to implement rate riders to recover the cost of qualifying projects if they appropriately achieve environmental benefits without unreasonable consumer costs. Our filings will provide the factual and analytical support necessary for the Commission to affirm the two key issues in the matter:

- Whether the selections in our Proposal are appropriate, given their environmental benefits and costs, and
- If so, whether our proposed rate mechanism is appropriate and consistent with the terms of the statute.

Following approval of the Sherco conversion plan and associated cost recovery filing we would proceed using a similar approach to our previous MERP conversion efforts. The Company would commence the project under an owner-managed multi-contract approach similar to the previous MERP, CapX2020 and other major projects we have successfully completed in the NSP regions over the past 13 years. We would establish an agreed upon scope, schedule, and budget with the Commission prior to proceeding and would expect to provide regular updates to the Commission on the status of the project through completion.

We would utilize a competitive request for proposal (RFP) process to purchase the major equipment and acquire specialized engineering design and construction resources. An RFP bidding process for the major components of the project ensures we obtain the most competitive pricing. As with the MERP projects, the Company's Engineering and Construction organization would provide overall project management and oversight with support from departments within the Company for environmental, purchasing, safety, and startup & commissioning. Maintaining direct control through project management and oversight of contracts for associated equipment, materials, and service contracts will reduce costs and ensure project quality and timeliness.

We have demonstrated through our successful large scale, multi-year MERP and CapX2020 initiatives, a transparent owner-managed approach that includes regular Commission updates and project costs that stem from competitively-bid contracts for all materials and services delivers on-time and on-budget projects that are in the public interest.

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VI. CUSTOMER COST IMPACTS

As we have discussed, our Reference Case is a continuation of the plan we laid out in our 2010 Resource Plan. We now know that it would not achieve compliance with CPP requirements, nor is it consistent with our vision of being a leading provider of cost-effective clean energy. The Updated 2015 Plan that we proposed in January 2015 began to shift the Company to a significantly lower-carbon system; however, with the information currently available it is not certain that the Updated 2015 Plan will be sufficient to achieve CPP compliance under reasonable assumptions of the CO_2 reductions that could be required of the Company under Minnesota's CPP State Plan. Conversely, we are confident that our Current Preferred Plan will achieve CPP compliance, and also provide the reasonably-priced clean energy that our customers are asking for, appropriately balance state energy policy priorities, and optimize the system investments our customers have made to-date with new investments that will maintain reliability.

In this Section, we provide a long-term view of the cost impacts of our Current Preferred Plan. Additionally, at the request of the Commission and the Department at the December 2015 hearing regarding the procedural schedule for this proceeding, we discuss our view and provide illustrative concepts of a potential future market for CO_2 allowances.

A. Long-Term View

To show the cost impact of our proposal over the course of the planning period, we provide a Compound Average Growth Rate (CAGR) comparison of our Current Preferred Plan, Updated 2015 Plan, and Reference Case. We derived this long-term projection using a shorter-range financial forecast and a special purpose Strategist model, similar to how we projected the long-range cost of our plans in previous filings in this proceeding.[24]

Figure 5 below illustrates the cost differences between the Reference Plan, Updated 2015 Plan and our Current Preferred Plan, compared to the national average nominal cost CAGR. Specifically, the annual average cost delta between our Reference Case and our Current Preferred Plan is less than one-half of one percent. Our Current Preferred Plan also achieves significantly greater CO_2 emissions reductions and is the only one of the three plans that is virtually certain to achieve

[24] We describe this methodology in more detail in Attachment B.

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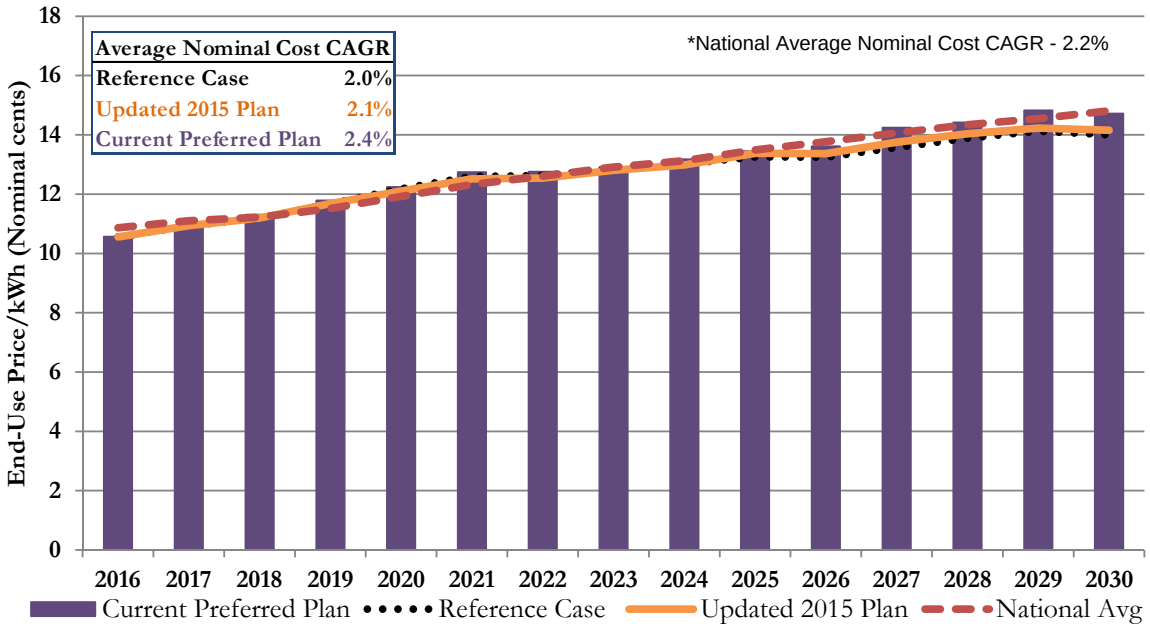
CPP compliance. Moreover, Figure 5 shows that the cost impacts associated with our Current Preferred Plan are roughly consistent with the expected national average increase in electricity prices, and over the long-term closely mimic the rate of inflation.

Figure 5: Current Preferred Plan Average Nominal Cost Comparison (NSP System)



*National energy cost forecast from Energy Information Administration (EIA) Annual Energy Outlook 2015, Table Energy Supply, Disposition, Prices and Emissions. End use prices, all sector average.[25]

While this view of the estimated long-term plan costs is different than presented in previous filings, the relative values are consistent.

B. Potential Customer Benefits of CO_2 Allowance Proceeds

While our Current Preferred Plan is not primarily driven by the CPP, based on what we know now of the state implementation plan, we believe this plan not only achieves, but likely exceeds, the CO_2 emissions reductions that could be required of

[25] The EIA's Annual Energy Outlook was published in April of 2015, and based on federal, state, and local laws and regulations in effect as of the end of October 2014. Therefore, the potential impacts of pending or proposed legislation, regulations, or standards such as the CPP would not be reflected in these projections.

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the Company. As a result, the Current Preferred Plan may generate surplus reductions in the form of CO_2 allowances (if Minnesota's CPP state plan is mass-based) or Emission Rate Credits (if the plan is rate-based). Depending on the design of the state plan, the Company could monetize these surplus reductions on our customers' behalf to mitigate some of the cost impacts of transitioning to a significantly lower-carbon system.

We provide as Attachment H a preliminary analysis of the potential value of CO_2 allowances, in excess of compliance needs, under two hypothetical State Plan scenarios and assuming different CO_2 allowance prices. This analysis is preliminary and speculative because the size of the allowance budget allocated to the Company under the State Plan is not yet known; further, and CO_2 allowance prices in future markets can only be estimated. We describe in Attachment H the rationale we used for the CO_2 allowance prices used below, and provide details of the hypothetical State Plan scenarios labeled "Scenario 1" and "Scenario 2."

If we assume a constant CO_2 allowance price of $21.50 per ton (the midpoint of the Commission's regulatory cost range under Minn. Stat. §216H.06), and assume a "Scenario 1" State Plan that regulates existing units only, contains no allowance set-asides other than the Clean Energy Incentive Program, allocates allowances based on 2010-2012 generation at CPP-regulated units,[26] and does not limit the number of years of allowance allocation to a retired unit, the Current Preferred Plan would generate allowance revenues of about $540 million over 2022-2030 ($258 million in Net Present Value or NPV terms). At the same CO_2 allowance price, if we assume a "Scenario 2" State Plan that contains many allowance set-asides and only allocates allowances for two years after unit retirement, the Current Preferred Plan would generate allowance revenues for our customers of only $75 million over 2022-2030 ($33 million NPV). We have not reflected these speculative potential revenues in any of the cost estimates of our Current Preferred Plan, and provide them here as only a preliminary analysis.

Table 16 below shows the value at three different CO_2 allowance prices that correspond to the Commission's low, midpoint, and high regulatory cost values.

[26] We note that EPA leaves the allowance allocation decision to states, and that discussion of the most appropriate allocation basis (generation or emissions, and whether any allowance set-asides are appropriate) is ongoing as of this filing.

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Table 16: Value of Potential CO_2 Allowance Sales Under Two State Plan Scenarios
(millions, undiscounted, over 2022 to 2030)

	State Plan Scenarios		
Allowance Price	**– 1 – Customer Value**	**– 2 – Customer Value**	**Value Impact to Customers**
$9/ton	$226	$31	($194)
$21.50/ton	$540	$75	($465)
$34/ton	$853	$119	($735)

The "Value Impact to Customers" column in this table represents the estimated CO_2 allowance value transferred from the Company's customers to other parties by a State Plan that sets aside significantly more allowances, and discounts the value of retiring coal units by allocating allowances for only a short time post-unit retirement.

Since all allowance values are assumed to accrue to the Company's customers, a "Scenario 1" State Plan would provide around $540 million to help mitigate the cost impacts of transitioning to a lower-carbon energy system. A "Scenario 2" State Plan would provide only $75 million, which is $465 million *less* value to mitigate customer cost impacts, shifting much of the value from our customers to other parties.

We believe that through our involvement in the MPCA's CPP State Plan development process, we can identify opportunities to further offset the cost impact of our proposal and achieve the greatest value for our customers. We also believe there are rate mechanisms, described in more detail below, which can provide predictable cost recovery and help to smooth cost impacts for our customers.

C. Near-Term Customer Rate Impacts

In compliance with the Commission's January 6, 2016 Order and in order to approximate the near-term impacts of plan implementation on customer rates and bills, we provide as Attachment E a detailed rate analysis of our Current Preferred Plan and Updated 2015 Plan. This includes a five-year detailed rate impact analysis with the estimated impacts by class per year.

We note the following factors could impact rates in 2016-2020:

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- *Tax credit extension*: With the extension of the Production Tax Credit, the costs of 600 MW wind PPAs beginning in 2020 is reduced significantly from the Base Cost of Energy forecast (Docket No. E002/MR-15-827), which assumed those PPAs would not benefit from PTCs. Wind PPAs are recovered through the fuel clause, which is where the cost reduction would appear for customers.
- *Renewables ownership:* The addition of 200 MW of owned solar and 400 MW of owned wind would result in an increase in base rates or rider rates due to the ownership of 200 MW of solar and 400 MW of wind, presumably recovered in the RES Rider.
- *Ceasing coal operations at Sherco:* The ceasing of coal operations at Sherco Units 1 and 2 would result in increased depreciation expense.

Primarily due to the tax credit extension, both our estimated Updated 2015 Plan and our Current Preferred Plan forecasts show lower fuel costs than our 2016-2020 fuel forecast prepared at the time of the Base Cost of Fuel filing. For example in 2020, the ITC and PTC tax incentives would reduce fuel costs by $99 million in the Current Preferred Plan, while the Updated 2015 Plan results in a $66 million reduction.

VII. NUCLEAR RESOURCE UPDATE

In our October 2 Reply, we expressed our support for utilizing our carbon-free nuclear baseload resources through the existing plant licenses as a means of achieving our goal of a 60 percent reduction of CO_2 emissions from 2005 levels by 2030. At the same time, we explained that our projected capital spend for Prairie Island is outpacing the estimates included in our Changed Circumstance filing in 2012.

We noted specifically that our five-year capital expenditure forecast from 2016 through 2020 has increased by roughly $175 million above what was anticipated in 2012, and that our forecast for the thirteen-year period from 2021 through 2034 would likely need to increase by roughly $600 to $900 million. We also noted that our fixed operating and maintenance (Fixed O&M) costs are lower than previously modeled and that our decreased Fixed O&M forecast largely offsets the increase in our forecasted capital spend.

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The Commission expressed understandable concern over our updated capital forecast during hearings in December 2015. We address those concerns here by providing additional information and analysis relating to our support for nuclear and to the costs associated with the continuing operation of Prairie Island. In particular, we provide modeling that takes into account our updated capital and Fixed O&M forecasts and demonstrates that Prairie Island has been, and continues to be, a cost-effective resource for our customers. We also discuss our updated capital expenditure forecasts for the periods from 2015-2020 and 2021-2034 at Prairie Island.

We believe the information provided in this section supports our continued operation of Prairie Island, including the investments we need to make to safely and reliably operate the plant over the next few years. We nevertheless recognize that our opinion is one of several that need to be considered in this process, that stakeholders would like to better understand the implications of our updated forecasts, and that there is some uncertainty at play when considering the costs to operate a two-unit nuclear plant for the remaining 19 years of its licensed life. Utilities, regulators, and stakeholders around the country are grappling with similar issues as they try to balance the increased regulatory pressure and costs associated with nuclear against emerging policies aimed at reducing CO_2 emissions.

We believe that any decision regarding the long-term future of Prairie Island should be made after a deliberate and thoughtful dialogue between the Company, our regulators, and our stakeholders. We further believe this dialogue should be informed by a longer-term, in-depth analysis of the cost-effectiveness of Prairie Island and the alternative paths that could be taken with respect to the plant. In fact, we have begun this work and share a preliminary analysis of one potential alternative later in this section. If the Commission and our stakeholders want to further explore this or other alternatives, we are committed to doing the additional work necessary to advance a fully informed and thoughtful decision-making process. We expect that a full analysis of the operations, economics, and potential alternatives for Prairie Island could be completed in the next 18 months, and we welcome the opportunity to cooperate with our regulators and our stakeholders on such a significant decision.

A. Relation to Supplemental Rate Case Testimony

Following our October 2 Reply, the Commission ordered the Company to file supplemental schedules and testimony in its pending electric rate case that describe

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and compare projected and actual Life Cycle Management costs (and, to the extent relevant, Extended Power Uprate costs) from 2008 through 2020 by generating unit and year, including the proposed 2016 test year, and the 2017 and 2018 plan years. As part of those descriptions and comparisons, the Company was ordered to include all changes and updates to projected costs from 2008 onward and to include all cites to relevant certificate of need, resource plan, and general rate case dockets. The Commission also ordered the Company to provide as part of those schedules and testimony a comparison of the relevant parts of the proposed 2016 test year, the 2017 plan year, and the 2018 plan year to the proposed five-year capital budget in the Company's pending Resource Plan proceeding.

In compliance with that Order, we are filing supplemental Direct Testimony in our pending rate case docket from Company Witnesses Christopher B. Clark (President), Timothy J. O'Connor (Senior Vice President and Chief Nuclear Officer), Scott L. Weatherby (Vice President for Nuclear Finance and Planning), and John J. Reed (Chief Executive Office at Concentric Energy Advisors). That testimony focuses on the period from 2016 through 2020, the additional $175 million of capital expenditure above what was anticipated in 2012 for that period, and why the capital projects underlying that forecast are necessary during those years and in our customers' best interest.

In this Resource Plan Supplement, by contrast, we address not only the next five years but also the latter portion of Prairie Island's licensed life and the additional $600 to $900 million in capital that we anticipate spending between 2021 and 2034. Because resource planning takes this longer view, we believe it is the appropriate forum to consider whether it is economic and prudent to operate Prairie Island through the end of its licensed life. We therefore welcome an in-depth discussion regarding the future of Prairie Island and, to that end, propose a process to continue that discussion after we have had additional time to study the impacts of continued operations, as well as potential alternatives.

B. Prairie Island's Past and Current Cost-Effectiveness

Our support for utilizing our nuclear baseload through the existing plant licenses is primarily driven by our conclusion that it is beneficial for our customers to do so. We recognize that the principal question in this regard is the plant's cost-effectiveness on a going-forward basis. We believe that it is also helpful, though, to consider the forecasts and modeling we presented in connection with our 2008 certificate of need and 2012 changed circumstance filings. These demonstrate that

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Prairie Island has always been cost-effective, even when we account for our updated capital forecast. We therefore briefly address these earlier forecasts and models before turning to our prospective analysis.

1. Past Forecasts & Modeling

At the time we filed our certificate of need in 2008, we provided an estimate of capital costs running to the end of Prairie Island's licensed life in 2034 in an effort to measure the plant's cost-effectiveness compared to either a super critical pulverized coal unit or a natural gas CC unit. We provided this information in response to Minn. Stat. §216B.243, subd. 3b, which states that "[a]ny certificate of need for additional storage of spent nuclear fuel for a facility seeking a license extension shall address the impacts of continued operations over the period for which approval is sought."

Because we sought authorization for enough casks to operate Prairie Island until 2034, we provided our best judgment with respect to the "impacts of continued operations" until that time. Looking to historical capital expenditures, we estimated that our routine capital investment would average approximately $20 million annually ($10 million per unit) and that we would spend an additional $600 million on large capital investments from 2008 through 2034. Using these numbers, we concluded that continued operation of Prairie Island was cost-effective by a margin of $2,194 million in PVRR. We then updated our capital forecast for Prairie Island in our 2012 changed circumstance filing and included additional capital expenditures in that model.

For a number of reasons that are discussed below, our 2008 capital forecast has proven to be lower than the actual costs incurred to-date. Likewise, our 2012 forecast appears to be lower with respect to our updated forecast for the out-years of Prairie Island's licensed life. As an initial matter, however, it is important to contrast our 2008 capital expenditure forecast from one more typically associated with a certificate of need filing and from the Monticello prudence review. In the Monticello docket, for instance, we had already spent more than forecasted in our LCM/EPU certificate of need filing, and we sought recovery of those capital expenditures after the construction project was completed.

There is no construction project at issue here. Our 2008 filing related to dry-storage casks and provided a forecast related to the "impacts of continued operation" for a two-unit nuclear plant over a twenty-six-year period. It was the first time we

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provided such an estimate and the first time we forecasted capital expenditures for the out-years of an extended-life nuclear plant. And unlike Monticello, we are updating the Commission with respect to our increased capital forecast having not yet exceeded our 2008 forecast and not expecting that we will exceed the total cost (capital plus Fixed O&M) we forecasted in our 2008 filing.

That said, one reason for the higher-than-anticipated capital expenditures is that our Nuclear Regulatory Commission (NRC) mandated compliance expenses have increased substantially in recent years, both as a result of new NRC requirements following the Fukushima Daiichi incident, and as a result of increased oversight and regulation by the NRC generally. Additionally, our estimate of spending $10 million per unit annually for routine capital investment has proven to be insufficient, despite that having been a reasonable estimate in light of historical spending up to and including 2008. Our experience with routine capital investment over this period mirrors that of other utilities operating similar nuclear plants.

Although our capital expenditure forecasts have increased since 2008, our Fixed O&M forecasts have decreased in nearly equal measure. In 2008, we provided a conservative estimate of Fixed O&M costs in connection with our certificate of need filing, which was based on our historic spending up to that point. Since that time, however, we have observed significantly lower-than-forecasted Fixed O&M spend, which caused us to revisit that forecast in conjunction with our resource plan and to reconsider what future Fixed O&M growth will be over the next 19 years of Prairie Island's licensed life. Based on historical spending from 2008 to present, we now forecast spending more than $1 billion less in Fixed O&M at Prairie Island from 2015 through 2034. And if we look at total spend (capital plus Fixed O&M) in connection with Prairie Island, our current forecast results in PVRR that is $981 million less than our 2008 certificate of need forecast and $91 million less than our 2012 changed circumstance forecast. Thus, our revised Fixed O&M forecast not only offsets our revised capital expenditure forecast, it results in a projected total project cost that is substantially less than we anticipated in both 2008 and 2012.

Had we used our current capital expenditure projections in our 2008 model, it would have shown that Prairie Island remained a valuable, cost-effective resource by a margin of approximately $2.04 billion in PVRR. Likewise with our 2012 changed circumstance proceeding, Prairie Island would have remained a cost-effective resource by a margin of approximately $305 million in PVRR, using the model from that filing. Further, because our 2012 modeling assigned no cost to CO_2, the PVSC of Prairie Island under that analysis would have been substantially higher. As a

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result, our updated capital and Fixed O&M forecasts would not have changed our conclusions with respect to the continued operation of Prairie Island in either the 2008 certificate of need or 2012 changed circumstance proceedings.

2. Prairie Island's Current and Future Cost-Effectiveness

We now turn to the present-day cost-effectiveness of Prairie Island. For this analysis, we used our current Strategist modeling from this docket and considered a base case with the current forecast for ongoing capital and O&M expenditures compared with a scenario where Prairie Island is retired immediately. In a number of ways, this analysis is highly conservative. First, we have assumed that all of the capital and O&M expenditures for Prairie Island for 2016 through end of life can be avoided entirely, despite the fact that nuclear units continue to experience significant Fixed O&M costs during the various stages of decommissioning and despite the fact that the NRC would likely require a number of Fukushima-related and other mandated projects to be completed even following a shutdown.

Second we have not included any adjustments for accelerated depreciation of the existing asset, or changes to decommissioning costs or fund accruals, both of which we address in greater detail later in this section. Third, we have not included the costs of addressing transmission system impacts that would be caused by shutting down a significant baseload unit, as we have not yet studied these transmission effects in detail. Finally, we have assumed that replacement capacity could be installed "overnight" in 2016, and Strategist was allowed to optimize both the immediate replacements and balance of the expansion plan through the end of the study period. For a number of reasons discussed later in this section, it is simply not possible to immediately retire Prairie Island, or any nuclear plant. Major system transitions of this sort take years to study, plan, and execute, and industry experience teaches that unplanned shutdowns can be enormously expensive by comparison.

The results of this very conservative analysis are shown below in Table 17:

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Table 17: Prairie Island Compared to a Natural Gas Combustion Turbine

Resource	PVSC	PVRR
Prairie Island	$52,519	$46,618
Combustion Turbine	$53,750	$46,824
Difference	$1,231	$206

Even our most conservative analysis, then, shows that "overnight" replacement of Prairie Island would result in $1.231 million of additional PVSC. We also evaluated the PVSC and PVRR associated with the capital expenditure and Fixed O&M forecasts over the near-term period from 2016-2020. Continued operations of Prairie Island through this period results in a PVSC savings of $456 million and PVRR savings of $177 million compared to the overnight replacement scenario.

To be sure, the PVRR of running Prairie Island results in a closer call. In this way, the social cost of carbon plays a role in driving our support for continuing to operate Prairie Island through its licensed life, just as it does our decision to cease coal operations at Sherco Units 1 and 2 in the 2020s. We further recognize that changes to certain modeling assumptions, such as lower gas forecasts, could cause the PVRR numbers to suggest – under this limited analysis – that retiring Prairie Island in the near term might result in lower PVRR. It is important to keep in mind, however, this is a theoretical analysis intended to provide a preliminary look at Prairie Island's baseline economics, that it cannot substitute for an in-depth study that accounts for actual retirement and replacement costs, and that there are significant benefits to our nuclear fleet that are not captured by this, or any, Strategist model.

3. Operational & Policy Concerns

We believe that continued operation of our nuclear fleet is also the best path forward from both a policy and reliability perspective. Nuclear comprises more than half of our carbon-free generation and – at the same time – provides our system with a baseload energy resource that ensures critical system reliability. In this way, it is a keystone of the carbon-reduction goals set forth in our Current Updated 2015 Plan. Renewable technology such as wind and solar cannot fulfil this role at a reasonable cost today. As a result, any near-term replacement of our nuclear plants would involve the addition of more natural gas to our fleet, meaning the closure of Prairie Island would have twin effects of heightening our customers' exposure to gas

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price volatility and significantly increasing our CO_2 emissions. We do not believe this is in the best interest of our Company, our customers, or the states we serve.

We recognize, however, that battery technology is evolving, that renewable costs have decreased in recent years, and that reliable renewable baseload energy may be on the horizon. With that in mind, we see our nuclear units as critical to meeting our carbon-reduction and reliability goals in the near-term (including our compliance with the CPP) and also as a bridge that can facilitate a transition to even greater renewable generation in the longer-term as battery technology improves and costs decline. At the same time, our nuclear fleet is an integral part of our diversified generation portfolio and provides an important hedge to gas price volatility.

Finally, combining the cessation of coal operations of Sherco Units 1 and 2 along with the shutdown of Prairie Island all in the 2020s would present enormous challenges and costs with respect to replacement generation, transmission, and system reliability. The continued operation of our nuclear fleet as a bridge resource will allow for a careful and focused transition away from coal generation in the 2020s before addressing the future of other baseload units.

C. Forecasted Investments

1. Forecasted Investments from 2016-2020

In total, we anticipate investing approximately $490 million in capital at Prairie Island from 2016 through 2020. This is roughly $175 million more than we forecasted as part of our 2012 changed circumstance filing. There are a few key drivers of our increased capital spend during this period. First, $84 million of this increase is due to regulatory mandates from the NRC. As described in our previous two rate cases, these NRC Fukushima, fire safety, physical security, and cyber security requirements did not exist or were not fully known between 2008 and 2012.

More than half of the remaining $90 million is a result of our decision to defer certain projects from the rough timeframes anticipated in our 2008 and 2012 forecasts. In fact, we invested $51 million less from 2008-2015 than we forecasted in our 2012 changed circumstance filing. The remaining capital expenditures during this period simply reflect our inability to perfectly forecast costs in a certificate of need proceeding broadly focused on the remaining life of a plant, as well as increasing costs of nuclear construction and life-cycle maintenance across the industry.

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As detailed in Mr. O'Connor's Supplemental Direct Testimony in our pending rate case, the major capital investments forecasted for 2016-2018 include reactor coolant pump replacements, heater drain tank pump speed controls, motor rewinds/replacements, cooling tower replacements, and the main electrical generator replacement for Prairie Island Unit 1. In his Supplemental Direct Testimony, Mr. O'Connor describes each of these projects and explains why they are necessary to safely and reliably operate the plant, even if Prairie Island were not to operate until the end of its licensed life.
Department of Commerce Information Request No. 74 in our currently pending electric rate case requested that we provide an estimate of the necessary retirement dates for Prairie Island Units 1 and 2 under the assumption that substantial (over $40 million per year for the site) new capital expenditures would not occur starting in 2016. Our forecasted capital expenditures for the combination of mandated compliance projects and dry fuel storage alone total $38.9 million in 2016, $36.1 million in 2017, and 34.8 million in 2018. These expenditures are necessary to operate the plant within the NRC's mandates and would leave very little additional capital within the $40 million annual budget to complete basic and necessary LCM projects during these years. Given this, and the fact that any single outage could require more than the remaining amount of budgeted capital to resume operations, it is impossible to predict how long Prairie Island could operate under these budget constraints.

2. Forecasted Investments from 2021-2034

In our October 2 Reply, we explained that our forecast for the fifteen-year period of 2021 through 2034 would likely need to increase by roughly $600 to $900 million. We revised our forecast following a project-by-project analysis of anticipated capital investments at Prairie Island from 2015 through 2034, and we believe that it is responsible to anticipate and plan for all of the projects underlying our forecast. In other words, our updated forecast reflects our best judgment regarding these costs, which we presented to the Commission in October so that it can undertake a thorough assessment of our Current Preferred Plan. That said, it is not possible to accurately predict not only which projects will be necessary over a 19-year period, but also what those projects will cost. It is likewise not possible to predict what regulatory mandates will arise in the future, and what compliance with those unknown mandates might cost. Given this uncertainty, we understand certain stakeholders' desire to explore and maintain future optionality with respect to Prairie Island, and we address those concerns below.

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D. Future Optionality at Prairie Island

As already discussed, we believe that Prairie Island continues to benefit our customers by producing cost-effective, carbon-free baseload energy that is a keystone to our carbon-reduction goals and a bridge to additional renewable development in the future. We recognize, however, that it is impossible to perfectly forecast costs for the remaining 19 years of Prairie Island's licensed life and that certain of our stakeholders may want to explore alternatives based on that uncertainty. To that end, we have begun to identify and analyze one potential alternative for the plant around the 2025 timeframe. We recognize that other alternatives exist. We present this preliminary analysis as an example of the considerations and analyses that would go into an in-depth discussion of alternatives, and we welcome further dialogue regarding this or other alternatives.

Before proceeding with any in-depth discussion of alternatives for Prairie Island, we would need to conduct a detailed study of its effect on our transmission system, as we did in connection with our proposal to cease coal operations of Sherco Units 1 and 2. This would include a MISO Y2 Study, our own reliability study, and a black start study – just as we are providing in connection with our Current Preferred Plan. And as we did for Sherco, we would need to conduct impact studies relating to our employees at Prairie Island and the community around Red Wing, Minnesota. Finally, the technical studies completed in connection with our Sherco proposal may need to be reconsidered, as the study models assumed that Prairie Island would continue to operate.

If the Commission and our stakeholders wish to have a longer-term discussion concerning the future of Prairie Island, we are committed to completing this work, which we expect would take approximately 18 months. At that point, we would welcome input from stakeholders and the Commission, and we believe that a decision could be made with respect to Prairie Island's future sometime in 2018. If a decision was reached to pursue an early retirement for Prairie Island, we would need an additional seven years to plan for the shutdown and decommissioning, including the construction of replacement generation and any transmission projects that would be needed to maintain system stability. This planning period is critical, as recent industry experience teaches that hastily planned (or unplanned) shutdowns can be extraordinarily expensive as compared to shutdowns that are preceded by several years of planning. Company witness Mr. John Reed discusses the importance of advanced planning for nuclear retirements in his Supplemental Direct

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Testimony, which is being filed in our pending rate case contemporaneously with this Supplement. The seven-year timeline is also similar to the one we have proposed in connection with Sherco Units 1 and 2, and would result in a shutdown of Prairie Island around 2025.

To be clear, we do not currently foresee an economically prudent time to retire Prairie Island prior to the end of its licensed life. That said, we believe that an off-ramp in the 2025 time period would result in certain financial benefits as compared to an earlier retirement. Net plant balance is set to peak in 2018 at $1.127 billion. A retirement in that time period would result in substantially increased stranded costs, in addition to the costs otherwise associated with early retirement. During the early 2020s, however, net plant balance begins to decrease and, by 2025, would be within approximately $125 million of today's value of $917 million. That additional $125 million of net plant would itself be more than offset by the additional 10 years of investment growth in our decommissioning fund, which has a current market value of approximately $725 million and earns a return of approximately 5-6 percent (or between $36 million and $43 million) annually.

Additionally, if a decision were made around 2018 to retire Prairie Island in the mid-2020s, we could reduce our capital expenditures during the intervening years, as we normally anticipate lower capital spend in the years leading up to a plant's planned retirement. While we have not yet studied this capital adjustment in-depth, we estimate that our capital expenditures could be reduced such that net plant in 2025 would be significantly less than today's value of $917 million—provided we have several years to plan for the retirement. The strategy of reduced capital expenditures in the 2020s would come with a risk of a modest capacity derate at Prairie Island beginning around 2022 due to decreased capital investment, but we see this as a reasonable risk if the Commission and our stakeholders wish to pursue an early retirement.

The growth of our decommissioning fund is a significant factor that should be taken into account when considering alternatives to operating Prairie Island through its licensed life. Table 18 below compares the approximate amounts of customer contributions versus investment growth that would be needed to fully fund decommissioning at Prairie Island for three examples of potential retirement years:

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Table 18: Decommissioning Funding Broken Into Customer Contributions and Investment Growth

	2020	2025	2034
Customer Contributions	$518 million (58.67%)	$374.5 million (40.87%)	$10 million (0.64%)
Investment Growth	$319 million (41.33%)	$541.8 million (59.13%)	$1.552 billion (99.36%)

In short, the longer our decommissioning fund enjoys market growth, the less our customers will be required to pay to fund decommissioning at Prairie Island. This, in combination with the decreasing trend in forecasted net plant balance over the early 2020s, suggests that a retirement significantly before 2025 would involve substantially higher decommissioning and stranded costs.

As already discussed, we have conducted some preliminary modeling around the replacement of Prairie Island with a natural gas CT plant in 2025. Doing so would result in an increase of $929,614 million in PVSC and $601,257 million in PVRR. This analysis incorporates our current best judgment as to the costs of building replacement generation, the depreciation associated with Prairie Island, and the acceleration of decommissioning costs at Prairie Island – including most significantly, the elimination more than a dozen years of investment growth. Our PVSC model also incorporates the regulatory cost of emitting additional CO_2, which we have valued at $21.50 per metric ton beginning in 2019.

It is important to note that we have not conducted an in-depth replacement study with respect to Prairie Island. That analysis would include many of the technical studies that have already been completed for Sherco and the inclusion of specific costs related to transmission remediation and decommissioning that we are not currently in a position to forecast. We view this high-level analysis as buttressing our earlier cost-effectiveness modeling and as supporting the continued operation of the plant, at the very least through the next few years as we further study alternative scenarios.

E. Next Steps

There is much work to be done if the Commission wishes to pursue an in-depth discussion concerning the future of Prairie Island. As already discussed, we would need to complete several technical and impact studies, as we did in connection with

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our Sherco proposal. We may also need to reevaluate the technical studies completed in connection with our Sherco proposal, in which we assumed the continued operation of Prairie Island on our system. We believe this analysis is critical to making a fully informed judgment on this significant planning issue, and we are committed to doing this work over the next 18 months if the Commission wishes to further explore alternatives to operating Prairie Island through its current licensed life.

Prairie Island remains cost-effective, and our near-term investments are necessary to continue operating the plant today. Additionally, the bulk or our anticipated capital investments will occur in the out-years of Prairie Island's licensed life. As a result, there is time to engage in a thoughtful process, and we welcome this opportunity to dialogue with our stakeholders in hopes of charting a path that is best for our customers and the states we serve.

VIII. ACTION PLANS

A. Five Year Action Plan (2016-2020)

Our Five Year Action Plan discusses near-term actions by resource type, which is primarily focused on wind and solar resource additions.

Wind. The remaining 400 MW of the 750 MW of wind generation resulting from our 2013 RFP is expected to achieve commercial operation in 2016, which includes the 200 MW Courtenay project for which the Company took over ownership in 2015. In light of the recent PTC extension, we plan to develop and finalize our acquisition plan later in 2016 for securing an additional 800 MW of PTC wind by 2019. Currently, in order to obtain the full benefit of the PTC, wind projects must secure a "safe harbor" designation by the end of 2016 by incurring at least 5 percent of the project costs. Construction must be completed by the end of 2018. The PTC is reduced in subsequent years for projects meeting these milestones. We believe it is in the best interest of our customers to obtain the full PTC value; it may therefore be necessary to bring a wind acquisition proposal before the Commission in the latter half of this year for approval on an accelerated schedule.

Solar. The 187 MW of utility-scale solar generation resulting from our 2014 RFP, and the 100 MW Aurora Solar project resulting from the 2012 CAP proceeding are expected to achieve commercial operation in 2016. In light of the recent federal 30 percent ITC extension, we plan to develop and finalize an acquisition plan later in

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2016 to secure an additional 400 MW of 30 percent-ITC eligible utility-scale solar resources by 2020. There are similar safe-harbor provisions for the ITC as there are for the PTC for wind, however we have a longer runway. We note that we may adjust the amount of utility-scale solar resources we would seek based on the amount of small solar resources added to our system. The amounts indicated in our Expansion Plan (Table 2) are based on the updated small solar forecast we discuss in Attachment B to this Supplement.

Hydro. We will continue to evaluate the potential and value of hydro resource options including the potential for hydro resources from Manitoba Hydro beyond the current contracts that expire in the mid-2020s.

Natural Gas/Oil Peaking. We will continue to analyze older CTs on the NSP System to avoid impact of increased forced outages due to a major equipment failure and associated unexpected loss of capacity.

Coal. After this Resource Plan proceeding concludes, we will develop and submit a proposal that seeks to implement our proposal to cease operation of Sherco Unit 2 in 2023 and Sherco Unit 1 in 2026, and construct replacement generation resources needed as a result of these changes

Nuclear. Continue to utilize our cost-effective nuclear resources to achieve carbon-reduction goals and maintain reliability. Continue to dialogue with our regulators and stakeholders regarding the future of Prairie Island. If the Commission wishes to further explore alternatives to operating Prairie Island through its current license, complete the economic, technical, socioeconomic studies necessary to advance that discussion.

North Dakota. If the North Dakota commission takes action to approve our proposed Negotiated Agreement, we expect to begin working with Commission staff in 2016 toward developing a Resource Treatment Framework that would likely be filed with the Commission sometime in 2017. We believe additional discussions with all of our state Commissions will be necessary during the five-year action planning period to address divergent energy policies and changes in cost allocations that may result.

B. Long Term Plan Action Plan (2021-2030)

Proposed actions during the 2021-2030 period:

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- Complete preparations for ceasing coal operation of Sherco Unit 2 in 2023 and Sherco 1 in 2026.
- Complete preparations to add our proposed natural gas CC at the Sherco site in 2026, achieving commercial operation prior to ceasing coal operations at Sherco Unit 1.
- Complete the natural gas infrastructure to supply the proposed Sherco CC.
- Complete preparations to add the proposed natural gas CT in North Dakota by the end of 2025.
- Effectively manage planned retirement of older CTs.
- Evaluate and determine the merits of extending or renewing expiring wind, thermal and hydro generation PPAs.
- Actively work to identify and act on opportunities to implement cost-effective and reliable distributed generation, electric storage units and other commercial ready technologies that are responsive to customer needs and comply with applicable requirements.

Minn. Stat. § 216H.02, subd. 1 requires that we provide an update on our progress toward the goal of achieving 80 percent CO_2 reduction by 2050. We expect our Current Preferred Plan to achieve at least at 35 percent CO_2 reduction from 2005 levels by 2020 and nearly 60 percent by 2030 – positioning us well to help Minnesota achieve its objective to reduce CO_2 by 80 percent by 2050. We note that our Monticello and Prairie Island nuclear facilities are essential to achieving the reductions we propose in our Current Preferred Plan and the 2030 CPP objectives. We discuss our nuclear units and their role on the NSP System more in depth in Section VII of this Supplement.

Our Current Proposed Plan achieves a 60 percent reduction in CO_2 emissions by 2030 milestone by adding 3,200 MW of new renewables and ceasing coal operations at Sherco Units 1 and 2 during the 2016-2030 planning period. Renewable additions begin with an 800 MW addition of competitively-priced PTC wind additions by 2020 and an additional 1,000 MW of non-PTC wind by 2030. Solar additions include adding 400 MW of competitively priced utility-scale ITC solar by 2020 and additional 1,000 MW by 2030. This adds to the 287 MW of utility-scale solar going into service in 2016. We note that we now expect small-scale solar resources to potentially reach 1,100 MW by 2030, which we discuss in Attachment B.

IX. PUBLIC INTEREST ANALYSIS

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TRADE SECRET INFORMATION AND NON-PUBLIC DATA EXCISED

Based on our detailed analysis, we conclude that the Current Preferred Plan is in the public interest. It puts the Company on a path to transform its fleet in a planful, coordinated manner that ensures we will meet our obligations under the CPP and the most stringent of our state renewable energy and carbon reduction requirements, while effectively managing costs and preserving flexibility on behalf of our customers. It provides our customers, employees, and our communities with certainty, while also maintaining a balanced diversity of energy sources, and investment opportunities that benefit our state economies and communities. Finally, it promotes an orderly, gradual transition of our generation fleet and thus avoids a scenario where the Company may have to retire and replace five baseload generating facilities in the early 2030s.

Minnesota Commission rules (Minn. R. 7843.0500, subp. 3) identify the factors that the Commission is to consider when determining if the Resource Plan selected is in the public interest. More specifically, these rules require that resource options and resource plans are to be evaluated on their ability to:

A. Maintain or improve the adequacy and reliability of utility service,
B. Keep the customers' bills and the utility rates as low as practicable, given regulatory and other constraints,
C. Minimize adverse socioeconomic effects and adverse effects upon the environment,
D. Enhance the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations, and
E. Limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control.

Our Current Preferred Plan is best able to meet these criteria, especially when analyzed on a comprehensive basis in light of the planning landscape facing the Company and the industry.

A. Reliability

Our Current Preferred Plan is designed to maintain the adequacy and reliability of the NSP System and will allow the Company to continue to provide safe and reliable service to its customers. Our plan promotes an orderly, gradual transition of our generation fleet and thus avoids a scenario where the Company may have to retire and replace five baseload generating facilities in the early 2030s.

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B. Impact to Customers' Bills

We developed our Current Preferred Plan with impacts to customers in mind. Given the regulatory and other constraints of the planning landscape, we sought to achieve additional flexibility and achievement of policy goals at a reasonable additional cost. For an incremental increase of less than one-half of one percent over the planning period compared to business as usual, we achieve nearly 60 percent reduction in our CO_2 emissions from 2005 levels, near certain CPP compliance, and assured reliability for our customers.

C. Socioeconomic and Environmental Effects

Our Current Preferred Plan will benefit our states by advancing both federal and state energy policies and by being nearly certain to comply with the final Clean Power Plan rules. It will also benefit our communities by allowing adequate time to transition our workforce and promoting economic development during this fleet transition. For these reasons, we believe that our Current Preferred Plan charts the right path forward for our Company and stakeholders.

D. Flexibility to Respond to Change

Our Current Preferred Plan was developed to position the Company well in the current planning landscape. Obtaining strategic flexibility is a key component of doing so. This flexibility enhances our ability to respond to changes in the financial, social, and technological factors affecting our operations during the planning period – and preserves optionality for us to respond to these factors beyond the planning period.

E. Limiting Risks

Much like the flexibility to respond to change, the strategic flexibility inherent in our Current Preferred Plan limits the risk of adverse effects on the Company and our customers from financial, social, and technological factors beyond our control. Key to limiting such risk is our planful and coordinated fleet transition that ensures we will meet our obligations under the CPP and the most stringent of our state renewable energy objectives and carbon reduction requirements.

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We envision an energy future that includes a dramatic reduction in carbon emissions so that, by 2030, our energy mix will be 63 percent carbon-free. Taking action to transition our fleet now mitigates the costs and risks of retiring a significant proportion of our baseload generation in the same time period along with environmental regulatory risks to the economic viability of our older coal units, and provides certainty to our customers and stakeholders throughout the planning period. Our proposal to achieve this vision will benefit our customers, communities, and the states we serve. Our customers will benefit from our cost-effective transition to the cleaner energy future they want, while preserving the reliable and safe service they expect, which we can accomplish for just a fraction of a percent more in incremental cost over earlier plans. Our Current Preferred Plan represents the best option to meet customers' needs in light of the planning landscape and presents the best path forward for the Company, our customers, and the energy future of the Upper Midwest area. For these reasons, we believe our Current Preferred Plan is in the public interest, and we respectfully request the Commission's approval for planning purposes.

Compliance Matrix

This Supplement to Xcel Energy's 2016-2030 Upper Midwest Resource Plan in part responds to the Minnesota Public Utilities Commission's ORDER REQUIRING SUPPLEMENTAL FILING issued January 6, 2016 in Docket No. E002/RP-15-21. The following table lists each Order requirement and cross-references the section in Supplement where we address each item.

The Supplement also responds to the November 6, 2015 Minnesota Department of Commerce request for various information , as well as the Department's December 17, 2015 Information Requests Nos. 66 through 74, in which the Department requested responses be provided concurrently with the Supplement. We have addressed the IRs either in IR format via standard email delivery and uploaded to the eDockets site or in the Supplement as noted below.

Order Requirements

Order Point	Content of Order Point	Location of Order Point as Addressed in Supplement
Order Point 1	Xcel shall file a supplement to its resource plan no later than January 29, 2016, and shall continue to share information with stakeholders. Upon submission, the Department will review Xcel's supplemental resource plan filing to determine the time the Department will need to analyze the new filing. Within 30 days of the supplemental filing, the Department will submit a letter to the Commission recommending a comment period and whether any additional information is needed. After reviewing the Department's recommendation and recommendations from any other party, the Executive Secretary is authorized to set a reply comment period.	January 29, 2016 Supplement to the 2016-2030 Upper Midwest Resource Plan ("Supplement")
Order Point 2	As part of its January 29, 2016 supplement, Xcel shall file:	
	a. A rate impact analysis of the revised proposal;	Supplement Sections VI, Attachment E

Order Requirements

Order Point	Content of Order Point	Location of Order Point as Addressed in Supplement
	b. A copy of the "Y-2 Study" by the Midcontinent Independent System Operator (MISO) about the effects of shutting down one or two of the Sherco facilities;	Attachment D1
	c. An analysis of alternatives to all or part of the energy and capacity that would otherwise be provided by natural gas combined cycle and combustion turbine resources, including alternatives such as demand response, improved system or grid efficiencies, and distributed energy resources;	Attachment F
	d. A proposed method to acquire proposed combined cycle and combustion turbine resources (e.g., a Company-issued request for proposals, a certificate of need, or some other process);	Supplement Section V.C.
	e. Information about potential sites for any proposed combined cycle facility;	Supplement Sections I., V.A., V.B.1.,2. Attachment B
	f. If the site for the proposed combined cycle facility is known, the estimated total costs, including costs of any extension of natural gas service and transmission lines, along with the basis for choosing the site; and	Supplement Section V.B.
	g. Estimated total costs, including costs of any extension of natural gas service and transmission lines, for adding a combustion turbine in North Dakota by 2025.	Supplement Sections V.A., V.B., Attachment B

Order Requirements

Order Point	Content of Order Point	Location of Order Point as Addressed in Supplement
Order Point 3	If Xcel files a Sherco Conversion Plan Proposal, it shall do so no earlier than one month following the issuance of a Commission order ruling on the merits of Xcel's resource plan. In any such initial filing, Xcel shall include a suggested procedural schedule, following consultation with the MPCA.	Supplement Sections V.D., VIII.A.

Department of Commerce – Requested Information in November 6, 2015 Comments

DOC Comments Page No.	Inquiry	Location of Information as Addressed in Supplement
Page 3	A copy of the "Y2 Study" by the Midcontinent Independent System Operator (MISO) about the effects of shutting down one or two of the Sherco facilities as discussed on pages 7-8 of Xcel's October 2, 2015 Reply Comments;	Attachment D1
Page 3	Costs and options for addressing potential reliability concerns of Xcel's proposal, and expected timelines for the "additional study" noted above;	Supplement Sections V.A., V.B. Attachments D, D1, D2, D3
Page 3	A copy of MISO's declaration of Sherco Units 1 and 2 as System Stability Resources (as noted above) and whether that declaration applies to shutting down both facilities or only one;	See Company's response to Clean Energy Organizations' Information Request No. 79, Attachment B submitted November 9, 2015. Available at https://www.edockets.state.mn.us

Department of Commerce – Requested Information in November 6, 2015 Comments

DOC Comments Page No.	Inquiry	Location of Information as Addressed in Supplement
Page 3	Identification of the process required and options available to address a MISO declaration of a facility or facilities as System Stability Resources;	Supplement Sections V.B., Att. D
Page 3	The basis for building a combined cycle, natural gas generation facility "no later than 2026" given that no party in this proceeding has previously recommended adding a combined cycle plant prior to 2030, the significant level of "dump energy" on Xcel's system, and the preference for renewable energy resources in Minnesota Statutes;	Combined Cycle: Supplement Section V.A Dump Energy: Attachment B Renewables: Attachment B
Page 4	How the Company proposes to acquire the combined cycle and combustion turbine resources (a Company-issued request for proposals, a certificate of need, or some other process);	Supplement Sections V.C, V.D.
Page 4	Any information about potential sites for such a combined cycle facility;	Supplement Sections V.A., V.B.
Page 4	If the site for the proposed combined cycle facility is known, the estimated total costs, including costs of any extension of natural gas service and transmission lines, along with the basis for choosing the site;	Supplement Sections V.A., V.B.
Page 4	Estimated total costs, including costs of any extension of natural gas service and transmission lines, for "adding a combustion turbine in North Dakota by 2025."	Supplement Sections V.A., V.B.

Department of Commerce – December 17, 2015 Information Requests

IR No.	Inquiry	Disposition of Response to IR
DOC-66	At the time Xcel files the January 29, 2016 supplement in this proceeding, please provide an updated *.FSV file for the reference case used by the Company in the new supplement or confirm that the most recently provided *.FSV file remains valid.	Submitted in IR format via email and uploaded to eDockets.
DOC-67	At the time Xcel files the January 29, 2016 supplement in this proceeding, please provide macro files (*.INP) which adjust Xcel's reference case *. FSV file to implement the contingencies explored by the Company in the new supplement or confirm that the most recently provided *.INP files remain valid.	Submitted in IR format via email and uploaded to eDockets.
DOC-68	At the time Xcel files the January 29, 2016 supplement in this proceeding, please provide macro files (*.INP) which adjust Xcel's reference case *. FSV file to implement the scenarios explored by the Company in the new supplement or confirm that the most recently provided *.INP files remain valid.	Submitted in IR format via email and uploaded to eDockets.
DOC-69	At the time Xcel files the January 29, 2016 supplement in this proceeding, please provide the post-processing spreadsheets, if any, which adjust the Strategist outputs to match those reported by the Company in the new supplement. Please provide such post-processing spreadsheets for the base case in each scenario explored by the Company in the supplement.	Submitted in IR format via email and uploaded to eDockets.

Department of Commerce – December 17, 2015 Information Requests

IR No.	Inquiry	Disposition of Response to IR
DOC-70	At the time Xcel files the January 29, 2016 supplement in this proceeding, please provide a macro file (*.INP) which adjusts the reference case to retire the A.S. King power plant in 2027. As part of the macro file, please include any expected impacts on: • Variable operations and maintenance costs; • Fixed operations and maintenance costs; • On-going capital expenditures; and • Any other expected impacts. (See pages 11-12 of Xcel's March 16, 2015 supplement for background information on such adjustments). If such adjustments are better incorporated in a post-processing spreadsheet, please provide such a post-processing spreadsheet.	Pursuant to a January 25, 2016 conversation with the Department of Commerce, the Company will provide the requested information by February 26, 2016. Noted as such and submitted in IR format via email and uploaded to eDockets.
DOC-71	At the time Xcel files the January 29, 2016 supplement in this proceeding, please provide a discussion of the potential transmission impacts of retiring the A.S. King power plant in 2027, to the extent they are known.	Pursuant to a January 25, 2016 conversation with the Department of Commerce, the Company will provide the requested information by February 26, 2016. Noted as such and submitted in IR format via email and uploaded to eDockets.

Department of Commerce – December 17, 2015 Information Requests

IR No.	Inquiry	Disposition of Response to IR
DOC-72	At the time Xcel files the January 29, 2016 supplement in this proceeding, please provide a brief discussion of whether the generating unit shut down scenarios explored by the Company in the new supplement include the present value of the expected impact of an earlier shut down on depreciation expense and related rate base costs (return on equity, deferred taxes, and so forth).	Submitted in IR format via email and uploaded to eDockets.
DOC-73	Regarding the generating units at Monticello and Prairie Island, at the time Xcel files the January 29, 2016 supplement in this proceeding, please explain why the fixed cost input in the most recent Strategist database are lower than the non-fuel production expenses (subtracting line 20 from line 34) listed in Xcel's FERC Form 1 for 2014.	Submitted in IR format via email and uploaded to eDockets.
DOC-74	At the time Xcel files the January 29, 2016 supplement in this proceeding, please provide an estimate of the necessary retirement dates for Prairie Island units 1 and 2 under the assumption that substantial (over $40 million per year for the site) new capital expenditures do not occur starting in 2016.	Reference Supplement Section IV.D.1.

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Attachment B
Updated Strategist Modeling and Outputs

In addition to the summary provided in body of the Supplement document, this Attachment presents and explains detailing Strategist modeling analysis that supports our Current Preferred Plan. Included here are a description of the revised modeling assumptions, the scenarios and sensitivities analyzed, and the results of an economic analysis comparing the Present Value Revenue Requirements (PVRR) and Present Value of Societal Costs (PVSC) outputs for each scenario. We also respond here to the Department of Commerce's July 2, 2015 Comments related to the treatment of dump energy in our modeling.

I. REVISED MODELING ASSUMPTIONS

Our January 2, 2015 Initial Filing detailed the Planning Framework, Strategist Assumptions and Sensitivities, and Scenarios Analyzed that formed the basis of our resource planning analysis. The updates and additional modeling presented in this Supplement build on all the planning analysis done since initially filing this Resource Plan. We clarify that we made no changes to our base assumptions, such as our underlying sales and natural gas price forecasts.

Our March 16, 2015 Resource Plan Supplement forms the basis of the analysis supporting the Current Preferred Plan we present in this Supplement. Two key changes that have occurred since the March 2015 Supplement and the October 2015 Reply filing are the extension of federal tax credits for renewable energy and the growth in our Community Solar Garden forecast. In the narrative below, we explain the impact to our Current Preferred Plan of these changes on our resource additions and the associated costs.

We have included the impacts of the tax credit extension in all of our economic analysis of our Current Preferred Plan, to incorporate the changed circumstances related to renewable energy costs. We have outlined the impact of the small solar adjustments to in the section below, but have not reflected those cost changes in the PVRR and PVSC comparisons in Section III below. As these changes are the result of policy recommendations outside the scope of our Current Preferred Plan, we felt it was appropriate to include only those resource changes proposed in our plan, in our cost impact analysis. Although we did not submit a detailed economic analysis with our October 2015 revised proposal, we note that the extension of the Production Tax Credit (PTC) and Investment Tax Credit (ITC) reduces the PVRR of our Current

Preferred Plan by $202 million; the changes to the small solar increases the PVRR by approximately $760 million.

A. Tax Extender (PTC, ITC) Updates to Wind and Solar Prices

Legislation was enacted in December 2015 that extended the availability of PTCs (primarily relating to wind projects) to 2019 and the 30 percent ITC (primarily related to solar projects) to 2022. The Consolidated Appropriations Act of 2016 also provided step downs in tax incentives in various years depending on the type of project and the date construction commences and/or the project is placed into commercial operation.

To incorporate these changes into the modeling, it was necessary to develop updated pricing for wind and solar for the varying tax levels, as well as develop additional alternatives to capture the year-by-year changes. In developing these new alternatives, it was assumed that the Internal Revenue Service will ultimately promulgate a safe harbor memorandum for the new law that has similar timing requirements related to construction start and in-service dates as the current memorandum (i.e. approximately two years of construction time allowed for safe harbor). The assumptions used are shown below in Table 1.

Table 1: Wind and Solar Tax Benefit Assumptions

Construction Start	COD, by End of:	First Full Year of Ops	PTC	ITC
2016	2018	2019	100%	30%
2017	2019	2020	80%	30%
2018	2020	2021	60%	30%
2019	2021	2022	40%	30%
2020	2022	2023		26%
2021	2023	2024		22%
2022	2024	2025		10%

The pricing for each alternative was developed in the same manner as described in the Appendix to the March 16, 2015 Resource Plan Supplement document, using a spreadsheet financial model to convert an owned project to Power Purchase Agreement (PPA) equivalent pricing. For the Current Preferred Plan that includes owned renewables, the original ownership revenue requirements were used, resulting

equivalent costs on a net present value basis of owned vs. PPA projects for a given tranche. The PPA equivalent pricing is shown below in Table 2.

Table 2: PPA Equivalent Pricing for Wind and Solar ($/MWh)

Tech Type:	Solar	Solar	Solar	Solar	Solar	Solar	Wind	Wind	Wind	Wind
Construction Start:	2016	2018	2019	2020	2021	2022+	2016	2017	2019	2020+
First Full Year of Ops:	2019	2021	2022	2023	2024	2025+	2019	2020	2022	2023+
Tax Benefit:	30% ITC	30% ITC	30% ITC	26% ITC	22% ITC	10% ITC	100% PTC	80% PTC	40% PTC	0% PTC
2019	67.30						21.98			50.78
2020	68.80						22.48	26.78		51.92
2021	70.35	69.54					22.98	27.38		53.08
2022	71.92	71.09	69.73				23.49	27.99	37.87	54.27
2023	73.53	72.69	71.29	70.96			24.02	28.62	38.72	55.49
2024	75.18	74.31	72.89	72.55	72.20		24.56	29.26	39.58	56.73
2025	76.86	75.98	74.52	74.18	73.82	95.00	25.11	29.91	40.47	58.00
2026	78.58	77.68	76.19	75.84	75.47	95.00	25.67	30.58	41.38	59.30
2027	80.35	79.42	77.90	77.54	77.16	95.00	26.25	31.27	42.30	60.63
2028	82.14	81.20	79.64	79.28	78.89	95.00	26.83	31.97	43.25	61.99
2029	83.98	83.02	81.43	81.05	80.66	95.00	27.44	32.68	44.22	63.38
2030	85.87	84.88	83.25	82.87	82.46	95.00	28.05	33.42	45.21	64.80
2031	87.79	86.78	85.12	84.72	84.31	95.00	28.68	34.17	46.22	66.25
2032	89.76	88.72	87.02	86.62	86.20	95.00	29.32	34.93	47.26	67.73
2033	91.77	90.71	88.97	88.56	88.13	95.00	29.98	35.71	48.32	69.25
2034	93.82	92.74	90.97	90.55	90.10	95.00	30.65	36.51	49.40	70.80
2035	95.92	94.82	93.00	92.57	92.12	95.00	31.34	37.33	50.51	72.39
2036	98.07	96.94	95.09	94.65	94.19	95.00	32.04	38.17	51.64	74.01
2037	100.27	99.12	97.22	96.77	96.30	95.00	32.76	39.02	52.80	75.67
2038	102.52	101.34	99.39	98.94	98.45	95.00	33.49	39.90	53.98	77.36
2039	104.81	103.61	101.62	101.15	100.66	95.00	34.24	40.79	55.19	79.09
2040	107.16	105.93	103.90	103.42	102.91	95.00	35.01	41.70	56.42	80.87

This extension provides material reductions in the cost of renewable energy acquisitions proposed in our each of our Resource Plan scenarios. We have therefore

adjusted our proposed wind additions in 2020 to be PTC-eligible in all scenarios analyzed in this Supplement, to allow for an apples-to-apples comparison between the plans. These changes were made to all scenarios in order to reflect how the current law impacted changing individual plans differently and therefore changes the delta analysis of the various plans.

The impact of this change on our Current Preferred Plan is a decrease in the overall PVRR of $202 million and a decrease in the overall PVSC of $203 million.

B. Small Solar Forecast Update

We launched our Solar*Rewards Community program in December 2014. As we have previously noted, we received an overwhelming response to our program – receiving nearly two thousand applications to-date. Modeling data regarding distributed solar was developed for the January 2, 2015 Initial Filing prior to the Company or Commission finalizing the tariffs and program offerings for individual distributed solar or community solar gardens installations. Subsequent to development of the initial models, the regulatory structure for distributed solar has become much clearer. We have more information on issues in the Community Solar Gardens proceeding (Docket No. E002/M-13-867) that were previously unresolved, and have therefore been able to update our forecast for purposes of this Supplement.

The initial data for cost and payment terms was estimated by the Company using its experience in other jurisdictions, primarily Colorado. In the Initial Filing, and carried forward into the Supplemental filing in March 2015, the assumption used was payments for 10 years at 8¢/kWh. Due to the magnitude of the solar programs proposed and modeled in these scenarios, the cost assumptions should be adjusted closer to current practice. In the alternative analysis with the small solar forecast adjustment discussed here, the costs and payment terms have been revised to payments for 20 years at 12¢/kWh.

In Table 3 below, we have accelerated the addition of small solar resources – a total of 422 MW in the pre-2020 timeframe in anticipation of the completion of several Solar*Reward Community projects and continuing our commitment to growing renewable resources.[1] While the current project pipeline for community solar gardens

[1] We adjusted our forecast for small solar, including community solar gardens and distributed generation (DG) in this Supplement based on a mixture of regulatory adjustments, detailed design, and project movement in the pipeline for our Solar*Rewards Community program.

exceeds this projection, we anticipate that some projects will experience difficulties in permitting, financing, or interconnection, therefore never reaching full operation.

Although the ITC has been extended, we believe that a majority of projects will be completed in the next year for the Solar*Rewards Community program based on established financing. Therefore, we have forecasted 259 MW of projects reaching operation by the end of 2016, and lowered the forecast after this time. Table 3 below shows the impact this adjusted small solar forecast has on our capacity/deficit position from the L&R analysis in the Supplement document.

Table 3: Small Solar Forecast Adjustment (MW) ICAP

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Current Preferred Plan – Proposed Solar Additions																
Small Solar Additions	42	45	49	53	58	17	20	24	29	34	41	49	59	71	85	675
Large Solar Additions	0	0	0	200	0	200	100	100	200	100	100	0	400	0	0	1,400
Total Additions by Year	42	45	49	253	58	217	120	124	229	134	141	49	459	71	85	2,076
Current Preferred Plan – Alterative Analysis w/Small Solar Forecast adjustment																
Small Solar Additions	259	159	91	83	76	17	20	24	29	34	41	49	59	71	85	1,097
Large Solar Additions	0	0	0	200	0	200	100	100	200	100	100	0	0	0	0	1,000
Total Additions by Year	259	159	91	283	76	217	120	124	229	134	141	49	59	71	85	2,097
Impact of Small Solar Forecast Adjustment on Current Preferred Plan																
Increased Small Solar	217	114	43	31	18	0	0	0	0	0	0	0	0	0	0	422
Adjusted Large Solar	0	0	0	0	0	0	0	0	0	0	0	0	-400	0	0	-400
Change in Total Additions by Year	217	114	43	31	18	0	0	0	0	0	0	0	-400	0	0	22

The impact of this adjusted small solar forecast is a shift in the type and timing of solar additions in our plan, which impacts the overall cost of the Current Preferred Plan. In order to accommodate the increase to the small solar forecast in the early years of the plan, the utility-scale solar additions we propose in our Current Preferred Plan would be reduced. As Table 3 above shows, we would remove the remaining 400 MW of utility-scale solar in the plan in 2028 at a fixed flat price of $95/MWh in order to add the more than 400 additional MW of small solar between 2016 and 2020 at a fixed flat price of $120/MWh. While this change does not significantly impact the net solar additions in the plan, it accelerates the installation of the solar, but would also increase the cost of the plan by moving to a different, less cost-effective form of solar.

The impact of this change is an increase in the overall PVRR of our Current Preferred Plan by approximately $759 million. The PVSC impact of this change on our Current Preferred Plan is an increase of $737 million.

C. Updated Nuclear Forecast

Certain fixed costs that do not affect the relative economics of plans being considered are typically not included in the Strategist database. As an example, costs related to the distribution and corporate services business areas, transmission costs not related to generation plans, and recovery of current ratebase for owned units that are not subject to change are not typically included in the model. Strategist does include all costs related to the operations of owned and PPA units (fuel, variable and fixed O&M, PPA payments), and the models used for this resource plan do include future capital expenditures and recovery of ratebase for the Sherco units, as the costs for Sherco vary among the different retirement scenarios. In total, the Strategist model represents about 46 percent of the total system revenue requirements that go into rates, with the other 54 percent being unrelated to decisions around resource selection or planning.

In an effort to provide increased transparency around our nuclear cost assumptions, we have elected to include an analysis of scenarios with the full costs of nuclear in the Scenario Outcomes below. We have updated the model for that analysis to include specific forecasted Capital and Fixed O&M (FOM) costs for the planning period for the Monticello and Prairie Island units.

The O&M costs that were in the model previously for those units have been updated to the most recent estimate of future O&M. In addition, costs that were not in the model previously related to future capital expenditures and recovery of current rate base were added to the model. The net results of adding these costs in, as well as the much lesser impact of adjusting the O&M forecast, results in an increase in the net present value of revenue requirements (or societal cost) that Strategist reports of around $3.6 billion. We clarify that this total Capital and FOM cost is not the "increase" in our nuclear cost forecast that we discussed in our October 2, 2015 Reply Comments; we discuss the $600-$900 million forecasted cost increase in Section VII of the Supplement document.

This does not result in an increase to the relative cost of any plan, but simply adds in costs that were never reported before. Essentially, Strategist was adjusted from reporting 46 percent of total system costs to around 51 percent of total system costs and, as the same adjustment was made to all plans, the delta in costs between the various plans is unchanged. The impact of these adjusted cost assumptions to the overall PVRR/PVSC of the modeling scenarios is shown below in Section VII on Table 10.

II. SCENARIOS AND SENSITIVITIES SUMMARY

A. Scenario Summary

To analyze our Current Preferred Plan, we included five key scenarios from our previous Resource Plan filings. Each of these scenarios was updated with the assumptions described above. All previous scenarios were run as they were described in the Initial Filing; however Sherco 2 is now the first unit retiring instead of Sherco 1.

1. Updated Previous Scenarios

Each of the scenarios described below used the baseline data from our March 2015 Supplemental filing, updated with the relevant modeling assumption revisions described above.

- *Reference Case:* Includes the continued operation of Sherco Units 1 and 2 through 2030, 400 MW of wind additions, over 400 MW of small solar additions, 287 MW of large solar additions, no assumptions changes.
- *Updated 2015 Plan:* Includes the continued operation of Sherco Units 1 and 2 through 2030, 1,800 MW of wind additions, over 1,600 MW of large solar additions, nearly 700 MW of small solar additions, updated for Federal ITC/PTC.
- *North Dakota Plan:* Consistent with March Supplement, contains no additional renewables beyond currently committed 750 MW of wind, no assumptions changes.

2. Current Preferred Plan and Variants

The scenarios below reflect the Current Preferred Plan, with various alternatives for replacement capacity of the Sherco unit retirements. We allowed the model to select both site-specific and generic replacement capacity alternatives for the Sherco units. The modeling of the site-specific alternatives is discussed in detail in Section V of the Supplement.

- *Current Preferred Plan*: Cease operation of a total of 1,400 MW of capacity and associated energy at Sherco Unit 2 in 2023 and Unit 1 in 2026, 1,800 MW of wind additions, over 1,400 MW of large solar additions, nearly 700 MW of small solar additions, updated for Federal ITC/PTC extension, goal of 50 percent ownership of renewables, Company-owned Fargo CT and Sherco CC.

- *Current Preferred Plan – All Generics*: Same as Current Preferred Plan, but with all generic thermal alternatives. Leave behind costs for not replacing generation at the Sherco site are not modeled within Strategist so are not included in the PVSC/PVRR's, but are calculated outside of models. Updated for tax credit extension.

3. Full Optimization Scenarios

We performed an unconstrained optimization incorporating the option of adding incremental Demand Response and Distributed Energy Resources.

- *Resource-Need Optimization:* Unconstrained optimization simultaneously filling energy and capacity needs.
- *Capacity-Need Optimization:* Unconstrained optimization filling capacity needs only.

The results of this analysis are included in Attachment F. A summary of the primary scenarios included in this Supplement is shown in Table 4 below.

Table 4: Summary of Scenarios Analyzed in this Supplement

Primary Sherco / Carbon / Renewable Alternatives	Strategist Output Code
Continued Operation (Run Both Units to 2030)	
Reference Case	1
Updated 2015 Plan	
Updated 2015 Plan - PTC Wind in 2020	10
North Dakota Plan	
Original North Dakota Plan - No additional renewables beyond currently committed	15
Current Preferred Plan	
Current Preferred Plan - Retire Sherco 2023 and 2026, accelerate renewables, Sherco CC, Fargo CT	28
Current Preferred Plan with all generic thermal replacements, excluding leave behind costs	28_A

B. Sensitivity Summary

To determine how changes in our assumptions impact the costs or characteristics of different Resource Plans, we examined our plans under a number of sensitivities. If a plan is extremely sensitive to changes in assumptions, it is not a robust course of action for the Company to pursue. Instead, we could conceivably propose an expansion plan that is less sensitive to assumption changes, but slightly more costly than the least-cost scenario under starting assumptions. For this Supplement, we used a subset of the same sensitivity cases that were used in the January 2, 2015 Initial and March 16, 2015 Supplemental Filings, selecting the sensitivities that are most relevant to the decisions being contemplated and that are of the most interest to the various parties to this case. Additionally, what was referred to as the "Traditional View" in the March 2015 Supplement (Sensitivity "R", Do Not Maintain CAPCON Length) is incorporated into all cases and is no longer considered a sensitivity.

Table 5 below gives a summary of the Modeling Sensitivities included in this Supplemental filing.

Table 5: Modeling Sensitivities

Base CO_2 (Mid) Costs	**Strategist Output Code**
Low Gas Prices	C
High Gas Prices	D
Zero CO_2 Costs	
No Regulated CO_2 (Contains Externality CO_2)	K
ND Assumptions (No Extern, No CO_2 Costs)	T
"Customer impact" (No Cap Credit, No Extern, No CO_2 Costs)	U
Other CO2 Sensitivities	
CO_2 $9, Start 2019	L
CO_2 $34, Start 2019	M
CO_2 $9, Start 2024	N
CO_2 $34, Start 2024	O
CO_2 at Federal SCC 3%	P

III. ECONOMIC ANALYSIS

After identifying the scenarios and sensitivities to update for this Supplement, we performed an updated resource planning analysis in largely the same manner we used for both our Initial Filing and our March 16, 2015 Supplement. To provide a comparison between the various cases we considered, we use a traditional resource planning method and rank the scenarios based on cost. In addition to a least-cost analysis, we perform a more holistic analysis to determine if our Current Preferred Plan is appropriately balanced within our planning framework when compared to the other scenarios.

We analyze the economics of the scenarios in both PVRR and PVSC terms. The PVSC results provide a baseline ranking of the overall societal benefits of each of the scenarios analyzed – applying the Minnesota Commission's regulatory cost of carbon dioxide and externalities values for criteria pollutants – and the externality for carbon in non-regulated years in the modeling period of 2015-2053. The PVRR-based analysis excludes carbon costs and all externalities values over the modeling period.

Because actual customer cost impacts are a key consideration within our planning framework, and due to the fact that not all of the NSP System states allow for an analysis that includes carbon costs or externalities, we also perform a least-cost analysis on a PVRR basis (North Dakota Plan). We present the results of these analyses in this section, and demonstrate that our Current Preferred Plan provides the most reasonable outcome under both a least-cost analysis and under a more comprehensive analysis.

1. Traditional Resource Planning Analysis

We first analyzed our modeling outputs on a PVSC basis to determine the least-cost plan including societal impacts. Table 6 below provides the PVSC outcomes for each of the key scenarios we analyzed for this Supplement.

Table 6: PVSC Results ($Millions)

Scenarios	PVSC Results
Current Preferred Plan	$51,293
Current Preferred Plan, All Generics	$51,280
Updated 2015 Plan	$51,458
Reference Case	$52,422
North Dakota Plan	$52,620

As shown above in Table 6, our Current Preferred Plan is the second lowest cost plan on a PVSC basis. Only the Current Preferred Plan with a generic Sherco Unit replacement ranks higher on a PVSC basis – with a minimal $13 million difference in PVSC. This difference is due to the exclusion of leave-behind costs for not replacing generation at the Sherco site, which are not modeled in Strategist.

Table 7 below provides the PVRR rankings of the same key scenarios.

Table 7: PVRR Results ($Millions)

Scenarios	PVRR Results
Current Preferred Plan	$45,606
Current Preferred Plan, All Generics	$45,582
Updated 2015 Plan	$45,302
Reference Case	$45,605
North Dakota Plan	$45,473

From a strictly PVRR perspective, as Table 7 above shows, the Reference Case is the lowest-cost plan. Table 7 also indicates that the North Dakota Plan ranks the next best on a PVRR basis, since it relies heavily on natural gas generation additions as compared to the Preferred or Current Preferred Plans. As we have mentioned previously, we do not believe that either of those plans would meet Clean Power Plan (CPP) compliance. Our Current Preferred Plan, with variations for site-specific and generic replacements for Sherco capacity, has the lowest PVRR ranking, as the benefits of the carbon emissions impacts of the plan are not captured in a PVRR analysis. A full matrix of PVRR and PVSC results is included in Section VII below.

After performing the PVSC and PVRR analyses, we evaluate the scenarios more holistically by analyzing their environmental performance, strategic flexibility, and cost. Table 8 below, the Run Key carries forward the PVSC and PVRR ranking of each scenario to provide a reference point for the broader analysis, but it also identifies key policy outcome metrics such as amount of CO_2 emissions reductions from 2005 levels and the amount of renewable energy added to the NSP System under each scenario.

Table 8: Run Key[2]

	PVSC Results ($M)	PVRR Results ($M)	2030 Coal Gen vs. Ref. Case	2030 Gas Burn (Bcf)	2030 Percent CO_2 Reduction	Total Expansion Plan Renewable Additions (MW)	CPP Compliant?
Current Preferred Plan	$51,293	$45,606	-59%	83	58%	3,200	Yes
Current Preferred Plan, All Generics	$51,280	$45,582	-59%	84	57%	3,200	Yes
Updated 2015 Plan	$51,458	$45,302	-16%	32	42%	3,200	Uncertain
Reference Case	$52,422	$45,605	-	58	23%	400	No
North Dakota Plan	$52,620	$45,473	+3%	68	19%	0	No

The comprehensive Run Key analysis shows that our Current Preferred Plan has the stronger performance in terms of carbon reductions and renewable energy additions to the NSP System. The renewable energy additions in our Updated 2015 Plan and Current Preferred Plans are consistent, but the timing and ownership has shifted, as shown in our Expansion Plans. This plan continues to provide the best value for our customers – achieving a balance between multiple objectives, including: reasonable costs, dramatic emissions reductions, anticipated compliance with the CPP, and maintaining reliability on our system. Our Current Preferred Plan proposes to time these resource changes such that we minimize the socioeconomic and technical impacts by allowing sufficient time to plan for fleet transitions.

IV. ALTERNATIVE SCENARIOS CONSIDERED

As part of the process of developing our Current Preferred Plan, we evaluated a broad range of alternatives. Our updated Strategist modeling included consideration of several alternative scenarios, including conversion of a Sherco Unit to a Boiler, and solar and wind resources in addition to generic and site-specific CT and CC alternatives. Here, we discuss these alternative Scenarios in greater detail.

[2] In this Run Key Table, the PVRR Results, change in coal generation in 2030 as compared to the Reference Case (2030 Coal Gen vs. Ref Case), amount of gas burned at our plants in 2030 in Billions of cubic feet (2030 Gas Burn (Bcf)), and the percent reduction of CO_2 from 2005 levels (2030 Percent CO_2 Reduction) are all considered under a cost sensitivity that excludes regulatory costs and CO_2 externalities in the dispatch. Under this sensitivity, there will be a tendency to overestimate CO_2 emissions, as coal would be 'priced' at a lower cost and the likelihood of dispatching the resource more frequently would therefore be increased.

2. Conversion of a Sherco Unit to Gas

As noted above, one unit at Sherco could be converted to a gas boiler, as the Department recommended in its July 2, 2015 Comments. We commissioned an external study of impacts and costs for converting either of Sherco Units 1 or 2 boilers to gas-fired and to evaluate the economic aspects of such a conversion. We note that a gas-fired boiler would be a capacity resource only, as the technical limitations of a long start-up time, a slow ramp rate, high O&M, and a high heat rate as compared to gas fired turbines would likely result in very low annual capacity factors of less than two percent due to the Unit's economic dispatch order position. Compared to our Current Preferred Plan, replacing a unit at Sherco with a gas boiler and adding a CC increases the PVSC by $36 million dollars.

In addition, continued operation of a large coal boiler that is converted to utilize gas also results in a number of operational issues. While the unit can be counted as a capacity resource after conversion, we believe that in order to qualify as a capacity resource in the Midcontinent Independent System Operator's (MISO) evolving capacity construct, firm gas supply may be required. The current capacity construct in MISO is on an annual basis from June 1 to May 31. If MISO changes to a seasonal capacity construct, firm gas may not be required during the summer season. However, as one Sherco unit is a large portion of the entire system capacity, it may not be practical from an operations perspective to have the unit available for only part of the year. In addition, the operating characteristics of the large unit that was designed for base load operation will push it to near the bottom of the dispatch order even with low gas costs being directly competitive with coal, if not better.

A converted gas unit would have a ramp rate of approximately 5 MW per minute from a minimum load level of 260 MW to full load. This is considerably slower than a CT, which has a ramp rate of approximately 10 MW per minute. We would expect that when the unit is dispatched it could be kept online for several days in order to cover the start costs, anticipated to be approximately $100k for labor plus 3,500 to 4,000 MMBTU of start fuel. Once taken through and orderly shut-down the unit will not be available for restart for at least one to two days.

3. All Renewables

We also considered replacing the capacity and energy from retirement of Sherco Units 1 and 2 with replacement of the capacity and energy entirely from renewable sources, as is required under Minn. Stat. § 216B.2422, subd. 4. Our Current Preferred Plan

includes 1200 MW of renewable additions by 2020. However, in addition to the significant amount of renewable generation we plan to add to our system, gas-fired generation plays an important role on the system and was also selected as a cost-effective resource addition to meet customer needs.

Variable resources such as wind and solar must be integrated with dispatchable gas-fired generation in order to ensure adequate system reliability. Gas-fired generation will likely be distributed at several locations around the NSP System to provide grid support and to efficiently utilize existing transmission infrastructure. If replacement generation is not located at the Sherco site, we would need to otherwise resolve a voltage deficiency in the Becker, Minnesota area and for the Monticello nuclear plant, which would require the conversion of one of the Sherco units to a synchronous condenser, a Static Var Compensator (SVC) or Statcom device.

The goal of a sustainable, cleaner energy future depends upon sufficient infrastructure to support delivery of utility-scale and distributed renewable resources. In particular, modernized transmission and distribution systems are critical to meet the challenges of emerging technologies, expanding renewable policies, and a comprehensive view of resource planning. Appendix H of our initial filing discussed some of the effort undertaken at both the transmission and distribution level to ensure increased levels of renewable generations can be accommodated.

V. TREATMENT OF DUMP ENERGY

As the Department noted in their July 2, 2015 Comments, our modeling shows a significant level of dump energy. In Strategist, DSM, wind, and solar are modeled as must-run resources and their generation is used to reduce customer load prior to performing thermal dispatch. The thermal dispatch includes several must-run units, such as large coal plants, as well as must-take PPAs, such as biomass. There are hours during which the modified load (customer load less DSM, wind, and solar generation) is less than the minimum physical operating level of the must-run thermal resources. Strategist reports the energy when generation is greater than load as dump energy. Dump energy occurs because Strategist does not allow the must-run thermal units and must-take PPAs to reduce their generation to balance load. The Department correctly explained in its comments that dump energy increases as more wind resources are added to the system. This occurs because the modified load will decrease as wind additions are increased. This results in more instances where the modified load is less than the must run thermal resources and there is a corresponding increase in dump energy.

In our analyses we assign a revenue credit to dump energy equal to 50 percent of the market energy price. In addition, by requiring the thermal units to operate at their minimum, the costs and emissions for the thermal generation related to the dump energy are included. Dump energy does not impact the optimization of the expansion plans or the dispatch of the generators in the model. We assigned the revenue credit outside the model after the optimization and dispatch is complete. We believe this modeling approach is appropriate and provides for the full value of wind to be accounted for, as it allows all the energy available from both wind and thermal units to be included in the analysis.

It is also important to note that over-builds would be immediately apparent if the reserve margin significantly exceeded the required reserve margin. This does not occur in our modeling. We conclude that our approach provides a consistent comparison of renewable and thermal resources.

The Department has also expressed concern that dump energy may indicate there is excess energy that can be applied to reduce the resource additions needed to meet customer load. Dump energy typically occurs, however, during low-load or off-peak periods. While the resources available during these low load periods may greater than the resources needed to serve these lower loads, it is not possible to "save" this energy and use it later when loads are higher.

Finally, as the Department noted, dump energy is a challenging issue from both a cost and CO_2 perspective. We propose to work with the Department to arrive at an agreed-upon methodology.

VI. LONG-TERM RATE IMPACT METHODOLOGY

Figure 5 in the body of the Supplement illustrates the estimated cost impact of our proposal over the course of the planning period. To calculate these long-term rate impacts of the Current Preferred Plan as compared to the Reference Case, we first developed a forecast of total rates through 2020 under the Reference Case assumptions. To do this, we used a combination of the Company's shorter range financial forecasts and a special-purpose Strategist model used to project total system revenue requirements for extended periods.

Typically, the Strategist model develops projections for generation-related costs. To derive a total system (including transmission, distribution, A&G, etc.) forecast, we expanded the standard Strategist model by adding capital and expense items

associated with the other costs that are not typically modeled. We input starting net plant and deferred tax balances, capital spend forecasts and O&M forecasts for the existing generation, transmission, distribution and overhead business areas, and calibrated the model such that the total revenue requirements through 2020 approximately tracked the more refined short-term financial forecasts during those years.

Developing a total rate forecast beyond 2020 when detailed company financial models are not available would depend on making assumptions for capital expenditures and O&M expenses for all areas of the business, including generation (both new and existing), transmission, distribution and corporate support services. Many of these assumptions would be highly speculative, and the resulting total rate forecast would be similarly speculative. As discussed in this Attachment in describing the modeling changes for the nuclear fleet, Strategist normally models only the generation-related portion of the business, or around 50 percent of the total revenue requirements. For the period beyond 2020, the costs not typically modeled in Strategist were escalated at a generic "inflation-proxy" rate of 2 percent, and were added to the annual costs from the IRP Scenario 1 (Reference Case) model results that are presented throughout this filing. This approach avoids speculation on areas of the business not related to resource planning, while preserving the detailed generation-related information from the Strategist model.

The annual deltas of the various scenarios (including the Updated 2015 Plan and the Current Preferred Plan) to the Reference Case were added to this underlying Reference Case total rate forecast to determine the total rates for these scenarios.

VII. SCENARIO OUTCOMES

An updated summary of the Strategist model's PVRR/PVSC outputs for the various scenarios and sensitivities is shown below in Table 9. Table 10 below shows the results including the nuclear cost assumptions described in Section I, Part C above.

Table 9: PVSC/PVRR Total ($M) for all Scenarios/Sensitivities

Scenarios	Number	Base	LOW GAS PRICE C	HIGH GAS PRICE D	ZERO CO2 K	LOW CO2 L	HIGH CO2 M	LATE LOW CO2 N	LATE HIGH CO2 O	SOCIAL COST OF CARBON P	ND ASSUM-PTIONS T	CUSTO-MER IMPACT U
Reference Case	1	52,422	49,050	57,073	47,587	48,781	55,882	48,320	53,235	66,308	45,605	45,934
Original 2015 Plan	10_A	52,083	49,225	56,063	47,755	48,818	55,193	48,386	52,663	64,863	45,924	46,229
Updated 2015 Plan	10	51,458	48,599	55,439	47,132	48,195	54,568	47,763	52,040	64,237	45,302	45,606
Current Preferred Plan (no Boiler)	28	51,293	48,283	55,463	47,317	48,293	54,155	47,896	51,805	63,457	45,606	45,956
Current Preferred Plan, All Generics, No Leave Behind Cos	28_A	51,280	48,261	55,465	47,295	48,273	54,148	47,876	51,797	63,464	45,582	45,934
Current Preferred Plan (Boiler + SHC CC x1)	B28	51,329	48,319	55,499	47,352	48,328	54,191	47,931	51,841	63,492	45,641	45,995
North Dakota Plan	15	52,620	49,013	57,568	47,535	48,792	56,252	48,305	53,464	67,051	45,473	45,761

Table 10: PVSC/PVRR Total ($M) for all Scenarios/Sensitivities with Nuclear Costs

Scenarios	Number	Base	LOW GAS PRICE C	HIGH GAS PRICE D	ZERO CO2 K	LOW CO2 L	HIGH CO2 M	LATE LOW CO2 N	LATE HIGH CO2 O	SOCIAL COST OF CARBON P	ND ASSUM-PTIONS T	CUSTO-MER IMPACT U
Original Reference	1	56,033	52,662	60,684	51,199	52,393	59,494	51,932	56,847	69,919	49,217	49,545
Original 2015 Plan	10_A	55,694	52,836	59,675	51,367	52,430	58,805	51,997	56,274	68,474	49,536	49,840
Updated 2015 Plan	10	55,070	52,211	59,051	50,743	51,806	58,179	51,374	55,652	67,848	48,913	49,218
Current Preferred Plan (no Boiler)	28	54,904	51,895	59,074	50,929	51,905	57,766	51,508	55,417	67,069	49,218	49,567
Current Preferred Plan, All Generics, No Leave Behind Cos	28_A	54,891	51,873	59,076	50,907	51,885	57,760	51,488	55,409	67,075	49,193	49,546
Current Preferred Plan (Boiler + SHC CC x1)	B28	54,940	51,931	59,110	50,964	51,939	57,802	51,543	55,453	67,103	49,253	49,607
Original ND Plan	15	56,231	52,624	61,180	51,146	52,403	59,864	51,916	57,076	70,663	49,085	49,373

Attachment C
Resource Plan Comparisons

As our Resource Plan has evolved substantially since our initial January 2015 filing, we provide here a comparison and update on the Expansion Plans for our Reference Case, Updated 2015 Plan, and Current Preferred Plan, to provide readers an easy reference between the scenarios. We have also included data on our updated Renewable Energy Standard (RES) and Solar Energy Standard (SES) Compliance positions under the Current Preferred Plan.

A. Expansion Plans

The Expansion Plans below represent only those resource additions we are proposing in each scenario. The Updated Load and Resources Table in the body of the Supplement included all of the existing and approved resource changes that we anticipate over the course of the planning period. Table 1 below provides our Reference Case Expansion Plan.

Table 1: Reference Case Expansion Plan – Installed Capacity (ICAP)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Wind	-	-	-	-	-	400	-	-	-	-	-	-	-	-	-	-	400
Combustion Turbine	-	-	-	-	-	-	-	-	-	-	690	690	460	-	-	-	1,840
Combined Cycle	-	-	-	-	-	-	-	-	-	-	-	-	-	778	-	-	778

Only the utility-scale resource additions proposed as part of our Reference Case are identified in Table 1. All small solar, as well as the 187 MW Solar Request for Proposals Portfolio[1] and the competitive acquisition process[2] (CAP) resources, are reflected as existing/approved resources, and therefore not included in the Expansion Plans. The 400 MW of wind in 2020 represents non-Production Tax Credit (PTC) additions, as we did not update the Reference Case to include the tax credit extension.

Table 2 below shows the Expansion Plan for our Updated 2015 Plan, referred to in previous filings as the Preferred Plan.

[1] Approved by the Commission in February 2015 in Docket No. E002/M-14-162.
[2] Docket No. E002/M-12-1240, includes 100 MW Aurora Solar project, 345 MW Calpine Mankato project, and the 232 MW Xcel Energy Black Dog 6 project.

Table 2: Updated 2015 Plan Expansion Plan (ICAP)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Large Solar	-	-	-	-	-	-	-	-	-	-	300	200	200	500	-	200	1,400
Wind	-	-	-	-	-	600	-	-	200	-	600	-	400	-	-	-	1,800
Combustion Turbine	-	-	-	-	-	-	-	-	-	-	460	460	230	230	-	-	1,380

The Updated 2015 Plan Expansion Plan is largely consistent with what we filed in the March 2015 Supplement, although the assumptions have been updated to reflect the extension of renewable energy tax credits. As a result, the 600 MW of wind in 2020 is modeled as benefiting from the PTC. Finally, the Current Preferred Plan Expansion Plan is included in Table 3 below.

Table 3: Current Preferred Plan Expansion Plan (ICAP)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Large Solar	-	-	-	-	200	-	200	100	100	200	100	100	-	400	-	-	1,400
Wind	-	-	-	-	800	-	-	400	-	-	400	200	-	-	-	-	1,800
CT	-	-	-	-	-	-	-	-	-	-	460	690	230	230	-	230	1,840
Fargo CT	-	-	-	-	-	-	-	-	-	-	230	-	-	-	-	-	230
Sherco CC	-	-	-	-	-	-	-	-	-	-	-	-	786	-	-	-	786

This Expansion Plan for the Current Preferred Plan matches the total proposed renewable resource additions included in our October 2, 2015 Reply. The updated assumption related to the renewable energy tax credit extension results in a shift in the type – from non-PTC to PTC – and timing of those resources, and an associated cost reduction for the 800 MW of wind added in 2019. Our October proposal included a proposed generic North Dakota CT in 2023, which after further analysis has shifted to a Company-owned CT in Fargo in 2025, although the unit may be placed in-service before 2025. Due to the site-specific resource additions we have selected for our Current Preferred Plan, the model's selection of natural gas capacity additions have adjusted. While a Sherco boiler conversion was considered in our October Reply Comments, it was not selected in our Current Preferred Plan for reasons discussed in Attachment B. Of note, the retirement of the Sherco units result in the need for additional CT capacity and the addition of a combined cycle in 2027.

B. Renewable Energy Standard Compliance Position

Our Current Preferred Plan continues to support and exceed our compliance through 2030 with the Renewable Energy Standard (RES) and objectives across the NSP

system that we presented in our January 2015 filing. Minnesota's RES requires the Company to generate or procure 30 percent of retail electric sales from renewable sources by 2020.[3] This scenario assumes the 3,900 MW of renewable energy additions laid out in our Current Preferred Plan and includes: 700 MW of small solar, 1,400 MW of large solar, and 1,800 MW of wind. Table 4 below details our compliance position through the generation of Renewable Energy Credits (RECs) with NSP System RES obligations in 2016 and 2020.

Table 4: Renewable Energy Standard Compliance, Current Preferred Plan

	2016	2020
NSP Calendar Year RECs	11,216,449	17,274,331
NSP RECs Available for Compliance	26,887,161	55,532,748
RECs Needed for Compliance	8,833,247	10,917,122

In our Current Preferred Plan, we expect to generate sufficient RECs to exceed the renewable energy obligations of those states in the NSP system.

C. Solar Energy Standard Compliance Position

The SES requires an additional 1.5 percent of retail sales to come from solar energy resources by 2020. Of the 1.5 percent SES, 10 percent must come from systems with capacity less than 20 kW.

Table 5: Solar Base Case

	2020
S-RECs Needed for SES Compliance	453,483
S-RECs Available to Meet Requirement	4,620,918
Total Compliance Energy	1,396,551

Table 5 above demonstrates that in our Current Preferred Plan, the 1,400 MW of additional utility-scale solar energy in the out-years of the planning period combined with the small solar and community gardens additions take us beyond our SES compliance obligations, and put us on a path toward fulfillment of Minnesota's energy policy vision.

[3] Minn. Stat. § 216B.1691.

Examining the Grid Impacts of Retiring Sherco Units 1 and/or 2

A Grid Primer and Summary Report of:

Midcontinent Independent System Operator (MISO) Attachment Y2 Study performed by: MISO (August 28, 2015)

Xcel Energy Transmission Reliability Study performed by: Xcel Energy Transmission Planning in conjunction with Siemens Power Technologies International (January 22, 2016)

Black Start Plan Analysis performed by: Xcel Energy Realtime Transmission Planning

January 29, 2016

This is designed to help prevent key information about our system and the grid from being accessible.

Contains Non-Public Information:
The Company developed this grid primer and summary report in an effort to provide a public report of its technical analyses and conclusions as they relate to the potential retirement of its Sherburne County Generating Plant (Sherco) Units 1 and 2. The reports and analyses themselves contain critical electrical infrastructure information (CEII) and other highly-sensitive information about the Xcel Energy and other regional transmission owner systems, so are entirely not public. We maintain that the partially-redacted study reports are "security information" as defined by Minn. Stat. § 13.37, subd. 1(a). We have also redacted limited portions of this summary report. We take seriously our responsibility to maintain the security of the information and systems involved in the delivery of safe, reliable energy to our customers. A key tenet of our security program is limiting the extent to which sensitive information is accessed or shared. This is designed to help prevent key information about our system and the grid from being accessible. While we are not providing full Attachment Y2 and Siemens study reports available with this filing, we are open to discussing the specifics of the reports with parties to this docket who have signed a supplementary Non-Disclosure Agreement, provided that the information would remain adequately protected. Alternatively, the Company will make the full study reports available for inspection by Xcel Energy regulators who have fulfilled MISO's CEII requirements and will also consider making them available to certain other parties to the proceeding who have fulfilled MISO's CEII requirements and Xcel Energy's supplementary non-disclosure requirements. We provide a full justification of our non-public treatment of this information in the cover letter accompanying our January 29, 2016 Resource Plan Supplement.

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I. INTRODUCTION

Xcel Energy initiated three technical studies to examine the transmission reliability impacts of its Sherburne County Generating Plant (Sherco) Units 1 and/or 2 if they were to cease operations: (1) a *Midcontinent Independent System Operator (MISO) Attachment Y2 Study*; (2) an *Xcel Energy Transmission Reliability Study*, performed in conjunction with Siemens Power Technologies International (Siemens); and (3) a *Black Start Plan Analysis*. The Company's conclusions from these studies is that: (1) ceasing operation of Sherco Units 1 and 2 would create system conditions that require mitigation; and (2) siting dispatchable, thermal generation at the Sherco site is the most cost-effective solution and provides the greatest level of certainty in terms of cost and reliability to meet the Company's energy and capacity requirements, maintain reliability for its customers, and support the Company's vision of a clean energy future.

The electric "grid" is a large complex machine consisting of generation and transmission facilities that operates across a very large geographic area. The NSP System is part of the Eastern Interconnection, which connects the electrical grids from the Rocky Mountains to the East Coast, and from Canada to the Gulf of Mexico. This interconnected network of generating resources and transmission infrastructure works together to seamlessly respond and adjust to dynamic and sometimes adverse circumstances to provide an adequate and reliable supply of electricity to customers. Each resource and system component plays a unique role based on its size, type and location on the system – and because the grid is so integrated, generation changes made to one utility's system can impact other portions of the system.

The Sherco Plant is the largest power station in the Midwest, consisting of three units that have a total generating capacity of 2,250 MW. Units 1 and 2 that are a focus in the 2016-2030 Resource Plan are wholly-owned baseload facilities with generating capacity of approximately 700 MW each for a total of approximately 1,400 MW. Both the Company's Sherco Plant and Monticello Nuclear Plant are located in Sherburne County Minnesota, making the location of these large, baseload generating facilities a very important consideration in maintaining system stability and reliability. Together, these plants total nearly 3,000 MW of generating capacity, or approximately 30 percent of the Company's total existing generating capacity.[1]

With the concentration of so much generation in one geographic area, the electrical

[1] Generating capacities are expressed as MISO Unforced Capacity (UCAP) values. Values for the Sherco Plant include both the Xcel Energy and the SMMPA ownership shares of Sherco Unit 3.

performance of the regional transmission system – and the entire mix of resources on the NSP System – is fundamentally designed around these Units. At its core, to preserve system stability and customer reliability the system must balance generation with changing load conditions and fluctuations caused by other disturbances. Large generating units like Sherco Units 1 and 2 afford the capability for the system to "ride through" these frequency disturbances by virtue of their sheer mass. Without the inertia, or resistance to a change in state of motion, afforded by these large units, system stability could be compromised.

Similarly, the frequency regulation of the transmission system is governed by the connected generating units. If system frequency deviates beyond allowable levels, protective devices will disconnect generation and/or customer load from the rest of the system. These disconnections can further exacerbate any imbalance between load and generation, which may cause further disconnections and shedding of load. Sherco Units 1 and 2 provide the spinning mass that assists in maintaining the 60 hertz (Hz) frequency for the region. They are uniquely able to do this because of their size and operating characteristics, which include the ability to quickly increase or decrease their output in response to system conditions. Therefore, potentially ceasing coal operations of one or both Sherco Units 1 and 2 as we have proposed in our Current Preferred Plan must consider more than replacement of the capacity and energy they provide to our customers.

When performing technical studies, we simulate a number of varied conditions that can consider changes in customer loads, projected changes to the generation mix, and ways to use the transmission system most efficiently. The studies generally analyze the way power flows over the grid, and search for places where the system might overload or fail, assuming specific circumstances. We measure these results against North American Electric Reliability Corporation (NERC) requirements.[2] NERC is designated by the Federal Energy Regulatory Commission as the Electric Reliability Organization, which is the independent entity that develops and enforces mandatory standards for the reliable operation and planning of the bulk-power system throughout North America, as called for in the Energy Policy Act of 2005.

NERC defines a reliable bulk-power system as one that is able to meet the electricity needs of end-use customers even when unexpected equipment failures or other factors reduce the amount of available electricity, and divides reliability into two categories:[3]

[2] We provide an abbreviated list of NERC Event Categories in Table 13 in Section IV.C.3 of this Summary Report.
[3] http://www.nerc.com/AboutNERC/Documents/NERC%20FAQs%20AUG13.pdf

- *Adequacy*. Adequacy means having sufficient resources to provide customers with a continuous supply of electricity at the proper voltage and frequency, virtually all of the time. Maintaining adequacy requires system operators and planners to take into account scheduled and reasonably expected unscheduled outages of equipment, while maintaining a constant balance between supply and demand.
- *Security*. For decades, NERC and the bulk power industry defined system security as the ability of the bulk-power system to withstand sudden, unexpected disturbances, such as short circuits or unanticipated loss of system elements due to natural causes. In today's world, the security focus of NERC and the industry has expanded to include withstanding disturbances caused by manmade physical or cyber attacks. The bulk-power system must be planned, designed, built and operated in a manner that takes into account these modern threats, as well as more traditional risks to security.

NERC additionally authorizes regional entities, which in the Upper Midwest is the Midwest Reliability Organization. Also a regional entity MISO is an independent, not-for-profit company authorized by FERC to provide open-access transmission service, operate the transmission grid, administrate a wholesale energy market, and perform regional transmission planning in 15 states throughout the Midwest and Southern United States, and Manitoba, Canada.[4] MISO is also the Regional Transmission Organization that ensures electric reliability and optimizes supply and demand bids for wholesale electric power in their region. The Xcel Energy operating companies that comprise the NSP System (Northern States Power Company-Minnesota and Northern States Power Company-Wisconsin) are signatories to the MISO Transmission Owners Agreement and are therefore members of MISO and thus subject to MISO Tariffs and requirements.

The three studies we initiated examined differing aspects of potentially retiring Sherco Units 1 and 2, as follows:

MISO Attachment Y2 Study. The MISO Tariff requires that any generation retirement be studied and approved by MISO to ensure that it results in no adverse effects to the reliability of the system. Therefore, the focus of this Study was on the impacts to the grid if one or both of Sherco Units 1 and 2 ceased operation. We initiated a Study

[4] Independent System Operators grew out of FERC Orders Nos. 888/889 where FERC suggested the concept of an Independent System Operator as one way for existing tight power pools to satisfy the requirement of providing non-discriminatory access to transmission. Subsequently, in Order No. 2000, FERC encouraged the voluntary formation of Regional Transmission Organizations to administer the transmission grid on a regional basis throughout North America (including Canada).

under Attachment Y2 of the MISO Tariff, which is a non-binding, informational study. The Y2 Study is intended to determine whether it is likely that the system resource would qualify as a System Support Resource (SSR) in conjunction with an Attachment Y Study, which is a final, binding study that must be conducted under the MISO tariff once a retirement date-certain is determined.[5]

The MISO Y2 Study concluded that retirement of Sherco Units 1 and 2 would result in violations of applicable planning criteria that would require transmission upgrades and the need for the Units to be designated as SSRs. Assuming a future Attachment Y study would have similar results, MISO would require that the identified violations be mitigated to its satisfaction prior to retirement of Sherco Unit 1 and Unit 2, if replacement generation is not located at Sherco.[6]

The Study found that retirement of both units would result in a major reactive power deficiency in the Monticello area that would cause a violation of Monticello's Nuclear Plant Interface Requirements (NPIR) voltage requirements that would be a violation of Monticello's Nuclear Plant Operating Agreement.[7] The plant would not be allowed to operate if the voltage falls below its NPIR minimum threshold. The Study also identified a number of other reliability issues, including thermal overloads of 115 kV and 345 kV transmission lines and some smaller scale voltage deficiencies.

Xcel Energy Transmission Reliability Study. We retained Siemens to study the effects of potential retirement of one or both Sherco Units on the transmission system, and technical implications and upgrade costs associated replacement of one or both Units at alternate locations on the NSP System. Our Study used the same system models as MISO used for its Y2 Study, but differed in that the Y2 Study did not examine replacement of all or a portion of Unit 1 and 2 generation. Our Reliability Study also set out to examine the potential impacts from the cumulative effect of additional larger generation unit retirements on the NSP System by also studying the shutdowns of the Monticello Nuclear Plant due to its proximate location to Sherco, and one Prairie Island Unit in combination with Sherco Units 1 and 2. We decided however to pause this work, in light of the increased interest in the future of our nuclear

[5] Per Section 38.2.7 of the MISO Open Access Transmission, Energy, and Operating Reserve Markets tariff.
[6] MISO has proposed tariff changes to the Attachment Y notification process that could make such Notice unnecessary. If a generating unit is being replaced with an equal- or larger-sized (MW) unit, an Attachment Y notice would not be required; only an Interconnection request for the new unit utilizing the existing interconnection rights would be required. An SSR study under Attachment Y of MISO's tariff would only be required if the new/replacement generating unit is smaller (MW) than the unit being retired.
[7] The Monticello Nuclear Plant, along with all nuclear plants in the United States have NPIR voltage requirements that are required to support FERC/NERC Regulation NUC-001. NUC-001 requires coordination between nuclear plant operators and transmission entities for the purpose of ensuring safe nuclear plant operation and shutdown.

units. As we discuss in Section VII of our January 29, 2016 Resource Plan Supplement, we intend to initiate a more broad and in-depth study of the effects of a potential shutdown of our nuclear units on our transmission system in 2016.

Our Reliability Study involved a full thermal analysis, full voltage analysis, and transient stability analysis, and confirmed that the existing transmission system with significant generation injection at Sherco works well, and plays a significant role in providing reliable service for NSP System customers and other customers in our portion of the MISO region. It also concluded that there are transmission upgrade costs and other trade-offs associated with replacing Sherco Units 1 and 2 at an alternative location, such as increased energy losses the farther the replacement generation is located from the Twin Cities load center.

Black Start Plan Analysis. A Black Start Plan specifies the process of restoring the grid to full operation without relying on the external transmission network following a full- or partial-black out. Black Start Plans are required by NERC, developed in concert with neighboring utilities, and are subject to review and approval by MISO. Sherco Units 1 and 2 are currently the primary Target Units, or first generating units to be repowered as part of our Black Start Plan. This analysis examined the viability and costs associated with changing the current system restoration path from Sherco Units 1 and 2.

Our Black Start Plan analysis concluded that without the current Sherco Unit 1 and 2 restoration path from our Initial Unit(s), we would need to rely on different restoration paths to multiple Target Units.[8] We will need additional facilities on the alternative restoration paths and altering our path causes restoration of our system and customer load to take longer. The expediency of the restoration path is particularly important in winter/cold weather, because a delay of as little as one hour could mean that we may have to begin draining our boiler systems or taking additional measures at our steam generating plants before they freeze and are damaged. If this is necessary, restarting those plants could take several days, which could impact restoration of our customers.

It is important to note that the assumptions used in these studies are based on expected conditions at the time they were initiated in early 2015. The system is dynamic and expected conditions can change when new generation comes online, new transmission lines are constructed, or existing lines are reconfigured.

[8] The Initial Unit is the first generating unit that sets restoration in motion. Target Units are the generating Units on the restoration path that was started by the Initial Unit.

We believe a combination of EPA's Clean Power Plan along with aging generation assets will significantly change the generation mix in the United States over the next 15 years. Not only have we started to perform studies to understand the potential impact of significant generation changes, the industry is also beginning to examine the potential impacts of a changing generation mix. Entities such as NERC and MISO are beginning to study the potential cumulative impacts of significant generation changes across the country.[9]

We have many years ahead of us to try to simulate and understand the cumulative effect of a different mix of generating units. We know what we have today works well, and to the extent replacement generation is located in similar electrical locations, we are confident the grid will continue to perform well.

II. CURRENT SYSTEM/GRID

A. Overview

The "grid" is a large complex machine consisting of existing generation and transmission facilities that operates across a very large area. The NSP System is part of the Eastern Interconnection, which connects the electrical grids from the Rocky Mountains to the East Coast and from Canada to the Gulf of Mexico.

The Twin Cities metro area is surrounded by a double circuit 345 kV *bulk* transmission system that extends from Benton County in the north, east to Chisago County, south to Dakota County, west to Scott County, and back north to Becker, Minnesota. This 600 mile ring of 345 kV lines encompassing nearly 1,300 square miles forms the backbone of the bulk transmission system feeding the Twin Cities load center. This 345 kV ring is connected through several bulk 345 kV lines tying to our neighboring utilities, and a 500 kV bulk transmission line to Manitoba Hydro in the north. These tie-lines connect the Twin Cities load center to the MISO generation market and the Eastern Interconnection – providing important "back-up," should there be an unexpected event that requires the Company to rely on the grid to maintain reliability for our customers.

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[9] *See* NERC Potential Reliability Impacts of EPA's Proposed Clean Power Plan (Phase I) at: http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Potential%20Reliability%20Impacts%20of%20EPA%E2%80%99s%20Proposed%20Clean%20Power%20Plan%20-%20Phase%20I.pdf and MISO Analysis of EPA's Final Clean Power Plan Study Scope (November 2015) at: https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/PAC/2015/20151111/20151111%20PAC%20Item%2003e%20Clean%20Power%20Plan%20Final%20Rule%20Analysis%20Scope.pdf

The 345 kV ring that surrounds the Twin Cities feeds the underlying Twin Cities 115 kV transmission grid, which connects to our low voltage distribution system that delivers the power directly to businesses, houses and other loads. The transmission system and the lower voltage distribution system in the Twin Cities area has developed over the past 100 years to serve the growing area, and is constantly being analyzed and updated to ensure optimal and reliable power delivery.

Our bulk transmission system is anchored at the corners by several large coal and nuclear generators that act as the baseload generation for the NSP System. They include Sherco (coal) and Monticello (nuclear) in the northwest and A. S. King (coal) and Prairie Island (nuclear) in the east and southeast. Together these plants provide over 4,020 MW of capacity and over 29,000 GWh of energy to our customers, which represents 46 percent of the NSP System generating capacity and 65 percent of the system energy. This generation is supplemented by several natural gas generating plants located on the 115 kV system in the Twin Cities. These generating units include Riverside, Highbridge, Black Dog, and Blue Lake. The 500 kV line that ties into Chisago County substation in the northeast connects the hydro power produced by Manitoba Hydro to the Twin Cities load center. A significant proportion of our wind power is located in southwest Minnesota and is tied into the Twin Cities through a number of lines developed over a period of years to connect the wind-rich areas in southwest Minnesota and South Dakota to the Twin Cities load center. A robust transmission system such as this facilitates the provision of reliable, low cost power to our customers from a diverse mix of generation resources, and mitigates risk from catastrophic events.

The existing grid is a valuable asset and an enabler that has and will continue to support the evolution and growth of our system. The grid has facilitated integration of substantial wind generation onto the NSP System by absorbing the inherent fluctuations of this variable generation type over a large area. Transmission enables the transfer of wind and solar and other types of generation from where it is most effectively located to customer load located elsewhere where it can be utilized to the fullest extent.

Over time, we expect that there will be more and more development of microgrids and other new technologies such as batteries. Rather than competing with the existing grid, these new technologies will be complementary, in that each system can support and help the other. For example, to the extent microgrids have challenges, the grid can help provide reliability to those areas – and as microgrids develop over time, there will be more and more integration of the capabilities they can provide into grid operations.

B. Key Elements Ensure Reliable Service

Electrical system reliability can be defined as the ability of the electrical grid, which includes transmission, generation, distribution and related components, to serve customer load under any system condition. Maintaining a reliable electricity supply for customers requires that generation, load and electrical losses balance – and maintain a 60 Hz frequency. If the frequency varies only one or two tenths of a hertz from 60 Hz, it can cause damage to equipment, and automated protection schemes will disconnect pieces of the grid to avoid damaging equipment.

A strong transmission system improves the reliability of the electric power system, and facilitates a diverse and low cost resource portfolio for customers – allowing lower cost resources with diverse fuel types, and resource types not available in the immediate area to be efficiently transported to serve their needs. For example, wind resources need to be constructed where the wind is strongest and most consistent; large-scale solar resources where there is sufficient land and the most consistent sunshine – both of which are generally away from large population centers. A robust transmission system brings together varied generating units – some built to run continually, others only to run at peak times when they are most needed, and renewable resources on an intermittent basis – together into an integrated grid.

The system must also be able to facilitate both "active" and "reactive" power, which are typically produced by non-renewable generating unit types. Active power, measured in watts, is the form of electricity that powers equipment. Reactive power, measured in volt-amperes reactive (VARs), is the energy supplied to create or be stored in electric or magnetic fields in and around electrical equipment. Reactive power is particularly important for equipment that relies on magnetic fields for the production of induced electric currents (e.g., motors, transformers, pumps and air conditioning). Reactive power can be transmitted only over relatively short distances, and thus must be supplied as needed from nearby generators. If reactive power cannot be supplied promptly and in sufficient quantity, voltages deteriorate and, in extreme cases, can result in a voltage collapse.

The grid must also be able to adjust to changing customer loads, the availability of diverse resources, and have sufficient redundancy built-in, making it capable to withstand the failure of its most critical lines, generators, or other components. As customer load changes over the course of a day, generation must change to accommodate the load at any given time. With the high penetration of renewables on the NSP System, we must ensure that we have adequate dispatchable generation to

both accommodate the load and whatever generation mix we have at each point in time. We must also maintain a spinning reserve – generation that is available at a moment's notice – to account for the largest contingency in the area.[10] Having large coal generating units has helped, because they have the ability to be "turned up" and "turned down" based on the level of renewable generation being delivered to the system at any given time.

C. Role of Sherco Units 1 and 2

Sherco Units 1 and 2, located in Becker, Minnesota play an important role in the reliable electrical service we provide to our customers. Together, they produce approximately 1,400 MW of capacity and associated energy, and are tied to the transmission grid through five 345 kV and two 115 kV lines.

As we have discussed, the ability to provide reliable electric service depends on a complex and interconnected network of generating resources and transmission infrastructure that provides capacity and delivers energy to customers. Each resource and system component in the network plays a unique role based on its size, type and location on the system. Sherco Units 1 and 2 are no different. In fact, the Upper Midwest system, and the NSP System, has been designed around Sherco Units 1 and 2, and relies on the unique aspects of these Units to not only generate capacity and energy for our customers, but also to provide numerous essential system operational services.

Potentially ceasing coal operations of one or both of these Units must consider more than replacement of their energy output. The Units' technical characteristics include:

- *Power Deliverability.* The existing transmission system has been developed to be able to receive the approximately 1,400 MW of power injected from Sherco Units 1 and 2 and to deliver it to various area substations to meet the electrical power demands of customers. This power deliverability capability is often referred to as "transfer capability" or "thermal limits" of the system. Transmission systems are made capable of receiving and moving power from specific generators at specific locations; changing generator characteristics or locations requires corresponding changes to grid capabilities.
- *Dynamic Stability.* The transmission grid is a vast interconnected machine with many parts. There are a mix of large and small gears in this machine, all spinning at the same rate (i.e. synchronous), simultaneously producing and

[10] Spinning Reserve is unloaded operating capacity available on units connected to and synchronized with the interconnected electric system and ready to take load immediately in response to a frequency deviation.

delivering electricity to customers. Generating units are the spinning gears in this machine. Large generators like Sherco Units 1 and 2 have large spinning shafts that provide a strong backbone for the machine's operation. With enough of these big "gears" spinning, the machine can stay electrically stable and continue operating without interruption when small gears drop in and out of operation (like when the wind stops blowing or sun stops shining), or when another big gear drops out, or a "contingency," happens to some part of the machine. These large gears are also more likely to stay connected to the grid during a contingency than the small gears because large rotating masses have more inertia and are therefore not as easily jarred, or disrupted by a disturbance. Having the large gears in place also enables more small gears to be connected to the machine because they don't have as much impact with the large gears in place. The large generating units thus provide "dynamic stability" to the grid.

- *Fault Current.* Large synchronous generating units provide "fault current," which is necessary for the system protection equipment to function properly. If the system has too little fault current, it is difficult for system protection systems to differentiate customer load from an electric fault, which could cause the protection system to not function properly.[11] The protection system is the overarching electrical monitoring scheme that assesses the real time condition of the transmission grid and acts to prevent damage to system components and prevent cascading failures. The large generating units operating today are important sources of fault current, and the protection system and existing deployed assets rely on sufficient fault current for the protection system and other electrical facilities to work as designed. Many of the electric devices that are deployed on the grid and in service today, such as wind generators and other assets, are engineered and designed to function properly with the amount of fault current that has been historically available on the grid. Therefore, changing the amount of fault current on the grid could not only impact protection systems, but could also impact other electric assets.
- *Black Start Capability.* In the event of a major regional grid outage, Sherco Units 1 and 2 are an integral resource to restoring power to the electrical grid, or "restarting the machine." Only dispatchable generating units of a certain size that are capable of creating and absorbing reactive power are eligible to perform black start functions. Our current plan requires Initial Unit(s) of approximately 110 MW and up to 300 MW to get the restoration started. Sherco Units 1 and 2, because of their ability to operate at lower outputs, along with their reactive capabilities, are considered eligible Target Units, which are

[11] For example, the protective equipment could misinterpret the load as a fault, and de-energize an unfaulted circuit.

the next units used in the restoration. Sherco Unit 3 is not a viable Target Unit, because it is too large for the Initial Unit(s) to start, so is started later in the process. Additionally, nuclear units are not viable Target Units, because they cannot vary their output and can only come online after the system is fully stable. Renewable generation, such as solar and wind are not currently considered eligible Target Units due to their inherent intermittent nature, and their inability to provide or absorb reactive power.

- *Voltage Support.* The real time conditions on the transmission system are constantly changing and require ongoing adjustments to maintain voltages at required levels. The Sherco 1 and 2 Units, as large synchronous power sources, provide significant system voltage support along with necessary "reactive power." Reactive power is required to start and run motors, like in air conditioners and industrial equipment (called "inductive loads"). Large population centers generally require large generating units located reasonably nearby to support system voltage effectively. As in the dynamic stability discussion, without enough large units in place, the machine isn't as capable and robust when it runs.

- *System Regulation.* System regulation essentially means the ability of the system to respond instantly to changes in usage, i.e. keeping the generators and loads exactly matched at all times. Sherco Units 1 and 2 have the electrical characteristics to provide this fast response balancing in real time. The system frequency, required to be maintained at 60 Hz in the US grid, is an active measure of this balance. When there are sudden large changes to the generation/load balance, as when a generating unit drops offline or a large industrial load (like a smelter) comes online, the frequency drops if there is insufficient regulation capability on the system. This is another aspect of the dynamic stability of the system.

III. TECHNICAL STUDIES OVERVIEW

As we have discussed, the grid is a complex machine that is integrated over very large portions of the country. The bulk and load serving NSP System has been developed over the past 100 years to serve the growing area, and is constantly being analyzed to ensure optimal and reliable power delivery. We have a great deal of experience both in studying the existing grid and operating it in many varying conditions (during high load, low load, high transfers, low transfers, storm conditions, outages or equipment).

When performing technical studies, we simulate a number of varied conditions that can consider changes in customer loads, projected changes to the generation mix, and

ways to use the transmission system most efficiently. The studies generally analyze the way power flows over the grid and search for places where the system might overload or fail, assuming specific circumstances. While studies are essential and provide important insights, our decades of operating and studying the existing system provides valuable insights and perspective in siting considerations for replacing Sherco Unit 1 and 2 generation.

We have stated previously that our initial assessment was that completely replacing the baseload energy from Sherco Units 1 and 2 with renewable energy facilities was likely infeasible from a reliability perspective. Our Studies support the conclusion that the addition of dispatchable, thermal generation at the Sherco site will ensure ongoing reliability of the NSP System for our customers in the most cost-effective manner. Having sufficient dispatchable generation on the system also supports the addition of the significant levels of renewable generation we propose with this Resource Plan.

We are confident that generation injections in locations where those electrical injections occur today will result in a high level of reliability and good performance from our transmission system. With that said, we have proposed to replace a portion of Sherco Units 1 and 2 energy and capacity with a natural gas combined cycle (CC) at the Sherco site. We believe this proposal is superior to alternatives, will provide necessary voltage support to the Monticello Nuclear Plant and surrounding area, and is cost-effective for our customers.

We note that the MISO Y2 Study and our Reliability Study identify transmission upgrades necessary to resolve the respective issues the studies identified. In addition to these transmission upgrades, there are additional (interconnection) transmission costs involved to connect generation to the grid. Therefore, to get a full picture of the costs, interconnection costs must to be added to the transmission upgrade costs.

A. Studies Performed

As outlined previously, we initiated three studies to understand the technical implications and to identify any mitigating measures that must be undertaken, as follows:

- *MISO Y2 Study*,
- *Xcel Energy Transmission Reliability Study,* and
- *Black Start Study*.

Our Studies used the best information available at the time they were initiated to develop the models used to conduct the analyses; MISO performed its Y2 Study in

accordance with their Business Practice Manuals.[12] However, all studies are essentially an attempt to predict what is going to happen in the future – and the conditions and underlying assumptions of a dynamic system are subject to change. Therefore, there are inherent limitations in any study effort.

B. MISO Attachment Y2 Study

1. Overview

As we discussed in our October 2, 2015 Reply Comments, we initiated a MISO Attachment Y2 Study to examine the reliability impacts from the potential retirement of one or both Sherco Units 1 and 2. The Y2 Study is intended to determine whether it is likely that the system resource would qualify as a System Support Resource (SSR) in conjunction with an Attachment Y Study, which is a final, binding study that must be conducted under the MISO tariff once a generation owner determines a retirement date-certain. The study impacts are measured based on the criteria set forth in the MISO Business Practices Manuals, which apply NERC requirements, and include monitoring and identifying the steady state branch/voltage violations and the transient stability violations on transmission facilities due to the unavailability of the generating resources.

The Company's request was for MISO to analyze retirement of Sherco Units 1 and 2 under two retirement scenarios: (1) retire Sherco Unit 1 and Sherco Unit 2 on May 31, 2021; and (2) retire Sherco Unit 2 on May 31, 2021 and Sherco Unit 1 on May 31, 2024. Because Sherco Units 1, 2, and 3 (in addition to Monticello) are the largest reactive power resources in the Twin Cities area, MISO specifically assessed the voltage implications under certain power transfer scenarios if all of these plants were out of service. Finally, due to the electrical proximity between the Monticello Nuclear Plant and Sherco, MISO assessed the voltages at Monticello's 115 kV and 345 kV busses to ensure they remained within the very specific and narrow range specified in Monticello's NPIR.

2. Study Results

The MISO Y2 Study concluded that ceasing operations at Sherco Units 1 and 2 would create system conditions that violate NERC requirements that would require transmission upgrades and the need for the Units to be designated as SSRs.

[12] *See* MISO Business Practice Manual BPM-020 at: https://www.misoenergy.org/Library/BusinessPracticesManuals/Pages/BusinessPracticesManuals.aspx

Assuming a future Attachment Y study would have similar results, MISO would require that the Company mitigate identified violations to its satisfaction prior to retirement of Sherco Unit 1 and Unit 2, if replacement generation is not located at Sherco.

At a high level, the MISO Y2 Study identified several voltage violations due to a substantial reactive power deficiency in the Monticello area that is a major concern and needs to be addressed to maintain voltages at Monticello Nuclear Plant within its permissible range. The Monticello Nuclear Plant cannot operate if its voltage is outside the permissible range. If only one Sherco Unit retires and the other Unit remains in service, the analysis identified a smaller reactive power deficiency that would need to be addressed, and some other relatively minor reliability issues that can be addressed by minor equipment installations such as capacitors.

The MISO Y2 Study also identified thermal violations (transmission lines above their rated capability) created when replacement generation was dispatched from others areas of the MISO system. For example, a rebuild of a 345 kV line to 3,000 Amperes was an identified action that would be needed to alleviate some identified thermal violations. With regard to system stability, the transient stability assessment showed acceptable behavior without Sherco Units 1 and 2.

The specific Study conclusions that require mitigation are as follows:

- Several voltage violations due to a reactive power deficiency in the area that violate Monticello's NPIR voltage requirements, would be a violation of Monticello's Nuclear Plant Operating Agreement, and would require the plant to cease operation until the voltage is within the NPIR range,
- A 25 MVAR capacitor bank would need to be installed in 2017 at WMU-Priam 115 kV bus to alleviate local voltage issues. (*Note*: this is existing MISO MTEP Project 4380, so will not result in incremental cost to the Company),
- A capacitor bank(s) would be needed at the 115 kV bus of a generating station to maintain the voltage above their minimum voltage requirements,
- The rebuild of a 345 kV line to 3,000 Amperes to alleviate a portion of the identified thermal violations,
- A 115 kV line may also need to be rebuilt to alleviate other thermal issues per the SSR criteria, and
- Voltages at Monticello's 115 kV and 345 kV buses are lower than the plant's voltage requirements.

We note that the CC generating unit we have proposed for the Sherco site would fully resolve these issues.

3. Mitigation of Identified Issues

The CC generating unit we have proposed for the Sherco site is our preferred option for mitigating the violations identified in the MISO Y2 Study. However, in the alternative, MISO identified potential ways to mitigate the identified impacts, which we estimate would cost approximately **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** in capital, plus significant ongoing operating and maintenance costs to mitigate. We outline these measures in Table 1 below, and also discuss the Synchronous Condenser, which at approximately **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** in capital, is the most significant of the mitigating measures.

Table 1: MISO Potential Mitigation Measures and Xcel Energy Estimated Cost ($Millions – 2015)

MISO Identified Potential Mitigation Measure	**Xcel Energy Potential Mitigation Measure and Estimated Cost**
Reductions and runbacks to existing generators	None
Transfer of certain feeder loads	None
Tripping of certain transmission lines	None
Install reactive capacity on system to maintain voltages at Monticello Nuclear Plant within permissible range as per the Monticello NPIR	Convert Sherco Unit 1 or Unit 2 to a Synchronous Condenser – **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]**
Install Proposed Project including a 25 MVAR capacitor bank to be installed at substation in 2017 *(already planned)*	No incremental cost to Company
An MTEP project addresses the 115kV system voltage issues resulting from events *(already planned)*	No incremental cost to Company
Increase capacity of a 115 kV line	Rebuild the line – **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]**
Install capacitor banks at generator station 115 kV bus.	Install capacitor bank(s) & upgrade substation – **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]**
Rebuild of 345 kV line to 3000 Amperes is needed to alleviate some identified thermal violations	Rebuild the line – **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]**

Synchronous Condenser – As we have described, large generators play a very important role on the system, one of which is providing necessary reactive power to the grid. If reactive power cannot be supplied promptly and in sufficient quantity, maintaining voltage is challenging, which is the case with Monticello's NPIR. Therefore, if no replacement generation is installed at Sherco, we would need to install other equipment that can both generate and absorb reactive power as needed to adjust the grid's voltage. Sherco would be a good location for this other equipment because reactive power can only be practically transmitted over relatively short distances.

There are currently three available options to address this issue: (1) a Synchronous Condenser (SC); (2) a Static Var Compensator (SVC); or (3) a Static synchronous compensator (Statcom). Considering the three alternatives, we believe the best option for the NSP System is to convert Sherco Unit 1 or Unit 2 to an SC. Installation and operation of an SC is identical to large electric motors and generators. It is controlled by a voltage regulator to either generate or absorb reactive power as needed to adjust the grid's voltage, or to improve power factor. Its principal advantage is the ease with which the amount of correction can be adjusted. However, importantly, SCs provide not only the required continuous range of voltage support, but are also a rotating mass that helps hold the grid electrically together following a disturbance such as a major fault. As we have described, there are significant system stability benefits associated with the inertia provided by large rotating masses.

As a point of reference, an SVC is a set of electrical devices for providing fast-acting reactive power. Unlike an SC, which is a rotating electrical machine, an SVC has no significant moving parts (other than internal switchgear). The main advantage of SVCs over simple mechanically-switched compensation schemes is their near-instantaneous response to changes in the system voltage. Similarly, a Statcom is a regulating device that can either provide or absorb reactive power. It is inherently modular and has better characteristics than an SVC. In contrast to an SVC, its maximum reactive output current will not be affected by the voltage magnitude, whereas the SVC's reactive output is proportional to the square of the voltage magnitude, which makes the provided reactive power decrease rapidly when voltage decreases, thus reducing its stability. In addition, the speed of response of a Statcom is faster than that of an SVC and its harmonic emission is lower. Statcoms typically exhibit higher losses and are generally more expensive than SVCs, so are not in widespread use.

Both SVCs and Statcoms are generally less expensive than SCs, however, neither offers the significant stability benefits that come from having large, rotating mass around our system – and both introduce harmonics into the grid. In general, harmonics cause power quality problems, and result in increased heating in equipment

and conductors, misfiring in variable speed drives, and torque pulsations in motors, which would potentially affect both our equipment and that of our customers. Additionally, there are other electronic devices on the system, such as the D.C. terminal in the western Twin Cities that has electronic equipment that can be negatively impacted by harmonics. For these reasons, we have determined the SC is the best solution for the NSP System.

4. Summary

We note that these results are based on assumptions and the MISO system as it was known in March 2015. We believe it is reasonable to conclude that the MISO Y2 Study results could be viewed as optimistic, since other generators assumed to be running at the time of this study will likely be different than when MISO performs their official Attachment Y analysis, which is currently required in the 26-week period preceding an actual planned Unit retirement.[13]

We are confident, however, that regardless of the status of other generators in the MISO system, the natural gas CC we have proposed to construct at the Sherco site in 2026 is the best solution to mitigate any technical issues associated with retiring Sherco Units 1 and 2.[14] As we have discussed, a large generator plays a very important role on the system, in terms of providing necessary reactive power and maintaining its voltage, frequency and overall stability. For the reasons we have discussed, by placing a large generator at the same injection point on the transmission system, we have absolute confidence that the system will function as well as it does today.

Placing a large generating unit at Sherco will handle the inevitable disturbances the grid successfully deals with every day, which range from ever-changing electric use (i.e., as people/businesses turn on and off electrical equipment), periodic changes to power transfers as electric markets dispatch generation every five minutes, to periodic outages (planned or unplanned), to adverse weather, and other impacts caused by humans, animals, trees, etc.

We discuss the MISO Y2 Study approach, assumptions and inputs in Section IV. below.

[13] As noted previously, MISO is contemplating changes to its Attachment Y requirements.
[14] The MISO Y2 Study identified minor issues related to retirement of the first Unit, which we believe can be resolved without the need for significant upgrades.

C. Xcel Energy Transmission Reliability Study

In early 2015, we engaged Siemens Power Technologies International to gain technical insights as to the local and regional transmission impacts of ceasing coal operations at Sherco Units 1 and 2. The study consisted of two components: (1) analyze alternative locations for replacement generation for Sherco Units 1 and 2, and (2) identify deficiencies in ensuring ongoing reliable energy delivery to our Upper Midwest customers by performing a full technical analysis of the impacts of retiring significant baseload generation from our system and determine potential long-term solutions.

We conducted our Reliability Study in phases: (1) Retirement of one of the Sherco Units 1 and 2; and (2) Retirement of both Sherco Units 1 and 2. The Study included the following analysis for both local and regional transmission facility impacts and disturbances with one or both Sherco Units 1 and 2 out of service:

- *Full thermal analysis*. Thermal analysis evaluates the steady-state flows (greater than 30 seconds) on the transmission system following a disturbance and identifies transmission facilities that are outside their allowable thermal ratings. The thermal analysis also calculates system losses.
- *Full voltage analysis*. Voltage analysis evaluates the steady-state voltages (greater than 30 seconds) on the transmission system following a disturbance, and identifies transmission facilities that are outside their allowable voltage limits.
- *Transient stability*. A transient stability analysis evaluates whether the power system electrically "stays together" and the impact on the transmission system following a disturbance, and identifies transmission facilities that are outside their allowable stability limits. Specifically, we looked at the ability of the grid to maintain electrical connection following disturbances.

Our Reliability Study used the same MISO MTEP14 models as the MISO Y2 Study, adjusted to reflect the 2020 timeframe, and applied the same planning criteria. However, because the MISO Y2 and the Reliability Studies have different base input assumptions, the two studies investigate different perspectives on the issue of retiring one or two Units at Sherco. Additionally, our Reliability Study differs from the MISO Y2 Study in that the MISO Y2 Study analyzed the impacts of turning off one or both Sherco Units 1 and 2 assuming no replacement generation. Its purpose was to determine how the system would behave in the absence of these generators. Our Reliability Study also analyzed impacts on the transmission system and estimated transmission upgrade costs related to ceasing coal operations at Sherco Unit 1 and 2 *and replacing the generation* at alternate locations as follows: (1) Metro – a location near the Twin Cities; (2) Southwest – a location in southwest Minnesota; and (3) Northwest – a location in eastern North Dakota.

Our Reliability Study's conclusions were consistent with the MISO Y2 Study conclusions, in that they also identified NERC violations that would need to be mitigated if Sherco Unit 1 and 2 are retired. Specifically, we concluded:

1) Siting replacement generating units outside of Sherco is technically feasible but would require transmission system upgrades.
2) The required transmission system upgrades for replacement generation outside of Sherco is dependent on other generation that is included in the study.
3) The further the replacement generation was located from the Twin Cities load center, the greater the transmission losses.

Importantly, our Reliability Study concluded that replacement with a large generating unit that provides similar benefits to the NSP System as Sherco Units 1 and 2 will cost-effectively ensure voltage, frequency, and reliable service for our customers. Additionally, the Study in combination with other identified costs supports that replacement at the current Sherco site is superior and the most economical of the alternatives studied. Finally, our Reliability Study supports the conclusion that locating thermal replacement generation at Sherco provides the most cost certainty with regard to required transmission upgrades, since the Sherco site can utilize existing transmission facilities and interconnection rights – and the grid is constructed such to expect a large generation injection at that location.

It is important to note that our Reliability Study was initiated in early 2015. Since that time, significant amounts of generation have entered the MISO interconnection queue, so the estimated transmission mitigation costs we outline are very likely optimistic, because the generating resources that are in the queue will come online and will "use up" transmission capacity that our Study assumed would be available in the future.

1. Siting Replacement Generating Units Outside of Sherco is Technically Feasible but Would Require Transmission System Upgrades

In this section, we outline the transmission mitigation costs of locating replacement generation at studied locations other than Sherco. The Reliability Study showed that transmission mitigation costs (not including interconnection costs) increase the further away you move the generation from the Twin Cities load center.

Table 2: Estimated Costs – One 750 MW Combined Cycle Unit
($millions - 2015)

Alternate Location	Transmission Mitigation	Generation Interconnection	Total
[TRADE SECRET BEGINS…			
Metro			
Northwest			
Southwest			
			…TRADE SECRET ENDS]

Table 3: Estimated Costs – Two 750 MW Combined Cycle Units
($ millions - 2015)

Alternate Location	Transmission Mitigation	Generation Interconnection	Total
[TRADE SECRET BEGINS…			
Southwest Metro			
Northwest Metro			
Northwest Southwest			
			…TRADE SECRET ENDS]

The indicated Generator Interconnection costs in Tables 2 and 3 above are planning level estimates for the electrical facilities necessary to connect the generating plant to the Point of Interconnection (POI) and include a 345 kV substation that will accommodate a CC unit with two simple cycle turbines and one steam turbine and the 345 kV line which will connect the generator to the MISO POI. The costs vary between generator locations due to the assumed lengths of the transmission line. The generation interconnection costs also include the expected cost to expand the POI substation to accommodate the line from the generator, costs for metering and relaying and other interconnection facilities required by the MISO generation interconnection process. The basis for the costs is historical facility studies performed for other Xcel Energy generator interconnections.

2. The Required Transmission System Upgrades for Replacement Generation Outside of Sherco is Dependent on Other Generation Included in the Study

Greater amounts of generation sited at locations other than Sherco result in the need for more significant transmission upgrades (and costs) to support delivery and interconnection of the generation, as shown in Table 3 above.

3. The Further the Replacement Generation was Located From the Twin Cities Load Center, the Greater the Transmission Losses

The Reliability Study results indicate that the further from the Twin Cities load center that the replacement generation is located, the higher the losses. Tables 4 and 5 below show transmission system losses for peak load and shoulder load conditions for the alternate replacement generation location.

Table 4: Total System Losses by Replacement Location – at Peak Load
(Megawatts)

One 750 MW CC Unit			Two 750 MW CC Units		
Alternate Location	**Total MW**	**Delta MW**	**Alternate Location**	**Total MW**	**Delta MW**
Base Scenario	1,739		Base Scenario	1,738	
Southwest	1,743	4	SW Metro	1,736	-2
Northwest	1,753	14	NW+Metro	1,743	5
Metro	1,725	-14	NW+SW	1,768	29

Note: Point of peak load is during 2020 Summer

Table 5: Total System Losses by Replacement Location – Shoulder Conditions
(Megawatts)

One 750 MW CC Unit			Two 750 MW CC Units		
Alternate Location	**Total MW**	**Delta MW**	**Alternate Location**	**Total MW**	**Delta MW**
Base Scenario	2,207		Base Scenario	2,199	
Southwest	2,221	13	SW+Metro	2,196	-3
Northwest	2,272	65	NW+Metro	2,256	57
Metro	2,180	-27	NW+SW	2,300	102

Note: Shoulder conditions is during 2020 Summer

These tables demonstrate that losses increase the farther away generation is located from the Twin Cities load center.

4. Summary

Our Reliability Study analyzed three alternate locations for siting replacement generation and concluded that siting replacement generation at locations other than Sherco will result in transmission upgrade costs that would not be needed if replacement generation is sited at Sherco. The number and cost of any required transmission upgrades is dependent on the location of the replacement generation, the amount of transmission capacity available from that location, and the amount of

"other" generation that will be competing with the replacement generation for transmission capacity.

Additionally, because significant generation has been added to the MISO generation interconnection queue since we started our Reliability Study in early 2015, the costs we have estimated for alternate locations are likely low and less certain because of how the MISO system will evolve as a result. Finally, the further the replacement generation is sited from the Twin Cities load center, the higher the amount of losses the generation experiences – and while not specifically evaluated in our Study, we believe siting replacement generation in wind rich areas such as southwest Minnesota will "use up" transmission capacity that can be used for the installation of additional wind or other renewable generation.

D. Black Start Analysis

As explained in our March 16, 2015 Supplement, Sherco Units 1 and 2 play a significant role on our system and in the entire Upper Midwest. One of the key roles these Units play is in restarting the system in the event of a catastrophic loss of power to all or a significant part of a geographic area. Normally, the electric power used within a generating plant is provided from the station's own generators. If all of the plant's main generators are shutdown, station power is provided by drawing power from the transmission grid, which can be used to start the plant. However, during a wide-area outage, power from the grid will not be available. In the absence of grid power, a so-called "black start" needs to be performed to "bootstrap," or self-start the power grid into operation without the use of external resources.

We are required by NERC to maintain a plan to restart the system, which must be coordinated with neighboring utilities and is subject to acceptance by MISO. In this section, we discuss the considerations that go into black start planning, and our conclusion that other restoration paths, while less efficient, are viable with various equipment upgrades.

1. Overview

Black Start planning involves developing models, strategies and procedures to configure the system such that one or more generators can be brought online – and at the same time, picking-up sufficient customer load to satisfy the generator's minimum requirements for stability. This process sets up "islands" where part of the transmission and distribution systems in a geographic area begin serving at least part of the load in that area. Once we determine an island is stable, we can synchronize

and reconnect/restore more generators and load, essentially expanding the island and restoring our interconnections with other utilities until the system is fully recovered. The longer the system is down, the harder it is to restore, so we work to determine the most efficient path(s) possible.[15]

We generally plan restoration assuming that the event that caused the outage caused no damage to the system. However, because this is a possibility, we must also plan alternate restoration paths that we can take in the event a portion of the system is damaged as part of the catastrophic event. We also must incorporate differing procedures based on the weather extremes in our geographic footprint. For example, any large generating unit that uses steam will take approximately one hour to wind down and fully stop operating. If ambient temperatures are cold, the water that remains in the Unit's pipes and boiler can freeze. Therefore, if we expect restoration of that Unit to take three or more hours, we may need to begin draining the pipes and boilers. If this occurs, our restoration of that generating unit will likely be delayed to the following day, after the unit goes through operational procedures that prepares it for a cold restart.

Sherco Unit 3 is the largest generating unit in the region and during a restoration event, we need it to provide the generating output necessary to restore customer load and the spinning reserves required for the NSP Island.[16] In the circumstance that a generator fails, Sherco Unit 3 has the capacity and the capability to ramp-up generation quickly to pick up the customer load that was lost by the failed generator. This becomes essential as the island grows, incorporating the neighboring utilities. However, Sherco Unit 3 is too large to be a Target Unit, so can only be started after we have at least one additional generator over-and-above the Initial Unit(s).

Our current plan gets from the Initial Unit(s) to Sherco Units 1 and 2 within a couple of hours. Because of their proximate location to Sherco Unit 3, the balance of the restoration plan is set in motion quickly to fully restore the system. As a steam unit, Sherco Unit 3 is impacted by the freeze potential we explained above if it takes longer than approximately four hours to power it up in the winter months. Therefore, getting

[15] The longer the system is down, equipment and facilities cool. Additional impacts include effects such as the fact that substation batteries will only keep the substations operational for a limited time. If the substation batteries deplete, we cannot easily isolate or energize the substation.

[16] In this case, the spinning reserves are the amount of additional generation that is on stand-by in the event that another generator within the island fails. To help ensure consistent availability and reliability of electricity during the restoration process, utilities keep generation capacity on reserve that can be accessed quickly if there is a disruption to the power supply. For example, if another generator or a major transmission line within the NSP/GRE/MP Island goes down, then NSP will access its reserve capacity at Sherco Unit 3 to compensate for that loss.

Sherco Unit 3 up and running quickly not only allows the Company to restore load faster and begin reaching out to neighboring utilities sooner – it also eliminates the concern of broader restoration delays associated with preventing the Unit from freezing.

2. Planning Considerations

Only certain types and sizes of generation are eligible to be considered Initial Units or Target Units. As noted previously, the Initial Unit(s) is the first generating unit that sets restoration in motion, and needs to be at least 110 MW and no more than 300 MW. It needs to be big enough to restore a larger Target Unit, but small enough to be able to start with an independent fuel source, such as fuel oil. Target Units are the generating units on the restoration path that are started by the Initial Unit(s). Eligible Target Units include coal, natural gas, hydro, and fuel oil – all of which are controllable and capable of both providing and absorbing reactive power. Renewable generation, such as solar and wind are not currently considered eligible Target Units due to their inherent intermittent nature, and their inability to provide or absorb reactive power. Nuclear units are also not eligible because they cannot vary their output, and can only come online after the balance of the system is fully stable.

When choosing a potential Target Unit as part of a black start study, we consider the following items (other than fuel source):

- Multiple generating units at the site
- Low minimum operating limits
- Ramp rate of the units
- How fast a unit can come on-line once it receives station power
- Unit's ability to act as a stabilizing unit in the island
- Amount of switching required in order to energize the unit

Special care is needed when energizing transmission lines during a system restoration due to the especially light loads present on the system. When lines are energized with little or no real power load, the charging current produces reactive power. We provide an example of how much reactive power may be needed when energizing an overhead transmission line in Table 6 below.

Table 6: Reactive Power Requirement for Energizing Overhead Transmission Lines

Transmission Voltage (kV)	MVAR per mile of line
69	0.011
115	0.033
230	0.125
345	0.164
500	0.770

Underground transmission lines produce even more reactive power that must be absorbed. The reactive power needs of an underground cable is *ten times* that of an overhead transmission line.

The same concern occurs when energizing transformers. The generation that is online must be able to absorb the reactive power injected into the system due to the energization of the transformer.

Table 7: Reactive Power Requirement for Energizing Transformers

Transformer Size (MVA)	MVAR Requirement
28	2.25
47	3.25
70	5.7
187	15
336	27-30
448	36
672	50.25

Before a line or transformer is energized, there must be sufficient generation MVAR capacity online to absorb the capacitive reactance produced by that line/transformer. If not balanced properly, it is easy to overwhelm the generator by collapsing its magnetic field, causing the generator to trip off-line, and potentially re-collapse the system.

When we begin to start-up motors and pumps at the next generating plant, the Initial Unit(s) must be capable of providing that reactive component back to the system in order to start the motors. Table 8 below outlines the amount of reactive power that is needed to start various sized motors at a typical power plant.

Table 8: Reactive Power Requirement for Starting Typical-Sized Generating Unit Motors

	Motor Start		Motor Running	
Motor HP	**MW Load**	**MVAR Load**	**MW Load**	**MVAR Load**
350	0.36	1.78	0.33	0.16
700	0.73	3.55	0.65	0.32
1500	1.55	7.61	1.4	0.68
2000	2.07	10.15	1.87	0.90
3000	3.11	15.23	2.8	1.35
6000	6.22	30.46	5.6	2.71

Starting large Target Units on our system requires around 30-40 MVAR of reactive power just to start the unit, which is substantial. The restoration path from the Initial Unit(s) to the Target Unit will inject an additional 75-110 MVAR of reactive power onto the system as transmission lines and transformers are energized, which the Initial Unit must absorb until the voltage reactors in our substations are energized.

The amount of MVARs needed for the restoration path will vary depending the on the path. Our current Black Start Plan requires an Initial Unit(s) of approximately 110 MW to 300 MW to restore our Target Unit – setting restoration in motion. Sherco Unit 3 is too large to be a viable Target Unit, because it is too large for the Initial Unit(s) to start, so is started later in the process. Additionally, as noted previously, nuclear units are not viable Target Units, nor are renewable generating units.

During this time, we must also be energizing transmission lines and transformers to bring customer load onto the system. We must balance the load and generation carefully, as without sufficient load, damage to our or customer equipment can occur from an overload of reactive power; if we energize lines and restore load too quickly, we can trip relays and will have to begin the process again. All substations on the current restoration path have emergency generators for maintaining full operating capability of switches, breakers, and relays at those substations. The emergency generators provide the AC power required to operate transformer pumps and fans as well as the transformer Load Tap Changers (LTCs). The emergency generators also maintain the battery chargers and ensure we maintain full battery capabilities. The substation batteries provide the DC power necessary for protective relaying, the motor operated disconnects, breaker trip coils, and communication equipment.

Generating units that interconnect with other utilities must also have a "sync scope," which is a device that measures frequency, voltage, and phase angle (Volts/VARs) to

ensure the two islands (one on each side of the interconnection) are perfectly in sync before interconnecting. If they are not perfectly in sync, both islands could go back down and equipment could sustain damage. This becomes important when we start to reconnect our system with our neighboring systems, or when we bring Minnesota and Wisconsin or North Dakota and South Dakota back together.

3. Summary

Each of our current non-renewable generating plants plays a unique role in the black start process. In addition to the key roles currently played by Sherco Units 1 and 2, our **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** plant plays a key role in restoring the **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** portion of our system. Altering the restoration path away from the Sherco site will require the addition of various equipment and/or facilities to other generating units and result in a longer restoration period. As we have discussed, restoration time is of greatest concern in winter/cold months.

The study determined that the existing **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** site as well as the **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** site were workable for future restoration plans, provided additional emergency generations were added to the system. There is still a delay of several hours in getting from the Initial Unit(s) to Sherco Unit 3, since additional time will be needed to bring either **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** up to a stable minimal load level, before getting to Sherco.

The existing **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** plant requires more switching to be part of the restoration plan and has more underground cables in the area that would add a substantial level of complexity to the switching procedures. It is not advisable to utilize **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** as a Target Unit if **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** are available as well as the **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** units. In order to utilize the **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** plant, at least 13 new emergency generators would be needed, which would also not be cost-effective or practical from an operational perspective. In comparison, the **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** would only require a combined five new emergency generators to be installed.

We outline the estimated costs of altering the current Sherco Units 1 and 2 restoration path in Table 9 below. We note that if generation is not replaced at Sherco, at least two of the new restoration paths would need to be used in order to ensure a viable path to Sherco Unit 3. For context, we also include the numbers of operating steps involved for each of the alternative paths, with greater numbers increasing the complexity and extending restoration time.

Table 9: Alternate Restoration Path – Estimated Cost and Operational Steps

Restoration Path	**Operational Steps** (Transmission)	**Estimated Additional Equipment Cost**
Current ME	22	
Current MW	16	
New Metro West 345 kV line	25	**[TRADE SECRET BEGINS… …TRADE SECRET ENDS]**
New Metro East 345/115 kV	32	**[TRADE SECRET BEGINS… …TRADE SECRET ENDS]**
Existing Paths with new Metro West 345 kV line	18	**[TRADE SECRET BEGINS… …TRADE SECRET ENDS]**
New Metro West 115 kV	24	**[TRADE SECRET BEGINS… …TRADE SECRET ENDS]**

Note: as discussed below, additional costs may be involved with the alternative 115 kV paths.

Our current restoration path relies on the 345 kV transmission system. Some of the above alternatives rely on the 115 kV system. When considering whether or not to use a 115 kV path over a 345 kV path, we must consider the active and reactive power required to energize the line. The higher voltage (345 kV) lines have a higher reactive power requirement for energization, but the lower voltage (115 kV) lines have higher resistance, which results in more line losses, which requires the generator(s) to provide more power (MW) to energize the equivalent 115 kV path.

We provide as Table 10 below, an example of two lines from our system that demonstrates these differences.

Table 10: 115 kV Compared to 345 kV Resistance and Reactive Power

Line voltage	Line Resistance	Reactive Power MVAR/mile
Blue Lake – Black Dog 115 kV	0.009531	0.033
Blue Lake – Black Dog 345 kV	0.000578	0.164

In blackstart planning, we try to balance the role of active and reactive power in the generator, so that there is enough reactive power to energize the next piece of equipment – but not so much so to lose too much active power to line losses, which reduces the numbers of customers we can restore initially.

We also need to maintain control of the system voltage as the restoration paths are energized. The 115 kV path will have a lower VAR requirement, which can lead to lower bus voltages as more equipment is energized. In this case, capacitor banks may need to be energized to boost the voltage. Conversely, the 345 kV path will have a higher VAR requirement than the 115 kV path, which can lead to higher bus voltages and the need to energize existing voltage reactors in order to lower the bus voltages.

Our current Black Start Plan and the NSP System have been designed around the 345 kV system and the understanding that during light loads, the bus voltages may be higher at one end of the transmission line than the other. We therefore have reactors strategically installed throughout the system to help control these voltages. We also have capacitor banks on the 345 kV system for high load periods, where the bus voltages may become depressed. However, while the proposed 115 kV restoration paths currently have some capacitor banks installed, more may be needed, depending on where the new generation is sited and which restoration path is chosen.

Our proposal to construct a natural gas CC unit at the Sherco site would provide for our current and most efficient Black Start Plan to remain in place. The proposed Unit would be big enough to start Sherco Unit 3 without incurring restoration delays, and the additional equipment and/or facilities costs and operational complexities in other parts of the system.

E. Conclusion

While our **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** generation sites are good potential Target units for the restoration plan, there are costs associated with system upgrades as well as a delay in getting

Sherco Unit 3 started. The best solution from a restoration perspective would be to install black start eligible replacement generation onsite at Sherco.

IV. STUDY ASSUMPTIONS, INPUTS, and ALTERNATIVES

A. MISO Y2 Study

MISO Attachment Y2 studies are performed at the request of the generator owner considering retirement of a generating unit(s), and are performed in accordance with the MISO Business Practice Manuals. Their purpose is to determine how the system behaves in the absence of whatever generating unit(s) is being requested to be shut down. MISO runs scenarios with and without the generating units in-service to determine the impacts to the regional transmission system and to identify any potential issues. The identified issues are shared with an adhoc study group made up of neighboring transmission owners and other entities to determine if the issues are real, and what potential solutions are needed to mitigate all of the system deficiencies. MISO does not look at replacement generation alternatives unless they proposed as solutions by members of the adhoc group.

1. Assumptions

We provide a summary of the MISO Y2 Study assumptions and inputs below. The study assumptions are detailed beginning on page 8 of the NON-PUBLIC MISO *System Support Resource Attachment Y2 Study Final Report, Xcel Energy, The Sherburne County Generating Plan ("Sherco") Units 1 & 2*, dated August 28, 2015.

Unit Power Output. Each Sherco Units 1 and 2 are rated at 730 MW total output power. Station service load is 47.5 MW for each unit, making the net output per Unit 682.5 MW.[17]

Retirement Scenarios. The Company's March 11, 2015 Attachment Y2 Study request sought study of two retirement scenarios for Sherco Units 1 and 2 as follows:

(1) Both Sherco Units 1 and 2 on May 31, 2021, and
(2) Sherco Unit 2 on May 31, 2021 and Sherco Unit 1 on May 31, 2024.

Study Models. Studies were performed using the following power flow models:

Scenario 1:

- 2021 Summer Peak (MTEP15_2020 Summer Peak starting point)

[17] 2015-2016 UCAP Unit Ratings: Sherco Unit 1 – 696.1 MW; Sherco Unit 2 685.8 MW.

- 2021 Shoulder (MTEP15_2020 Shoulder 90% wind starting point)
- 2021 Winter Peak (MTEP15_2020 Winter Peak starting point)
- 2025 Summer Peak (MTEP15_2025 Summer Peak) Scenario 2:
- 2021 Summer Peak (MTEP15_2020 Summer Peak starting point)
- 2021 Shoulder (MTEP15_2020 Shoulder 90% wind starting point)
- 2021 Winter Peak (MTEP15_2020 Winter Peak starting point)
- 2025 Summer Peak (MTEP15_2025 Summer Peak)
- 2024 Shoulder (MTEP14_2024 Shoulder)

For the model, two sub-scenarios were created which represent the "before" and "after" generator retirements for each retirement scenario. The most relevant 2014 Security Constrained Economic Dispatch (SCED) input data from MTEP14 series was used and updated to reflect conditions in MTEP15 series models.

Model Assumptions - Generation. Units for which an Attachment Y had been completed during the relevant period were modeled as offline. Additionally, Attachment Y Units whose suspensions end before 2020 were modeled in-service.

Model Assumptions – Transmission. Significant transmission projects in service prior to the potential retirement dates were as follows:

- MTEP Project 3831 Great Northern Transmission Line (June 2020). To be added to MTEP14 2024SSH model only, MTEP15 models will have it already.
- MTEP Project 7910 Mud Lake – Brainerd 5L upgrade. Minnesota Power confirmed expected I/S date to be in 2019.
- MTEP Project 7913 Little Falls – Langola Tap – St. Stephen (115 kV) upgrade. Minnesota Power confirmed expected in-service date to be in 2019.
- MTEP Project 3127 N La Crosse – N Madison – Cardinal – Eden – Hickory Creek 345 kV. To be added to MTEP15 2020SUM and MTEP15 2020SSH only, later models already have them.

Additionally, Minnesota Power (MP) provided topology updates to MTEP14-2024SSH and a correction to all cases for its Silver Bay Generation and Iron Range-Forbes 230kV Line summer rating (summer cases only). Finally, each Units station service load was disconnected in the "after" as part of the retirement of the corresponding Unit(s), and the Xcel Energy (XEL) area slack bus was changed due to the potential retirement of Sherco Unit 2.

2. Criteria and Methodology

PTI PSS/E was used to perform AC contingency analysis. Cases were solved with automatic control of LTCs, phase shifters, DC taps, switched shunts enabled (regulating), and area interchange disabled. Contingency analysis was performed on before and after cases. The results were compared to determine if there were any criteria violations due to the Unit(s) change of status.

The *Steady State Thermal* and *Steady State Voltage* Planning Criteria for each Transmission Owner (XEL, Great River Energy (GRE), MP, American Transmission Company (ATC), Dairyland Power Cooperative (DPC), Southern Minnesota Municipal Power Agency (SMMPA), and Ottertail Power (OTP)) were applied.

MISO Transmission Planning Business Process Manuals – SSR Criteria. As specified in the MISO BPM-020-R12, (Section 6.2 beginning on page 133)[18] the System Support Resource criteria for determining if an identified facility is impacted by the suspension of the units will be:

- Under system intact and category B contingencies, branch thermal violations are only valid if the flow increase on the element in the "after" suspension scenario is equal to or greater than:
    a) 5 percent of the "to-be-retired" unit(s) MW amount (i.e. 5% PTDF) for a "base" violation compared with the "before" suspension scenario, or
    b) 3 percent of the "to-be-retired" unit(s) amount (i.e. 3% OTDF) for a "contingency" violation compared with the "before" suspension scenario.
- Under system intact and category B contingencies, high and low voltage violations are only valid if the change in voltage is greater than 1% as compared to the "before" suspension voltage calculation.
- Under category C contingencies, for the valid thermal and voltage violations as specified above, generation re-dispatch, system reconfiguration, or load shedding were considered if applicable.
- Angle/voltage stability studies will be performed if necessary.

3. Summary of Retirement Scenario Cases

Tables 11, 12 and 13 below provide summaries of the Case results, as they relate to NERC Event Categories. We note that Case 1 is Sherco Units 1 and 2 out of service

[18] MISO Business Practice Manual BPM-020 can be found at https://www.misoenergy.org/Library/BusinessPracticesManuals/Pages/BusinessPracticesManuals.aspx

and Case 2 is Sherco Unit 2 out of service. In order to make the results more easily understandable, we have included a brief definition of the NERC Event Categories in the Table 14 immediately following our summary of the Case results.

Table 11: Scenario 1 Case Summary

	Events/Violations		
NERC Event Category	**Summer Peak**	**Shoulder**	**Winter Peak**
P1		84/84 Thermal (MP) 2/2 Line Loading (MP) 119/907 Voltage (MP) 99/110 Voltage (XEL) 5/5 Voltage (GRE) 6/11 Voltage (*resolved by switching on local capacitor banks*) 2/3 Voltage (*addressed within GRE service area*)	
P2		2/2 Line Loading (MP) 119/907 Voltage (MP) 99/110 Voltage (XEL) 5/5 Voltage (GRE) 3/21 Voltage (*resolved by MTEP 9064*)	1/1 Thermal (MP) 2/2 Voltage (*addressed by transferring feeder load onto adjacent sources*)
P3		1/1 Thermal (XEL) 84/84 Thermal (MP) 97/142 Voltage (XEL) 119/907 Voltage (MP) 99/110 Voltage (XEL)	
P4		3/21 Voltage (*resolved by MTEP 9064*)	
P5		99/110 Voltage (XEL) 5/5 Voltage (GRE) 6/11 Voltage (*resolved by switching on local capacitor banks*) 1/3 Voltage (*resolved by Coal Creek generation reduction*)	1/1 Voltage (GRE – *resolved by MTEP 4380*)
P6	4 Voltage (XEL)	97/142 Voltage (XEL) 99/110 Voltage (XEL)	
P7		99/110 Voltage (XEL) 6/11 Voltage (*resolved by switching on local capacitor banks*)	

Table 12: Scenario 2 Case Summary

	Events/Violations		
NERC Event Category	**Summer Peak**	**Shoulder**	**Winter Peak**
P1		9/13 Voltage (XEL)	
P2		9/13 Voltage (XEL) 2/2 Voltage (GRE – *resolved by MTEP 4380*)	1/1 Thermal (MP)
P3		9/13 Voltage (XEL) 14/549 Voltage (MP) 6/11 Voltage (MP) 59/59 Thermal (MP)	
P4			
P5		2/2 Voltage (GRE – *resolved by MTEP 4380*)	
P6	3/3 Voltage (XEL)		
P7			

Table 13: Shared Cases (Scenarios 1 and 2) Summary

	Events/Violations		
NERC Event Category	**Summer Peak**	**Shoulder**	**Winter Peak**
P1	2/2 Voltage (GRE)		
P2			
P3		5/1 Thermal (XEL) 2/2 Thermal (MP) 8/10 Voltage (XEL) 4/7 Voltage (MP)	
P4			
P5			
P6		8/10 Voltage (XEL)	
P7			

Table 14: Abbreviated List of NERC Event Category Definitions[19]

P1	Single Contingency – Loss of one of the following: * Generator * Transmission Circuit * Transformer * Shunt Device * Single Pole of a DC line
P2	Single Contingency – * Opening of a line section w/o a fault * Bus Section fault * Internal Breaker fault (non-Bus-tie-Breaker) * Internal Breaker Fault (bus-tie Breaker)
P3	Multiple Contingency – Loss of one of the following: * Generator * Transmission circuit * Transformer * Shunt Device * Single pole of a DC line
P4	Multiple Contingency – (Fault plus stuck breaker) Loss of multiple elements caused by a stuck breaker (non-Bus-tie Breaker) attempting to clear a Fault on one of the following: * Generator * Transmission Circuit * Transformer * Shunt Device * Bus Section * Loss of multiple elements caused by a stuck breaker (Bus-tie Breaker) attempting to clear a Fault on the associated bus
P5	Multiple Contingency (*Fault plus relay failure to operate)* – Delayed Fault Clearing due to the failure of a non-redundant relay protecting the Faulted element to operate as designed, for one of the following: * Generator * Transmission Circuit * Transformer * Shunt Device * Bus Section
P6	Multiple Contingency (*two overlapping single contingencies)* – Loss of one of the following: * Transmission Circuit * Transformer * Shunt Device * Single pole of a DC line
P7	Multiple Contingency (*Common Structure)* – The loss of: * Any two adjacent (vertically or horizontally) circuits on common structure * Loss of a bipolar DC line

[19] For a full description of NERC's event categories, *please see*:
http://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-4.pdf beginning at page 8.

4. Special Voltage Stability Study – Monticello Nuclear

As noted previously, due to the electrical proximity between the Monticello Nuclear generating plan and Sherco, the voltages at Monticello's 115 kV and 345 kV buses received special attention. This special study was to determine whether Monticello's voltage will remain within the plant's NPIR limits at all times, and whether the region around Monticello would be at risk of voltage collapse under certain power transfer scenarios.

Model Preparation. The voltage results of the steady state power flow showed a significant number of voltage violations in the 2021 shoulder case compared to the number of voltage violations in the 2021 summer case in the Twin Cities area, which can be attributed to the number of online units in each case. Only few units in the Twin Cities area are online in the shoulder case, however all the units in the Twin Cities are online in the summer case. The presence of these units supports the voltage stability in the summer case compared to the shoulder case.[20] For this reason, MISO determined the 'Source' and the 'Sink' to implement the power transfer needed for the voltage stability study based on the 2021 shoulder case. All the online units within the Twin Cities area were used as the 'Sink' subsystem (their output was reduced) and all the units outside the Twin Cities are the 'Source' subsystem.

Contingencies. The voltage stability studies selected the events observed to cause the highest voltage drop at Monticello combined with the loss of Sherco Unit 3 to implement NERC P3 contingencies.

Methodology. MISO used the PSS-E PV Analysis tool. For the base case, all taps and switched shunts were allowed for automatic adjustments and Area interchange control was disabled. For the contingency case, all taps and switched shunts were locked and Area interchange control was disabled. The branch loading check (thermal violations check) was disabled to study only the impact of the power transfer on the voltage, and the Machine active power limits were honored.

Verification of the Voltage Collapse Conditions. To verify that power flow solution blows-up due to true voltage collapse conditions and not due to some numerical issues, numerous switched shunt actions were verified right before reaching the blow-up status. All online generators within the Twin Cities reached their Qmax limit, which proved that the case blow-up as the power transfer reached the knee of the P-V curve as shown.

[20] The status of each unit in that area was determined automatically during the SCED process.

Transient Stability. Considering the size of the two Sherco Units and due to their proximity from the two nuclear plants (Monticello and Prairie Island) that have special frequency requirements, a transient stability assessment was needed. This assessment was done to study the impact of the retirement of Sherco Units 1 and 2 in 2021. A similar study must be conducted if the Company decides to retire only one of the Sherco Units 1 and 2.

MISO used the dynamic model MTEP14-2019 Summer Shoulder with specific assumptions including Sherco unit 1 and unit 2 kept offline and all of the applicable generation and transmission assumptions listed earlier. As per MTEP14 Transient Stability Assessment, the MISO West Sub-region is more stressed during high transfers in shoulder periods.[21] After applying all the above changes, SCED was performed on the case. Ten disturbances selected from the MTEP14 study in addition to three disturbances provided by GRE were each simulated for 20 seconds. PSS-E version 32 was used in simulating these disturbances. Again, the Transmission Owner Planning Criteria and Monticello NPIR were considered; the rotor angle, bus voltage, and bus frequency channels in XEL, MP, GRE, and MH were selected.

5. Limitations

The MISO Y2 study is a "first come, first served" study where only generators that have already requested to retire are considered when performing the study. MISO does not attempt to predict which generators they believe will retire in the future. With the Clean Power Plan, it is very likely additional generators not included in the MISO Y2 Study performed for Sherco Unit 1 and 2 scenarios will be retired, which could impact Sherco Unit 1 and 2 retirement.

B. Xcel Energy Transmission Reliability Study

1. Sherco 1 Study Replacement Scenarios

We initiated our Reliability Study to further investigate the transmission impacts associated with replacement generation for one or two Sherco units being located at various locations on the NSP System. We identified three potential locations that include both greenfield and brownfield conditions. Our considerations in choosing the locations include proximity to existing transmission facilities, generation facilities, and natural gas pipelines – and other factors, such as potential land availability needed to accommodate new generation. The alternative locations are as follows:

[21] The MTEP15 dynamic model was not yet ready.

- Metro
- Southwest
- Northwest

2. Sherco 1 and 2 Study Replacement Scenarios

We considered nine scenarios for Sherco Units 1 and 2 replacement:

1. CAPCON 700 MW, Metro 600 MW[22]
2. CAPCON 700 MW, Northwest 700 MW
3. CAPCON 700 MW, Southwest 700 MW
4. Northwest 700 MW, Metro 600 MW
5. Northwest 700 MW, Southwest 700 MW
6. Northwest 1,400 MW
7. Southwest 700 MW, Metro 600 MW
8. Southwest 1,400 MW
9. Metro 1,200 MW

Linear power flow methods (DCCC) were used to perform contingency analysis on each of the nine scenarios for the summer and shoulder peak system conditions. Based on these thermal results potential mitigation was identified and estimated.

Four scenarios were selected for further analysis based internal stakeholder input.

1. Southwest 750 MW, Metro 750 MW
2. Northwest 750 MW, Metro 750 MW
3. Northwest 750 MW, Southwest 750 MW
4. Sherburne County 1,500 MW (Stability Only)

3. Study Methodology

The replacement scenarios were evaluated for the study year 2020. Summer peak and shoulder peak cases were developed based on the MISO MTEP14, 2019 summer peak and summer shoulder cases. These cases were updated from 2019 to 2020 by adding in the MISO MTEP14 Appendix A projects with an in-service date before June 1, 2020. In addition to transmission projects, all generator projects located in the MISO DPP study cycle through the DPP 2014 February benchmark cases that were

[22] CAPCON is the generating resources being added to the NSP System as a result of the Competitive Acquisition proceeding in Docket No. E002/CN-12-1240. These resource include: Mankato Energy Center II, Aurora Solar, and Black Dog 6.

located in the region were added to the cases. The CC generation was dispatched based on a merit order in the shoulder peak cases.

a. Steady State Analysis

Summer peak and shoulder cases were evaluated for steady-state thermal and voltage issues using PSSE version 33 and PSSMUST version 10.2 Contingency criteria was based on the MTEP14 contingencies files.

- NERC Category A with system intact (no contingencies)
- NERC Category B contingencies
  - Single element outages, at buses with a nominal voltage of 100 kV and above, in the following areas: WEC (area 295), XEL (area 600), MP (area 608), SMMPA (area 613), GRE (area 615), OTP (area 620), ITCM (area 627), MEC (area 635), WAPA (area 652), MDU (area 661), DPC (area 680), ALTE (area 694), WPS (area 696), MGE (area 697), UPPC (area 698)
  - multiple-element outages initiated by a fault with normal clearing such as multi-terminal lines, in Iowa, North Dakota, South Dakota, Minnesota and Wisconsin.
- NERC Category C
  - NERC Category C events, in Iowa, North Dakota, South Dakota, Minnesota and Wisconsin.

Monitored elements for each of the areas are described in the Table 15 below.

Table 15: Monitored System Elements

Owner/ Area	Monitored Facilities	Thermal Limits		Voltage Limits	
		Pre-Disturbance	Post-Disturbance	Pre-Disturbance	Post-Disturbance
ATCLLC	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.1/0.9
DPC	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.1/0.9
GRE	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.1/0.92
ITCM	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.07/1.05/0.93
MDU	57 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.1/0.9
MEC	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.96/0.95	1.05/0.96/0.95
MHEB	69 kV and above	100% of Rate A	100% of Rate B	1.12/1.1/1.07/1.05/1.04/0.99/0.97/0.96/0.95	1.15/1.1/0.94/0.9
MP	69 kV and above	100% of Rate A	100% of Rate B	1.05/1.0	1.1/0.95
OTP	40 kV and above	100% of Rate A	100% of Rate B	1.07/1.05/0.97	1.1/0.92
SMMPA	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.1/0.9
WAPA	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.1/0.9
XEL	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.1/0.92
Monticello	345 kV	100% of Rate A	100% of Rate B	1.0492/0.9914	1.0492/0.9914
Monticello	115 kV	100% of Rate A	100% of Rate B	1.05/1.0087	1.05/1.0087
Prairie Island	345 kV	100% of Rate A	100% of Rate B	1.05/0.9911	1.05/0.9911
Prairie Island	161 kV	100% of Rate A	100% of Rate B	1.05/0.9969	1.05/0.9969

A branch is considered thermally constrained if the following conditions are met.

1. The branch is loaded above its applicable normal or emergency rating, and
2. A replacement scenario generator has a larger than 5% DF on the overloaded facility under system intact or post contingent, or
3. The impact of the replacement scenario is greater than 10% of the applicable rating of the overloaded facility

A bus is considered a voltage constraint if both of the following conditions are met.

1. The bus voltage is outside of applicable normal or emergency limits, and
2. The change in bus voltage is greater than 0.01 per unit.

b. System Loss Analysis

Real power losses for the study were based on a comparison of total system losses from the benchmark base cases and the replacement scenario cases.

c. Reactive Power Analysis

Reactive power production for the study was studied by comparing the amount of reactive power produced in the Xcel Energy area in the benchmark base case compared to the replacement scenario cases.

4. Transient Stability

Transient stability was performed using PSSE version 32.2. Transient stability analysis was performed using the MTEP14 stability package. Disturbances were simulated on the benchmark case and the study cases to identify any significant impacts.

a. Disturbance Criteria

The stability simulations as part of this study took into account both regional and local contingencies. For local contingencies generic clearing times were used and the fault admittances for single line to ground faults were estimated by assuming the Thevenin impedance of the positive, negative, and zero sequence networks at the point of the fault are equal.

b. Performance Criteria

Simulation results were evaluated using the MRO System Performance Table in the MRO System Performance Standard TPL-503-MRO-01. Transient voltages must be within the default limits of 0.70-1.20 per unit with the exception of specific buses, areas or companies that have different requirements. All machine rotor angle oscillations must be positively damped with a minimum damping factor of 5% for disturbances with a fault, or 10% for line trips without a fault.

Transient apparent impedance swings on all lines were monitored after fault clearing using the mrely1 user written model. The mrely1 model uses a generic three-zone mho characteristic. Apparent impedance transient swings into the inner two zones are unacceptable for NERC Category B disturbances. Apparent impedance transient swings into the inner two zones of distance relays are unacceptable for NERC

Category C disturbances, unless a relay trip will not result in instability (including voltage instability), uncontrolled separation, or cascading outages.

5. Mitigation Cost Assumptions

Unit cost tables were developed for the overhead transmission lines, substation, transformers, and any reactive power instillations that were needed for the study effort. These costs were based on new construction and in 2015 dollars.

6. Limitations

The Reliability Study, when it was initiated in early 2015, included a number of projects from the MISO interconnection queue that were assumed to be going into service at the time the study was performed. Because of this, any changes to the MISO Queue could have an impact on the conclusions of the our Reliability Study – with the likely outcome of increasing the identified estimated interconnection costs for projects analyzed.

C. Black Start Analysis

1. Assumptions and Inputs

The primary purpose of the study was to investigate the impacts of retiring Sherco Units 1 and 2, on the NSP Power System Restoration Plan. The study looked at future blackout scenarios where Sherco Units 1 and 2 are not available for restoration efforts. The intent was to identify potential new Target Units and the associated restoration paths for those units. The Study also identified potential challenges with the various scenarios and what potential upgrades would be required to make those viable options for future restoration plans. The Study assumed that the natural gas pipeline supplies for potential new Target Units is adequate to start and run the plants for the restoration plan.

The Black Start Study utilized the same study models that were created for the Xcel Energy Transmission Reliability Study, modified for the blackout scenario base cases, from which multiple Target Units and associated restoration paths were studied. Due to the proximity from where the proposed replacement generation in the model was sited to the primary Twin Cities load center, we eliminated the Northwest generation and the Southwest generation locations – only studying the Metro location and other existing plant locations.

2. Alternatives Examined

We analyzed four new potential restoration paths: (1) a 345kV path to **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]**, (2) a 115kV path to **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** with underground cable, (3) another 115kV path to **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** using overhead lines, and then (4) a combination 345/115 kV path to **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]**. After the generation was started at each of the new Target Units, the restoration paths were energized to Sherco.

3. Study Methodology

To demonstrate generator capability is adequate to perform its black start functions, the Initial and Target Units must stay within real and reactive limitations based on that unit's most recent D-curve, or operating limits.[23] Unit loading must be dispatched so that the contingent loss of one of the units will not cause the other online units to exceed their real and reactive power capabilities or their governor response capability.

The Initial Unit(s) requires that the terminal voltage of the generators must be 13.1 kV (95%), if the loading on that generator exceeds 10 MW. A temporary reduction to 12.8 kV (93%) is allowed for unit output less than 10 MW. Due to these restrictions and the current tap settings on the generator step-up transformers (GSU), there are additional voltage constraints for the 115 kV bus.

For the Initial and Target Units to be considered capable of performing their functions within the our Black Start Plan, they must be able to energize at least one restoration path between the black start substation, and the new Target Unit. The Initial Unit(s) must be able to start the new Target Unit and then continue the restoration path to the Sherco substation and be able to complete the Sherco Unit 3 load start-up sequence without causing violations to the above criteria.

[23] In addition to producing capacity and energy to meet customer load requirements, generating units help control voltage on the grid by producing and absorbing reactive power (MVAR); *producing* MVAR helps *increase* the voltage, and *absorbing* MVAR helps *decrease* the voltage. When a generator is producing or absorbing reactive power, it cannot produce its maximum MW output because its operating capability is partially "used up" from producing or absorbing reactive power. Therefore, a generating unit's D-curve shows the operating limits for a generating unit in terms of the relationship between the active power (MW) it is producing and the reactive power it is either producing or absorbing – and how they are balanced within the unit's maximum operating limits.

To effectively analyze the restoration paths, we created scripts to simulate the major switching steps outlined for each switching step along the restoration path. For each major step in the restoration path development, we monitored bus voltages at key transmission substations and the Initial Units' real and reactive power output. Both the steady-state and immediate post-switching (time 0+) results were displayed for each step, as outlined in Table 16 below.

Table 16: Steady-State and Immediate Post-Switching Results

	Switching Limits		Steady State Limits	
	Low Voltage	High Voltage	Low Voltage	High Voltage
All buses	0.90 pu	1.05 pu	0.95 pu	1.05 pu

We did not actively monitor transmission equipment loadings because the amount of load energized to support each restoration path did not exceed the lowest rating of any one piece of series connected equipment.

4. General Findings

The Study determined that **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** would not be a good Target Unit due to the difficulty in switching to get there for the operators, as well as the number of emergency generators that would need to be added to the system. The overhead path, while longer and requiring an additional generator to be installed, was a better option than the underground path. The reactive power requirements for the underground path were a challenge and could require an additional Initial Unit(s).

The Metro East 345/115 kV path and the Metro West 345 kV paths were the preferred paths to the alternate Target Units. However the process of bringing the Target Unit online and up to minimum load will delay the restart of Sherco Unit 3, and the restoration of off-site station power to both Monticello and Prairie Island. Importantly, the existing paths to Sherco Units 1 and 2 or the new proposed onsite CC unit allows restoration of offsite station power to both nuclear plants and start-up procedures for Sherco Unit 3 in the most efficient timeframe.

System Support Resource Attachment Y2 Study

Final Report

Xcel Energy

The Sherburne County Generating Plant ("Sherco") Units 1 & 2

August 28, 2015

Redacted

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Sherco 1 Replacement Power Study

Prepared for

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Attachment E
Estimated Rate Impacts

In order to show the impacts of our plan on customer rates and bills, we have included an estimated rate impact analysis of our Updated 2015 and Current Preferred Plan below that includes the breakdown of anticipated increases by customer class. The estimated customer impacts are shown for the five-year period from 2016-2020 at the Minnesota customer class levels. In this Attachment, we present the results of that analysis and discuss the methodology we used to calculate the revenue requirements associated with our Updated 2015 and Current Preferred Plans.

A. Rate Forecast Methodology

To calculate the rate impacts of the Updated 2015 and Current Preferred Plans, we started with the 2016 Budget forecast of total revenue requirements for 2016-2020, developed in July 2015. This is the forecast that formed the basis for the 2016 MN Electric Rate Case (Docket No. E002/GR-15-826) filed in November 2015. [1]

The assumption differences between the Rate Case, the Updated 2015 Plan, and the Current Preferred Plan are as follows:

1. *Rate Case:* Our rate case model includes the following resource additions:

   - 287 MW of solar Power Purchase Agreements (PPA) in 2017, made up of the 100 MW Aurora distributed solar project (Docket No. E002/M-15-330) and 187 MW from our Solar Request for Proposals (Docket No. E002/M-14-162)
   - Updated Community Solar Gardens forecast we reflected in our March 2015 Supplement, totaling over 200 MW by 2020
   - Rooftop solar additions of 9 MW per year through 2020, reflecting Solar Rewards and Made in Minnesota projects
   - 200 MW Courtenay wind project, expected to achieve commercial operation by end of 2016
   - 200 MW Odell wind PPA, expected to achieve commercial operation in 2016

[1] The Company filed an electric rate case application for a 2016-2018 multi-year rate plan in November, 2015. The information contained in that filing includes specific assumptions and adjustments for ratemaking, and will therefore differ from the estimated rate impact information provided in this filing.

- 600 MW of non-Production Tax Credit (PTC) PPA wind, reflecting the proposal in our Updated 2015 plan, before the extension of the PTC
- 345 MW Calpine Corporation Mankato Energy Center natural gas combined cycle project, expected in-service no later than 2019
- 232 MW Xcel Energy Black Dog natural gas combustion turbine project, expected to achieve commercial operation no later than 2019
- Sherco Units 1 and 2 operational through 2030

These changes are summarized in Table 1 below.

Table 1: 2016 Rate Case Resource Additions

	Rate Case				
	2016	**2017**	**2018**	**2019**	**2020**
Solar PPA MW	0	287	0	0	0
Solar Gardens MW	33	36	40	44	49
Rooftop Solar MW	9	9	9	9	9
Owned Wind w/ PTCs MW	200	0	0	0	0
PPA Wind w/ PTCs MW	200	0	0	0	0
PPA Wind wo/ PTCs MW	0	0	0	0	600
Black Dog MW	0	0	0	232	0
Calpine expansion PPA MW	0	0	0	345	0

2. Updated 2015 Plan

The Updated 2015 Plan reflects the same resources shown in the rate case above, with the exceptions of the 600 MW of non-PTC PPA wind in 2020 switches to PTC wind in the Updated 2015 Plan, to reflect the extension of the renewable energy tax credits.

The changes from the Rate Case forecast to the Updated 2015 Plan are shown in Table 2 below.

Table 2: Changes from 2016 Rate Case to Updated 2015 Plan

	2016	**2017**	**2018**	**2019**	**2020**
PPA Wind w/ PTCs MW	-	-	-	-	+600
PPA Wind wo/ PTCs MW	-	-	-	-	-600

3. Current Preferred Plan

The resource additions in our Current Preferred Plan reflect all the changes described above, as well as the resource adjustments described below and shown in Table 3 below:

- Ceasing operations of Sherco Unit 1 in 2026 and Sherco Unit 2 in 2023
- 200 MW of owned solar, added in 2018 and in 2020
- 200 MW of PPA solar, added in 2018 and in 2020
- 400 MW of owned PTC wind in 2018
- 400 MW of PPA wind with PTC in 2018

The changes from the Updated 2015 Plan to the Current Preferred Plan are shown in Table 3 below.

Table 3: Changes from Updated 2015 Plan to Current Preferred Plan

	2016	2017	2018	2019	2020
Owned Solar MW	-	-	+100	-	+100
Solar PPA MW	-	-	+100	-	+100
Owned Wind w/ PTCs MW	-	-	+400	-	-
PPA Wind w/ PTCs MW	-	-	+400	-	-

Table 4 below summarizes all the resources included in our Revenue Requirements analysis of the Current Preferred Plan costs.

Table 4: Current Preferred Plan Resources

	Current Preferred Plan				
	2016	2017	2018	2019	2020
Owned Solar MW	-	-	100	0	100
Solar PPA MW	0	287	100	0	100
Solar Gardens MW	33	36	40	44	49
Rooftop Solar MW	9	9	9	9	9
Owned Wind w/ PTCs MW	200	0	400	0	0
Owned Wind wo/ PTCs MW	0	0	0	0	0
PPA Wind w/ PTCs MW	200	0	400	0	0
PPA Wind wo/ PTCs MW	0	0	0	0	0
Black Dog MW	0	0	0	232	0
Calpine expansion PPA MW	0	0	0	345	0

B. Estimated Rate Impacts by Class per Year

We note that a detailed analysis of rate impacts in a resource planning process with long-time horizons is difficult to produce due to changes in our rates and resource needs that will occur over time. Because of the simplifying assumptions made in both the calculation methodology and the input variables, these estimated impacts may not correspond with actual rates that the Commission sets for various rate classes in the future.

To estimate customer impacts for the immediate five-year period, we estimated revenue requirements similar to a Jurisdictional Cost of Service (JCOSS) for each year, and then performed an estimated Class Cost of Service (CCOSS) analysis – both of which required us to make a number of assumptions.

To determine the JCOSS, we had to make a number of assumptions, including the following:

- Full recovery of the Company's internal five-year forecasts of capital, O&M, and sales,[2]
- Return on Equity (ROE) requested in Docket No. E002/GR-15-826 of 10.00 percent,
- A forecast of debt and equity ratios and debt rates appropriate for the five-year modeling term,
- Estimated typical and precedential regulatory adjustments made in rate cases, such as Advertising, Association Dues, Corporate Aviation, Customer Deposits, Foundation Administration, Incentive Compensation, Investor Relations, the Monticello Extended Power Uprate (EPU) prudence decision from Docket No. E002/CI-13-754, Nobles Amounts over the Certificate of Need, the Prairie Island EPU Amortization, Removal of Non-Asset Trading, and the Sherco Life Extension,

We added the following adjustments appropriate to the Updated 2015 Plan scenario and to the Current Preferred Plan.

Updated 2015 Plan scenario:

- The generation resources described in Table 2 above were modeled to create a fuel forecast. The differences in purchased energy and purchased capacity were added as expenses to the revenue requirements model. Since purchased energy is recovered through the fuel clause, we also assumed an equal amount of fuel

[2] Data as of August, 2015.

clause revenue.

Current Preferred Plan scenario:

- The generation resources described in Table 4 above were modeled to create a fuel forecast. The differences in purchased energy and purchased capacity were added as expenses to the revenue requirements model. Since purchased energy is recovered through the fuel clause, we also assumed an equal amount of fuel clause revenue.
- We estimated rate base, operating expenses, and tax credits related to the owned wind and solar resources and added them to the revenue requirements model.
- We estimated book and tax depreciation expenses, associated balances, and associated property taxes related to an earlier retirement of Sherco Units 1 and 2. These were added to the revenue requirements model.
- We estimated changes to variable O&M at coal, gas combined cycle, and gas combustion turbine plants due to the different fuel dispatch assumptions associated with the generation resource assumptions and adjusted the revenue requirements model.

We caution, however, that this information should not be interpreted as directly comparable to the customer rate impact information we provide as part of a rate case filing for reasons such as the following:

- The internal forecast for 2019-2020 is not prepared at the level of detail necessary for support of a rate case,
- While the forecast includes typical regulatory adjustments, we have not attempted to remove one-time effects or other one-time adjustments that are not specifically known at this time,
- We have made no determination of a rate case filing schedule over this period; the forecast provided assumes full recovery of annual deficiencies, suggesting a full rate case annually, and
- All factors of the Cost of Capital, including debt rates, return on equity, and debt-equity ratios, are subject to change through a rate case.

C. Determining Class Rate Impacts

After the Minnesota jurisdiction projected total revenue requirements for the period are developed, the costs are allocated to customer class based on the approved CCOSS allocation methods from the Company's last rate case order (Docket No.

E002/GR-13-868). Below, we provide detail on the Commission approved methods for allocating all production-related costs.

1. Allocation of Production Related Costs

a. Capital-Related Production Costs

When allocating capital-related production costs, the Company uses the plant stratification approach approved by the Commission in the Company's last five rate cases.

The plant stratification approach begins by comparing the replacement cost of each type of generation plant (fossil, combined cycle, etc.) to the replacement cost of a combustion turbine. Combustion turbines are 100 percent capacity/demand-related since they are the generation source with the lowest capital cost and the highest operating cost. For each generation type, the percent of total generation costs that exceeds the cost of combustion turbine peaking plant are classified as being energy-related. These costs are in excess of the capacity/demand-related portion, and as such, were not incurred to obtain capacity, but rather to obtain lower cost energy.

We show the Commission-approved plant stratification analysis that we applied to capital-related production costs for each plant type in Table 5 below:

Table 5: Stratification Analysis by Plant Type

Plant Type	Replacement Value $/kW	Capacity Ratio	Capacity/Demand Percentage	Energy Percentage
Combustion Turbine	$792	$792 / $792	100.0%	0.0%
Fossil	$2,022	$792 / $2,022	39.2%	60.8%
Nuclear	$4,146	$792 / $4,146	19.1%	80.9%
Combined Cycle	$1,037	$792 / $1,037	76.3%	23.7%
Wind	$14,894	$792 / $14,894	5.3%	94.7%
Solar	$8,182	$792 / $8,182	9.7%	90.3%

After production capital costs for each type of generation plant are split into capacity-related and energy related components based on the percentages shown in Table 5 above, those costs that have been classified as being energy-related are allocated to class using the E8760 energy allocator. The E8760 allocator is calculated by taking the forecast hourly load for each of the 8,760 hours of the test year for each customer class, then weighting the hourly load by the forecasted hourly marginal energy cost in each respective hour. The approved E8760 allocator from the last rate case order is

shown in Table 6 below:

Table 6: Approved E8760 Energy Allocator

MN	Residential	Commercial Non-Demand	C&I Demand	Lighting
100.00%	29.24%	3.33%	67.01%	0.42%

The capital costs that have been classified as being capacity or demand-related are allocated to customer class using the Commission-approved D10S capacity allocator. The D10S allocator is simply each class's load that is coincident with the NSP System peak load. The Commission approved D10S class allocator percentages are shown in Table 7 below:

Table 7: Approved D10S Capacity Allocator

MN	Residential	Commercial Non-Demand	C&I Demand	Lighting
100.00%	34.86%	3.72%	61.42%	0.00%

b. Fuel and Purchased Energy Expenses

These costs are allocated to class using the Commission approved E8760 energy allocator shown in Table 6 above.

c. Production O&M Expense

When allocating Other Production O&M expenses, the Company used the Commission ordered "Location" method. This method starts by identifying those production O&M expenses that vary directly with energy output. Using this criteria, the only expenses that vary directly with output are expenses for chemicals and water use. These costs are allocated to class using the E8760 allocator shown in Table 6. The remaining O&M costs are split into capacity and energy-related components based on the type of production plant associated with the costs. The stratification percentages shown in Table 5 were used to separate costs. Energy-related costs are allocated to class using the E8760 allocator, while capacity-related costs are allocated using the D10S allocator.

2. Calculation of Class Rate Impacts of the Updated 2015 Plan

After all costs had been allocated and revenue requirements by class were calculated, we then determined the estimated bill impacts by class relative to the current rate level. To do this, we calculated the current rate level using the compliance ordered revenues by class with riders included from Docket E002/GR-13-868. We used this calculation to estimate monthly billing units by customer class and resulting typical bills. The CCOSS allocation based estimates of relative percent class increases for the period were then applied to current typical bills to estimate the average dollar per month increase by customer class (see Table 8 below).

Using the above methodology, the incremental costs in the last year of the period (2020) for the Preferred Plan would be expected to increase the average Residential rate by about 4.5 percent on a compounded annual basis through 2020. That is equivalent to a total increase of $20.48 per month above the current rate level.

The impact to the average Large Demand Billed rate would be an increase of about 3.0 percent on a compounded annual basis through 2020, which is equivalent to an increase of 1.37 cents per kWh above the 2015 level.

Table 8: Updated 2015 Plan Estimated Rate Impacts by Class per Year

Rate Class Impacts \1	2015	2016	2017	2018	2019	2020	Comp'd Incr/Yr
Residential (avg rate, ¢/kWh)	12.654¢	13.934	14.372	14.663	15.285	15.775	N/A
Cumul Increase (¢/kWh)		1.280	1.718	2.009	2.632	3.122	N/A
Cumulative Increase (%)		10.12%	13.58%	15.88%	20.80%	24.67%	4.51%
$ Impact/Month, @ 656 kWh		$8.40	$11.27	$13.18	$17.26	$20.48	N/A
Sm Non-Dmd (avg rate, ¢/kWh)	11.970¢	12.934	13.248	13.402	13.769	14.013	N/A
Cumul Increase (¢/kWh)		0.963	1.277	1.431	1.799	2.042	N/A
Cumulative Increase (%)		8.05%	10.67%	11.96%	15.03%	17.06%	3.20%
$ Impact/Month, @ 952 kWh		$9.17	$12.16	$13.62	$17.12	$19.44	N/A
Demand (avg rate, ¢/kWh)	8.649¢	9.219	9.435	9.559	9.834	10.023	N/A
Cumul Increase (¢/kWh)		0.570	0.786	0.911	1.185	1.374	N/A
Cumulative Increase (%)		6.59%	9.09%	10.53%	13.70%	15.89%	2.99%
$ Impact/Month, @ 38,865 kWh		$221.52	$305.49	$354.00	$460.52	$534.16	N/A
Street Ltg (avg rate, ¢/kWh)	15.137¢	17.100	18.340	19.081	19.928	20.810	N/A
Cumul Increase (¢/kWh)		1.964	3.204	3.945	4.791	5.673	N/A
Cumulative Increase (%)		12.97%	21.17%	26.06%	31.65%	37.48%	6.57%
$ Impact/Month, @ 60 kWh		$1.18	$1.92	$2.37	$2.87	$3.40	N/A
1/ Average 2015 Rates are Based on the Outcome of Docket No. E002/Gr-13-868.							

3. Calculation of Class Rate Impacts with the Current Preferred Plan

Table 9 below shows the estimated bill impacts by class relative to the current rate level for the Current Preferred. The incremental costs in the last year of the period (2020) for the Current Preferred Plan would be expected to increase the average Residential rate by about 4.7 percent on a compounded annual basis through 2020. That is equivalent to a total increase of $21.39 per month above the current rate level.

The impact to the average Large Demand Billed rate would be an increase of about 3.25 percent on a compounded annual basis through 2020, which is equivalent to an increase of 1.5 cents per kWh above the 2015 level.

Table 9: Current Preferred Plan Estimated Rate Impacts by Class per Year

Rate Class Impacts \1	2015	2016	2017	2018	2019	2020	Comp'd Incr/Yr
Residential (avg rate, ¢/kWh)	12.654¢	13.945	14.384	14.778	15.397	15.914	N/A
Cumul Increase (¢/kWh)		1.292	1.731	2.124	2.744	3.260	N/A
Cumulative Increase (%)		10.21%	13.68%	16.79%	21.68%	25.77%	4.69%
$ Impact/Month, @ 656 kWh		$8.47	$11.35	$13.93	$18.00	$21.39	N/A
Sm Non-Dmd (avg rate, ¢/kWh)	11.970¢	12.945	13.261	13.515	13.879	14.147	N/A
Cumul Increase (¢/kWh)		0.975	1.290	1.545	1.908	2.177	N/A
Cumulative Increase (%)		8.14%	10.78%	12.91%	15.94%	18.18%	3.40%
$ Impact/Month, @ 952 kWh		$9.28	$12.28	$14.71	$18.17	$20.72	N/A
Demand (avg rate, ¢/kWh)	8.649¢	9.228	9.446	9.666	9.937	10.149	N/A
Cumul Increase (¢/kWh)		0.580	0.797	1.018	1.288	1.501	N/A
Cumulative Increase (%)		6.70%	9.22%	11.77%	14.90%	17.35%	3.25%
$ Impact/Month, @ 38,865 kWh		$225.35	$309.77	$395.57	$500.67	$583.22	N/A
Street Ltg (avg rate, ¢/kWh)	15.137¢	17.105	18.345	19.159	20.004	20.890	N/A
Cumul Increase (¢/kWh)		1.968	3.209	4.022	4.867	5.753	N/A
Cumulative Increase (%)		13.00%	21.20%	26.57%	32.16%	38.01%	6.65%
$ Impact/Month, @ 60 kWh		$1.18	$1.93	$2.41	$2.92	$3.45	N/A

Attachment F
Demand Response, Grid Efficiency, and Distributed Energy Resources as Alternative Resources

The Commission's January 6, 2016 Order required an analysis of the potential for demand response (DR), improved system or grid efficiencies, and distributed energy resources (DER) to replace all or part of the energy and capacity that would otherwise be provided by new gas-fired resources. Below we provide our view of the future viability of DR and DER, including supply-side, demand-side and grid efficiencies as replacement for large generators.

We have also included a Strategist simulation where all possible alternatives, including incremental demand response, distributed generation, grid modernization, utility scale renewables, and thermal units are simultaneously considered and optimized. In various Stakeholder sessions, the Company has referred to such a process as a "Grand Optimization."

As discussed in greater detail below, conducting an analysis that considers all possible alternatives is difficult given the solution option capacity constraints of the Strategist software and current desktop computer processing capabilities. However, the Company has attempted to conduct such an exercise to the greatest extent possible reflecting the above limitations. Ultimately, our Strategist modelling found that the Company's Current Preferred Plan provides a balanced approach that allows us to add significant amounts of renewable resources while also considering impacts on customer costs, procurement, construction and operations.

A. DER as Replacement of Central Station Generation

We believe there are three fundamental and sequential questions related to technological viability, economics and policy that must be addressed in order to assess whether DERs are a viable replacement for central station generation in the planning horizon considered in this resource plan.

1) **Technological Viability** - Do technologies currently exist to meet the required reliability, safety and operational standards at the scale necessary to effectively replace large central station generation?
2) **Economics** - If replacement is technologically viable, how does the cost of DER options compare to the alternatives over the near and long-term?

3) **Policy** - Are there policy reasons that support expansion of distributed resources as an alternative to new central station generation?

We address each of these questions below.

1) Do technologies currently exist to meet the required reliability and operational standards at the scale necessary to effectively replace large central station generation?

As we consider the retirement of Sherco Units 1 and 2, it is important to understand the services and functions that will need to be replaced, particularly those beyond energy and capacity. As noted in our March 16, 2015 Supplement, the Units' size, location and operating characteristics make them unique in the NSPM system and provide important services related to system stability, grid support, and black start capabilities. This is in addition to the replacement capacity and energy required to reliably meet system demand. For context, Sherco Units 1 and 2 are approximately 750 MW each for a combined 1,500 MW of generation.

Given the role of Sherco Units 1 and 2 in the system, a comparable replacement portfolio of distributed resources must be able to:

- Supply the necessary long-term capacity and energy when and where it is needed, in accordance with established safety, security and reliability standards;
- Balance generation with changing load conditions and fluctuations to maintain proper voltage and frequency for the region; and
- Stabilize the grid in the event of a wide-area outage.

Other technical issues and system requirements may emerge upon further study. For example, as discussed in our response to Clean Energy Organizations' Information Request No. 29, advanced inverters may provide some benefits for managing high penetrations of renewable resources, but inverter-connected resources at high levels of penetration generally do not provide the fault current necessary for utility protective relays to operate. As noted in our March Supplement, we have contracted with an independent third party to study the technical impacts of our proposal.

While we recognize the future potential of distributed technologies, it is our understanding that no precedent exists to confidently prove that a distributed portfolio comprised of today's distributed technologies could consistently satisfy all three of these conditions. While it may be possible to design a theoretical portfolio

that addresses these requirements, committing to such a plan in practice introduces significant uncertainty and risks, particularly to reliability. Until more operational and performance information is available to better understand what capabilities these technologies do and do not have under a full range of operating conditions and in the context of a large-scale shift away from centralized resources, we recommend continued presence of large-scale, centralized generation in our fleet.

That said, we see the potential for distributed resources to take on a growing role in coming years and are committed to leveraging them as they become technically viable, cost-competitive, and have an established and acceptable operational record. Over time, it is possible that DER technology could advance to the point that distributed resources could become viable alternatives to centralized generation, but such a decision must be based on well-established capabilities, instead of projections.

Below we provide an overview of the likely core components of a hypothetical distributed resource portfolio consisting of DR, DER, and grid efficiencies. As noted above, it is untested and unknown if and to what extent these resources may work together to replace new large-scale, centralized generation.

- *Supply-side Resources* – These resources are necessary to provide the energy and capacity necessary to meet customers' needs.
    - Distributed Generation. Distributed generation would need to be deployed at an unprecedented scale, strategically dispersed and centrally managed to maintain reliable service.
    - Energy Storage. Storage is a critical complement to DG that addresses the intermittency of renewable DG and allows DG to be dispatchable. Battery storage may also provide other system services, such as voltage and frequency regulation, black start capabilities and spinning and non-spinning reserve, though more research is needed to test how those services can be dispatched and "stacked."

- *Demand-side Resources* – These resources have the potential to reduce and/or shift customer demand, thus deferring or avoiding the need for supply-side investments. Demand-side resources, by definition, rely on actions on the customer's side of the meter, which introduces questions of dispatchability and dependability.

- Demand Response. Existing demand response programs could be expanded to reduce peak demand and reduce the need for additional peaking capacity.
- Energy Efficiency. Aggressive energy efficiency could lower customer demand and energy, which could reduce the need for generation.
- Rate Design. With the enabling metering technology, rates could be redesigned to encourage customers to shift energy use more to off-peak, thus reducing the need for additional peaking capacity. Examples include time-of-use rates and demand charges.

- *Grid Efficiencies* – Through technological advances, the grid can be operated to reduce losses and potentially provide capacity benefits.
  - Voltage control. Voltage control, as enabled by an Advanced Distribution Management System (ADMS), Field Area Network (FAN), and other distribution system technologies, can provide energy or capacity benefits. Voltage can be controlled to reduce energy use by maintaining voltage at the lowest acceptable level (often referred to as Distribution Voltage Optimization). An alternative control scheme is to use the system as a stand-by resource or spinning reserve. This is done by maintaining voltage in the typical range (as we do today), and lowering the voltage only when a capacity shortage occurs. Such a reduction can have a significant initial impact, but is expected to taper off over time to a lower plateau. A hybrid scheme may be possible where the system is operated in the conservation mode normally, but if a capacity need is identified, the control reverts to a "Virtual Spinning Reserve" mode.

It is important to acknowledge the pivotal role that grid modernization investments have in enabling DER to play an increased role in the future. For example, communications and control software and technologies such as ADMS, FAN, and Distributed Energy Resources Management System (DERMS), are vital for the control, management and optimization of these resources, making them necessary prerequisites for treating DERs as reliable system resources. For example, the ADMS will enable increased hosting capacity, which is the amount of distributed energy that can be hosted on the distribution system, by allowing, in conjunction with other controls, active mitigation of potentially problematic voltage and load situations.

2) If replacement is technologically viable, how does the cost of DR and DER options compare to the alternatives over the near and long-term?

As discussed above, we believe technology has not sufficiently matured to enable DERs as alternatives to new large-scale generation additions. As is common with technologies still climbing the maturity or commercialization curve, many of the distributed resource technologies that would be needed are not cost-competitive with established technologies. As discussed below, the DER and incremental DR alternatives were not selected in our Grand Optimization due to their higher cost.

However, our existing DR programs continue to be an important part of our resource portfolio, as demonstrated by the increase in our DR forecast. The Company has a long history of success with DR. Currently, we have exceeded 930 MW in the Upper Midwest since we began offering load management programs for customers in the 1980s. While we remain committed to providing customer options, we must continue to be vigilant in adjusting the portfolio in order to be compliant with the rules set by federal regulation and MISO. Further, we must take the opportunity to develop and test customer programs using new technology prior to depending upon them as a resource on our system or in the MISO market.

We have acknowledged that it is likely there will be some attrition over the planning period, wherein customers begin to choose new opportunities with lower demand reduction potential. This may at times be a trade-off between further participation and the ability to self-control, which could reduce our portfolio in the short-term.

Given the modeling result, we have not adjusted our moderate demand response forecast. However, we continue to review new customer choices for DR including dynamic pricing options (time-of-use, peak pricing, etc.), new technologies (smart thermostats), and updated rates to encourage participation. We have also begun investing in a Demand Response Management System to help facilitate new opportunities as they arise due to changing technology.

While the cost declines observed for solar DG and storage over the past few years are encouraging, it is unclear and perhaps unlikely that these cost declines can overcome the economies of scale inherent in larger-scale alternatives. Similarly, while distributed resources may provide other benefits over time, such as deferred or avoided transmission and distribution investments, it is premature to assign a definitive timeline and value to those benefits.

3) Are there policy reasons that support expansion of distributed resources as an alternative to new central station generation?

We recognize the growing interest among our regulators, stakeholders and customers In transitioning to a 21st century electric system and are advancing these interests in several different ways. We agree that it is a worthwhile goal to make plans to move away from coal and other carbon-emitting resources in favor of carbon-free alternatives, as demonstrated by our proposal in this transformational Resource Plan. These proposals are responsive to state energy policy goals, which seek to dramatically lower the state's contribution to climate change, maximize energy efficiency and conservation, and promote renewable energy, among others. The question is in how best to meet those policy goals, while also satisfying the basic requirements of safe, reliable, secure and affordable energy.

With the technological and economic challenges currently facing DERs, we believe we are not yet at the point where DERs can fulfill or have an advantage in satisfying those basic requirements at the scale and speed implicit in this question. We are taking steps to reduce the challenges and prepare for the future grid, such as through our grid modernization efforts and solar plus storage demonstration project proposal, but it is still too early to confidently choose DERs as a reasonable and complete alternative to new central station generation additions.

B. Strategist Analysis

The first step in beginning the optimization was to define the available alternatives to be considered. To narrow the scope of the exercise, the alternatives were reduced to the following representative options:

- *Incremental Demand Response Option* - The DR option was constructed by extrapolating results from the Brattle DR Potential Study[1] to future years. The Brattle study did not contemplate or produce results directly related to this use, and extrapolating the results of the study is inherently an estimate or proxy. To adequately project costs and availability of DR resources many years out would require a new analysis, and could likely produce very different results. Nevertheless, the proxy DR resource was developed as a new optional resource that is incremental to the "Base" DR included in all cases. The incremental capacity and costs were derived by taking the difference between the "High"

[1] Appendix O of our Initial Filing.

and "Base" DR scenarios included in our initial filing. Costs for the new program were then escalated at inflation to determine the costs for an incremental program starting at various years. The incremental DR capacity made available is greater than two new combustion turbines.

- *Incremental Distributed Generation Option* – The alternative reflects current information on distributed small solar projects with representative pricing at $120/MWh with no escalation. Flat pricing assuming technology and project development improvements are expected to offset any inflation.
- *Incremental Grid Modernization* – Costs and operational attributes for grid modernization are not clear enough at this time to develop a reasonable optimization alternative for inclusion in the modeling. We discussed grid modernization qualitatively above.
- *Incremental Renewables* – The same expansion alternatives with vintages and tax benefits that were used in the main scenarios were also included in the Grand Optimization. However, tranches with identical tax benefits were limited to certain specified years to reduce the computational requirements of the model. As an example, 30% ITC solar was limited to be installed in 2021, and full PTC wind was limited to 2018, rather than being available in all years. Late wind with no PTC benefit and late solar with 10% ITC benefit were also offered as options after the expiration of the PTC and ITC benefits.
- *Thermal Alternatives* – The generic thermal CT and CC units were made available in all years. Generic not site specific alternatives were used.

The Grand Optimization tests many resource options for cost-effectiveness including DR, distributed generation, wind generation with and without PTC benefits, and solar generation with 30% or 10% ITC benefits, along with the thermal generation options. Because of the number of resource options available to choose from in each year, the cumulative number of possible combinations is enormous. If there were no limits placed on the Strategist model's logic, the model would need to evaluate every resource option added an arbitrarily large number of times every year to ensure every possible resource combination was evaluated. The size of the problem quickly becomes too large for the software.

Strategist automatically begins to disregard combinations when the problem gets too large, a process called "truncation." Strategist truncates the excess combinations (in the Company's version there are 2,500 combinations retained) based on accumulated cost to the year it needs to truncate. Thus, a plan might get truncated in 2020 if it was not one of the lowest cost 2,500 plans in 2020, even though later in the simulation it

might have ultimately ended up being lower-cost had it been allowed to continue in the process. There must be a balance between limiting the number of options per year while ensuring every option has equal chance for its benefits and costs to be included in the final results of the optimization.

There are multiple ways to solve the truncation problem. One way is to prescreen options before putting them into the Strategist model based on relative costs. The Company has done this in evaluating thermal generation technologies. Some thermal generation technologies have been prescreened based on having a cost advantage for similar benefits. An example of a prescreened option is how the Company compared the cost of a 2x1 combined cycle versus a 1x1 combined cycle (CC). The Company determined that over a typical range of capacity factors, the installed cost of a 2x1 CC on a $/kW basis is significantly more favorable than the cost of a 1x1 CC, while providing very similar energy benefits. By prescreening and removing the 1x1 CC option from Strategist, the scale of the problem is reduced.

The Company has not prescreened DR, DG, wind, or solar resource options in the Grand Optimization as these options and the timing of their additions is the main focus of the analysis.

Solving an optimization of this size also requires a "trial and error" iterative approach. Initially, the model is allowed to select any type of resource, but only in smaller quantities. As iterative results indicate what types of technologies are consistently selected at particular times, a small number of these consistently-selected alternatives can be switched from being part of the optimization to being locked in. When the model no longer has to consider them as alternatives, it reduces the problem size. In the next run, the model is allowed to consider additional alternatives beyond those locked in to the plan. If more are taken, then those additional resources are also locked in. By iteratively offering and then locking in resources, a stable point can be determined when the model has just as much of a particular resource as it desires; that is, no additional resources are selected even when available. This iterative approach is essentially the same process that the Company has followed in determining its proposals in March and October 2015.

The Grand Optimization was analyzed in two steps. The first step is a capacity-need only optimization, with the second step including the system energy benefits of non-capacity (or "superfluous") resources in a resource-need optimization. Both steps find the lowest PVSC based on the assumptions and meet the required reserve margin; however, a capacity-need optimization allows the Strategist Model to add

resource options only if there is a capacity need to meet the required reserve margin. By contrast, a resource-need optimization allows the Strategist Model to add resource options even if there is not a capacity need to meet the required reserve margin. An example to explain the distinction between the two optimizations is to consider a wind resource option with production tax credit benefits - the wind alternative contributes relatively little to firm capacity, and a very large amount of wind would be required to offset the need for even one CT. However, the low-cost energy could very well be below the marginal system energy costs, resulting in significant economic value if added as a resource. The wind would most likely not be selected in a capacity-need optimization, but could very likely be selected in the resource-need optimization.

1. Capacity-Need Optimization Process and Results

The Company started the capacity-need optimization from the results of the Company's Current Preferred Plan. In this Plan, which adds 1,800 MW of wind and 1,000 MW of solar and retires Sherco Units 1 and 2 in 2026 and 2023 respectively, there is one combined cycle unit added and nine combustion turbine units added from 2018 to 2030. An optimized capacity-view with wind, solar, DR, and DG options should add a similar amount of firm capacity. An iterative process as described above was followed, and the PVSC from each iteration was compared to the prior iteration to ensure that the optimization was getting more efficient. The least-cost solution of the capacity-need optimization is displayed below in Table 1. It is important to note that no "real-world" constraints were placed on the number or type of options that could be added in a given year, and no attempt was made to smooth the rate impact of the additions. In actuality, the results of this exercise need to be tempered with considerations of system operational limitations, contracting, negotiating and construction logistics (especially wind equipment transport and limited tall crane availability for turbine erection), large step increases in customer costs, etc. Since there is no capacity need until 2024, after a Sherco unit is retired, all the resource additions are in 2024 or later. The capacity-need optimization adds 800 MW of late wind, 3600 MW of late solar, four CTs, and one CC from 2024 to 2030. The DR and DG alternatives were not selected due to the higher cost of those resources.

Table 1: Capacity-Need Expansion Plan

28_C: Capacity-Need Optimization	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Small Solar	48	42	45	49	53	58	17	20	24	29	34	41	49	59	71	85	723
Large Solar	-	-	287	-	-	-	-	-	-	-	-	800	1,800	800	-	200	3,887
Wind	350	200	200	-	-	-	-	-	-	-	-	-	400	400	-	-	1,550
PPA CT	-	-	-	-	-	-	-	-	-	230	460	230	-	-	-	-	920
PPA CC	-	-	-	-	345	-	-	-	-	-	778	-	-	-	-	-	1,123
Fargo CT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BD/Sherco CT	-	-	-	-	232	-	-	-	-	-	-	-	-	-	-	-	232
SH Boiler	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sherco CC/BD CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Incremental DR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Incremental DG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

2. Resource-Need Optimization

The number of possible combinations in the resource-need optimization is much greater than the possible combinations in the capacity-need optimization. The resource-need optimization considers increments of wind, solar, and DR options above the number required to meet the reserve margin and internally adds them to the system to evaluate cost effectiveness. Since Strategist quickly exceeds its maximum number of combinations with these incremental superfluous resources, the Company had to extensively use an iterative process.

As we discussed earlier, the iterative process uses the results of a prior incremental test to determine if in the next run a resource should be locked in place or removed. The Company took the PVSC results of each run to verify that the solution to the optimization was becoming more efficient with each iteration.

The resource-need optimization used the results of the capacity-need optimization as well as the Company's Current Preferred Plan to help set the initial constraints. As an example, since the PTC wind and 30% ITC solar are similar or lower cost than corresponding non-PTC late wind and 10% ITC late solar additions of the capacity-need optimization, the resource-need optimization would be expected to add no less renewable energy than the capacity-need optimization.

Using run results and the iterative process, the least-cost plan consisted of PTC wind, combustion turbines, and late solar as the best options. The least-cost solution of the resource-need optimization is displayed below in Table 2. The resource-need optimization adds 5,200 MW of PTC wind, 2,600 MW of late solar, and seven combustion turbines. Again, the DR and DG alternatives were not selected due to the higher cost of those resources. As with the capacity-need results, no "real-world"

constraints were set on the options by year and the same considerations would apply to convert theoretical results such as this into an actual plan.

Table 2: Resource-Need Expansion Plan

28_B: Resource-Need Optimization	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Small Solar	48	42	45	49	53	58	17	20	24	29	34	41	49	59	71	85	723
Large Solar	-	-	287	-	-	-	-	-	-	-	-	-	1,400	1,000	-	200	2,887
Wind	350	200	200	-	5,200	-	-	-	-	-	-	-	-	-	-	-	5,950
PPA CT	-	-	-	-	-	-	-	-	-	-	690	690	230	-	-	-	1,610
PPA CC	-	-	-	-	345	-	-	-	-	-	-	-	-	-	-	-	345
Fargo CT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BD/Sherco CT	-	-	-	-	232	-	-	-	-	-	-	-	-	-	-	-	232
SH Boiler	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sherco CC/BD CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Incremental DR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Incremental DG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

In summary, the capacity-need and resource-need optimizations indicate that the Company's Current Preferred Plan is consistent and prudent. Applying a more rateable approach to renewables, while still incorporating large amounts of PTC-eligible wind and tax incented solar makes sense for customers. Our Current Preferred Plan represents a balance of the Resource-Need and Capacity-Need Expansion Plans. Adding 5,200 MW of wind in 2018 based on the results of the Resource-Need Optimization is not a viable option from a rate-impact, contracting, construction or operations perspective. Likewise, waiting until 2026 to add additional renewables based on the Capacity-Need Optimization fails to account for the energy and environmental benefits of adding competitive fixed price renewable energy resources to our system in the near-term. Our plan balances the advantages of adding significant amount of renewables–1,200 MW by 2020–but in a manner that also considers the impacts on customer costs.

Attachment G
Socioeconomic Study Summary

The Company has worked with the Leeds School of Business at the University of Colorado Boulder and the Labovitz School of Business and Economics at the University of Minnesota Duluth to prepare an analysis of the economic impacts on the state of Minnesota, including Sherburne County, of alternative retirement and replacement scenarios for the Sherburne County generating Units 1 and 2 (Sherco). This study was initiated in response to the Commission's request in our Sherco Life Cycle Management (LCM) proceeding.[1] This study – Economic Impacts of Sherco Plant Alternatives – is included with this filing as Attachment F1 and looked at impacts on employment, gross domestic product (GDP), and disposable personal income on those locations impacted by a change in operating expenditures, capital expenditures, and electricity rates. The scenarios, explained in more detail below, included various Sherco unit retirement dates and the replacement of the two Sherco units with one combined cycle (CC) at the Sherco site and one CC located in Dakota County.

While this study did not model a scenario that directly reflects our Current Preferred Plan (ceasing coal generation at Sherco Unit 1 in 2026 and Sherco Unit 2 in 2023), those dates do fall within the range of scenarios analyzed, with retirement dates ranging from Sherco 1 and 2 in 2020 to Sherco 1 in 2031 and Sherco 2 in 2025. Retirement of either of the Sherco units generates initial positive economic impacts in Sherburne County as a result of decommissioning activities and the construction of a combined cycle at the Sherco site and is then followed by negative economic impacts. The pattern of positive impacts followed by negative impacts is due to shifting the retirement to a date earlier than the economic end of life. The long-term economic effect on Sherburne County after this initial activity is negative under most scenarios due to lost operating and maintenance activity. The construction of replacement generation for one Sherco unit retirement, sited in Dakota County in the scenarios examined for this study, generates positive economic impacts in Dakota County during the construction phase and the succeeding years as a result of ongoing operations. The effect of Sherco unit retirements is a shift in employment from Sherburne County to Dakota County, or the location in which replacement generation is constructed. The timing of those impacts varies in relation to the timing of

[1] *In the Matter of Xcel Energy's Sherco Life Cycle Management Study/2014 Integrated Resource Plan*, Docket No. E002/RP-13-868.

generator retirement and replacement. Construction of replacement generation within Minnesota helps to offset some of the negative economic impacts in the State of Minnesota associated with lost generation.

A. Methodology

The research analysis method used for this study was the Regional Economic Models, Incorporated's (REMI) input-output, general equilibrium, econometric, and economic geography model, using state and national economic and demographic data, as well as data from the Company including capital expenditures, operating expenditures, and revenue requirements for each scenario. The study covered a period from 2015 through 2040, looking at near-term, mid-term, and long-term impacts of alternative retirement and replacement scenarios for Sherco Units 1 and 2. This study period was selected in order to capture the economic activity in the near-term related to decommissioning and the construction of replacement generation, as well as the longer-term impacts of operations and employment at the replacement facilities.

While the specific location of replacement generation for the Sherco units is unknown, Dakota County was selected because it is within Minnesota and the study's purpose was to examine impacts on the State of Minnesota. In addition, it allows for the transfer of economic impacts, such as jobs from Sherco to another location, to be quantified. Therefore, economic impacts were analyzed in this report for Sherburne County, Dakota County, and the rest of Minnesota.

The study examined four scenarios and a baseline scenario, detailed in Table 1 below. We include for comparison the Current Preferred Plan scenario, to illustrate the similarity of the retirement dates and replacement plans between our plan and the scenarios studied. These scenarios correspond to the Updated 2015 Plan and alternative retirement scenarios that were presented in the March 16, 2015 Supplement. The results of the retirement scenarios included in the study are reported as the change in economic impacts relative to the baseline scenario. Replacement generation options included in the study were modeled based on combinations of comparatively-sized gas-fired CC generators, located at the site of our Black Dog plant in Dakota County and at the existing Sherco site.

Table 1: Scenarios Analyzed in the Socioeconomic Study

Scenario	Unit 1 Retirement Date	Unit 2 Retirement Date	Unit 1 Replacement	Unit 2 Replacement
Baseline/ Updated 2015 Plan	2031	2031	Combined Cycle at Sherco	Combined Cycle at Black Dog
SHC1 2031 SHC2 2025	2031	2025	Combined Cycle at Sherco	Combined Cycle at Black Dog
SHC1 2025 SHC2 2025	2025	2025	Combined Cycle at Sherco	Combined Cycle at Black Dog
SHC1 2020 SHC2 2020	2020	2020	Combined Cycle at Sherco	Combined Cycle at Black Dog
SHC1 2023 SHC2 2020	2023	2020	Combined Cycle at Sherco	Combined Cycle at Black Dog
Current Preferred Plan*	2026	2023	Combined Cycle at Sherco	Combustion Turbine in Fargo

**Not analyzed in this study, but included for comparison.*

B. Results

Overall, the study found that all early retirement scenarios, when compared to the Baseline, result in comparatively slower growth within the Minnesota economy. This impact, however, represents a relatively small percentage of the overall Minnesota economy, as the state's total Gross Domestic Product (GDP) for 2014 was $316 billion. The impact on statewide GDP, shown in Table 2 below, was between $16 million and $90 million, representing a less than one percent impact. None of the scenarios reviewed has a recessionary impact on the state.

Table 2: Sherco Retirement Impacts on the Minnesota Economy, 2015-2040 Averages

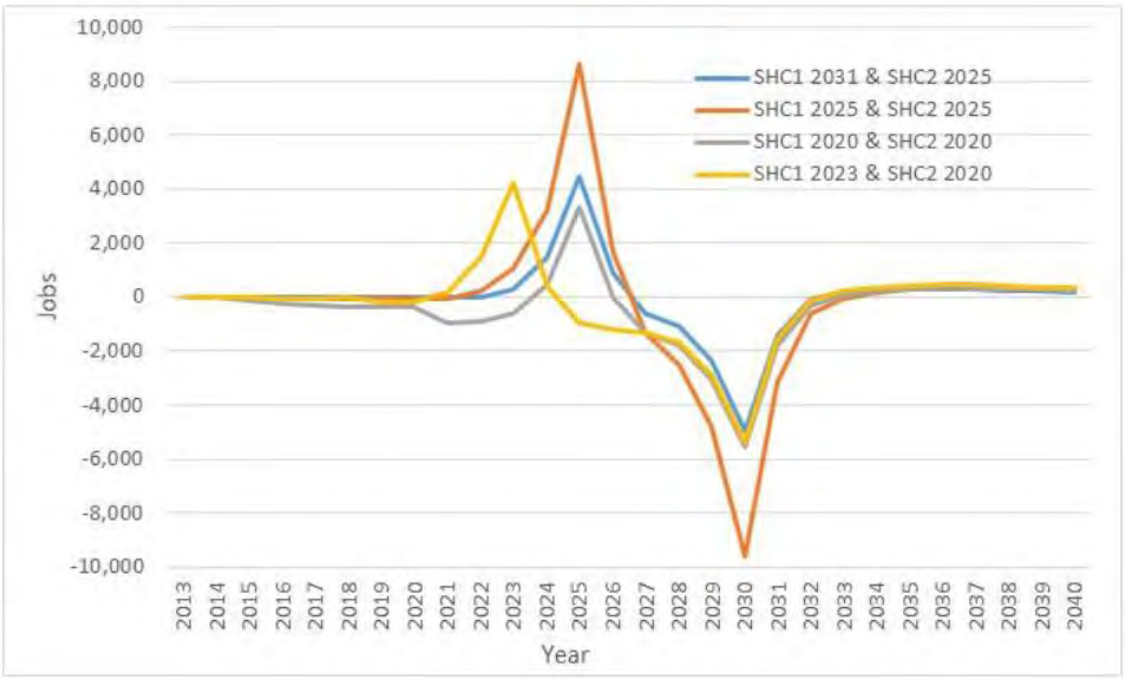
Metric	Units	2015–2040			
		SHC1 2031/ SHC2 2025	SHC1 2025/ SHC2 2025	SHC1 2020/ SHC2 2020	SHC1 2023/ SHC2 2020
Total Employment	Jobs	-75	-258	-570	-300
	Percent Change	*0.00%*	*-0.01%*	*-0.01%*	*-0.01%*
Gross Domestic Product	Dollars (Thousands)[1]	-16,021	-53,257	-89,966	-49,813
	Percent Change	*0.00%*	*-0.01%*	*-0.02%*	*-0.01%*
Real Disposable Personal Income	Dollars (Thousands)[1]	-13,719	-47,919	-83,485	-52,443
	Percent Change	*0.00%*	*-0.01%*	*-0.03%*	*-0.02%*

[1] Fixed (2014) dollars.

All scenarios will result in increased revenue requirements associated with the capital cost of replacement generation. The increase in revenue requirements will result in increased electricity rates for residential, commercial, and industrial utility customers, which will in turn have a negative economic impact on the state overall. The extent of the economic impacts is affected by factors that include the retirement cost of existing units, the source of inputs for capital investments, the ongoing operating costs, the sources of fuels, and the revenue requirements assigned to the customer base.

The study showed the impacts of the various retirement scenarios on private employment, shown in Figure 1 below, as compared to the baseline. This illustrates how the timing of the impacts on employment shifts relative to the retirement dates. In each scenario, there is a near-term increase in employment relative to the baseline due to decommissioning and the construction of replacement generation. The subsequent dip in employment below the baseline is due to the retirement of the Sherco units.

Figure 1: Sherco Retirement Impact on Minnesota Private Employment



C. Summary

While the Socioeconomic Study did not model a scenario that directly reflects our Current Preferred Plan, our proposed 2023 and 2026 retirement dates fall within the range of scenarios analyzed. Results show that all early retirement scenarios, when compared to a baseline, result in moderately slower growth in the Minnesota economy. The closure of Units 1 and 2 showed negative impacts on employment, GDP, and disposable personal income in Sherburne County. However, construction of replacement generation within Minnesota creates positive impacts where the replacement is constructed and helps to offset some of the negative economic impacts in the state associated with early retirement. The path charted by our Current Preferred Plan provides certainty for stakeholders, as well as an 8 to 10 year transition period. With our proposal for on-site replacement generation, we demonstrate our commitment to promoting economic development in Central Minnesota.

NORTHERN STATES POWER

ECONOMIC IMPACTS OF SHERCO PLANT ALTERNATIVES

Research by:

Business Research Division
Leeds School of Business
University of Colorado Boulder

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October 15, 2015

A report prepared for Northern States Power.

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DEFINITIONS

Employment: Includes the number of full-time and part-time jobs (headcount) by business physical location.

Deflators: Measure of price changes within an industry.

Gross Domestic Product: Total value of final goods and services produced each year within a country or region.

Leakage: Economic activity that occurs outside the area of study but is driven by activity within the study area.

Metropolitan Statistical Area: Geographic areas with 50,000 or more population.[1]

Multiplier: Change in total economic activity driven by a change in direct economic activity.

Output: Total production value of goods and services, including intermediate goods purchased and value added.

Personal Income: Includes all sources of income, including employee compensation, proprietors' income, rental income, capital income, and transfer payments.

[1]For more information, visit: http://www.whitehouse.gov/sites/default/files/omb/assets/fedreg_2010/06282010_metro_standards-Complete.pdf, retrieved July 13, 2014.

EXECUTIVE SUMMARY

This document presents the results of an analysis prepared by the Leeds School of Business to quantify the economic impacts on the state of Minnesota of alternative retirement dates for the Northern States Power Company (NSP) coal-fired Sherco 1 and Sherco 2 generating units. The purpose of an economic impact study is to identify the impacts on employment, gross domestic product, disposable personal income, and other economic metrics for those locations impacted by a change in operating expenditures, capital expenditures, property taxes, and electricity rates.

The study area was the state of Minnesota. Impacts on Sherburne County and Dakota County are reported separately from all other counties in the state. Sherburne County is reported separately because the Sherco generating units are both located there, and this separation allows the local effect of an early Sherco retirement to be identified. Dakota County is reported separately because it may be a viable location for the construction of the generation needed to replace the retired Sherco generation. While the location of replacement generation is currently unknown, the purpose of the study was to examine impacts on the state of Minnesota. Therefore, it was important to select a location for replacement generation within the state in order to maintain the focus on Minnesota economic impacts.

The study period was the years 2015 through 2040. This period was selected to capture the near-term economic activity related to decommissioning Sherco and constructing replacement generation, as well as the effects of a change in electricity rates. An abbreviated description of the four retirement scenarios is provided below. A detailed description of the scenarios is provided in the Scenarios section of the report.

The study examined four retirement scenarios and a baseline scenario. The baseline scenario included operating Sherco 1 and Sherco 2 through 2031, then replacing them with the combined cycle generators. Four retirement scenarios were included, and the study results are reported as the change in economic impacts of these scenarios relative to the baseline scenario. The replacement generation that was modeled was based on combinations of comparatively sized gas-fired combined cycle generators located at the Black Dog site in Dakota County and at the Sherco site.

- SHC1 2031 & SHC2 2025: Sherco 1 and Sherco 2 will stop operation in 2031 and 2025, respectively. Sherco 2 will be replaced with a combined cycle generator constructed at Black Dog, and Sherco 1 will be replaced with a combined cycle generator constructed at the Sherco site.
- SHC1 2025 & SHC2 2025: Sherco units 1 and 2 will stop operation in 2025 and be replaced with combined cycle generators constructed at the Sherco site and the Black Dog site.
- SHC1 2020 & SHC2 2020: Sherco units 1 and 2 will retire in 2020 and be replaced with combined cycle generators constructed at the Sherco site and the Black Dog site.
- SHC1 2023 & SHC2 2020: Sherco 2 will retire in 2020 and be replaced with a combined cycle generator constructed at the Black Dog site. Sherco 1 will retire in 2023 and be replaced with a combined cycle generator constructed at the Sherco site.

The research team used the REMI model for the analysis. The model used by Leeds was provided by REMI specifically for the state of Minnesota using national and Minnesota economic and demographic data. The REMI model used for this analysis is the three region, PI+ model 1.6.8 for Sherburne County, Dakota County, and the rest of Minnesota. The 1.6.8 model includes historical data through 2012. NSP provided data that included capital expenditures, operating expenditures, revenue requirements, and taxes for each scenario. The research team worked under the assumption that the company provided good-faith estimates for each scenario.

The study findings show that the continued operation of and investments in Sherco units 1 and 2 through 2031, followed by replacement with combined cycle generators, will have the greatest ongoing positive economic contribution to the Minnesota economy. The retirement and replacement scenarios have varying degrees of impact on the Sherburne County and Dakota County economies. Retiring either of the Sherco units generates positive economic activity in Sherburne County during the decommissioning phase, but produce a negative economic cost during the succeeding years under most scenarios due to lost operating and maintenance activity. The construction of replacement generation in Dakota County generates positive economic activity during the construction phase and during the succeeding years given the change in local operations. There will be an increase in revenue requirements for all retirement scenarios due to the capital-related costs of replacement generation. These higher costs will increase electricity rates for residential, commercial, and industrial utility customers and will have a negative economic impact on Sherburne County, Dakota County, and the rest of Minnesota. The extent of the economic impacts is affected by factors that include the retirement costs of existing units, the sources of inputs for capital investments, the ongoing operating costs, the sources of fuels, and the revenue requirements assigned to the customer base.

Comparing the four alternative scenarios to the baseline scenario, the time series of economic impacts on Minnesota GDP is illustrated in Figure 1. The figure shows the near-term benefits accrued during the decommissioning and construction phase, followed by a negative impact due to higher revenue requirements over the remainder of the study period. The smallest negative economic impact results from the retirement and replacement of generators in 2025 and 2031. The greatest negative economic impact relative to the baseline results from the earlier retirement of both Sherco 1 and Sherco 2 in 2020 and the replacement in 2026 and 2031.

The lack of indigenous fossil resources in Minnesota limits potential gains in fuel switching. Since Minnesota does not have indigenous coal or natural gas resources, it necessitates importing fuel from other states and requiring gas pipeline upgrades. The baseline scenario and each early retirement scenario require additional investments in gas pipelines and transmission totaling about 10% of total capital expenditures.

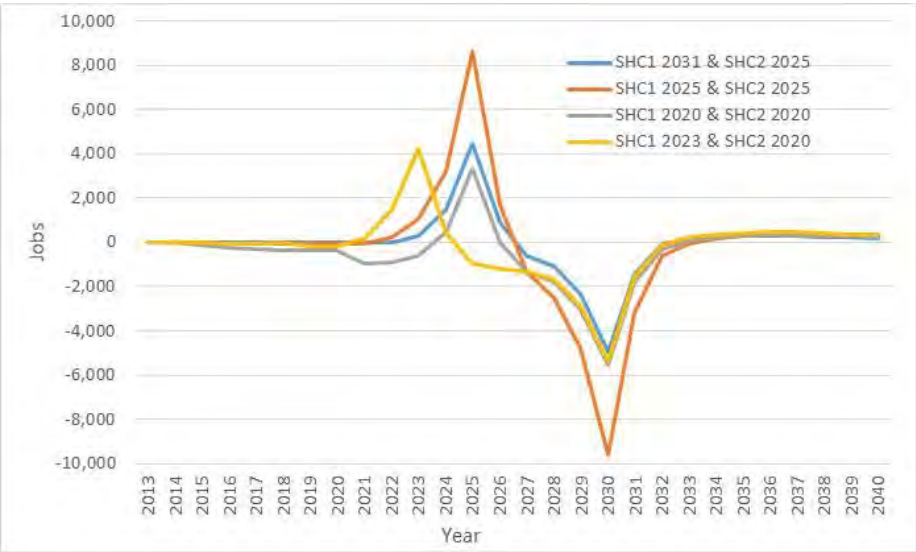
Since all scenarios involve generator retirement and replacement, the spikes and dips in economic activity are largely due to timing—specifically the timing of activity compared to the baseline scenario. Retiring units in 2020 instead of 2031, for instance, increases economic activity in the 2020s, but decreases economic activity in the 2030s. Since all of the alternative scenarios retire and replace Sherco

1 and Sherco 2 sooner than the baseline scenario, then all of the alternative scenarios also shift economic activity earlier.

FIGURE 1: SHERCO RETIREMENT IMPACT ON MINNESOTA GDP

A similar pattern is shown for Minnesota private employment, which is shown in Figure 2. Likewise, the near-term activity related to the decommissioning of existing generation and the constructing of replacement generation increases jobs. While employment continues to increase in Minnesota under all scenarios over the study period, early retirement of the Sherco generators results in a decrease in Minnesota employment compared to the baseline scenario.

FIGURE 2: SHERCO RETIREMENT IMPACT ON MINNESOTA PRIVATE EMPLOYMENT



In addition to the differences between near-term and long-term effects shown above, there are also location specific impacts for Sherburne County, Dakota County, and the rest of Minnesota. Compared to the baseline scenario, most retirement scenarios show negative impacts on Sherburne County given that this location will experience decreasing generation operations over time. Dakota County benefits from early retirement of the first Sherco generator because the construction and new operating activity at the Black Dog site will be a boost to the county economy, effectively outweighing the economic costs associated with higher revenue requirements. However, while the near-term benefits of constructing the replacement generation in Dakota County may be large, these employment benefits decline rapidly and are not large over the entire study period. Locally, the impact of early retirement is a shift in employment from Sherburne County to Dakota County; statewide, employment continues to grow but at a slower rate.

A summary of all economic metrics for each retirement scenario is shown in Table 1 for the state of Minnesota. Each of the retirement and replacement scenarios place Minnesota on a slightly slower economic growth trajectory between 2015 and 2040, though the change in growth is relatively small. From 2015 to 2040, under the various scenarios, total statewide employment is lower, on average, by 75 jobs to 570 jobs as compared to the baseline; GDP is lower by $16 million to $90 million, and real disposable personal income is lower by $14 million to $83 million. In percentage terms, the change from the baseline scenario is less than one-tenth of 1%.

While the economic impacts of the retirement and replacement scenarios may appear large in absolute values, the percentage change of the impacts is relatively small in light of the magnitude of the overall Minnesota economy. Accordingly, the impacts are not recessionary—the economy continues on a trajectory of growth, albeit slightly slower growth.

TABLE 1: SHERCO RETIREMENT IMPACTS ON THE MINNESOTA ECONOMY, AVERAGE 2015–2040

		Average 2015–2040			
Metric	Units	SHC1 2031/ SHC2 2025	SHC1 2025/ SHC2 2025	SHC1 2020/ SHC2 2020	SHC1 2023/ SHC2 2020
Total Employment	Jobs	-75	-258	-570	-300
	Percent Change	*0.00%*	*-0.01%*	*-0.01%*	*-0.01%*
Gross Domestic Product	Dollars (Thousands)[1]	-16,021	-53,257	-89,966	-49,813
	Percent Change	*0.00%*	*-0.01%*	*-0.02%*	*-0.01%*
Real Disposable Personal Income	Dollars (Thousands)[1]	-13,719	-47,919	-83,485	-52,443
	Percent Change	*0.00%*	*-0.01%*	*-0.03%*	*-0.02%*

[1]Dollars are fixed (2014) dollars.

A summary of all economic metrics for each retirement scenario is shown in Table 2 for Sherburne County. Most of the retirement and replacement scenarios place Sherburne County on a slightly slower economic growth trajectory between 2015 and 2040, though the change in growth is relatively small. From 2015 to 2040, under the various scenarios, the changes in total statewide employment ranges between 5 and -140 jobs as compared to the baseline; the changes in GDP range between -$4 million and -$19 million, and the changes in real disposable personal income range between -$2 million and -$11 million. In percentage terms, the change from the baseline scenario is less than 1%.

TABLE 2: SHERCO RETIREMENT IMPACTS ON SHERBURNE COUNTY, AVERAGE 2015–2040

Metric	Units	Average 2015–2040 SHC1 2031/ SHC2 2025	SHC1 2025/ SHC2 2025	SHC1 2020/ SHC2 2020	SHC1 2023/ SHC2 2020
Total Employment	Jobs	-31	-22	-140	5
	Percent Change	*-0.07%*	*-0.05%*	*-0.34%*	*0.01%*
Gross Domestic Product	Dollars (Thousands)[1]	-4,097	-6,863	-18,871	13,737
	Percent Change	*-0.11%*	*-0.18%*	*-0.48%*	*0.35%*
Real Disposable Personal Income	Dollars (Thousands)[1]	-2,406	-2,920	-10,584	2,668
	Percent Change	*-0.05%*	*-0.06%*	*-0.22%*	*0.06%*

[1]Dollars are fixed (2014) dollars.

A summary of all economic metrics for each retirement scenario is shown in Table 3 for Dakota County. Most of the retirement and replacement scenarios place Dakota County on a slightly faster economic growth trajectory between 2015 and 2040, though the change in growth is relatively small. From 2015 to 2040, under the various scenarios, the changes in total statewide employment ranges between 18 and -12 jobs as compared to the baseline; the changes in GDP range between -$445,000 and -$6 million, and the changes in real disposable personal income range between -$714,000 and -$7 million. In percentage terms, the change from the baseline scenario is less than 1%.

TABLE 3: SHERCO RETIREMENT IMPACTS ON DAKOTA COUNTY, AVERAGE 2015–2040

Metric	Units	Average 2015–2040 SHC1 2031/ SHC2 2025	SHC1 2025/ SHC2 2025	SHC1 2020/ SHC2 2020	SHC1 2023/ SHC2 2020
Total Employment	Jobs	18	0	-12	7
	Percent Change	*0.01%*	*0.00%*	*0.00%*	*0.00%*
Gross Domestic Product	Dollars (Thousands)[1]	-445	-3,757	-5,751	-3,430
	Percent Change	*0.00%*	*-0.01%*	*-0.02%*	*-0.01%*
Real Disposable Personal Income	Dollars (Thousands)[1]	-714	-4,508	-6,641	-5,182
	Percent Change	*0.00%*	*-0.02%*	*-0.02%*	*-0.02%*

[1]Dollars are fixed (2014) dollars.

STUDY METHODOLOGY

The Business Research Division at the University of Colorado Boulder was hired by Northern States Power to conduct economic impact analyses on retirement scenarios for the Sherco generating units in Sherburne County, Minnesota. This analysis examines the economic impacts of various early retirements of Sherco 1 and Sherco 2. Economic impact studies detail the direct spending that a company or activity has on the area of study, as well as the indirect impact, which is the ripple effect that direct spending has on other businesses in the community. This term is also referred to as the *multiplier effect*, wherein companies utilize the local supply chain. A multiplier is a numeric way of describing the full effects of money changing hands within an economy. For instance, when NSP purchases natural gas, this affects the mining and transportation industries. This is the indirect impact. Additionally, spending by employees has an inherent effect on local communities as they purchase groceries, clothes, and gas; pay rent or a mortgage; get haircuts, etc. This is understood as the induced impact.

The research team used the REMI model for the analysis. Appendix 1 provides an overview of the REMI model. The REMI model is a dynamic forecasting and policy analysis model that incorporates econometric, input-output, and computable general equilibrium techniques. The model was created by REMI specifically for the state of Minnesota using national and Minnesota economic and demographic data. The REMI model used for this analysis is the three region, PI+ model 1.6.8 for Sherburne County, Dakota County, and the rest of Minnesota, with 2012 data as the last historical year within the model.

NSP defined the scenarios to be examined in this study. These are described in detail in the Scenarios section. A baseline scenario was provided by NSP which included operating Sherco units 1 and 2 through 2031, followed by replacement with combined cycle generators. The research team developed economic scenarios that included spending and rate changes brought about by four different Sherco retirement and replacement scenarios. The result is a simulated forecast of the economy under scenarios where utility rates and spending on operating and capital expenditures change. Last, the report compares the simulations to the baseline scenario to quantify the economic impacts on the Minnesota economy and on Sherburne County and Dakota County.

The research team collected data on NSP estimates related to ongoing operating and maintenance expenditures, capital expenditures, and revenue requirements. The timing of operating and capital

expenditures is specific to each scenario. The research team worked under the assumption that the company provided good-faith estimates for each scenario.

Data were provided in nominal dollars, quantified in the year of expected impact. The impacts are presented in fixed, 2014 dollars, and discounted by the model using industry price deflators.

Costs were entered into the REMI model based on total activity expenditures. The researchers deferred to the model for the local purchasing coefficients for each economic region modeled, which included Sherburne County, Dakota County and the rest of Minnesota. This reduces subjectivity and error associated with asking NSP the source and composition of labor, capital, and intermediate inputs to production by community. The local purchasing coefficients within REMI change over time based on changing demand.

ECONOMIC MODEL AND THE MINNESOTA ECONOMY

The REMI model used for this analysis is the three region, PI+ model 1.6.8 for Sherburne County, Dakota County, and the rest of Minnesota. The model used for this study excludes the government spending response to changes in GDP. The REMI model includes an input-output table, industry spending patterns, and local purchasing coefficients.

When working with statewide models, the research team calibrates demographics using state demography forecasts for age, gender, and race. However, given the detailed economic regions, which included Sherburne County, Dakota County, and rest of Minnesota, no further model calibration was applied given the detailed data available for these economic regions.

Sherburne County and Dakota County are part of the Minneapolis-St. Paul-Bloomington Metropolitan Statistical Area. Data from the Bureau of Labor Statistics' Quarterly Census of Employment and Wages show the area recorded 1.8 million total nonfarm covered employees in 2014; Sherburne County represented 1.4%, or 25,835 of the total, and Dakota County represented 10%, or 180,324 of the total. Data from the Bureau of Economic Analysis shows Minnesota GDP of $316 billion in 2014. Real GDP in the state grew at a rate of 1.4% year-over-year. Per capita personal income for the state in 2014 was $48,711. Per capita personal income in 2013, which is the most current data available, was $50,687 in Dakota County and $36,358 in Sherburne County.

The REMI standard regional control places Sherburne County, Dakota County, and the rest of Minnesota on a growth trajectory throughout the analysis horizon, with faster rates of growth in the short term and slowing growth over the entire study period (Figure 3). Similar to recent years, Sherburne County is projected to grow employment at a faster rate than Dakota County and the rest of the state.

FIGURE 3: EMPLOYMENT FORECAST, 2015–2040

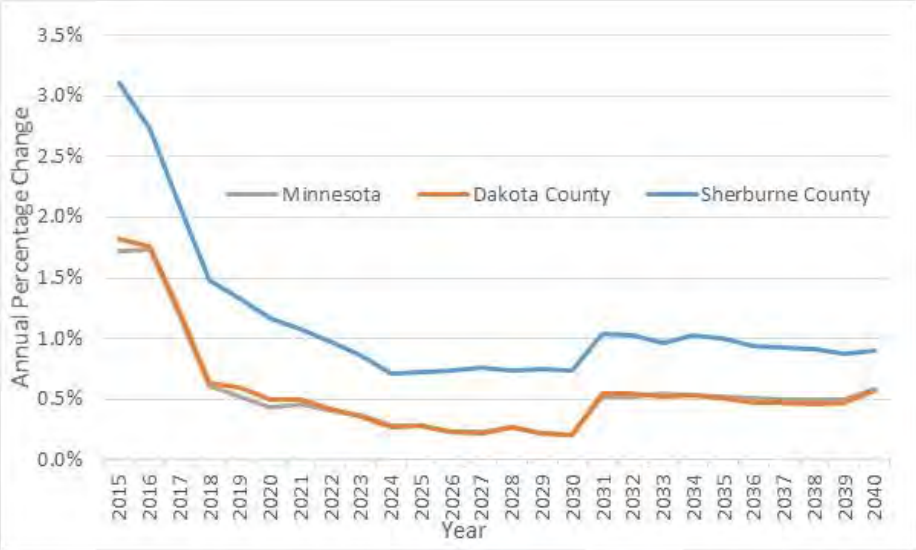
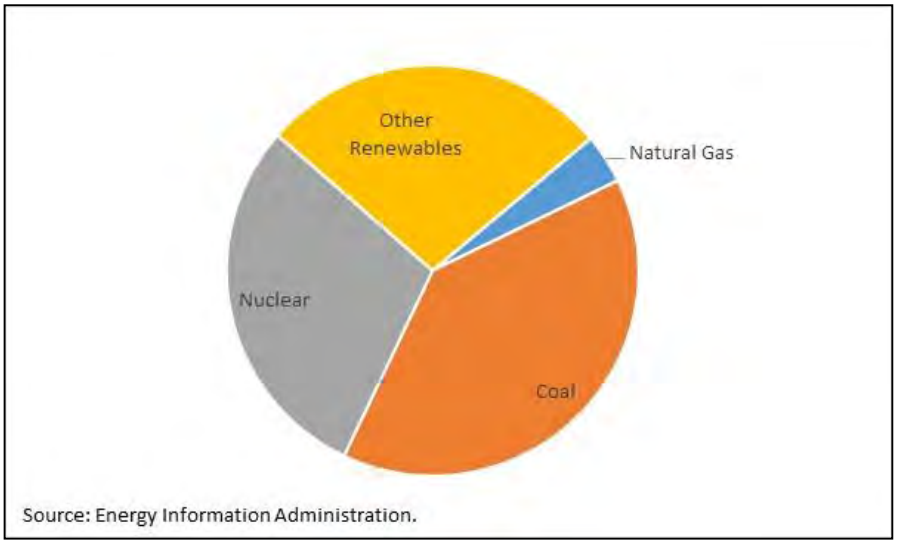


TABLE 4: PROJECTED COMPOUND ANNUAL GROWTH RATES, 2015–2040

COUNTY	EMPLOYMENT	GDP	PERSONAL INCOME
Sherburne County	1.1%	2.4%	3.0%
Dakota County	0.5%	2.1%	2.5%
Rest of Minnesota	0.5%	2.1%	2.3%

As a side point, Minnesota ranked 33rd in the nation in total energy production and 18th for total energy consumed per capita in 2012. As shown in Figure 4, approximately 46% of energy generated in the state came from coal-fired power plants, and an additional 21% was produced by nuclear power plants. Minnesota ranked 7th in wind-generated electricity and is also a top producer of ethanol, with more than 20 corn-based ethanol production plants.

FIGURE 4: MINNESOTA ELECTRICITY GENERATION, GIGAWATT HOURS, 2012



SCENARIOS

Sherco Generating Units 1 and 2 were built in the 1970s, and a third unit was built in the 1980s. Since installation, these units have been operating for 38, 37, and 27 years, respectively, as of 2014. The 2,400 MW station burns an estimated 30,000 tons of Montana and Wyoming coal daily. In addition to normal operating maintenance, investments have been made to improve the ability of wet scrubbers in Units 1 and 2 to capture sulfur dioxide and ash, as well as in technology to reduce particulates. Modifications and upgrades have been completed to achieve over 90% reduction of sulfur dioxide (SO_2) to meet Best Achievable Retrofit Technology (BART) criteria.

The five scenarios include one baseline scenario where Sherco 1 and Sherco 2 are operated through the Xcel Energy 2016–2030 Upper Midwest Resource Planning period and four retirement scenarios. These scenarios correspond to the Preferred Plan and Preferred Plan Sherco retirement scenarios provided in the March 16, 2015 Supplement. The only change in these scenarios was to replace the first two combined cycle units represented by generic combined cycle units with location specific combined cycle units. This change was required to quantify the economic impacts of Sherco retirements on the local and the state economy.

Baseline

This is the "Preferred Plan" (Resource Plan Scenario 10, Sensitivity RU) presented in the Supplement with location specific combined cycles used instead of the generic combined cycle units for the first two

combined cycle additions. Sherco 1 and Sherco 2 continue operation through the end of the Resource Planning period (2030). On-going capital replacement projects continue for both units to maintain reliable operations. The level of investment declines a few years before retirement. These units stop generating January 1, 2031 and remain in standby operating condition until they are retired June 1, 2031. This delay occurs in order to retain accreditation for the Midcontinent Independent System Operator (MISO) capacity year. No Selective Catalytic Reduction (SCR) technology is installed on Sherco 1 and Sherco 2. The replacement combined cycle generators are installed in 2031.

SHC1 2031 & SHC2 2025

This is the "Preferred Plan with Retire 1 Unit 2025" (Resource Plan Scenario 10B, Sensitivity RU) presented in the Supplement with location specific combined cycles used instead of the generic combined cycle units for the first two combined cycle additions. Sherco 2 will stop generating at the end of the year 2025. This unit will remain in standby operating condition until it is retired June 1, 2026. A replacement combined cycle generator will be constructed at the Black Dog site and begin operation upon the Sherco 2 retirement in 2026. No SCR will be added to Sherco 2. On-going capital replacement projects will continue until a few years before the retirement date, then decline to zero the year of retirement.

Sherco 1 will stop generating January 1, 2031, and remain in standby operating condition until it is retired June 1, 2031. No SCR will be added to Sherco 1. A replacement combined cycle generator will be constructed at the Sherco site and begin operation upon the retirement of Sherco 1 in 2031. On-going capital replacement projects will continue until a few years before the retirement date, then decline to zero the year of retirement.

SHC1 2025 & SHC2 2025

This is the "Preferred Plan with Retire 2 Units 2025" (Resource Plan Scenario 10G, Sensitivity RU) presented in the Supplement with location specific combined cycles used instead of the generic combined cycle units for the first two combined cycle additions. Sherco 2 will stop generating at the end of the year 2025. This unit will remain in standby operating condition until it is retired June 1, 2026. A replacement combined cycle generator will be constructed at the Black Dog site and begin operation upon the Sherco 2 retirement in 2026. No SCR will be added to Sherco 2. On-going capital replacement

projects will continue until a few years before the retirement date, then decline to zero the year of retirement.

Sherco 1 will stop generating at the end of the year 2025. This unit will remain in standby operating condition until it is retired June 1, 2026. A replacement combined cycle generator will be constructed at the Sherco site and begin operation June 1, 2031. No SCR will be added to Sherco 1. On-going capital replacement projects will continue until a few years before the retirement date, then decline to zero the year of retirement.

SHC1 2020 & SHC2 2020

This is the "Preferred Plan with Retire 2 Units 2020" (Resource Plan Scenario 10E, Sensitivity RU) presented in the Supplement with location specific combined cycles used instead of the generic combined cycle units for the first two combined cycle additions. Sherco 1 and Sherco 2 will stop generating at the end of the year 2020. Both units will remain in standby operating condition until they are retired June 1, 2021. A replacement combined cycle generator will be constructed at the Black Dog site and begin operation June 1, 2026. An additional replacement combined cycle generator will be constructed at the Sherco site and begin operation June 1, 2031. No SCR will be added to Sherco 1 or to Sherco 2. On-going capital replacement projects continue for both units to maintain reliable operations. The level of investment declines a few years before retirement.

SHC1 2023 & SHC2 2020

This is the "Preferred Plan with Retire 1 Unit 2020, 1 Unit 2023" (Resource Plan Scenario 10F, Sensitivity RU) presented in the Supplement with location specific combined cycles used instead of the generic combined cycle units for the first two combined cycle additions. Sherco 2 will stop generating at the end of the year 2020. This unit will remain in standby operating condition until it is retired June 1, 2021. A replacement combined cycle generator will be constructed at the Black Dog site and begin operation June 1, 2024. No SCR will be added to Sherco 1. On-going capital replacement projects will continue until a few years before the retirement date, then decline to zero the year of retirement.

Sherco 1 will stop generating at the end of the year 2023. This unit will remain in operating status and be retired June 1, 2024. A replacement combined cycle generator will be constructed at the Sherco site and begin operation June 1, 2031. No SCR will be added to Sherco 2. On-going capital replacement

projects will continue until a few years before the retirement date, then decline to zero the year of retirement.

DATA AND ASSUMPTIONS

NSP provided the research team with capital expenditures, operating expenditures, and revenue requirements for each scenario. The timing of operating and capital expenditures is specific to each scenario. The research team worked under the assumption that the company provided good-faith estimates for each scenario. For modeling purposes, cost assumptions were provided in nominal dollars. For comparison purposes, NSP converted inputs from nominal to real dollars using internal deflators. Costs in real dollars are presented in the following section.

Real costs were entered into the REMI model based on total activity expenditures. The researchers deferred to the model for the local purchasing coefficients for inputs given that three subregions are specified for this study. This reduces subjectivity and error associated with obtaining the source and composition of labor, capital, and intermediate inputs to production by community from NSP. The local purchasing coefficients within REMI change over time based on changing demand.

Capital Expenditures

The lowest capital cost scenario is the SHC1 2020 & SHC2 2020 in which NSP continues to operate Sherco units 1 and 2 until 2020 and then replaces them with combined cycle units at the Black Dog site and the Sherco site. This scenario, as shown in Table 5, has an estimated capital cost of $1.6 billion between 2015 and 2040, which includes on-going capital needs to repair and replace individual components to reliably continue operation of both units until 2020.

Alternatively, the baseline scenario is the highest capital cost scenario, estimated at nearly $1.9 billion as both Sherco units 1 and 2 in Sherburne County are retired in 2031 and are replaced with combined cycle generating units in Dakota County and Sherburne County (Table 5 and Table 6).

TABLE 5: CAPITAL EXPENDITURES (2014 DOLLARS), 2015–2040

Scenario	Total Spending (Millions)	Difference from Baseline (Millions)	Percentage Change
Baseline	$1,860.8	$0.0	0.0%
SHC1 2031 & SHC2 2025	$1,814.6	-$46.2	-2.5%
SHC1 2025 & SHC2 2025	$1,812.7	-$48.1	-2.6%
SHC1 2020 & SHC2 2020	$1,631.1	-$229.7	-12.3%
SHC1 2023 & SHC2 2020	$1,689.7	-$171.1	-9.2%

TABLE 6: CHANGE IN CAPITAL EXPENDITURES BY LOCATION (2014 DOLLARS), 2015–2040

Scenario	Difference in Sherburne County (Millions)	Difference in Dakota County (Millions)	Difference from Baseline (Millions)
Baseline	$0.0	$0.0	$0.0
SHC1 2031 & SHC2 2025	-$63.0	$16.8	-$46.2
SHC1 2025 & SHC2 2025	-$65.0	$16.8	-$48.1
SHC1 2020 & SHC2 2020	-$246.5	$16.8	-$229.7
SHC1 2023 & SHC2 2020	-$194.6	$23.5	-171.1

Operating and Maintenance

In addition to the consideration of capital expenditures, fixed and variable operating and maintenance costs vary by scenario. At $982 million, the baseline scenario has the highest operating and maintenance costs—3.5% to 25.8% higher than the alternative scenarios (Table 7). The various retirement and replacement scenarios reduce total fixed and variable operating costs.

TABLE 7: OPERATING EXPENDITURES (2014 DOLLARS), 2015–2040

Scenario	Total Fixed Operating and Maintenance (Millions)	Total Variable Operating and Maintenance (Millions)	Total Spending (Millions)	Difference from Baseline (Millions)	Percentage Change
Baseline	$923.0	$59.1	$982.0	$0.0	0.0%
SHC1 2031 & SHC2 2025	$897.6	$49.9	$947.5	-$34.5	-3.5%
SHC1 2025 & SHC2 2025	$855.3	$39.3	$894.6	-$87.4	-8.9%
SHC1 2020 & SHC2 2020	$663.1	$65.2	$728.3	-$253.7	-25.8%
SHC1 2023 & SHC2 2020	$715.2	$43.7	$758.9	-$223.1	-22.7%

Total fixed and variable operating costs would increase in Dakota County under the alternative scenarios, while costs would decrease in Sherburne County (Table 8).

TABLE 8: CHANGE IN OPERATING EXPENDITURES (2014 DOLLARS), 2015–2040

Scenario	Difference in Sherburne County (Millions)	Difference in Dakota County (Millions)	Difference from Baseline (Millions)
Baseline	$0.0	$0.0	$0.0
SHC1 2031 & SHC2 2025	-$64.5	$30.0	-$34.5
SHC1 2025 & SHC2 2025	-$117.1	$29.7	-$87.4
SHC1 2020 & SHC2 2020	-$310.5	$56.8	-$253.7
SHC1 2023 & SHC2 2020	-$264.8	$41.6	-$223.1

Property Taxes

Property taxes were a separate consideration given the location of the alternative scenarios. While other taxes, such as income taxes and sales taxes, are important considerations, property taxes are particularly important because of the localized impact of the revenue stream. The tax impact was not

explicitly modeled in this study. However, a reduction in activity at Sherco would result in a reduction in property taxes in Sherburne County, and an increase in activity at Black Dog would result in an increase in property taxes in Dakota County.

Revenue Requirements

Based on the level of operation and capital expenditures detailed in this report, NSP estimated the increase in revenue requirements included in electricity rates for electric customers for the four early retirement scenarios compared to the baseline scenario. This effectively isolates the revenue requirements and the electricity rate impact for the alternative scenarios and holds economic growth and electricity demand constant.[2] Revenue requirements are not equal to the sum of operation and capital expenditures because capital expenditures are recovered over the life of the asset. Therefore, revenue requirements occur over the life of the asset and include both a return of and return on capital. The revenue requirements estimate the additional electric revenues that would be recovered from customers for each scenario, despite the location of the supply chain for operating and capital purchases. At $1.1 billion, the change in revenue requirements is largest for the SHC1 2020 & SHC2 2020 Scenario between 2015 and 2040 (Table 9). Changes in revenue requirements were applied to residential, commercial, and industrial customers in Minnesota.

TABLE 9: CHANGE IN REVENUE REQUIREMENTS FOR MINNESOTA CUSTOMERS (NOMINAL), 2015–2040

Scenario	Dollar Change (Millions)	Percentage Change
Baseline	$0.0	0.0%
SHC1 2031 & SHC2 2025	$146.6	0.1%
SHC1 2025 & SHC2 2025	$806.4	0.7%
SHC1 2020 & SHC2 2020	$1,111.9	0.9%
SHC1 2023 & SHC2 2020	$826.9	0.7%

RESULTS

Continued operation of and investments in Sherco units 1 and 2 will have an ongoing positive economic contribution to the Minnesota economy. Scenarios involving early retirement and replacement of one or both of the units would also have near-term economic benefits, but the economic benefits of the baseline scenario are comparatively larger than the early retirement scenarios. The extent of the economic impacts is affected by factors that include the retirement costs of existing generating units,

[2]Electricity costs were entered as fuel cost variables: "Electricity (Commercial Sectors) Fuel Cost (amount)" for nonresidential sectors, and "Consumer Price (amount) for the residential sector."

the sources of inputs for capital investments, the ongoing operating costs, the sources of fuels, and the revenue requirements assigned to the customer base.

The retirement and replacement scenarios have varying degrees of impact on the Dakota County and Sherburne County economies. Retiring Sherco units in Sherburne County generates positive economic activity during the decommissioning phase but instills a negative economic cost during the other years due to lost operating and maintenance activity and to higher revenue requirements placed on residential and business utility customers. The construction and new operating activity at the Black Dog site in Dakota County would be a boost to the county economy, effectively outweighing the economic costs associated with higher revenue requirements. While these benefits accrue to Dakota County, it essentially shifts economic benefits from Sherburne County to Dakota County, and the overall impact on the Minnesota economy is marginally negative compared to the baseline scenario. The economic impacts of the retirement and replacement scenarios may appear large in absolute values, but the percentage change of the impacts is relatively small compared to the magnitude of the overall Minnesota economy. Accordingly, the impacts are not recessionary—the economy continues on a trajectory of growth, albeit slightly slower growth.

To quantify the economic contribution of the baseline scenario, the projected capital expenditures and operating expenditures from 2015 through 2040 were removed from the Minnesota economy. The resulting decrease in economic activity is the economic contribution of projected operations. This analysis excludes the revenue requirements associated with current operations of Sherco 1 and 2 since those revenue requirements are imbedded in the overall system revenue requirements for the company. The alternative scenarios were modeled using the changes in spending compared to baseline scenario on capital expenditures, operating expenditures, taxes, and revenue requirements. The revenue requirements for the alternative scenarios were supplied for the overall system, and it was possible to model the impact of *change* in revenue requirements for the retirement scenarios because the only system changes between the baseline scenario and the retirement scenarios include the retirement and replacement effects. Everything else in the system was left unchanged.

The following is a net analysis, examining the benefits as well as the costs. The growing demand for energy and plant energy output is controlled by comparing the economic impacts of the retirement

scenarios to the baseline scenario. This section reports the impacts in fixed (2014) dollars and the following paragraphs summarize the economic impacts by scenario.

Baseline Scenario Economic Contribution

In terms of economic contributions to the state of Minnesota, the baseline scenario, which includes continued long-term operation of Sherco units 1 and 2 until retirement and replacement in 2031, yields 980 jobs on average over the 26-year time horizon (Table 10). The baseline scenario would yield a contribution to total GDP of $2.8 billion in fixed 2014 dollars over the forecast horizon from 2015–2040, excluding the revenue requirements to customers.[3,4] Despite the Sherburne County location of Sherco units 1 and 2, the economic benefits of capital and operating expenditures extend beyond Sherburne County as direct and indirect goods and services are purchased from vendors throughout the state and as employee disposable income is spent in the larger Minnesota economy. Detailed results are available in Appendices 2,3, and 4.

TABLE 10: ECONOMIC CONTRIBUTION OF SHERCO 1 AND 2, AVERAGE 2015–2040

Metric	Units	Sherburne County	Dakota County	Rest of MN	Total
Total Employment	Jobs[1]	527	228	224	980
	Percent Change	*1.3%*	*0.1%*	*0.0%*	*0.0%*
Private Non-Farm Employment	Jobs[1]	465	215	205	885
	Percent Change	*1.3%*	*0.1%*	*0.0%*	*0.0%*
Gross Domestic Product	Dollars (Thousands)[1]	65,815	25,391	16,065	107,273
	Percent Change	*1.7%*	*0.1%*	*0.0%*	*0.0%*
Real Disposable Personal Income	Dollars (Thousands)[1]	40,606	15,168	14,369	70,141
	Percent Change	*0.9%*	*0.1%*	*0.0%*	*0.0%*

[1]Dollars are fixed (2014) dollars. Note: The baseline scenario is the total economic impact (excluding rate impact); other scenarios are in comparison to the baseline scenario.

SHC1 2031 & SHC2 2025 Economic Impacts

This scenario includes the retirement of Sherco 2 in 2025 and its replacement with a combined cycle generator at Black Dog, and the retirement of Sherco 1 in 2031 and its replacement with a combined cycle generator at Sherco. This early retirement scenario has the second-highest capital expenditures and operating costs, and the second-lowest revenue requirements. This scenario records mixed economic impacts on the Minnesota economy and on Sherburne and Dakota counties. Economic benefits are recorded during the intensive decommissioning and construction phases, while economic costs are generally recorded during the nonconstruction phases. This is due to the rate burden on

[3] Revenue requirements for each scenario are calculated for the entire NSP system rather than just for Sherco 1 and 2.

[4] Total contributions to GDP are summed over the entire period while averages are shown in Table 10 (26 years times $107,273K equals $2.8 billion).

consumers (both residential and commercial/industrial) as the higher revenue requirements overshadow the benefits associated with construction activity and lower operating costs. The higher revenue requirements are levied on all customers, while the economic benefit from construction is diluted due to leakage—some goods and services are sourced from outside the state.

The costs and benefits are not shared equally by location in Minnesota—Dakota County is a net beneficiary while Sherburne County and the rest of Minnesota incur higher costs. These deviations are relatively small compared to the overall Minnesota economy, while they are slightly larger in Sherburne County and Dakota County. The magnitude and periodic variation in economic impacts is apparent in the private employment figures. Compared to the baseline scenario, over the 26-year horizon, Sherburne County employment is lower by an average of 31 jobs per year, Dakota County is higher by an average of 18 jobs per year, and the rest of Minnesota is lower by an average of 62 jobs per year, as shown in Table 11.

TABLE 11: SHC1 2031 & SHC2 2025 ECONOMIC IMPACTS COMPARED TO BASELINE, AVERAGE 2015–2040

Metric	Units	Sherburne County	Dakota County	Rest of MN	Total
Total Employment	Jobs[1]	-31	18	-62	-75
	Percent Change	*-0.1%*	*0.0%*	*0.0%*	*0.0%*
Private Non-Farm Employment	Jobs[1]	-27	16	-46	-57
	Percent Change	*-0.1%*	*0.0%*	*0.0%*	*0.0%*
Gross Domestic Product	Dollars (Thousands)[1]	-4,097	-445	-11,479	-16,021
	Percent Change	*-0.1%*	*0.0%*	*0.0%*	*0.0%*
Real Disposable Personal Income	Dollars (Thousands)[1]	-2,406	-714	-10,602	-13,719
	Percent Change	*-0.1%*	*0.0%*	*0.0%*	*0.0%*

[1]Dollars are fixed (2014) dollars.

Since this scenario involves generator retirement and replacement sooner than the baseline scenario, the spike and dip in economic activity is largely due to timing—specifically the timing of activity compared to the baseline scenario. Retiring Sherco 2 in 2025 instead of 2031 increases economic activity in the 2020s, but decreases economic activity in the 2030s—hence, the spike in employment followed by the decrease. (See Figure 5.)

As shown in Figure 5, Dakota County records the greatest employment impact. This is due to the new construction and operations within Dakota County. Sherburne County records only a modest dip in employment, buoyed by activity during the Sherco unit shutdown and decommissioning phase.

FIGURE 5: SHC1 2031 & SHC2 2025 IMPACT ON PRIVATE EMPLOYMENT

Total capital spending and operating and maintenance costs for this early retirement scenario are less than those for the baseline scenario. Revenue requirements are greater than in the baseline scenario, and this increase is greater than the decrease in total operating costs. The economic impacts are tempered, however, due the size of these impacts relative to the large local economy. The Minnesota economy ranked 17th nationally in 2014 in terms of state GDP at $316 billion and 17th in terms of employment at 2.8 million. As shown in Table 11, slower growth in GDP of $16 million and 75 fewer jobs represent less than one-tenth of a percent change in economic growth statewide. The impacts are greater for Sherburne County and Dakota County given they are the locations incurring the greatest operating changes.

SHC1 2025 & SHC2 2025 Economic Impacts

This scenario includes the retirement of Sherco units 1 and 2 in 2025, replaced with combined cycle generators at Sherco and Black Dog. This scenario has the third-highest fixed capital costs, operating costs, and revenue requirements, and records mixed economic impacts on the Minnesota economy and on Sherburne and Dakota counties. Economic benefits are recorded during the intensive decommissioning and construction phases, while economic costs are generally recorded during the nonconstruction phases. This is due to the rate burden on residential and business consumers as the

higher revenue requirements overshadow the benefits associated with construction activity and lower operating costs. The higher revenue requirements are levied on all customers, while the economic benefit from construction is diluted due to leakage—some goods and services are sourced from outside the state.

The costs and benefits are not shared equally by location in Minnesota—Dakota County is a net beneficiary while Sherburne County and the rest of Minnesota incur higher costs. These deviations are relatively small compared to the overall Minnesota economy, although slightly larger relative impacts are recorded in Sherburne County and Dakota County. The magnitude and periodic variation in economic impacts is apparent in the private employment figures. As shown in Table 12, over the 26-year horizon, Sherburne County employment is lower by an average of 22 jobs, Dakota County is flat, and the rest of Minnesota is lower by 237 jobs compared to the baseline scenario.

TABLE 12: SHC1 2025 & SHC2 2025 ECONOMIC IMPACTS COMPARED TO BASELINE, AVE. 2015–2040

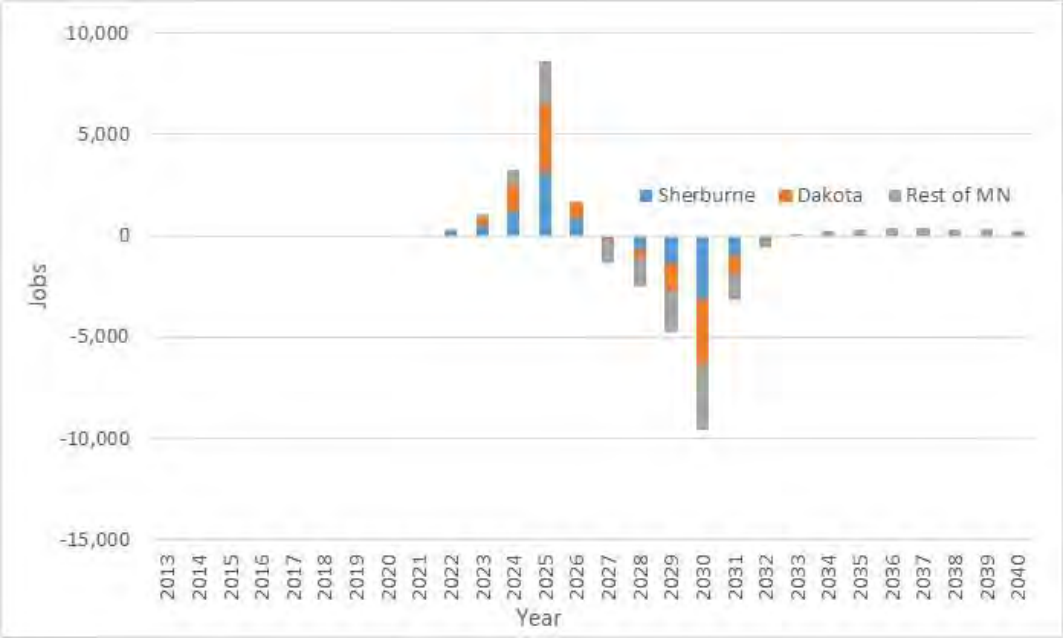
Metric	Units	Sherburne County	Dakota County	Rest of MN	Total
Total Employment	Jobs[1]	-22	0.2	-237	-258
	Percent Change	*-0.1%*	*0.0%*	*0.0%*	*0.0%*
Private Non-Farm Employment	Jobs[1]	-22	0	-187	-209
	Percent Change	*-0.1%*	*0.0%*	*0.0%*	*0.0%*
Gross Domestic Product	Dollars (Thousands)[1]	-6,863	-3,757	-42,640	-53,257
	Percent Change	*-0.2%*	*0.0%*	*0.0%*	*0.0%*
Real Disposable Personal Income	Dollars (Thousands)[1]	-2,920	-4,508	-40,494	-47,919
	Percent Change	*-0.1%*	*0.0%*	*0.0%*	*0.0%*

[1]Dollars are fixed (2014) dollars.

Since this scenario involves generator retirement and replacement sooner than the baseline scenario, the spike and dip in economic activity is largely due to timing. Retiring Sherco 1 and Sherco 2 in 2025 instead of 2031 increases economic activity in the 2020s, but decreases economic activity in the 2030s—hence, the spike in employment followed by the decrease. (See Figure 6.)

Visible in Figure 6, Dakota County records the greatest employment impact. This is due to the new construction and operations within Dakota County. Sherburne County only records a modest dip in employment, buoyed by activity during the decommissioning phase and the reconstruction of Sherco 1.

FIGURE 6: SHC1 2025 & SHC2 2025 IMPACT ON PRIVATE EMPLOYMENT



Despite the decrease in total capital spending and decrease in operating and maintenance costs for this early retirement scenario, the economic impacts are dampened by the project horizon, the higher revenue requirements, and the relatively large local economy. The Minnesota economy ranked 17th nationally in 2014 in terms of state GDP at $316 billion and 17th in terms of employment at 2.8 million. Slower growth in GDP of $53 million and 258 fewer jobs represent less than one-tenth of a percent change in economic growth statewide (Table 12). The impacts are greater for Sherburne County and Dakota County given they are the locations incurring the greatest operating changes.

SHC1 2020 & SHC2 2020 Economic Impacts

This scenario includes placing Sherco 1 and 2 in standby mode in 2020, replaced with new combined cycle generators at Black Dog in 2026 and at Sherco in 2031. This scenario has the lowest fixed capital costs and operating costs and the highest revenue requirements, and records mixed economic impacts on the Minnesota economy and on Sherburne and Dakota counties. Economic benefits are recorded during the intensive decommissioning and construction phases, while economic costs are generally recorded during the nonconstruction phases. This is due to the rate burden on residential and business consumers as the higher revenue requirements overshadow the benefits associated with construction activity and lower operating costs. The higher revenue requirements are levied on all customers, while

the economic benefit from construction is diluted due to leakage—some goods and services are sourced from outside the state.

The costs and benefits are not shared equally by location in Minnesota—Dakota County averages modest employment losses despite gaining a generating facility—mostly due to the delayed replacement facility in Dakota County. Sherburne County loses some operating activity and the rest of Minnesota incurs higher utility costs. These deviations are relatively small compared to the overall Minnesota economy, although slightly larger relative impacts are incurred in Sherburne County and Dakota County. The magnitude and periodic variation in economic impacts is apparent in the private employment figures. As shown in Table 13, over the 26-year horizon, Sherburne County employment is lower by an average of 140 jobs, Dakota County is lower by an average of 12 jobs, and the rest of Minnesota is lower by 418 jobs compared to the baseline scenario.

TABLE 13: SHC1 2020 & SHC2 2020 ECONOMIC IMPACTS COMPARED TO BASELINE, AVERAGE 2015–2040

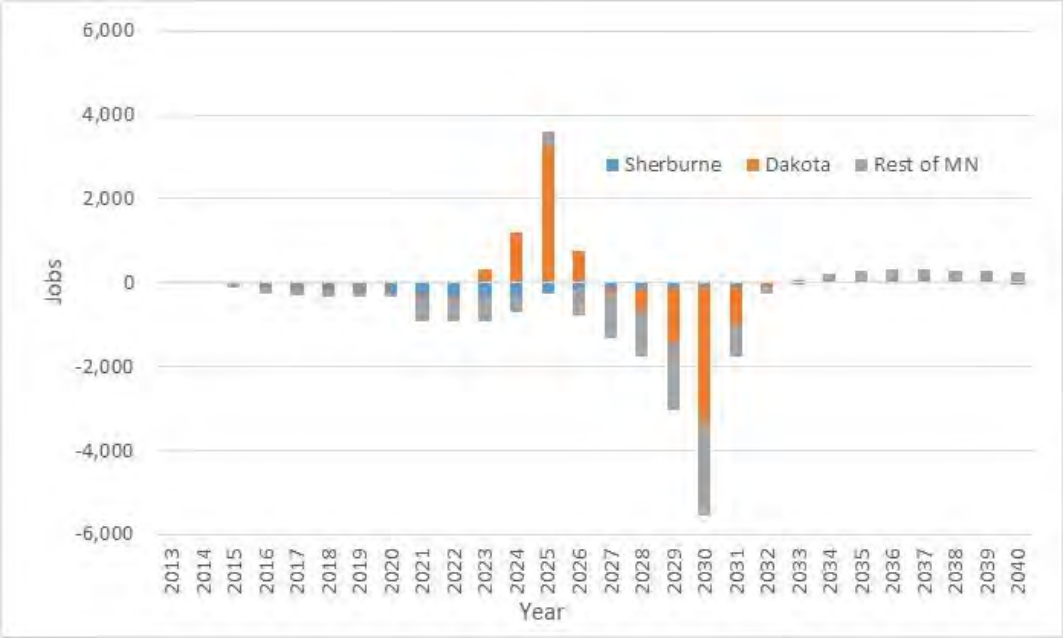
Metric	Units	Sherburne County	Dakota County	Rest of MN	Total
Total Employment	Jobs	-140	-12	-418	-570
	Percent Change	*-0.3%*	*0.0%*	*0.0%*	*0.0%*
Private Non-Farm Employment	Jobs[1]	-121	-10	-334	-465
	Percent Change	*-0.3%*	*0.0%*	*0.0%*	*0.0%*
Gross Domestic Product	Dollars (Thousands)[1]	-18,871	-5,751	-65,339	-89,966
	Percent Change	*-0.5%*	*0.0%*	*0.0%*	*0.0%*
Real Disposable Personal Income	Dollars (Thousands)[1]	-10,584	-6,641	-66,262	-83,485
	Percent Change	*-0.2%*	*0.0%*	*0.0%*	*0.0%*

[1]Dollars are fixed (2014) dollars.

Since this scenario involves generator retirement and replacement sooner than the baseline scenario, the spike and dip in economic activity is largely due to timing. Retiring Sherco 1 and Sherco 2 in 2020 instead of 2031 increases economic activity in the 2020s, but decreases economic activity in the 2030s—hence, the spike in employment followed by the decrease. (See Figure 7.)

As Figure 7 shows, Dakota County records the greatest employment impact. This is due to the new construction and operations within the county. Sherburne County only records a modest dip in employment, buoyed by activity during the decommissioning phase and the construction of a natural gas combined cycle unit at the Sherco site.

FIGURE 7: SHC1 2020 & SHC2 2020 IMPACT ON PRIVATE EMPLOYMENT



Despite the decrease in total capital spending operating and maintenance costs for this early retirement scenario, the economic impacts are dampened by the project horizon, the higher revenue requirements, and the relatively large local economy. The Minnesota economy ranked 17th nationally in 2014 in terms of state GDP at $316 billion and 17th in term of employment at 2.8 million. Slower growth in GDP of $90 million and 570 fewer total jobs represent less than one-tenth of a percent change in economic growth statewide. The impacts are greater for Sherburne County and Dakota County given they are the locations incurring the greatest operating changes.

SHC1 2023 & SHC2 2020 Economic Impacts

This scenario includes the retirement of Sherco 2 in 2020, replaced with a combined cycle generator at Black Dog, and the retirement of Sherco 1 in 2023, replaced with a combined cycle generator at Sherco. This alternative scenario has the second-lowest fixed capital costs and operating costs, and the second-highest revenue requirements, and records mixed economic impacts on the Minnesota economy and on Sherburne and Dakota Counties. Economic benefits are recorded during the intensive decommissioning and construction phases, while economic costs are generally recorded during the nonconstruction phases. This is due to the rate burden on residential and business consumers as the higher revenue requirements overshadow the benefits associated with construction activity and lower operating costs.

The higher revenue requirements are levied on all customers, while the economic benefit from construction is diluted due to leakage—some goods and services are sourced from outside the state.

The costs and benefits are not shared equally by location in Minnesota—Dakota County and Sherburne County record a net increase in economic activity, while the rest of Minnesota incurs higher utility costs. However, these deviations are relatively small compared to the overall Minnesota economy. The magnitude and periodic variation in economic impacts is apparent in the private employment figures. As shown in Table 14, over the 26-year horizon, Sherburne County employment is higher by an average of 5 jobs, Dakota County is higher by an average of 7 jobs, and the rest of Minnesota is lower by 313 jobs compared to the baseline projection.

TABLE 14: SHC1 2020 & SHC2 2023 ECONOMIC IMPACTS COMPARED TO BASELINE, AVERAGE 2015–2040

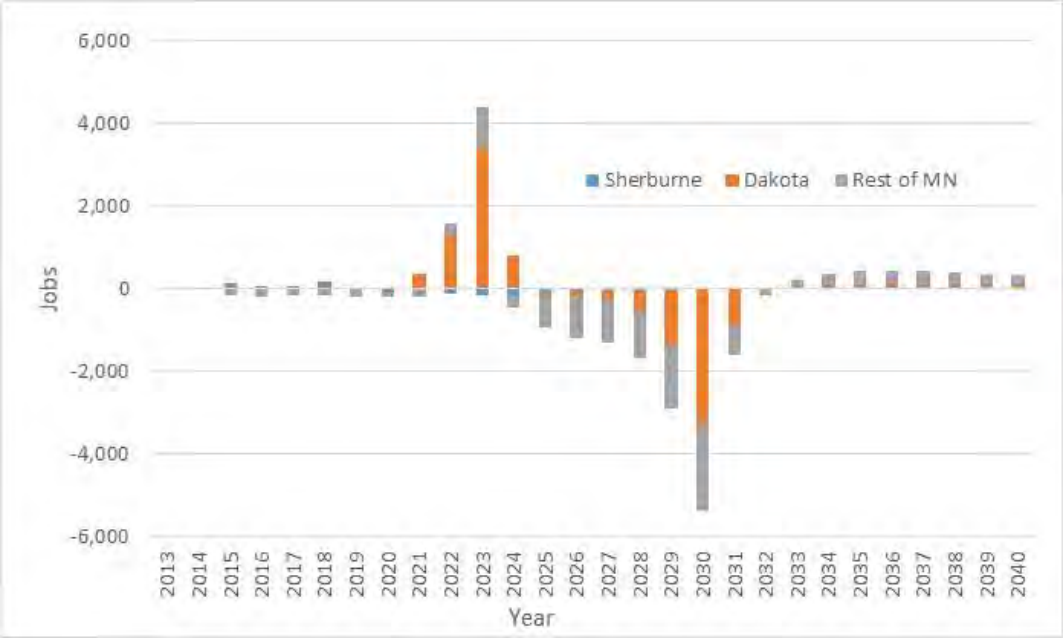
Metric	Units	Sherburne County	Dakota County	Rest of MN	Total
Total Employment	Jobs[1]	5	7	-313	-300
	Percent Change	*0.0%*	*0.0%*	*0.0%*	*0.0%*
Private Non-Farm Employment	Jobs[1]	2	8	-248	-239
	Percent Change	*0.0%*	*0.0%*	*0.0%*	*0.0%*
Gross Domestic Product	Dollars (Thousands)[1]	13,737	-3,430	-60,123	-49,813
	Percent Change	*0.4%*	*0.0%*	*0.0%*	*0.0%*
Personal Income	Dollars (Thousands)[1]	2,668	-5,182	-49,930	-52,443
	Percent Change	*0.1%*	*0.0%*	*0.0%*	*0.0%*
Real Disposable Personal Income	Dollars (Thousands)[1]	5	7	-313	-300
	Percent Change	*0.0%*	*0.0%*	*0.0%*	*0.0%*

[1]Dollars are fixed (2014) dollars.

Since this scenario involves generator retirement and replacement sooner than the baseline scenario, the spikes and dips in economic activity are largely due to timing. Retiring Sherco 1 in 2023 instead of 2031, and retiring Sherco 2 in 2020 instead of 2031 increases economic activity in the 2020s, but decreases economic activity in the 2030s—hence, the spike in employment followed by the decrease. (See Figure 8.)

As Figure 8 indicates, Dakota County records the greatest employment impact. This is due to the new construction and operations within Dakota County. Sherburne County records only a modest dip in employment, buoyed by activity during the decommissioning phase and the construction of a natural gas combined cycle unit at the Sherco site.

FIGURE 8: SHC1 2023 & SHC2 2020 IMPACT ON PRIVATE EMPLOYMENT



Despite the decrease in total capital spending and operating and maintenance costs for this early retirement scenario, the economic impacts are dampened by the project horizon, the higher revenue requirements, and the relatively large local economy. The Minnesota economy ranked 17th nationally in 2014 in terms of state GDP at $316 billion and 17th in term of employment at 2.8 million. Slower growth in GDP of $50 million and 300 fewer total jobs represent less than one-tenth of a percent change in economic growth statewide. The impacts are greater for Sherburne County and Dakota County given they are the locations incurring the greatest operating changes.

CONCLUSION

This paper provides an analysis of the economic impact of early retirement and replacement of the coal-fired Sherco 1 and Sherco 2 units with an equivalent MW amount of combined cycle gas-fired generation capacity. This report finds the costs associated with an increase in revenue requirements to pay for early retirement and replacement are modestly greater than the economic benefits associated with the change in capital investments and operating costs.

This analysis uses data on operations, maintenance, capital expenditures, and revenue requirements provided by NSP on the current Sherco 1 and 2 units and on four retirement scenarios.

Overall, the study found the following:

- Current Sherco operations have an impact that extends beyond Sherburne County as NSP purchases goods and services from vendors throughout Minnesota and as income earners spend disposable personal income throughout the state.
- Some of the construction and operating benefits do not impact the Minnesota economy as goods and services are sourced from out of state while the increase in revenue requirements (costs) are placed on all Minnesota NSP customers (residential, commercial, and industrial).
- The lack of indigenous fossil resources in Minnesota limits potential gains in fuel switching. Since Minnesota does not have indigenous coal or natural gas resources, it necessitates importing fuel from other states and requiring gas pipeline upgrades.
- The baseline scenario and each early retirement scenario require additional investments in gas pipelines and transmission totaling about 10% of total capital expenditures.
- All early Sherco retirement scenarios will result in higher revenue requirements of $147 million–$1.7 billion, or 0.1%–0.9% for NSP's Minnesota electricity customers, partially due to fuel costs. This negative economic impact is greater than the economic benefits associated with the construction of replacement generation and changes in operations.
- Continued operation of and investments in Sherco units 1 and 2 through 2031 will have the greatest ongoing positive impact to the Minnesota economy.
- Compared to the baseline scenario, all early Sherco retirement scenarios result in comparatively slower growth within the Minnesota economy in terms of:
    - Employment (-75 to -570 jobs on average)
    - GDP (-$16 million to -$90 million on average), and

  - Real disposable personal income (-$14 million to -$83 million).

Note: These changes represent a relatively small percentage of the overall Minnesota economy, Sherburne County economy, and Dakota County economy, and none of the scenarios are recessionary.

- The statewide economic losses compared to the baseline scenario increase as the retirement of Sherco units are moved to earlier dates because of the need for earlier capital expenditures and increased costs to rate payers.
  - Scenario SHC1 2020 & SHC2 2020 results in the greatest statewide decrease in GDP compared to the baseline scenario.
  - The SHC1 2031 & SHC2 2025 retirement scenario results in the smallest economic loss compared to the baseline scenario.
- As a percentage of local economic activity, Sherburne County experiences the greatest negative impact under most retirement scenarios due to the reduction in local operating activity, while Dakota County records the largest positive impacts due to the construction of replacement generation at the Black Dog site. The study period impacts are generally a decrease in employment in Sherburne County, as well as a shift of employment from Sherburne County to Dakota County. Construction of replacement generation on the Sherco site buffers some of the negative economic impacts associated with lost generation.

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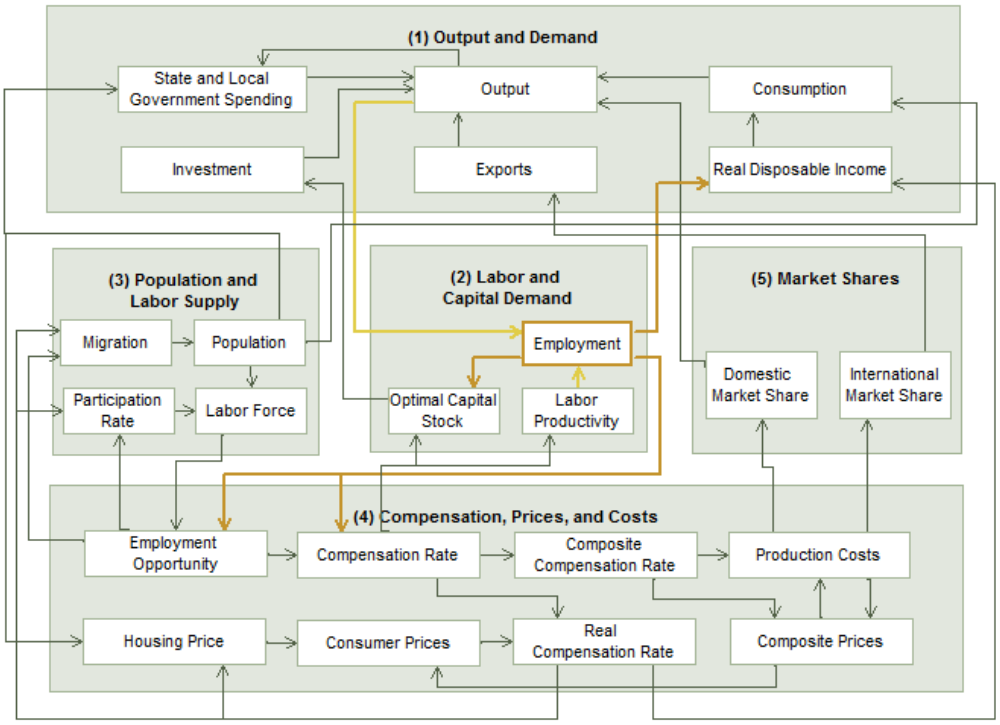
APPENDIX 1: OVERVIEW OF REMI POLICY INSIGHT

This summary was provided by REMI, Inc.

Policy Insight is a structural economic forecasting and policy analysis model. It integrates input-output, computable general equilibrium, econometric, and economic geography methodologies. The model is dynamic, with forecasts and simulations generated on an annual basis and behavioral responses to wage, price, and other economic factors.

The REMI model consists of thousands of simultaneous equations with a structure that is relatively straightforward. The exact number of equations used varies depending on the extent of industry, demographic, demand, and other detail in the model. The overall structure of the model can be summarized in five major blocks: (1) Output and Demand, (2) Labor and Capital Demand, (3) Population and Labor Supply, (4) Wages, Prices and Costs, and (5) Market Shares.



Block 1. Output and Demand

This block includes output, demand, consumption, investment, government spending, import, product access, and export concepts. For each industry, demand is determined by the amount of output, consumption, investment and capital demand on that industry. Consumption depends on real disposable income per capita, relative prices, differential income elasticities and population. Input productivity depends on access to inputs because the larger the choice set of inputs, the more likely that

the input with the specific characteristics required for the job will be formed. In the capital stock adjustment process, investment occurs to fill the difference between optimal and actual capital stock for residential, non-residential, and equipment investment. Government spending changes are determined by changes in the population.

Block 2. Labor and Capital Demand

The Labor and Capital Demand block includes the determination of labor productivity, labor intensity and the optimal capital stocks. Industry-specific labor productivity depends on the availability of workers with differentiated skills for the occupations used in each industry. The occupational labor supply and commuting costs determine firms' access to a specialized labor force.

Labor intensity is determined by the cost of labor relative to the other factor inputs, capital and fuel. Demand for capital is driven by the optimal capital stock equation for both non-residential capital and equipment. Optimal capital stock for each industry depends on the relative cost of labor and capital, and the employment weighted by capital use for each industry. Employment in private industries is determined by the value added and employment per unit of value added in each industry.

Block 3. Population and Labor Supply

The Population and Labor Supply block includes detailed demographic information about the region. Population data is given for age and gender, with birth and survival rates for each group. The size and labor force participation rate of each group determines the labor supply. These participation rates respond to changes in employment relative to the potential labor force and to changes in the real after tax compensation rate. Migration includes retirement, military, international and economic migration. Economic migration is determined by the relative real after tax compensation rate, relative employment opportunity and consumer access to variety.

Block 4. Wages, Prices, and Costs

This block includes delivered prices, production costs, equipment cost, the consumption deflator, consumer prices, the price of housing, and the wage equation. Economic geography concepts account for the productivity and price effects of access to specialized labor, goods and services.
These prices measure the price of the industry output, taking into account the access to production locations. This access is important due to the specialization of production that takes place within each industry, and because transportation and transaction costs of distance are significant. Composite prices for each industry are then calculated based on the production costs of supplying regions, the effective

distance to these regions, and the index of access to the variety of output in the industry relative to the access by other uses of the product.

The cost of production for each industry is determined by cost of labor, capital, fuel and intermediate inputs. Labor costs reflect a productivity adjustment to account for access to specialized labor, as well as underlying compensation rates. Capital costs include costs of non- residential structures and equipment, while fuel costs incorporate electricity, natural gas and residual fuels.

The consumption deflator converts industry prices to prices for consumption commodities. For potential migrants, the consumer price is additionally calculated to include housing prices. Housing price changes from their initial level depend on changes in income and population density.

Compensation changes are due to changes in labor demand and supply conditions and changes in the national compensation rate. Changes in employment opportunities relative to the labor force and occupational demand change determine compensation rates by industry.

Block 5. Market Shares

The Market Shares equations measure the proportion of local and export markets that are captured by each industry. These depend on relative production costs, the estimated price elasticity of demand, and effective distance between the home region and each of the other regions. The change in share of a specific area in any region depends on changes in its delivered price and the quantity it produces compared with the same factors for competitors in that market. The share of local and external markets then drives the exports from and imports to the home economy.

The Labor and Capital Demand block includes labor intensity and productivity as well as demand for labor and capital. Labor force participation rate and migration equations are in the Population and Labor Supply block. The Wages, Prices, and Costs block includes composite prices, determinants of production costs, the consumption price deflator, housing prices, and the wage equations. The proportion of local, inter-regional and export markets captured by each region is included in the Market Shares block.

APPENDIX 2: DETAILED ECONOMIC IMPACTS OF SCENARIOS ON THE MINNESOTA ECONOMY

The following tables exhibit the economic impacts of the baseline scenario on the Minnesota economy, as well as the economic impacts of the alternative scenarios compared to the baseline scenario.

TABLE 15: ECONOMIC CONTRIBUTION OF BASELINE SCENARIO ON THE MINNESOTA ECONOMY

Category	Units	Average					
		Year 1-5	Year 6-10	Year 11-15	Year 16-20	Year 21-25	2015-2040
Total Employment	Jobs	545	511	631	3,115	241	980
Private Non-Farm Employment	Jobs	515	454	567	2,920	112	885
Gross Domestic Product	Dollars (Thousands)[1]	58,758	56,019	73,325	345,997	18,944	107,273
Real Disposable Personal Income	Dollars (Thousands)[1]	29,475	33,754	45,510	207,539	40,525	70,141

[1]Dollars are fixed (2014) dollars. Note: Scenario 1 is the total economic impact (excluding rate impact); other scenarios are in comparison to Scenario 1.

TABLE 16: ECONOMIC CONTRIBUTION OF SHC1 2031 & SHC2 2025 ON THE MINNESOTA ECONOMY

Category	Units	Average					
		Year 1-5	Year 6-10	Year 11-15	Year 16-20	Year 21-25	2015-2040
Total Employment	Jobs	-23	349	286	-1,286	246	-75
Private Non-Farm Employment	Jobs	-21	348	262	-1,192	269	-57
Gross Domestic Product	Dollars (Thousands)[1]	-2,656	36,698	6,624	-161,786	32,256	-16,021
Real Disposable Personal Income	Dollars (Thousands)[1]	-2,813	17,126	-32,173	-83,661	25,542	-13,719

[1]Dollars are fixed (2014) dollars. Note: The decrease in economic activity from 2016-2020 and the increase in economic activity from 2021-2025 is due to timing of expenditures in this scenario compared to the alternative scenario.

TABLE 17: ECONOMIC CONTRIBUTION OF SHC1 2025 & SHC2 2025 ON THE MINNESOTA ECONOMY

Category	Units	Average					
		Year 1-5	Year 6-10	Year 11-15	Year 16-20	Year 21-25	2015-2040
Total Employment	Jobs	-50	895	395	-2,874	245	-258
Private Non-Farm Employment	Jobs	-46	884	332	-2,650	339	-209
Gross Domestic Product	Dollars (Thousands)[1]	-5,747	85,523	-16,608	-360,954	17,216	-53,257
Real Disposable Personal Income	Dollars (Thousands)[1]	-6,365	40,301	-89,229	-211,488	14,438	-47,919

[1]Dollars are fixed (2014) dollars. Note: The decrease in economic activity from 2016-2020 and the increase in economic activity from 2021-2025 is due to timing of expenditures in this scenario compared to the alternative scenario.

TABLE 18: ECONOMIC CONTRIBUTION OF SHC1 2020 & SHC2 2020 ON THE MINNESOTA ECONOMY

Category	Units	Average					
		Year 1-5	Year 6-10	Year 11-15	Year 16-20	Year 21-25	2015-2040
Total Employment	Jobs	-293	-545	-681	-1,687	207	-570
Private Non-Farm Employment	Jobs	-276	-472	-554	-1,463	300	-465
Gross Domestic Product	Dollars (Thousands)[1]	-28,154	-72,538	-135,514	-239,782	6,515	-89,966
Real Disposable Personal Income	Dollars (Thousands)[1]	-23,050	-93,037	-171,610	-151,162	4,032	-83,485

[1]Dollars are fixed (2014) dollars. Note: The decrease in economic activity from 2016-2020 and the increase in economic activity from 2021-2025 is due to timing of expenditures in this scenario compared to the alternative scenario.

TABLE 19: ECONOMIC CONTRIBUTION OF SHC1 2023 & SHC2 2020 ON THE MINNESOTA ECONOMY

Category	Units	Average					
		Year 1-5	Year 6-10	Year 11-15	Year 16-20	Year 21-25	2015-2040
Total Employment	Jobs	-71	1,252	-1,683	-1,481	361	-300
Private Non-Farm Employment	Jobs	-70	1,231	-1,597	-1,294	423	-239
Gross Domestic Product	Dollars (Thousands)[1]	3,270	128,358	-229,536	-202,810	35,226	-49,813
Real Disposable Personal Income	Dollars (Thousands)[1]	-8,685	42,906	-218,317	-123,437	29,645	-52,443

[1]Dollars are fixed (2014) dollars. Note: The decrease in economic activity from 2016-2020 and the increase in economic activity from 2021-2025 is due to timing of expenditures in this scenario compared to the alternative scenario.

APPENDIX 3: DETAILED ECONOMIC IMPACTS OF SCENARIOS ON SHERBURNE COUNTY

The following tables exhibit the economic impacts of the baseline scenario on the Sherburne County economy, as well as the economic impacts of the alternative scenarios compared to the baseline scenario.

TABLE 20: CONTRIBUTION OF BASELINE SCENARIO ON THE SHERBURNE COUNTY ECONOMY

Category	Units	Average					
		Year 1-5	Year 6-10	Year 11-15	Year 16-20	Year 21-25	2015-2040
Total Employment	Jobs	490	430	422	1,242	136	527
Private Non-Farm Employment	Jobs	461	378	367	1,135	63	465
Gross Domestic Product	Dollars (Thousands)[1]	66,831	58,796	62,471	132,322	18,373	65,815
Real Disposable Personal Income	Dollars (Thousands)[1]	26,949	30,386	32,658	85,887	30,426	40,606

[1]Dollars are fixed (2014) dollars. Note: Scenario 1 is the total economic impact (excluding rate impact); other scenarios are in comparison to Scenario 1.

TABLE 21: CONTRIBUTION OF SHC1 2031 & SHC2 2025 ON THE SHERBURNE COUNTY ECONOMY

Category	Units	Average					
		Year 1-5	Year 6-10	Year 11-15	Year 16-20	Year 21-25	2015-2040
Total Employment	Jobs	0	-55	-79	-26	-1	-31
Private Non-Farm Employment	Jobs	0	-54	-72	-18	3	-27
Gross Domestic Product	Dollars (Thousands)[1]	-25	-3,045	-14,301	-4,458	455	-4,097
Real Disposable Personal Income	Dollars (Thousands)[1]	7	-2,180	-5,664	-3,457	-1,052	-2,406

[1]Dollars are fixed (2014) dollars.

TABLE 22: CONTRIBUTION OF SHC1 2025 & SHC2 2025 ON THE SHERBURNE COUNTY ECONOMY

Category	Units	Average					
		Year 1-5	Year 6-10	Year 11-15	Year 16-20	Year 21-25	2015-2040
Total Employment	Jobs	0	392	422	-911	-17	-22
Private Non-Farm Employment	Jobs	0	383	357	-870	12	-22
Gross Domestic Product	Dollars (Thousands)[1]	-58	34,907	22,691	-93,905	324	-6,863
Real Disposable Personal Income	Dollars (Thousands)[1]	-8	18,054	31,922	-54,491	-9,707	-2,920

[1]Dollars are fixed (2014) dollars.

TABLE 23: CONTRIBUTION OF SHC1 2020 & SHC2 2020 ON THE SHERBURNE COUNTY ECONOMY

Category	Units	Average					
		Year 1-5	Year 6-10	Year 11-15	Year 16-20	Year 21-25	2015-2040
Total Employment	Jobs	-129	-325	-204	-62	-5	-140
Private Non-Farm Employment	Jobs	-124	-302	-172	-38	6	-121
Gross Domestic Product	Dollars (Thousands)[1]	-9,864	-39,616	-37,735	-12,002	981	-18,871
Real Disposable Personal Income	Dollars (Thousands)[1]	-5,567	-18,993	-17,643	-9,094	-3,171	-10,584

[1]Dollars are fixed (2014) dollars.

TABLE 24: CONTRIBUTION OF SHC1 2023 & SHC2 2020 ON THE SHERBURNE COUNTY ECONOMY

Category	Units	Average					
		Year 1-5	Year 6-10	Year 11-15	Year 16-20	Year 21-25	2015-2040
Total Employment	Jobs	106	-92	-69	30	44	5
Private Non-Farm Employment	Jobs	95	-100	-67	31	41	2
Gross Domestic Product	Dollars (Thousands)[1]	35,663	7,779	-2,351	12,822	14,728	13,737
Real Disposable Personal Income	Dollars (Thousands)[1]	9,369	39	-3,123	2,171	4,463	2,668

[1]Dollars are fixed (2014) dollars.

APPENDIX 4: DETAILED ECONOMIC IMPACTS OF SCENARIOS ON DAKOTA COUNTY

The following tables exhibit the economic impacts of the baseline scenario on the Dakota County economy, as well as the economic impacts of the alternative scenarios compared to the baseline scenario.

TABLE 25: CONTRIBUTION OF BASELINE SCENARIO ON THE DAKOTA COUNTY ECONOMY

Category	Units	Average					
		Year 1-5	Year 6-10	Year 11-15	Year 16-20	Year 21-25	2015-2040
Total Employment	Jobs	1	1	78	1,065	36	228
Private Non-Farm Employment	Jobs	1	1	77	1,026	10	215
Gross Domestic Product	Dollars (Thousands)[1]	-535	-422	8,014	121,058	2,954	25,391
Real Disposable Personal Income	Dollars (Thousands)[1]	-84	-251	3,445	62,511	11,543	15,168

[1]Dollars are fixed (2014) dollars. Note: Scenario 1 is the total economic impact (excluding rate impact); other scenarios are in comparison to Scenario 1.

TABLE 26: CONTRIBUTION OF SHC1 2031 & SHC2 2025 ON THE DAKOTA COUNTY ECONOMY

Category	Units	Average					
		Year 1-5	Year 6-10	Year 11-15	Year 16-20	Year 21-25	2015-2040
Total Employment	Jobs	-3	338	535	-820	39	18
Private Non-Farm Employment	Jobs	-3	333	495	-798	50	16
Gross Domestic Product	Dollars (Thousands)[1]	-286	33,672	51,237	-93,710	5,803	-445
Real Disposable Personal Income	Dollars (Thousands)[1]	-448	15,509	26,996	-44,887	-1,096	-714

[1]Dollars are fixed (2014) dollars.

TABLE 27: CONTRIBUTION OF SHC1 2025 & SHC2 2025 ON THE DAKOTA COUNTY ECONOMY

Category	Units	Average					
		Year 1-5	Year 6-10	Year 11-15	Year 16-20	Year 21-25	2015-2040
Total Employment	Jobs	-6	341	489	-873	43	0
Private Non-Farm Employment	Jobs	-5	337	450	-845	56	0
Gross Domestic Product	Dollars (Thousands)[1]	-591	34,087	44,762	-102,846	4,291	-3,757
Real Disposable Personal Income	Dollars (Thousands)[1]	-873	15,510	16,888	-52,685	-2,282	-4,508

[1]Dollars are fixed (2014) dollars.

TABLE 28: CONTRIBUTION OF SHC1 2020 & SHC2 2020 ON THE DAKOTA COUNTY ECONOMY

Category	Units	Average					
		Year 1-5	Year 6-10	Year 11-15	Year 16-20	Year 21-25	2015-2040
Total Employment	Jobs	-15	281	460	-845	47	-12
Private Non-Farm Employment	Jobs	-14	280	427	-816	60	-10
Gross Domestic Product	Dollars (Thousands)[1]	-1,592	26,952	40,202	-99,992	3,826	-5,751
Real Disposable Personal Income	Dollars (Thousands)[1]	-1,867	6,144	13,960	-50,546	-2,247	-6,641

[1]Dollars are fixed (2014) dollars.

TABLE 29: CONTRIBUTION OF SHC1 2023 & SHC2 2020 ON THE DAKOTA COUNTY ECONOMY

Category	Units	Average					
		Year 1-5	Year 6-10	Year 11-15	Year 16-20	Year 21-25	2015-2040
Total Employment	Jobs	-17	1,208	-393	-828	60	7
Private Non-Farm Employment	Jobs	-16	1,182	-418	-794	75	8
Gross Domestic Product	Dollars (Thousands)[1]	-2,437	118,085	-48,109	-95,211	8,425	-3,430
Real Disposable Personal Income	Dollars (Thousands)[1]	-2,127	53,008	-24,533	-51,351	-2,038	-5,182

[1]Dollars are fixed (2014) dollars.

Attachment H
Preliminary Assessment of CO_2 Markets under the Clean Power Plan

We present this preliminary assessment of potential revenues from carbon dioxide (CO_2) credits in future markets under the Clean Power Plan (CPP), in response to requests by the Department of Commerce and Commissioners during the December 3, 2015 Minnesota Public Utilities Commission hearing.

Although our Current Preferred Plan is not primarily driven by the CPP, we believe this plan will not only achieve, but likely exceed, the CO_2 reductions that could be required of the Company under Minnesota's CPP State Plan. As a result, the Current Preferred Plan may generate excess reductions in the form of CO_2 allowances (if Minnesota's plan is mass-based) or Emission Rate Credits (if the plan is rate-based), which under the CPP would be tradable to the owners of other CPP-regulated units within the state or in other states. As long as Minnesota's plan allows the Company to monetize the value of these reductions on behalf of our customers, this value could be used to help reduce the rate impact of transitioning our generation portfolio to a much lower-carbon system.

This Attachment estimates the value to our customers of excess CO_2 reductions under two State Plan scenarios. However, we emphasize the preliminary nature of this assessment: both the size and value of the allowances or ERCs we generate, beyond those used for our own compliance, are subject to uncertainty because they depend on State Plan decisions yet to be made and predictions about prices in CO_2 credit markets not yet in existence.

A. CPP Final Rule, State Plans and CO_2 Credit Markets

The CPP final rule sets CO_2 targets, for 2022 and each year thereafter, for each of the states in our Upper Midwest System. The targets are provided in "rate-based" form (pounds of CO_2 per MWh, both specific to coal and gas units and for each state as a whole) and "mass-based" form (total tons of CO_2, by year, on aggregate for all the CPP-regulated units in a state). Only the Minnesota targets affect the Company directly, since we own and operate CPP-regulated units only in Minnesota; however, the costs and benefits of compliance will be shared among customers in all our five states.

The rule allows each state to develop a State Plan to achieve the targets, providing states considerable flexibility in how they do this. It allows EPA to impose a Federal

Plan on any state that fails to submit an approvable plan. Initial State Plan submittals are due in September 2016, with the option to seek an extension to September 2018 to submit a final plan. The Minnesota Pollution Control Agency (MPCA) is the lead agency with responsibility to develop Minnesota's State Plan, in consultation with other agencies and stakeholders. The Company has been an active participant in MPCA's stakeholder group, as well as similar processes in our other states and regional stakeholder processes, discussing State Plan design decisions. We have been working to identify areas of agreement among utilities and other stakeholders.

A key decision in State Plan design is whether to take a rate-based or mass-based approach. A rate-based approach would seek to achieve the pounds of CO_2 per MWh targets, either on a statewide level or using the subcategory rates specific to coal and natural gas combined cycle units, and would allow eligible activities – including renewable energy, energy efficiency, and nuclear uprates – to earn Emission Rate Credits (ERCs) that could be used by regulated units for compliance. A mass-based approach would seek to achieve the total tons of CO_2 targets, requiring all regulated units to surrender CO_2 allowances equivalent to their emissions in a compliance period.

One of the most important flexibility mechanisms in the CPP is the option for states to create CO_2 credit markets – i.e. allow the owners of CPP-regulated units in a state to transact CO_2 allowances or ERCs with other regulated units, or with other entities, within the state or in other states. This would enable regulated unit owners to purchase allowances or ERCs for compliance, if this is more cost-effective than reducing emissions on their own system, or sell allowances or ERCs, if a regulated unit owner is able cost-effectively to reduce emissions such that it holds more allowances or ERCs than it needs for compliance.

EPA views this compliance flexibility as key to containing costs, and appropriate for CO_2, since the climate benefits of reducing emissions are independent of location. EPA does not mandate that State Plans allow trading, but provides much of the necessary infrastructure, including presumptively approvable model trading rules, EPA-administered allowance and ERC tracking systems, accreditation of credit verifiers, etc. EPA also allows trading between State Plan states and states who accept a Federal Plan. However, EPA proposes that regulated units in mass-based states may only trade with those in other mass-based states, and units in rate-based states may only trade with those in other rate-based states.

Minnesota and the other states the Company serves in the Upper Midwest are all actively considering allowing CO_2 credit trading in their CPP State Plans. However, none of our states has yet determined whether their plan will be mass-based or rate-based, and because of EPA's proposed restriction on trading between rate and mass, the geographic scope and liquidity of future CO_2 credit markets is unknown.

B. Scenario Analysis: Potential Value of CO_2 Credits to Our Customers

The Current Preferred Plan includes actions – coal unit retirement, maintenance of nuclear units, renewable energy additions, and ongoing energy efficiency savings – that are projected to reduce CO_2 potentially beyond what the State Plan requires of the Company. These actions may put the Company in the position of being a net allowance or ERC seller, after the Company has surrendered sufficient allowances or ERCs to bring its own units into compliance. This section presents a preliminary analysis of the value to our customers of these actions, under different possible credit prices and State Plan designs.

Uncertainties affecting the size of the Company's allowance budget include whether Minnesota and other states in the region take mass-based or rate-based approaches to compliance, how the State Plan allocates allowances in a mass-based approach, and which actions are eligible for ERC issuance in a rate-based approach. Uncertainties affecting the price obtainable for any allowances or ERCs include whether states allow trading in their plans, how much EPA's proposed restriction on trading between rate and mass limits the geographic scope and liquidity of CO_2 credit markets, and the structure of CO_2 credit markets that may emerge.

1. Credit Prices

Estimating the market value of CO_2 reductions requires assuming a price for allowances or ERCs in markets not yet in existence. The Commission's current regulatory cost range under Minn. Stat. § 216H.06 – $9 to $34 per short ton of CO_2 emitted – represents one potential price range for allowances (not ERCs).[1] The Company applies the midpoint of this range, $21.50 per ton, as a base assumption in resource planning, and applies the two ends of the range as sensitivities. The MPCA and Minnesota Department of Commerce recently released a request for comments on

[1] April 28, 2014 Order. *In the Matter of Establishing an Updated Estimate of the Costs of Future Carbon Dioxide Regulation on Electricity Generation Under Minn. Stat. § 216H.06*. Docket No. E999/CI-07-1199.

the 2016 update of the regulatory cost range, making a preliminary recommendation to retain the range at $9 to $34 per ton.[2]

The Company agreed with the agencies that this range remains reasonable with the information currently available.[3] The Commission's regulatory cost range was first established in 2008, at a time when Congress was contemplating economy-wide, mass-based CO_2 "cap and trade" proposals, and reflected expert predictions of the CO_2 price that might emerge in such markets. While none of these proposals was signed into law, and today power sector CO_2 regulation is proceeding under section 111(d) of the Clean Air Act, as noted above, EPA has provided for market-based compliance mechanisms in both State and Federal Plans. Minnesota and other states in the region appear to be strongly considering this option, so a market-based regulatory cost appears to be a reasonable assumption.

We do not, however, know whether Minnesota's plan will involve allowance or ERC trading, what other states in the region might choose, or how broad or liquid CO_2 credit markets might be. Experience with existing CO_2 markets in the United States and internationally suggests that efficient market design and geographically broader markets lead to lower CO_2 prices, and prices in existing United States CO_2 markets have historically been in the lower end of the Commission's range.[4] However, with CPP State Plans still in such early stages, and actual CPP markets not yet in existence, it seems premature to conclude that prices will be lower than $9 (or higher than $34). For this analysis, we have used the same $9, $21.50, and $34 per ton that we use in Strategist modeling.

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[2] December 3, 2015 Request for Comments. *In the Matter of Establishing an Updated Estimate of the Costs of Future Carbon Dioxide Regulation on Electricity Generation Under Minn. Stat. § 216H.06*. Docket No. E999/CI-15-708, Docket No. E999/CI-07-1199. The Agencies recommended shifting the date utilities are required to begin applying the range to 2022, which reflects the first year utilities will face a cost to comply with the CPP.
[3] January 14, 2016 *Comments on Updating the Estimated Cost of Future Carbon Dioxide Regulation under Minn. Stat. § 216H.06*. Docket No. E999/CI-15-708.
[4] For example, $12.73 per metric ton ($11.55 per short ton) in the most recent allowance auction in California, and $7.50 per short ton in the most recent allowance auction in the northeastern states Regional Greenhouse Gas Initiative. Prices in prior auctions were lower. See http://www.arb.ca.gov/cc/capandtrade/auction/auction.htm and http://www.rggi.org/market/co2_auctions/results.

The Commission has no corresponding estimate that could be applied as a price per ERC, and there are no existing rate-based CO_2 markets from which to estimate a price of ERCs.[5]

2. State Plan Decisions Affecting Company's Allowance Budget

The size of the Company's allowance budget will depend on many decisions yet to be made in Minnesota's State Plan. Strategist modeling provides a forecast of CO_2 emissions from our CPP-regulated units; however, whether and by how much the allowance budget allocated to the Company (under a mass-based plan) exceeds those emissions will depend on how the plan allocates allowances. Similarly, our overall ERC position (under a rate-based plan) will depend on the activities eligible for ERC crediting.

We here provide analysis of a mass-based plan simply because the Commission's regulatory cost range under Minn. Stat. § 216H.06 provides an allowance price in dollars per ton of CO_2, and we have no comparable basis for predicting a price per ERC. We note that the Company has not yet concluded whether a mass- or rate-based plan is better for our customers.

To estimate our allowance position, we compare projected emissions from CPP-regulated units to the allowance budget that would be allocated to the Company under two hypothetical State Plan scenarios. Both begin with the statewide CO_2 budget for existing units from the CPP, and apply a set of allocation assumptions to derive the share of this budget allocated to the Company.

Scenario 1 assumptions:

- Plan covers existing units only, not new units;
- MPCA demonstrates to EPA that the risk of emission leakage[6] is low in Minnesota, and does not implement allowance set-asides to address leakage;

[5] There are existing markets providing prices for Renewable Energy Credits (RECs) of different types and vintages, and there is some overlap between the types of activities that can generate ERCs and those that can generate RECs. However the overlap is partial, and ERCs and RECs will be separate compliance instruments (ERCs for CPP compliance, RECs for compliance with state renewable energy mandates). Currently low REC prices reflect, among other factors, that relatively cost-effective renewable energy has put many utilities in the situation of having ample RECs for compliance with state renewable energy mandates. However, eventual prices for ERCs will be driven by supply and demand in new CPP markets, which will depend on how many states choose rate-based plans. We have not assumed REC prices provide a proxy for ERC prices.
[6] The CPP defines emission leakage as the incentive to shift generation from affected units regulated under section 111(d) of the Clean Air Act to non-affected units (e.g. new units regulated under section 111(b)).

- Plan includes the Clean Energy Incentive Program (CEIP) allowance set-aside to encourage pre-2022 renewable energy and low-income energy efficiency, and the corresponding matching allowances from EPA;
- Plan includes no other allowance set-asides;
- Plan allocates allowances to affected unit owners based on 2010-2012 generation;[7]
- Plan does not limit the years of allowance allocation to a retired unit;
- The Company earns some allowances back from the CEIP set-aside by implementing eligible activities (wind and solar installed, and low-income energy efficiency implemented, after September 2018).[8]

Scenario 2 assumptions:

- Plan covers existing units only, not new units;
- MPCA adopts EPA's proposed allowance set-asides to address leakage: a set-aside for renewable energy at five percent of the state's allowance budget, and an output-based set-aside for existing natural gas combined cycle units;
- Plan includes the CEIP allowance set-aside to encourage pre-2022 renewable energy and low-income energy efficiency, and the corresponding matching allowances from EPA;
- Plan includes other set-asides, for purposes yet to be determined, totaling an additional 20 percent of the statewide allowance budget;
- Plan allocates allowances to affected unit owners based on 2010-2012 generation;
- Plan allocates no allowances to a retired unit after two years, redirecting these allowances to the renewable energy set-aside;[9] and

[7] We here adopt the default allowance allocation method from EPA's proposed Federal Plan, while noting that EPA leaves the allowance allocation decision to states, and that discussion of the most appropriate allocation basis (generation or emissions, and whether any allowance set-asides are appropriate) is ongoing as of this filing.

[8] Xcel Energy, MPCA and others have urged EPA to shift the eligibility date for the CEIP earlier, making new wind and solar installed, and low-income energy efficiency implemented, after initial plan submittal in September 2016 (rather than after final plan submittal in September 2018) eligible for CEIP allowances or ERCs. Since EPA's decision on this issue is not yet known, this analysis assumes CEIP eligibility as currently proposed.

[9] As proposed by EPA in the proposed Federal Plan. Neither this nor any other allowance allocation provision is binding for an approvable State Plan.

- The Company earns some allowances back from the CEIP, renewable energy, and existing natural gas combined cycle allowance set-asides, but is not assumed to earn any allowances back from other set-asides.

3. Results

The difference in the allowances available to monetize on behalf of our customers (after surrendering sufficient allowances to cover our CPP-regulated unit emissions) is significant between the two State Plan scenarios above.

Scenario 1, because it includes no allowance set-asides except the CEIP and does not limit the years of allowance allocation to retired units, results in a larger Company budget and therefore larger compliance buffer. Once the Company surrenders sufficient allowances to cover its CPP-regulated unit emissions each year, there is a remainder of between 1 and 4 million tons per year, totaling about 25 million tons cumulatively over 2022-2030. These allowances are assumed available for sale to the owners of CPP-regulated units in any state that adopts a mass-based plan. At $21.50 per ton, the undiscounted value over 2022-2030 is $540 million ($258 million in net present value terms).

Scenario 2 has significantly more allowance set-asides: for renewable energy (5 percent of the state budget), for existing natural gas combined cycle units, and for other purposes (20 percent of the state budget); in all, set-asides amount to 29-33 percent of the state budget, before accounting for additional allowances redirected from retired units to the renewable energy set-aside. Scenario 2 also discontinues allowance allocation to a retired unit two years after retirement, which significantly reduces the Company's budget. The Company earns some allowances back from the CEIP, renewable energy, and existing NGCC set-asides by implementing those actions, but is assumed to receive no allowances from the other set-asides, which simply redirect allowance value to other entities and purposes. Once the Company surrenders sufficient allowances to cover its CPP-regulated unit emissions each year, there is a deficit in some years and a small remainder in others, and over 2022-2030 a much smaller remainder of 3.5 million tons cumulatively. These allowances are assumed available for sale to the owners of CPP-regulated units in any state that adopts a mass-based plan. At $21.50 per ton, the undiscounted value over 2022-30 is $75 million ($33 million in net present value terms).

At $21.50 per ton, the difference between State Plan scenarios 1 and 2 is an undiscounted value of $465 million over 2022-2030 ($225 million in net present value

terms). The value at three different CO_2 allowance prices, corresponding to the Commission's low, midpoint, and high regulatory cost values, is shown below:

Table 1: Value of allowances, in excess of compliance needs, under two State Plan scenarios (hundreds of million dollars, undiscounted, over 2022 to 2030)

Allowance Price	Scenario 1	Scenario 2	Difference
$9/ton	$226	$31	$194
$21.50/ton	$540	$75	$465
$34/ton	$853	$119	$735

The "difference" column in this table essentially represents the value transferred from the Company's customers to other parties, in or out of state, by shifting to a State Plan that sets aside significantly more allowances, and discounts the value of retiring coal units by allocating allowances for only a short time post-retirement.

Since all allowance value is assumed to accrue to the Company's customers, a state plan similar to Scenario 1 would provide around $540 million to help mitigate the rate impacts of transitioning to a lower-carbon energy system. A state plan similar to Scenario 2 would provide $465 million less to mitigate customer cost impacts, and would shift much of this value from our customers to other parties.

4. Rate-Based Compliance

The actions in our Current Preferred Plan would also generate a large number of ERCs if Minnesota adopts a rate-based State Plan. Actions eligible for ERC issuance ultimately depend on the State Plan, but the eligible actions under the CPP include:

- *Renewable energy*: generation starting January 1, 2022 from new facilities placed in service after January 1, 2013. The Company's new wind and solar placed in service after 2012, including projects earlier approved by the Commission, and projects proposed in the Current Preferred Plan, are eligible;
- *Energy efficiency*: electricity savings starting January 1, 2022, from measures placed in service after January 1, 2013, are eligible;
- *Nuclear uprates*: the 71 MW uprate at our Monticello nuclear generating station is eligible, since it was placed in service after 2012;
- *New Canadian hydro*: if the Company executes a new power purchase agreement with a new or uprated hydro facility in Canada, this would be eligible;

- *Affected units*: ERCs generated by natural gas combined cycle units operating below the subcategory rate specified for that year, as well as combined cycle units generating gas-shift ERCs, are eligible;[10]
- *CEIP*: generation and savings in 2020-21 from renewable energy projects that commence construction, and low-income energy efficiency measures placed in service, after final state plan submittal in 2018, including ERCs from the EPA match of 1:1 for renewable energy and 2:1 for low-income energy efficiency.[11]

Greater uncertainty surrounds the ERC eligibility of actions such as distributed generation, repowering on-site of an existing renewable energy facility built before 2012, combined heat and power, etc.

Based on preliminary estimates of the ERCs generated from our proposed actions, we expect the Company would generate more ERCs than needed to bring our regulated units into compliance. These ERCs are assumed available for sale to the owners of CPP-regulated units in any state that adopts a rate-based plan. We have not attempted to estimate a value of excess ERCs, since we have no basis for predicting an ERC price comparable to the available methods for CO_2 allowance prices; however, as with allowances, the value of any excess ERCs accrues to our customers and could be used to reduce the electricity rate impacts of transitioning the Company's generation portfolio to a lower-carbon system.

C. State Plan Positions

The Company has not yet taken a position whether a rate-based or mass-based State Plan is best for our customers, since that decision is dependent on the specifics of each plan. A mass-based plan has advantages in terms of simplicity of administration and compliance, but – as indicated by the two Scenarios above – poses risks of allowance allocation decisions that could significantly increase costs to our customers. A rate-based plan has lower allocation risks, but is significantly more complex to administer as proposed by EPA. We are currently in the process of identifying, in discussion with the MPCA, other utilities, and other stakeholders, areas of agreement for each plan type.

[10] Gas-shift ERCs are a special type of ERCs awarded to combined cycle units that operate above their unit-specific 2012 baseline level of operation. Gas-shift ERCs may only be used for compliance by coal units.
[11] As mentioned above, we are not assuming for this analysis that EPA moves the CEIP eligibility dates earlier, nor that MPCA submits its State Plan earlier than the September 2018 deadline.

If MPCA selects a mass-based plan, we believe this plan should:

- Enable interstate trading through a "trading-ready" approach;
- Cover existing affected coal and natural gas combined cycle units only, not new units;[12]
- Demonstrate to EPA that the risk of emission leakage is low in Minnesota, using state Renewable Energy Standard and Conservation Improvement Program mandates, integrated resource plans, etc.;
- Allocate allowances to the owners of affected units on behalf of their customers. Allowance auctions serve no policy objective in a fully regulated state like Minnesota, merely increasing costs to customers without achieving additional CO_2 reductions;
- Allocate allowances to an affected unit that retires after 2012 for the duration of the CPP program. The analysis above illustrates the significant amount of value transferred from our customers to other parties, in and out of state, by redirecting these allowances;
- Not assign a "shelf life" to previously issued allowances;
- Allocate allowances among affected unit owners based on 2010-12 operations;[13]
- Minimize allowance set-asides, which utilities agree are likely to increase costs, except for the Clean Energy Incentive Program (CEIP) set-aside;[14]
- Require that the state allowance budget be used only for purposes of compliance, and that allowances may not be retired for other purposes;
- Include, but explore the ability to improve, the CEIP.

If the State Plan significantly deviates from the above principles, a rate-based plan may be better for our customers. If MPCA selects a rate-based plan, we believe this plan should:

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[12] The Clean Air Act defines existing units as those constructed prior to, and new units as those constructed subsequent to, January 8, 2014 – the date of EPA's release of the proposed New Source Performance Standard under Clean Air Act section 111(b).

[13] For example, allowances could be allocated based on 2010-12 generation (as proposed by EPA in the proposed Federal Plan), 2010-12 emissions, or another basis. EPA leaves the allocation method to states' discretion. The most appropriate method (both whether based on generation or emissions, and whether any allowance set-asides are appropriate) remains under discussion as of this filing. Whatever the method, the plan should incorporate EPA's correction in the final CPP for Sherburne County Unit 3, replacing 2012 data with typical-year generation or emissions.

[14] Whether any targeted set-asides are appropriate likewise remains under discussion as of this filing. In general, utilities agree allowance set-asides should be minimal and used with caution, since each set-aside reduces the budget allocated to utility customers and thus increases their costs.

- Enable interstate trading through a "trading-ready" approach;
- Use the subcategory-specific emission performance rates for fossil fuel-fired steam generating units and stationary combustion turbines;
- Leverage Minnesota's robust renewable energy and energy efficiency policies to streamline EPA's evaluation, monitoring and verification requirements for ERC crediting;
- Make the broadest possible set of zero-carbon actions eligible to earn ERCs, including but not limited to:
    - renewable energy (all types defined as renewable in state statute),
    - renewable energy uprates and repowering,
    - distributed generation,
    - end-use energy efficiency,
    - demand response and demand-side management,
    - nuclear uprates,
    - Canadian hydro,
    - existing natural gas combined cycle operating below the applicable subcategory rate or generating gas-shift ERCs, and
    - transmission and distribution efficiency improvements;
- Not assign a "shelf life" to ERCs;
- Award ERCs to existing (pre-2012) renewable energy facilities that are significantly repowered on the same site after 2012;
- Include, but explore the ability to improve, the CEIP.

CERTIFICATE OF SERVICE

I, SaGonna Thompson, hereby certify that I have this day served copies or summaries of the foregoing document on the attached list of persons.

xx by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States mail at Minneapolis, Minnesota;

or

xx by electronic filing.

Docket No. E002/RP-15-21

Dated this 29th day of January 2016

/s/

SaGonna Thompson
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John	Lindell	agorud.ecf@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	Yes	OFF_SL_15-21_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Peter	Madsen	peter.madsen@ag.state.mn.us	Office of the Attorney General-DOC	Bremer Tower, Suite 1800 445 Minnesota Street St. Paul, Minnesota 55101	Electronic Service	Yes	OFF_SL_15-21_Official
Kavita	Maini	kmaini@wi.rr.com	KM Energy Consulting LLC	961 N Lost Woods Rd Oconomowoc, WI 53066	Electronic Service	Yes	OFF_SL_15-21_Official
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	OFF_SL_15-21_Official
Mary	Martinka	mary.a.martinka@xcelenergy.com	Xcel Energy Inc	414 Nicollet Mall 7th Floor Minneapolis, MN 55401	Electronic Service	Yes	OFF_SL_15-21_Official
Daryl	Maxwell	dmaxwell@hydro.mb.ca	Manitoba Hydro	360 Portage Ave FL 16 PO Box 815, Station Main Winnipeg, Manitoba R3C 2P4 Canada	Electronic Service	No	OFF_SL_15-21_Official
Brian	Meloy	brian.meloy@stinson.com	Stinson,Leonard, Street LLP	150 S 5th St Ste 2300 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-21_Official
Erin	Mittag	emittag@mncenter.org	Minnesota Center for Environmental Advocacy	26 E Exchange Street, Suite 206 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_15-21_Official
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Andrew	Moratzka	apmoratzka@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	Yes	OFF_SL_15-21_Official

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Alan	Muller	alan@greendel.org	Energy & Environmental Consulting	1110 West Avenue Red Wing, MN 55066	Electronic Service	No	OFF_SL_15-21_Official
Carl	Nelson	cnelson@mncee.org	Center for Energy and Environment	212 3rd Ave N Ste 560 Minneapolis, MN 55401	Electronic Service	Yes	OFF_SL_15-21_Official
David W.	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency	Suite 300 200 South Sixth Street Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-21_Official
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Daniel P	Wolf	dan.wolf@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_15-21_Official
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Northern States Power Company, a Minnesota corporation
Minneapolis, Minnesota 55401
SOUTH DAKOTA ELECTRIC RATE BOOK - SDPUC NO. 2

PRELIMINARY STATEMENT

Section No. 3
1st Revised Sheet No. 1
Cancelling Original Sheet No. 1

SUBDIVISION 1 INDEX OF COMPANY'S SERVICE AREA

Northern States Power Company supplies electric service at retail in the State of South Dakota in the incorporated municipalities, unincorporated named communities and hamlets, townships and counties listed below.

COMMUNITIES		COMMUNITIES		COMMUNITIES	
Alexandria		Forestburg (U)		Ramona	
Artesian		Fulton		Renner (U)	
Baltic		Garretson		Roswell	D
Benton Township	N	Germantown Township	N	Salem	
Brandon	N	Grant Township	N	Sanborn County	
Brandon Township	N	Hanson County		Sherman	
Bridgewater		Harrisburg		Sioux Falls	
Bridgewater Township	N	Howard Township	ND	Sioux Falls Township	N
Canistota		La Valley Township	N	Split Rock Township	N
Canova		Lake County		Spring Valley Township	N
Canton		Lennox		Springdale Township	N
Canton Township	N	Lincoln County		Sverdrup Township	N
Carthage		Logan Township	N	Tea	
Centerville		Lyons Township	N	Turner County	
Centerville Township	N	Mapleton Township	N	Union Township	ND
Chancellor		Marion		Valley Springs Township	N
Crooks		McCook County		Vilas	
Delapre Township	N	Miner County		Wall Lake Township	N
Dell Rapids		Minnehaha County		Wayne Township	N
Dell Rapids Township	N	Monroe		Wellington Township	N
Dolton		Monroe Township	N	Winfred (U)	
Dolton Township	N	Moody County		Worthing	
Ellis		Palisade Township	N		
Emery		Perry Township	N		
Fedora (U)					

(U) Denotes unincorporated community

(Continued on Sheet No. 3-2)

Date Filed: 06-30-11 By: Judy M. Poferl Effective Date: 08-01-12
President and CEO of Northern States Power Company, a Minnesota corporation
Docket No. EL11-019 Order Date: 07-18-12

S:\General-Offices-GO-01\PSF\RA\Rates\Current\Sd_elec\SE_3_01_r01.DOC

APPENDIX N4 – RENEWABLE ENERGY COMPLIANCE POSITIONS

Our Upper Midwest Integrated System provides service to five states—and each state has varying levels of renewable energy requirements. Each state's target is expressed as a percentage of electric retail sales from qualifying resources by a certain date. Specific targets are as follows:

- North Dakota and South Dakota each has a voluntary Renewable and Recycled Energy Objective to have 10 percent renewable or recycled energy by 2015.[1]
- Michigan has a Renewable Energy Standard that requires Xcel Energy to have 10 percent renewable energy by 2015.
- Wisconsin has a Renewable Portfolio Standard that requires Xcel Energy to have approximately 12.9 percent renewable energy by 2015.
- Minnesota has a Renewable Energy Standard that requires Xcel Energy to have 30 percent by 2020, including interim targets of:
    - Of the 30 percent, Minnesota's RES requires Xcel Energy to have 25 percent of the Minnesota retail sales to come from wind energy by 2020.[2]
    - In addition, Minnesota's SES requires Xcel Energy an additional 1.5 percent of the electricity it provides to Minnesota retail customers to come from solar energy by 2020.

A. Renewable Energy Credit Accounting and Management

We plan and operate our NSP system generation and transmission facilities as an integrated system in the most cost effective way possible to the benefit of all customers across the five state jurisdictions and that complies with the regulations of each of these states. In order to meet each of the Renewable Energy Standards in those states, we maintain a set of banked Renewable Energy Credits (REC) for future compliance. We maintain our REC inventory in the regional Midwest Renewable Energy Tracking System (M-RETS), which was established for compliance tracking

[1] As defined in North Dakota Century Code, 49-02-25, recycled energy means "systems producing electricity from currently unused waste heat resulting from combustion or other processes into electricity and which do not use an additional combustion process. The term does not include any system whose primary purpose is the generation of electricity unless the generation system consumes wellhead gas that would otherwise be flared, vented, or wasted." South Dakota Codified Law 49-34A-94 contains a similar definition.

[2] This requirement is included in the total 30 percent RES, and we are authorized to count a limited amount of solar energy towards this 25 percent. Large hydro does not count as a renewable energy source for purpose of the Minnesota RES. Minn. Stat. § 216B.1691

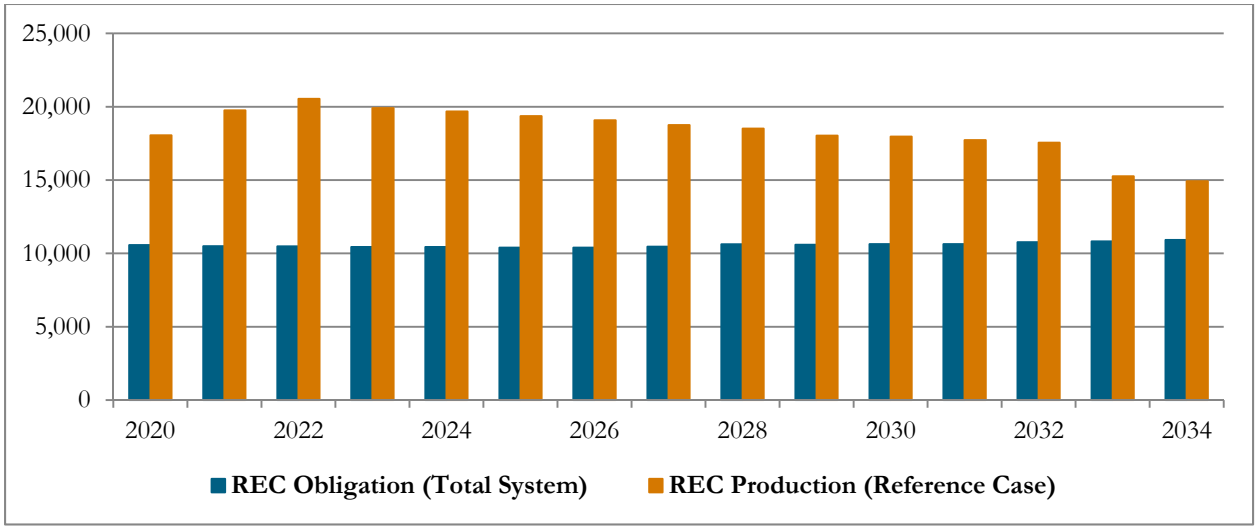
relative to state renewable energy standards. In M-RETS, one MWh of generation from a renewable source equates to one REC.

The Company currently expects to generate a sufficient amount of RECs throughout the planning period to satisfy our current renewable obligations without adding any renewable capacity beyond the projects we currently have under contract.

B. Renewable Energy Standard and Objective Compliance

Figure 1 below demonstrates our compliance through the Resource Plan planning period with all renewable energy standards and objectives across the NSP system with existing and currently approved resources. This evaluation assumes no large scale solar or wind additions, however includes modest distributed solar additions throughout the planning period. Appendix N5, filed June 1, 2018, is the company's most recent Minnesota biennial RES Compliance filing.

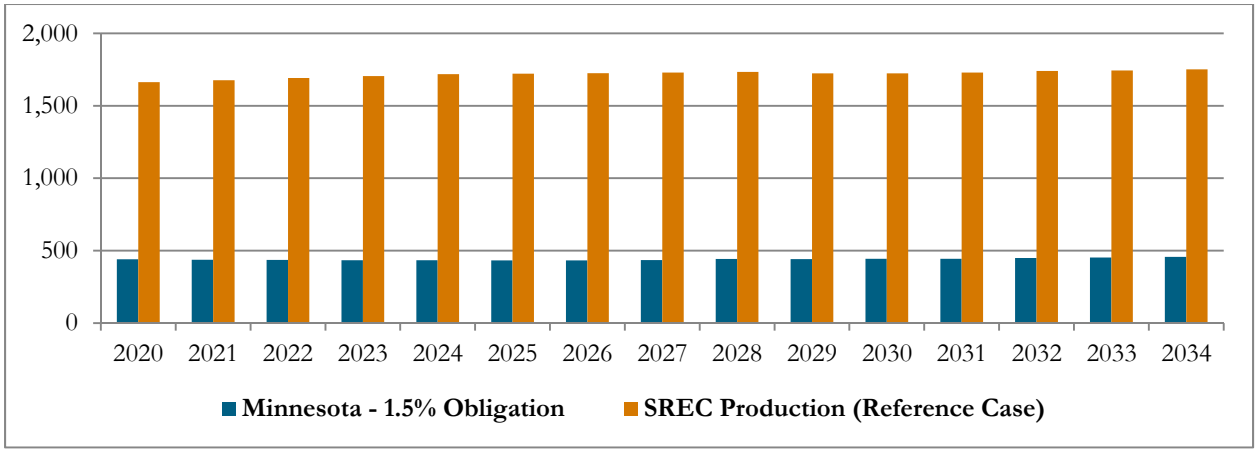
Figure 1: Annual RES & REO REC
NSP System Obligation & Production



C. Solar Energy Standard Compliance

Figure 2 below demonstrates our compliance with the Minnesota 1.5 percent Solar Energy Standard (SES) through the Resource Plan planning period with existing and currently approved programs. This evaluation assumes no large scale solar additions, however includes modest distributed solar additions throughout the planning period. Appendix N7, filed June 1, 2019, is the company's most recent Minnesota SES Compliance filing.

Figure 2: State of Minnesota Annual SES REC Obligation & Production



414 Nicollet Mall
Minneapolis, MN 55401

June 25, 2018

—VIA ELECTRONIC FILING—
PUBLIC DOCUMENT
TRADE SECRET INFORMATION EXCISED

REFILED

Mr. Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101-2147

RE: RENEWABLE ENERGY OBLIGATION (REO)-RENEWABLE ENERGY STANDARD (RES) COMPLIANCE REPORT

COMMISSION CONSIDERATION AND DETERMINATION ON COMPLIANCE WITH RENEWABLE ENERGY STANDARDS
DOCKET NO. E999/M -18-78

RENEWABLE ENERGY CERTIFICATE RETIREMENT AND REPORTING FOR COMPLIANCE YEAR 2017
DOCKET NO. E999/PR-18-12

GREEN PRICING VERIFICATION FILING PROCESS
DOCKET NO. E999/PR-02-1240

Dear Mr. Wolf:

On June 1, 2018, Northern States Power Company, a Minnesota corporation, submitted a Non-Public version of the attached compliance report to fulfill the verification and filing requirements for the Renewable Energy Standards (RES) Renewable Energy Credit (REC) retirement and Green Pricing REC retirement, along with the RES biennial filing obligations required by Minn. Stat. § 216B.1691, Subd. 3.

On June 13, 2018, the MN Department of Commerce (DOC) made a request that we refile the report with public information on subscriptions to Renewable*Connect – Government to allow the DOC to communicate overall trends in voluntary purchases to the public. The Company contacted the Renewable*Connect-Government customer and received written authorization to refile the information as public. The Company submits this letter and the attached report containing the requested public information in the above-referenced docket.

This filing is made pursuant to the Minnesota Public Utilities Commission's April 17, 2014 NOTICE OF BIENNIAL FILING OBLIGATIONS, which established Docket No. E999/M-14-237. We have provided the required information in the attached Excel spreadsheet templates. Attachment A contains REC retirements, biennial reporting obligations, and REC sales and purchases.

Attachment A contains certain portions that have been designated as Trade Secret information pursuant to Minnesota Statute § 13.37, subd. 1(b). In particular, the information designated as Trade Secret derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use.

REC Retirement

By May 1, 2018, the Company retired approximately 7.4 million RECs, representing 25 percent of annual retail sales for calendar year 2017, using the Midwest Renewable Energy Tracking System (M-RETS). The Company is therefore in compliance with the Minnesota RES requirements identified in Minn. Stat. § 216B.1691 and the Commission's March 19, 2010 Order in Docket No. E999/CI-03-869. In addition, by May 1, 2018, the Company retired a large number of RECs for our Green Pricing Programs as detailed in Attachment A.

The required information specified in the Commission's April 17, 2014 NOTICE and the May 28, 2013 ORDER FINDING UTILITIES IN COMPLIANCE WITH MINN. STAT. § 216B.1691 AND MODIFYING BIENNIAL REPORTING PROCEDURES in Docket No. E999/M-12-958, including the RES calculations, the RECs retired and the names of the M-RETS retirement sub-accounts, is provided in Attachment A.

As noted in Attachment A.6, we sold 356,310 RECs allocated to the Company's Minnesota jurisdictional share during the 2017 calendar year. The Company also

purchased 169,500 RECs for our Windsource program and has included those quantities in Attachment A.6.

Biennial REO-RES Compliance

This report provides the Company's actual retail sales data from 2017 and forecasted retail sales data for 2018 – 2020, generation data summary for this reporting period, other state RES or Objectives to which the utility is subject, actions taken to address the RES requirements, and a discussion of potential obstacles to meeting our requirements and solutions to the same.

Pursuant to Minn. Stat. § 216.17, subd. 3, we have electronically filed this document and served copies on all parties on the attached service list. If you have any questions about this information, please contact me at bria.e.shea@xcelenergy.com or (612) 330-6064.

Sincerely,

/s/

BRIA E. SHEA
DIRECTOR, REGULATORY AND STRATEGIC ANALYSIS

Attachment
c: Service Lists

CERTIFICATE OF SERVICE

I, Lynnette Sweet, hereby certify that I have this day served copies or summaries of the foregoing document on the attached list of persons.

xx by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States Mail at Minneapolis, Minnesota

xx electronic filing

DOCKET NOS. E999/PR-02-1240
E999/PR-18-12
E999/M-18-78

Dated this 25th day of June 2018

/s/
_____
Lynnette Sweet
Regulatory Administrator

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	OFF_SL_2-1240_OFF_SL_2-1240_02-1240
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1800 St. Paul, MN 55101	Electronic Service	No	OFF_SL_2-1240_OFF_SL_2-1240_02-1240
Carl	Cronin	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_2-1240_OFF_SL_2-1240_02-1240
Ian	Dobson	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	No	OFF_SL_2-1240_OFF_SL_2-1240_02-1240
Brian	Draxten	bhdraxten@otpco.com	Otter Tail Power Company	P.O. Box 496 215 South Cascade Street Fergus Falls, MN 565380498	Electronic Service	No	OFF_SL_2-1240_OFF_SL_2-1240_02-1240
Dennis	Eisenbraun	deisenbraun@mpsutility.com	Moorhead Public Service Dept. (E)	500 Center Ave PO Box 779 Moorhead, MN 56561-0779	Electronic Service	No	OFF_SL_2-1240_OFF_SL_2-1240_02-1240
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_2-1240_OFF_SL_2-1240_02-1240
J Drake	Hamilton	hamilton@fresh-energy.org	Fresh Energy	408 St Peter St Saint Paul, MN 55101	Electronic Service	No	OFF_SL_2-1240_OFF_SL_2-1240_02-1240
Susan	Mackenzie	susan.mackenzie@state.mn.us	Public Utilities Commission	121 7th Place E Ste 350 St. Paul, MN 551012147	Electronic Service	No	OFF_SL_2-1240_OFF_SL_2-1240_02-1240
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David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency	220 South Sixth Street Suite 1300 Minneapolis, Minnesota 55402	Electronic Service	No	OFF_SL_2-1240_OFF_SL_2-1240_02-1240
Mark	Rathbun	mrathbun@grenergy.com	Great River Energy	12300 Elm Creek Blvd Maple Grove, MN 55369	Electronic Service	No	OFF_SL_2-1240_OFF_SL_2-1240_02-1240
Michael	Reinertson	michael.reinertson@avantenergy.com	Avant Energy	220 S. Sixth St. Ste 1300 Minneapolis, Minnesota 55402	Electronic Service	No	OFF_SL_2-1240_OFF_SL_2-1240_02-1240
Craig	Rustad	crustad@minnkota.com	Minnkota Power	1822 Mill Road PO Box 13200 Grand Forks, ND 582083200	Electronic Service	No	OFF_SL_2-1240_OFF_SL_2-1240_02-1240
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Trevor	Smith	trevor.smith@avantenergy.com	Avant Energy, Inc.	220 South Sixth Street Suite 1300 Minneapolis, Minnesota 55402	Electronic Service	No	OFF_SL_2-1240_OFF_SL_2-1240_02-1240
Daniel P	Wolf	dan.wolf@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 551012147	Electronic Service	No	OFF_SL_2-1240_OFF_SL_2-1240_02-1240

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1800 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_18-12_Official
Carl	Cronin	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_18-12_Official
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Ian	Dobson	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	Yes	OFF_SL_18-12_Official
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Bryan	Gower	bgower@apx.com	APX, Inc.	N/A	Electronic Service	No	OFF_SL_18-12_Official
Casey	Jacobson	cjacobson@bepc.com	Basin Electric Power Cooperative	1717 East Interstate Avenue Bismarck, ND 58501	Electronic Service	No	OFF_SL_18-12_Official
Nate	Jones	njones@hcpd.com	Heartland Consumers Power	PO Box 248 Madison, SD 57042	Electronic Service	No	OFF_SL_18-12_Official
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John	Richards	johnrichards@nweco.com	Northwestern Wisconsin Electric Company	104 S. Pine St. Grantsburg, WI 54840	Electronic Service	No	OFF_SL_18-12_Official
Craig	Rustad	crustad@minnkota.com	Minnkota Power	1822 Mill Road PO Box 13200 Grand Forks, ND 582083200	Electronic Service	No	OFF_SL_18-12_Official
Robert K.	Sahr	bsahr@eastriver.coop	East River Electric Power Cooperative	P.O. Box 227 Madison, SD 57042	Electronic Service	No	OFF_SL_18-12_Official
Christopher	Schoenherr	cp.schoenherr@smmpa.org	SMMPA	500 First Ave SW Rochester, MN 55902-3303	Electronic Service	No	OFF_SL_18-12_Official
Mrg	Simon	mrgsimon@mrenergy.com	Missouri River Energy Services	3724 W. Avera Drive P.O. Box 88920 Sioux Falls, SD 571098920	Electronic Service	No	OFF_SL_18-12_Official
Trevor	Smith	trevor.smith@avantenergy.com	Avant Energy, Inc.	220 South Sixth Street Suite 1300 Minneapolis, Minnesota 55402	Electronic Service	No	OFF_SL_18-12_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Carol	Westergard	cwestergard@otpco.com	Otter Tail Power Company	215 S Cascade St Fergus Falls, MN 56537	Electronic Service	No	OFF_SL_18-12_Official
Daniel P	Wolf	dan.wolf@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_18-12_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	OFF_SL_18-78_Official
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William A.	Blazar	bblazar@mnchamber.com	Minnesota Chamber Of Commerce	Suite 1500 400 Robert Street North St. Paul, MN 55101	Electronic Service	No	OFF_SL_18-78_Official
Jon	Brekke	jbrekke@grenergy.com	Great River Energy	12300 Elm Creek Boulevard Maple Grove, MN 553694718	Electronic Service	No	OFF_SL_18-78_Official
Mark B.	Bring	mbring@otpco.com	Otter Tail Power Company	215 South Cascade Street PO Box 496 Fergus Falls, MN 565380496	Electronic Service	No	OFF_SL_18-78_Official
Christina	Brusven	cbrusven@fredlaw.com	Fredrikson Byron	200 S 6th St Ste 4000 Minneapolis, MN 554021425	Electronic Service	No	OFF_SL_18-78_Official
Douglas M.	Carnival	dmc@mcgrannshea.com	McGrann Shea Carnival Straughn & Lamb	N/A	Electronic Service	No	OFF_SL_18-78_Official
Kenneth A.	Colburn	kcolburn@symbioticstrategies.com	Symbiotic Strategies, LLC	26 Winton Road Meredith, NH 32535413	Electronic Service	No	OFF_SL_18-78_Official
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1800 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_18-78_Official
George	Crocker	gwillc@nawo.org	North American Water Office	PO Box 174 Lake Elmo, MN 55042	Electronic Service	No	OFF_SL_18-78_Official
Carl	Cronin	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_18-78_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
David	Dahlberg	davedahlberg@nweco.com	Northwestern Wisconsin Electric Company	P.O. Box 9 104 South Pine Street Grantsburg, WI 548400009	Electronic Service	No	OFF_SL_18-78_Official
Curt	Dieren	curt.dieren@dgr.com	L&O Power Cooperative	1302 S Union St Rock Rapids, IA 51246	Electronic Service	No	OFF_SL_18-78_Official
Ian	Dobson	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	Yes	OFF_SL_18-78_Official
Kristen	Eide Tollefson	healingsystems69@gmail.com	R-CURE	28477 N Lake Ave Frontenac, MN 55026-1044	Electronic Service	No	OFF_SL_18-78_Official
Oncu	Er	oncu.er@avantenergy.com	Avant Energy, Agent for MMPA	220 S. Sixth St. Ste. 1300 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_18-78_Official
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	Yes	OFF_SL_18-78_Official
Edward	Garvey	garveyed@aol.com	Residence	32 Lawton St Saint Paul, MN 55102	Electronic Service	No	OFF_SL_18-78_Official
Bryan	Gower	bgower@apx.com	APX, Inc.	N/A	Electronic Service	No	OFF_SL_18-78_Official
Tony	Hainault	anthony.hainault@co.hennepin.mn.us	Hennepin County DES	701 4th Ave S Ste 700 Minneapolis, MN 55415-1842	Electronic Service	No	OFF_SL_18-78_Official
Kimberly	Hellwig	kimberly.hellwig@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_18-78_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
John	Helmers	helmers.john@co.olmsted.mn.us	Olmsted County Waste to Energy	2122 Campus Drive SE Rochester, MN 55904-4744	Electronic Service	No	OFF_SL_18-78_Official
Jared	Hendricks	hendricksj@owatonnautilities.com	Owatonna Public Utilities	PO Box 800 208 S Walnut Ave Owatonna, MN 55060-2940	Electronic Service	No	OFF_SL_18-78_Official
Annete	Henkel	mui@mnutilityinvestors.org	Minnesota Utility Investors	413 Wacouta Street #230 St.Paul, MN 55101	Electronic Service	No	OFF_SL_18-78_Official
Lori	Hoyum	lhoyum@mnpower.com	Minnesota Power	30 West Superior Street Duluth, MN 55802	Electronic Service	No	OFF_SL_18-78_Official
Casey	Jacobson	cjacobson@bepc.com	Basin Electric Power Cooperative	1717 East Interstate Avenue Bismarck, ND 58501	Electronic Service	No	OFF_SL_18-78_Official
Nate	Jones	njones@hcpd.com	Heartland Consumers Power	PO Box 248 Madison, SD 57042	Electronic Service	No	OFF_SL_18-78_Official
Julie	Ketchum	N/A	Waste Management	20520 Keokuk Ave Ste 200 Lakeville, MN 55044	Paper Service	No	OFF_SL_18-78_Official
Brian	Krambeer	bkrambeer@tec.coop	Tri-County Electric Cooperative	PO Box 626 31110 Cooperative Way Rushford, MN 55971	Electronic Service	No	OFF_SL_18-78_Official
Dave	McNary	David.McNary@hennepin.us	Hennepin County DES	701 Fourth Ave S Ste 700 Minneapolis, MN 55415-1842	Electronic Service	No	OFF_SL_18-78_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
John	McWilliams	jmm@dairynet.com	Dairyland Power Cooperative	3200 East Ave SPO Box 817 La Crosse, WI 54601-7227	Electronic Service	No	OFF_SL_18-78_Official
Stacy	Miller	stacy.miller@state.mn.us	Department of Commerce	State Energy Office 85 7th Place East, Suite 500 St. Paul, MN 55101	Electronic Service	No	OFF_SL_18-78_Official
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	OFF_SL_18-78_Official
Dalene	Monsebroten	dalene@mncable.net	Northern Municipal Power Agency	123 2nd St W Thief River Falls, MN 56701	Electronic Service	No	OFF_SL_18-78_Official
Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP	33 South Sixth St Ste 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_18-78_Official
Ben	Nelson	benn@cmpasgroup.org	CMMPA	459 South Grove Street Blue Earth, MN 56013	Electronic Service	No	OFF_SL_18-78_Official
Dale	Niezwaag	dniezwaag@bepc.com	Basin Electric Power Cooperative	1717 East Interstate Avenue Bismarck, ND 58503	Electronic Service	No	OFF_SL_18-78_Official
David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency	220 South Sixth Street Suite 1300 Minneapolis, Minnesota 55402	Electronic Service	No	OFF_SL_18-78_Official
Samantha	Norris	samanthanorris@alliantenergy.com	Interstate Power and Light Company	200 1st Street SE PO Box 351 Cedar Rapids, IA 524060351	Electronic Service	No	OFF_SL_18-78_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Russell	Olson	rolson@hcpd.com	Heartland Consumers Power District	PO Box 248 Madison, SD 570420248	Electronic Service	No	OFF_SL_18-78_Official
Mary Beth	Peranteau	mperanteau@wheelerlaw.com	Wheeler Van Sickle & Anderson SC	44 E. Mifflin Street, 10th Floor Madison, WI 53703	Electronic Service	No	OFF_SL_18-78_Official
Mark	Rathbun	mrathbun@grenergy.com	Great River Energy	12300 Elm Creek Blvd Maple Grove, MN 55369	Electronic Service	No	OFF_SL_18-78_Official
Michael	Reinertson	michael.reinertson@avantenergy.com	Avant Energy	220 S. Sixth St. Ste 1300 Minneapolis, Minnesota 55402	Electronic Service	No	OFF_SL_18-78_Official
John C.	Reinhardt		Laura A. Reinhardt	3552 26Th Avenue South Minneapolis, MN 55406	Paper Service	No	OFF_SL_18-78_Official
Kevin	Reuther	kreuther@mncenter.org	MN Center for Environmental Advocacy	26 E Exchange St, Ste 206 St. Paul, MN 551011667	Electronic Service	No	OFF_SL_18-78_Official
Craig	Rustad	crustad@minnkota.com	Minnkota Power	1822 Mill Road PO Box 13200 Grand Forks, ND 582083200	Electronic Service	No	OFF_SL_18-78_Official
Robert K.	Sahr	bsahr@eastriver.coop	East River Electric Power Cooperative	P.O. Box 227 Madison, SD 57042	Electronic Service	No	OFF_SL_18-78_Official
Richard	Savelkoul	rsavelkoul@martinsquires.com	Martin & Squires, P.A.	332 Minnesota Street Ste W2750 St. Paul, MN 55101	Electronic Service	No	OFF_SL_18-78_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Christopher	Schoenherr	cp.schoenherr@smmpa.org	SMMPA	500 First Ave SW Rochester, MN 55902-3303	Electronic Service	No	OFF_SL_18-78_Official
Dean	Sedgwick	N/A	Itasca Power Company	PO Box 457 Bigfork, MN 56628-0457	Paper Service	No	OFF_SL_18-78_Official
Mrg	Simon	mrgsimon@mrenergy.com	Missouri River Energy Services	3724 W. Avera Drive P.O. Box 88920 Sioux Falls, SD 571098920	Electronic Service	No	OFF_SL_18-78_Official
Trevor	Smith	trevor.smith@avantenergy.com	Avant Energy, Inc.	220 South Sixth Street Suite 1300 Minneapolis, Minnesota 55402	Electronic Service	No	OFF_SL_18-78_Official
Beth H.	Soholt	bsoholt@windonthewires.org	Wind on the Wires	570 Asbury Street Suite 201 St. Paul, MN 55104	Electronic Service	No	OFF_SL_18-78_Official
Steve	Thompson	stevet@cmpasgroup.org	Central Minnesota Municipal Power Agency	459 S Grove St Blue Earth, MN 56013-2629	Electronic Service	No	OFF_SL_18-78_Official
Pat	Treseler	pat.jcplaw@comcast.net	Paulson Law Office LTD	4445 W 77th Street Suite 224 Edina, MN 55435	Electronic Service	No	OFF_SL_18-78_Official
Roger	Warehime	warehimer@owatonnautilities.com	Owatonna Public Utilities	208 South WalnutPO Box 800 Owatonna, MN 55060	Electronic Service	No	OFF_SL_18-78_Official
Paul	White	paul.white@prcwind.com	Project Resources Corp./Tamarac Line LLC/Ridgewind	618 2nd Ave SE Minneapolis, MN 55414	Electronic Service	No	OFF_SL_18-78_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Cam	Winton	cwinton@mnchamber.com	Minnesota Chamber of Commerce	400 Robert Street North Suite 1500 St. Paul, Minnesota 55101	Electronic Service	No	OFF_SL_18-78_Official
Robyn	Woeste	robynwoeste@alliantenergy.com	Interstate Power and Light Company	200 First St SE Cedar Rapids, IA 52401	Electronic Service	No	OFF_SL_18-78_Official
Daniel P	Wolf	dan.wolf@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_18-78_Official
Thomas J.	Zaremba	TZaremba@wheelerlaw.com	WHEELER, VAN SICKLE & ANDERSON	44 E. Mifflin Street, 10th Floor Madison, WI 53703	Electronic Service	No	OFF_SL_18-78_Official

Minnesota Public Utilities Commission
Docket No. E999/PR-18-12
Docket No. E-999/M-18-78

Minnesota Department of Commerce
Docket No. E999/PR-02-1240

Renewable Energy Certificate Retirement Report for Renewable Energy Standards and Green Pricing Programs
REC Retirement Compliance Reporting

Due: June 1st, 2018
For the Reporting Period:
January 1, 2017 - December 31, 2017*
*Exception for Worksheet A.6: Ordering pt. 4C requires reporting REC sales & purchases for the **2 preceding calendar years**.

Instructions

Note: items in red indicate changes in reporting from previous year
Complete the following worksheets and e-file in **Excel (XLS or XLSX)** format:

- Worksheet 1, Utility Info
- Worksheet 2, Renewable Energy Standard Retail Sales
- Worksheet 3, Green Pricing Program Retail Sales
- Worksheet 4, RES & Green Pricing REC Retirements
- Worksheet 5, Biennial Compliance Reporting
- Worksheet 6, RECs Bought and Sold During the Reporting Period

To e-file, login, or register, at: https://www.edockets.state.mn.us/EFiling/home.jsp
For directions on how to e-file, see: http://www.commerce.state.mn.us/eDocFile/eFilingHelp.html
For questions about Renewable Energy Certificate retirement or compliance with Renewable Energy Standards, contact Kelly Martone at 651-201-2245 or at kelly.martone@state.mn.us.
For questions about Green Pricing or about filling out this spreadsheet, send an email to: DG.Energy@state.mn.us.
For questions about e-filing, contact Karen Santori at 651-539-1530 or at karen.santori@state.mn.us .

Minnesota Public Utilities Commission: Docket No. E999/PR-18-12, Docket No. E-999/M-18-78 **Attachment 1**
Minnesota Department of Commerce: Docket No. E999/PR-02-1240 Reporting Period: January 1, 2017 - December 31, 2017

Renewable Energy Certificate Retirement Report for Renewable Energy Standards and Green Pricing Programs

Report Year	2017	Date Submitted	June 1, 2018

FILING UTILITY INFORMATION		CONTACT INFORMATION	
Company ID #	85	Contact Name	Pamela Gibbs
Company Name	Xcel Energy	Contact Title	Regulatory Case Specialist
Street Address Line 1	414 Nicollet Mall	Contact Telephone	612-330-2889
Street Address Line 2		Contact E-Mail	pamela.k.gibbs@xcelenergy.com
City	Minneapolis	COMMENTS/NOTES	
State	MN		
Zip Code	55401		

Filing for **RENEWABLE ENERGY STANDARDS** on behalf of:

Utility Name	Utility Name	Utility Name	Utility Name
Northern States Power Company - Minnesota			

Filing for **GREEN PRICING PROGRAMS** on behalf of:

Utility Name	Utility Name	Utility Name	Utility Name
Northern States Power Company - Minnesota			

Minnesota Public Utilities Commission: Docket No. E999/PR-18-12, Docket No. E-999/M-18-78 **Attachment 2**
Minnesota Department of Commerce: Docket No. E999/PR-02-1240 Reporting Period: **January 1, 2017 - December 31, 2017**

Total Retail Sales to Minnesota Customers and
Renewable Energy Certificates Required to be Retired for RENEWABLE ENERGY STANDARD Compliance

Retail Sales Total (MWh)	29,739,386
RES Percentage Obligation	25%
RECs Required to be Retired	7,434,847
Actual RECs Retired	7,434,847

Enter current reporting year data.

Utility ID #	Utility	Retail Sales Amount (MWh)	Notes
85	Xcel Energy (NSP-MN)	29,739,386	

Minnesota Public Utilities Commission: Docket No. E999/PR-18-12, Docket No. E-999/M-18-78 **Attachment 3**
Minnesota Department of Commerce: Docket No. E999/PR-02-1240 Reporting Period: **January 1, 2017 - December 31, 2017**

GREEN PRICING Program Sales

TOTAL **GREEN PRICING** Sales (MWh)	220,817
RECS retired for **GREEN PRICING** programs	220,817

List the cumulative retail sales of green pricing electricity, including utility-managed community solar, and the number of customers as of December 31, 2017.

Utility ID # (on Worksheet 1)	Utility Name	Program Name	No. of Program Customers	Program Sales (MWh)	Retail Rate ($/kWh)	Notes
85	Xcel Energy (NSP-MN)	Windsource Minnesota	52,872	178,613	$0.0353	
85	Xcel Energy (NSP-MN)[1]	Renewable * Connect	882	3,097	$0.03555	2017 Month-to-Month Rate
85	Xcel Energy (NSP-MN)[1]	Renewable * Connect	794	5,082	$0.03243	2017 5-year rate
85	Xcel Energy (NSP-MN)[1]	Renewable * Connect	534	28,459	$0.03193	2017 10-year rate
85	Xcel Energy (NSP-MN)[1]	Renewable * Connect Government	1	5,566	$0.03093	2017 Rate
85	Xcel Energy (NSP-MN)	Community Solar Gardens		0		No sales since company receives all RECs and subscribers do not get CSG energy

[1] The total amount of program sales stated above and the equivalent REC Retirement quantities are approximately 95 MWh higher than what was filed in the 2017 Renewable*Connect compliance filing dated April 1, 2018, due to a discovered discrepancy between company billing data reports and company program subscription reports. It was found that customers' sales continued to be accounted for although some customers had previously terminated their subscriptions. This artificial increase in sales, lead to an increase in REC retirements. The reporting issue has been corrected and the same 95 RECs will be reduced from the 2018 Renewable*Connect sales numbers.

Minnesota Public Utilities Commission: Docket No. E999/PR-18-12, Docket No. E-999/M-18-78 **Attachment 4**
Minnesota Department of Commerce: Docket No. E999/PR-02-1240 Reporting Period: **January 1, 2017 - December 31, 2017**

Renewable Energy Certificate Retirements for Renewable Energy Standards and Green Pricing Programs

Renewable Energy Standard REC Retirement Account Name:	**NSP-MN RES Retirement 2017 - D893545D-DFF4**		
Green Pricing REC Retirement Account Name:	**NSP-MN Windsource Retirement-2017 - 0D6D0392-993F**		
Green Pricing REC Retirement Account Name:	**MN Renewable Connect 2017 - F899ED0D-DAE2**		
Total RECs	7,434,847	220,817	1 REC = 1 MWh

MRETS ID	MRETS Generator Facility Name	Generator Fuel Type	RECS retired for **RENEWABLE ENERGY STANDARD** compliance	RECS retired for **GREEN PRICING** programs	NOTES
M677	Adams - Adams Wind	Wind	48,994		
M656	Agassiz Beach - Agassiz Beach	Wind	3,674		
M277	Apple River (Unit 1)(Units 3-4) - Apple Ri	Hydroelectric Water	22,481		
M831	Big Blue Wind Farm - Big Blue Wind Farm	Wind	104,259		
M278	Big Falls (Units 1-3) - Big Falls	Hydroelectric Water	86,705		
M1051	Black Oak Wind Farm	Wind	0	59,500	Purchased RECs Retired for Windsource GPP
M432	Boeve Windfarm - Boeve Windfarm	Wind	0	7,332	Windsource
M965	Border Winds Wind Farm - Border Wind	Wind	22,974		
M459	Carleton College - Carleton College	Wind	2,995		
M279	Cedar Falls (Units 1-3) - Cedar Falls	Hydroelectric Water	70,038		
M387	Chanarambie Power Partners (1) - Chana	Wind	77,050		
M388	Chanarambie Power Partners (2) - Chana	Wind	72,568		
M280	Chippewa Falls (Unit 1) - Chippewa Falls	Hydroelectric Water	17,493		
M320	Chippewa Falls (Unit 2) - Chippewa Falls	Hydroelectric Water	30,664		
M321	Chippewa Falls (Unit 3) - Chippewa Falls	Hydroelectric Water	42,652		
M322	Chippewa Falls (Unit 4) - Chippewa Falls	Hydroelectric Water	38,018		
M323	Chippewa Falls (Unit 5) - Chippewa Falls	Hydroelectric Water	3,437		
M324	Chippewa Falls (Unit 6) - Chippewa Falls	Hydroelectric Water	25,564		
M352	Cisco Wind Energy - Cisco Wind Energy	Wind		30,442	Windsource
M689	Community Wind North - North Commu	Wind	32,341		
M690	Community Wind North - North Wind Tu	Wind	30,419		
M707	Cornell (Unit 1-4) - Cornell (Unit 1-4)	Hydroelectric Water	172,035		
M872	Cow Poo - Cow Poo	Biogas	6,495		
M678	Danielson - Danielson Wind Farms	Wind	34,210		
M282	Dells (Units 1-7) - Dells	Hydroelectric Water	100,452		
M887	Diamond K Dairy, Inc. - Diamond K Dairy,	Biogas	911		
M351	East Ridge - East Ridge	Wind	17,628		
M353	Ewington Energy Systems - Ewington Ene	Wind	47,173		
M355	Fenton Power Partners I (1) - Fenton Pov	Wind	312,161		
M356	Fenton Power Partners I (2) - Fenton Pov	Wind	196,515		
M433	Fey Windfarm - Fey Windfarm	Wind	4,019		
M760	Fibrominn LLC - Fibrominn Multi	Biomass	285,610		
M366	FPL Energy Mower County - FPL Energy M	Wind	171,317		
M629	FreEner-g-2009-01 - FreEner-g-2009-01	Solar	28		
M630	FreEner-g-2010-01 - FreEner-g-2010-01	Solar	451		
M317	French Island (Unit 1) - French Island (Un	Biomass	66,619		
M274	French Island (Unit 2) - French Island (Un	Biomass	56,123		
M742	GL Bio Gas I, LLC - GL Bio Gas I	Biogas	10,831		
M493	Grand Meadow Wind Farm - Grand Mea	Wind	212,175		
M577	Grant County Wind - Grant County Wind	Wind	40,633		
M885	GreenWhey Energy, Inc - GreenWhey En	Biogas	21,792		
M283	Hayward (Unit 1) - Hayward	Hydroelectric Water	1,752		
M484	Hibbing Public Utility - Laurentian	Biomass	339,975		
M509	Hilltop Power - Hilltop	Wind	455		
M284	Holcombe (Unit 1) - Holcombe (Unit 1)	Hydroelectric Water	64,500		
M328	Holcombe (Unit 2) - Holcombe (Unit 2)	Hydroelectric Water	76,911		
M329	Holcombe (Unit 3) - Holcombe (Unit 3)	Hydroelectric Water	73,349		
M431	Jeffers Wind 20 - Jeffers Wind 20	Wind	129,784		
M285	Jim Falls (Unit 1) - Jim Falls (Unit 1)	Hydroelectric Water	151,770		
M519	Jim Falls (Unit 3) - Jim Falls (Unit 3)	Hydroelectric Water	7,239		
M430	Jim Falls (Units 2) - Jim Falls (Units 2)	Hydroelectric Water	137,450		

MRETS ID	MRETS Generator Facility Name	Generator Fuel Type	RECS retired for **RENEWABLE ENERGY STANDARD** compliance	RECS retired for **GREEN PRICING** programs	NOTES
M452	JJN Windfarm - JJN Windfarm	Wind		4,848	Windsource
M635	Kas Brothers Windfarm - Kas Brothers W	Wind	2,014		
M386	K-Brink Wind Farm - K-Brink Wind Farm	Wind		7,562	Windsource
M534	Koda 1 - Koda Energy	Biomass	161,940		
M286	Ladysmith (Units 1-3) - Ladysmith	Hydroelectric Water	22,692		
M639	Lake Benton Power Partners II (LBII) - LB	Wind	207,860		
M728	Lake Benton Power Partners, LLC - Lake E	Wind	213,275		
M302	Laurie River 1 - Laurie River 1	Hydroelectric Water	1,379		
M303	Laurie River 2 - Laurie River 2	Hydroelectric Water	1,609		
M758	LCO Band of Lake Superior Chippewa Ind	Hydroelectric Water	28,664		
M305	McArthur Falls - McArthur Falls	Hydroelectric Water	18,958		
M655	MCC - Solar	Solar	1,473		
M447	McNeilus Group - McNeilus Group	Wind	44,210	21,442	Windsource
M287	Menomonie (Units 1-2) - Menomonie	Hydroelectric Water	50,254		
M730	Merrick Solar - Merrick Solar	Solar	236		
M681	Metro Wind - Metro Wind	Wind	477		
M390	MinnDakota Wind (1) - MinnDakota Win	Wind	111,152		
M732	MinnDakota Wind (1b) - MinnDakota Wi	Wind	129,024		
M391	MinnDakota Wind (2) - MinnDakota Win	Wind	132,198		
M738	MNRDF_DNR - MNRDF_DNR	Solar	274		
M508	Moraine II - Moraine II	Wind	104,346	5,125	Windsource
M392	Moraine Wind - Moraine Wind	Wind	91,134		
M606	Neshonoc - Neshonoc	Hydroelectric Water	3,901		
M643	Nobles Wind Farm - Nobles Wind Farm I	Wind	188,927		
M646	Nobles Wind Farm - Nobles Wind Farm II	Wind	226,105		
M393	Norgaard North - Norgaard North	Wind	9,333		
M394	Norgaard South - Norgaard South	Wind	7,438		
M657	North Shaokatan Wind - Group	Wind	21,857		
M1064	North Star Solar PV - North Star Solar PV	Solar	0	8,061	Renewable Connect
M1064	North Star Solar PV - North Star Solar PV	Solar	0	1,224	Renewable Connect Government
M1045	Odell Wind Farm (1) - Odell Wind Farm (	Wind	0	28,578	Renewable Connect
M1045	Odell Wind Farm (1) - Odell Wind Farm (	Wind	0	4,341	Renewable Connect Government
M636	Olsen Windfarm LLC - Olsen Windfarm	Wind	2,025		
M694	Pine Bend - Pine Bend	Biogas	59,473		
M304	Pine Falls - Pine Falls	Hydroelectric Water	26,340		
M363	Pipestone - Pipestone	Wind	14,627		
M966	Pleasant Valley Wind Farm - Pleasant Val	Wind	7,796		
M307	Pointe du Bois - Pointe du Bois	Hydroelectric Water	10,047		
M791	Prairie Rose Wind - Prairie Rose Wind, LL	Wind	242,784		
M275	Red Wing (Unit 1) - Red Wing (Unit 1)	Biomass	115,345		
M330	Red Wing (Unit 2) - Red Wing (Unit 2)	Biomass	109,984		
M642	Ridgewind - Ridgewind	Wind	57,603		
M288	Riverdale (Units 1-2) - Riverdale	Hydroelectric Water	3,848		
M359	Rock County	Wind	0	32,680	Windsource
M362	Rock Ridge Power Partners - Rock Ridge I	Wind	4,302		
M658	Ruthton Ridge Wind - Group	Wind	32,544		
M706	SAF Hydro, LLC - SAF Hydro	Hydroelectric Water	83,694		
M289	Saxon Falls (Units 1-2) - Saxon Falls	Hydroelectric Water	10,426		
M389	Shane's Wind Machine - Shane's Wind M	Wind	4,216		
M306	Slave Falls - Slave Falls	Hydroelectric Water	22,144		
M796	Slayton Solar - Slayton Solar LLC	Solar	5,447		
M364	South Ridge Power Partners - South Ridg	Wind	4,111		
M627	SRMN2010-J-01 - SRMN2010-J-01	Solar	2,661		
M714	SRMN2011-01 - SRMN2011-01	Solar	1,477		
M737	SRMN2011-02 - SRMN2011-02	Solar	1,730		
M882	SRMN2011-03 - SRMN2011-03	Solar	150		
M766	SRMN2012-01 - SRMN2012-01	Solar	1,698		
M786	SRMN2012-02 - SRMN2012-02	Solar	2,057		

MRETS ID	MRETS Generator Facility Name	Generator Fuel Type	RECS retired for **RENEWABLE ENERGY STANDARD** compliance	RECS retired for **GREEN PRICING** programs	NOTES
M797	SRMN2012-03 - SRMN2012-03	Solar	2,301		
M836	SRMN2012-04 - SRMN2012-04	Solar	231		
M881	SRMN2013-01 - SRMN2013-01	Solar	2,518		
M883	SRMN2013-02 - SRMN2013-02	Solar	2,260		
M291	St. Anthony (Units 1-5) - St. Anthony	Hydroelectric Water	136,878		
M711	St. Croix Falls (Unit 1-8) - St. Croix Falls (U	Hydroelectric Water	222,203		
M559	St. John's Solar Farm - St. John's Solar Fa	Solar	1,610		
M649	St. Joseph Windfarm Inc. - St. Joseph Wir	Wind	24,603		
M308	St. Leon Wind Energy - St. Leon Wind En	Wind	19,991		
M368	St. Olaf College - St. Olaf College	Wind	1,782		
M875	St. Paul Cogeneration - St. Paul Cogenera	Biomass	225,425		
M292	Superior Falls (Units 1-2) - Superior Falls	Hydroelectric Water	21,515		
M396	Tholen Transmission Inc. (North) - Tholer	Wind	14,604		
M397	Tholen Transmission Inc. (South) - Tholer	Wind	10,736		
M293	Thornapple (Units 1-2) - Thornapple	Hydroelectric Water	16,326		
M294	Trego (Units 1-2) - Trego	Hydroelectric Water	16,591		
M561	Uilk Wind Farm - Uilk Wind Farm	Wind	7,772		
M683	Valley View - Valley View Wind	Wind	18,941		
M453	Velva Windfarm - Velva Windfarm	Wind	15,182		
M395	West Ridge - West Ridge	Wind	5,837	4,573	Windsource
M395	West Ridge - West Ridge	Wind	0		
M897	Western Technical College - Western Tec	Hydroelectric Water	1,897		
M295	White River (Units 1-2) - White River	Hydroelectric Water	5,065		
M276	Wilmarth (Unit 1) - Wilmarth (Unit 1)	Biomass	57,580		
M338	Wilmarth (Unit 2) - Wilmarth (Unit 2)	Biomass	59,689		
M638	Wind Power Partners - Wind Power Parti	Wind	28,920		
M434	Windcurrent Farms - Windcurrent Farms	Wind	0	5,109	Windsource
M365	Windvest Power Partners - Windvest Pov	Wind	4,025		
M721	Winona County Wind - Winona County V	Wind	245		
M712	Wissota (Unit 1-3) - Wissota (Unit 1-3)	Hydroelectric Water	144,143		
M713	Wissota (Unit 4-6) - Wissota (Unit 4-6)	Hydroelectric Water	152,539		
M625	WM Renewable Energy - Burnsville - WM	Biomass	65,635		
M626	Woodstock Municipal Wind - Woodstock	Wind	1,321		
M802	Zephyr Wind, LLC (CWS) - Zephyr Wind (	Wind	29,256		
M792	Zephyr Wind, LLC (CWS) - Zephyr Wind (:	Wind	37,278		

Minnesota Public Utilities Commission: Docket No. E999/PR-18-12, Docket No. E-999/M-18-78 **Attachment 5**
Minnesota Department of Commerce: Docket No. E999/PR-02-1240 Reporting Period: **January 1, 2016 - December 31, 2017**

Biennial Compliance reporting

Please report the following items in compliance with the PUC May 28, 2013 Order in Docket No. E999/M-12-958

Ordering Point

4.A. & 5.H. The year through which the utility can maintain compliance with its current renewable portfolio*
*Include banked Renewable Energy Credits (RECs)

Beyond 2040

4.B. & 5.I. Projected compliance for the current plus three (3) upcoming years. Include banked RECs.

Year	Actual/Projected MN retail sales (MWh)	RES Req.(%)	RES Req. (MWh)	Projected Resources (MWh)	Projected Surplus/ (Deficit) (MWh)
2017	29,739,386	25%	7,434,847	8,377,040	7,951,109
	[TRADE SECRET BEGINS		TRADE SECRET BEGINS		
2018		25%			
2019		25%			
2020		30%			
	TRADE SECRET ENDS]				TRADE SECRET ENDS]

5.E.2 & 5.F. Identify other State Renewable Standards or Objectives to which the utility is subject, and the percentage of renewable energy allocated to meet the renewable requirements.

State	RES Req. (MWh)	RES Req. (%)	Percent of utility's total system renewable generation apportioned to this state (%)*

WI	842,719	12.89%	15.97%
MI	14,118	10%	0.33%
SD	205,031	10% Voluntary	5.14%
ND	0	Voluntary	5.43%

*apportionment of renewable energy should reflect each state's percentage of the utility's total system sales.

5.E.3 (i) **The status of the utility's renewable energy mix relative to the objective & standards.**

The Company's overall renewable energy mix exceeds the renewable portfolio standard (RPS) obigations for the state of Minnesota, and other states it operates in, and is sufficiently able to comply with the current requirements. The Company continues to increase its renewable energy mix, primarily in wind and solar, in an effort to maintain compliance with increased obligations, reduce costs, and decrease the carbon footprint.

5.E.3(ii) **Efforts taken to meet the objective and standards**

The Company recently has received approval to add 1850 MW of wind resources to add to the renewable portfolio. These resources are a combined mixture of Self-Build, Build-Own-Transfers(BOT), and Power Purchased Agreement (PPAs) projects and are all expected to achieve commercial operations prior to 2021 in order to qualify for the Production Tax Credit (PTC). The approval of these projects continues to prove to be a reasonable and prudent way for NSP to meet its obligations under the MN Renewable Energy Standard.

5.E.3(iii) **Obstacles encountered or anticipated in meeting the objective or standards**

In 2020, the Renewable Portfolio Standard (RPS) increases the overall RES, has a 24% wind requirement as part of the 30% RES, as well as an additional 1.5% solar obligation. The existing and approved resources will satisfactorily meet all requirements through 2030. The 2030 SES 10% goal will substantially increase the solar need, and will necessitate the addition of solar resources in the future.

5.E.3(iv) **Potential solutions to the obstacles**

See question 5.E.3(ii) for potential solutions to meet required objectives and standards. This issue will be addressed in future resource plans.

5.G. **List any renewable generation facilities expected to become operational during the upcoming year**

Facility Name	Type	Capacity (MW)	Cap. Factor (%)	Expected Comm'l Operation Date
Community Solar Gardens	Solar	various	16-19%	various
Small Solar - RDF Projects	Solar	various	16-19%	various
Solar*Rewards Incentive Installations	Solar	various	16-19%	various

5.K. **Identify efforts taken to adequately protect against undesirable economic impacts on ratepayers, including, but not limited to keeping customer's bills and the utility's rates as low as practicable, given regulatory and other constraints.**

In an effort to acquire low cost wind energy, the Company issued an RFP in late 2016. The timing of this RFP permitted the projects to qualify for the PTC tax benefits. The Company will continue to take advantage of market opportunities, as these are identified as beneficial to the rate payer.

Minnesota Public Utilities Commission: Docket No. E999/PR-18-12, Docket No. E-999/M-18-78 **Attachment 6**
Minnesota Department of Commerce: Docket No. E999/PR-02-1240 Reporting Period: **ary 1, 2016 - December 31, 2017**

M-RETS RECs Bought and Sold

Ordering pt. 4C requires reporting REC sales & purchases for the 2 preceding calendar years

REC Purchases Total	169,500
REC Sales Total	356,310

Enter current reporting year data.

Wholesale REC Purchases	Wholesale REC Sales	PRICE	NOTES
	7,372	$24.00	Poultry Waste
	3,907	$24.00	Poultry Waste
	70,857	$23.00	Poultry Waste
	64,974	$25.00	Poultry Waste
	12,000	$28.00	Poultry Waste
	79,331	$28.00	Poultry Waste
	117,868	$29.00	Poultry Waste
30,000		$0.80	Windsource Purchase
25,000		$0.80	Windsource Purchase
40,000		$0.80	Windsource Purchase
12,000		$0.80	Windsource Purchase
55,000		$0.80	Windsource Purchase
7,500		$0.80	Windsource Purchase

APPENDIX N6 – RENEWABLE ENERGY STANDARD (RES) RATE IMPACT REPORT

Renewable Energy Standard (RES) Rate Impact Report

Northern States Power Company
July 2019

I. REGULATORY CONTEXT

A. Procedural History

Minn. Stat. §216B.1691 (Renewable Energy Objectives) identifies the eligible renewable generation technologies, the percentage of retail sales that must come from renewables, and the reporting requirements that each electric utility shall undergo with regard to the statute's objectives. In 2011, subd. 2(e) was enacted to require electric utilities to file reports with the Commission estimating the rate impacts resulting from utility actions taken to comply with the renewable energy objectives of the state. During the 2013 legislative session, Minn. Stat. §216B.1691 subd. 2(e) was amended to require the Commission, in consultation with the Department of Commerce, to devise a uniform rate impact reporting system.

On November 6, 2013, the Commission issued a Notice of Comment Period that included a staff proposal for a format for a uniform reporting system. The Notice also proposed four "general guiding principles" to assist the Commission with developing the uniform reporting system. The general guiding principles were to: 1) Foster transparency; 2) Support consistency, coordination, and non-burdensome administration; 3) Provide realistic representation of baseline, actual-to-date and future expected costs for achieving and maintaining standard compliance; and 4) Enable comparison across utilities.

On October 2, 2014 in Docket E999/CI-11-852, the Commission deliberated regarding the matter of utility renewable energy cost impact reports required by Minn. Stat. § 216B.1691, subd.2e. During these deliberations, the Commission decided on a variety of motions regarding the information that utilities were to provide when reporting on the estimated rate impacts resulting from actions taken to comply with the Renewable Energy Standard (RES) and Solar Energy Standard (SES) established in Minn. Stat. § 216B.1691, including the requirement that utilities file the report as an appendix in their Integrated Resource Plan.

On January 6, 2015 the Commission issued an Order establishing a uniform report system for estimating the rate impact of complying with the RES and SES.

II. FORMAT USED FOR RATE IMPACT CALCULATIONS

The RES and SES rate impacts provided in this report incorporate a general template format consistent with Commission's January 6, 2015 Order. This report:

a. Includes direct costs including payments under PPAs and revenue requirements associated with utility-owned renewable energy projects;

b. Provides a narrative discussion about the cost impacts that adding generators powered by renewable sources could have on a utility (See Appendix Q: NSP Wind & Solar Integration Study (Enernex);

c. Includes estimates of transmission costs attributable to renewables;

d. Includes direct avoided costs, including avoided energy and capacity costs, and/or avoided costs of facilities the utility could have added to its system instead of renewable resources as necessary to meet RES/SES;

e. Includes consideration of indirect avoided SO2 and NOx permit costs and avoidance of future CO_2 emissions based on costs set by Minn. Stat. § 216H.06;

f. Calculates separate rate impacts for the RES and SES;

g. Provides rate impacts on both annualized and levelized formats;

h. Includes rate impact calculations consistent with those outlined on page 21 of the Briefing Papers;

i. Includes all facilities used to comply with the RES and SES, regardless of when they were constructed.

III. METHODOLOGY

As required by the statute, we calculated separate rate impacts for the RES and for the SES. The RES rate impact calculations were performed for two different time frames: Historic Years 2005-2019 and Future Years 2020-2034. Recognizing that the SES was adopted in 2013, the first full calendar year was 2014. However, there was minimal solar on our system prior to 2017. Therefore, the SES rate impact we present herein uses Historical Years 2017-2019 and Future Years 2020-2034.

A. Historic RES Rate Impact (2005-2019)

We determined historic rate impacts by comparing the actual direct costs associated with all the Company's renewable generation each year with an estimate of the direct costs that would have been incurred had we acquired the same accredited generation capacity (MW)[1] and energy (MWh) from non-renewable resources. We used historic Midcontinent Independent System Operator (MISO) cost of new entry (CONE) values from 2005-2013, with updates to align with Strategist assumptions[2] to estimate avoided capacity costs. We estimated avoided energy costs using historic MISO locational marginal prices (LMPs) for the NSP market node.[3] For 2019, we estimated avoided energy costs using the Minnesota Hub forward curve. Included in the cost of renewables are estimates of transmission costs directly attributable to renewable resources. Tables 9 and 10 in Part III.D of this report identify transmission projects that, from the Company's perspective, are directly attributable to renewable generation resources. Three of the identified transmission projects are MISO multi-value projects[4] (MVPs). Since MVP transmission projects provide a variety of benefits to the electric system, 70 percent of the MVP transmission projects costs that are allocated to NSP customers were included as a direct cost of renewables for purposes of this report. For all other transmission projects identified in Tables 9 and 10, we included 100 percent of the project costs allocated to NSP customers as a direct cost of renewables.

In developing the historic RES rate impact calculations, the Company focused its efforts on estimating and reporting impacts to retail customers. The Tables below show only retail customer impacts of complying with the RES and SES. These costs are reflective of the entire NSP System.

1 MW in this instance refers to the aggregate MW of MISO accredited capacity NSP claimed for its fleet of renewable generation resources (both owned and purchased).
2 See Appendix F2: Strategist Assumptions and Inputs for additional detail
3 See Table 10 in this report for historical MISO values used in these calculations.
4 The MVPs are Lacrosse-Madison, Big Stone-Brookings, and CAP X 2020-Brookings.

B. Future RES Rate Impact (2020-2034)

Future RES rate impacts were derived by comparing NSP electric system cost projections within the Strategist computer model for two different futures: 1) a "RES" future that reflects the Reference Case in the 2020-2034 Resource Plan, and, 2) a "No RES" future in which only RES resources existing on the system today are removed, and instead are replaced with an equivalent amount of our new generic wind and solar resource options at current pricing levels. In doing so, the Company was able to isolate the cost of bringing early RES and SES resources onto the system for compliance purposes rather than economics.

It is important to note that we slightly modified our approach to the future RES rate impact in this analysis as compared to previous reports, in which we replaced all existing RES resources with thermal generation. Unlike in previous years, new wind and solar resources are now least-cost options relative to thermal replacement resources – and as a result, wind are solar are selected ahead of thermal options in the Strategist Expansion Plan Optimizations. Therefore, the future rate impact calculations contained herein isolate the higher costs of early wind and solar additions made to satisfy RES requirements, as opposed to adding the equivalent amount of renewables at current, economic cost levels.

For biomass resources, the "No RES" case assumes market energy and capacity replacement costs. We used the Minnesota Hub forward curve to forecast replacement energy costs and our generic CT capacity costs to forecast replacement capacity costs. Comparing the costs of the existing biomass resources to market pricing allowed us to identify the above market costs of these resources. For hydro resources, we opted to include the costs associated with existing resources in both the "RES" and "No RES" scenarios. Our small hydro resources were not added for RES compliance purposes or due to any mandates, and therefore do not contribute to any RES related rate impacts.

As stated, the "RES" case is represented by the "Reference Case" that is discussed throughout this Resource Plan document. Details as to the major assumptions contained in the "Reference Case" (e.g., fuel prices, sales forecast, resource additions, resource retirements, CO_2 costs/values, etc.) can be found in Appendix F2 of this Resource Plan. The "Reference Case" assigns a cost to CO_2 emissions of $25.00/ton starting in 2025 and escalates annually at the inflation rate; this value also represents the avoided costs of CO_2 attributed to renewables. As existing renewable

resources are now being replaced with new lower cost generic renewables instead of thermal resources in this rate impact analysis, the carbon impacts between the two scenarios are not impactful.

By taking the difference between the annual system costs of the "RES" and "No RES" cases, we estimated the future costs (or savings) associated with all of the Company's actions to comply with the RES. It is important to emphasize that this comparison of a "RES" future and "No RES" future focuses exclusively on existing RES resources, as we are able to meet the RES requirements during the planning period with existing resources alone. We excluded any of the new 1,850 MW of wind, and also excluded additional future renewables contained in the "Reference Case," as these renewable additions are driven by economics as opposed to RES compliance. As a result, the future rate impacts identified in this report are not inclusive of all renewables and may be markedly different from rate impacts calculated for incremental renewable resources.[5]

For future years in the "RES" scenario, we included transmission costs associated with RES wind resources using the same methodology as described above for the historical rate impact. For the "No RES" scenario, future wind avoided transmission costs were derived using an average of the transmission costs associated with owned projects in our 1,850 MW wind portfolio. Since in the "No RES" scenario, we are assuming that existing RES resources are replaced with new generic wind additions in 2020, we felt the timing coincided well with the 1,850 MW of wind additions and therefore that using transmission cost assumptions informed by those projects was appropriate. We did not assume any transmission costs or avoided transmission costs for biomass or hydro resources in either the "RES" or "No RES" scenario.

C. Historical SES Rate Impact (2017-2019)

Historical SES rate impacts were derived using the same methodology as described above for the historical RES rate impact. The historical rate impact report starts in 2017. This is because there were minimal amounts of solar on the system in years prior. Counting these prior years would dilute the overall historical rate impact on a levelized basis.

[5] Incremental in this instance refers to additional renewables added to the system in the future.

D. Future SES Rate Impact (2020-2034)

Future SES rate impacts were derived in a manner similar to that described above for future RES rate impacts. We made comparisons between Strategist computer model runs for two different futures: (1) a "SES" that includes all existing renewables as well as additional renewables (including solar) that the optimization selects based on economics, and (2) a "No SES" future in which existing solar generation resources contained in the "SES" case are stripped out and replaced with equivalent amount of our new generic solar resource options priced at current market levels starting in 2020. The difference in annual system direct costs between these analyses represents the future year costs or savings associated with the Company's future actions to comply with the SES. The "SES" case is identical to the "Reference Case" discussed throughout this Resource Plan.

We assumed that no transmission costs were attributable to SES resources, given the relatively smaller quantities of solar that are currently interconnected to our system. The MISO MVP and CAPX2020 buildouts were primarily driven by wind, and thus solar additions are assumed to have not yet prompted any major transmission expenditures. Given this, we also assumed no avoided transmission costs for the generic replacement solar that was included in the "No SES" future.

E. Conclusions

Our analysis shows that the RES and SES mandates have generally increased costs for customers, as they prompted renewable adoption before these resources were economic. In past Resource Plans, removing the RES and SES resources generally resulted in higher thermal generation adoption. We have now reached a point, however, where wind and solar resources are the most economic options, and therefore are selected in portfolio optimization modeling ahead of thermal resources. Because of this new reality, we had to slightly modify our approach to calculating the RES/SES rate impact, as discussed above. Modifying the analysis to include renewable replacement, as opposed to thermal replacement, reveals higher rate impacts caused by RES and SES resources over time, driven the reality that new wind and solar resources are now much lower cost resource options than they were in the past.

Table 1: Annualized Historic RES Rate Impact (2005-2012)[6]

	Historic Period							
RES Generation	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
[7]Total RES Generation PPA & Owned (GWh)	2,755	2,556	3,852	5,083	5,297	5,735	6,739	7,115
Costs Associated with RES Generation	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
[7]Purchased Power (PPA) & Owned (millions)	$120	$123	$183	$266	$303	$321	$378	$421
RES attributable transmission (millions)	$35	$51	$76	$87	$90	$93	$91	$89
Total RES Costs (millions)	$155	$175	$260	$353	$394	$413	$469	$509
[8]Total cost for RES generation ($/MWh)	$56.27	$68.28	$67.41	$69.48	$74.31	$72.09	$69.56	$71.59
Avoided Costs Due to RES	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
Avoided energy costs PPAs & Owned (millions)	$128	$115	$206	$242	$135	$168	$181	$182
Avoided capacity cost PPAs & Owned (millions)	$34	$34	$41	$38	$40	$30	$40	$43
Avoided transmission cost (millions)	$10	$10	$12	$11	$12	$9	$12	$13
Avoided emission cost PPAs & Owned (millions)	$0	$0	$0	$0	$0	$0	$0	$0
Total avoided costs PPAs & Owned (millions)	$172	$159	$259	$291	$188	$208	$233	$239
[8]Total avoided costs PPAs & Owned ($/MWh)	$62.30	$62.35	$67.35	$57.34	$35.41	$36.21	$34.51	$33.58
Total RES Premium/Discount (millions)	-$17	$15	$0	$62	$206	$206	$236	$270
Total RES Premium/Discount ($/MWh)	-$6.03	$5.94	$0.06	$12.14	$38.90	$35.87	$35.05	$38.02
	Historic Period							
Annualized RES Rate Impacts	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
NSP total retail sales (GWh)	41,800	42,096	43,021	42,573	41,080	42,186	42,318	41,879
% Retail Sales	100%	100%	100%	100%	100%	100%	100%	100%
NSP retail rate impact ($/MWh)	-$0.40	$0.36	$0.01	$1.45	$5.01	$4.88	$5.58	$6.46
NSP retail rate impact (cents/kWh)	-.04¢	.04¢	.00¢	.14¢	.50¢	.49¢	.56¢	.65¢

[6] Total amounts may not be exact due to rounding.
[7] Category has been updated over the historical period to reflect the exclusion of RES resource that the Company does not receive RECs from, overall impacts were minimal
[8] GWh-to-MWh calculations assume a factor of 1,000 (1 GWh = 1,000 MWh).

Table 2: Annualized Future RES Rate Impact (2013-2019)[6]

	Historic Period						
RES Generation	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019[9]**
[7]Total RES Generation PPA & Owned (GWh)	7,551	8,376	8,341	10,223	11,692	10,743	11,365

Costs Associated with RES Generation	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
[7]Purchased Power (PPA) & Owned (millions)	$424	$456	$479	$480	$546	$504	$650
RES attributable transmission (millions)	$87	$85	$83	$81	$78	$75	$75
Total RES Costs (millions)	$511	$541	$563	$561	$624	$580	$725
[8]Total cost for RES generation ($/MWh)	$67.62	$64.62	$67.48	$54.83	$53.35	$53.98	$63.76

Avoided Costs Due to RES	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Avoided energy costs PPAs & Owned (millions)	$238	$291	$195	$223	$292	$306	$331
Avoided capacity cost PPAs & Owned (millions)	$50	$30	$33	$40	$53	$58	$74
Avoided transmission cost (millions)	$13	$15	$16	$20	$26	$35	$44
Avoided emission cost PPAs & Owned (millions)	$0	$0	$0	$0	$0	$0	$0
Total avoided costs PPAs & Owned (millions)	$301	$336	$244	$283	$371	$398	$448
[8]Total avoided costs PPAs & Owned ($/MWh)	$39.88	$40.10	$29.23	$27.70	$31.74	$37.07	$39.44
Total RES Premium/Discount (millions)	$209	$205	$319	$277	$253	$182	$276
Total RES Premium/Discount ($/MWh)	$27.74	$24.52	$38.25	$27.13	$21.61	$16.91	$24.32

	Historic Period						
Annualized RES Rate Impacts	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
NSP total retail sales (GWh)	41,854	41,861	41,267	41,263	40,793	41,896	40,555
% Retail Sales	100%	100%	100%	100%	100%	100%	100%
NSP retail rate impact ($/MWh)	$5.00	$4.91	$7.73	$6.72	$6.19	$4.34	$6.82
NSP retail rate impact (cents/kWh)	.50¢	.49¢	.77¢	.67¢	.62¢	.43¢	.68¢

[9] 2019 resembles the same methodology as the historic period using the forward Minn Hub price curve to estimate avoided energy costs

Table 3: Annualized Future RES Rate Impact (2020-2026)[6]

	Future Period						
RES Generation	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
[7]Total RES Generation PPA & Owned (GWh)	9,791	9,102	9,113	8,491	8,256	8,024	7,781

Costs Associated with RES Generation	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
[7]Purchased Power (PPA) & Owned (millions)	$670	$689	$689	$659	$650	$648	$689
RES attributable transmission (millions)	$71	$68	$66	$63	$61	$59	$57
Total RES Costs (millions)	$742	$757	$754	$722	$711	$708	$746
[8]Total cost for RES generation ($/MWh)	$75.74	$83.17	$82.76	$85.05	$86.10	$88.18	$95.93
Avoided Costs Due to RES	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Avoided energy costs PPAs & Owned (millions)	$282	$285	$290	$286	$287	$284	$284
Avoided capacity cost PPAs & Owned (millions)	$6	$6	$6	$5	$5	$5	$5
Avoided transmission cost (millions)	$19	$24	$22	$22	$23	$21	$20
Avoided emission cost PPAs & Owned (millions)	$0	$0	$0	$0	$0	$0	$0
Total avoided costs PPAs & Owned (millions)	$307	$315	$318	$313	$314	$310	$309
[8]Total avoided costs PPAs & Owned ($/MWh)	$31.33	$34.65	$34.94	$36.88	$38.08	$38.64	$39.70
Total RES Premium/Discount (millions)	$435	$442	$436	$409	$396	$398	$438
Total RES Premium/Discount ($/MWh)	$44.41	$48.52	$47.82	$48.17	$48.02	$49.54	$56.23

	Future Period						
Annualized RES Rate Impacts	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
NSP total retail sales (GWh)	40,607	40,318	40,284	40,151	40,171	40,010	40,024
% Retail Sales	100%	100%	100%	100%	100%	100%	100%
NSP retail rate impact ($/MWh)	$10.71	$10.95	$10.82	$10.19	$9.87	$9.94	$10.93
NSP retail rate impact (cents/kWh)	1.07¢	1.10¢	1.08¢	1.02¢	.99¢	.99¢	1.09¢

Table 4: Annualized Future RES Rate Impact (2027-2034)[6]

	Future Period							
RES Generation	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
[7]Total RES Generation PPA & Owned (GWh)	7,491	7,258	7,076	7,037	6,822	6,662	5,682	5,385
Costs Associated with RES Generation	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
[7]Purchased Power (PPA) & Owned (millions)	$701	$680	$662	$641	$670	$670	$580	$530
RES attributable transmission (millions)	$56	$55	$53	$52	$50	$48	$47	$45
Total RES Costs (millions)	$758	$735	$715	$693	$720	$718	$626	$575
[8]Total cost for RES generation ($/MWh)	$101.12	$101.20	$101.06	$98.43	$105.50	$107.84	$110.22	$106.81
Avoided Costs due to RES	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Avoided energy costs PPAs & Owned (millions)	$284	$280	$277	$283	$285	$286	$258	$234
Avoided capacity cost PPAs & Owned (millions)	$5	$2	$2	$2	$2	$2	$2	$2
Avoided transmission cost (millions)	$19	$17	$17	$16	$15	$11	$10	$9
Avoided emission cost PPAs & Owned (millions)	$0	$0	$0	$0	$0	$0	$0	$0
Total avoided costs PPAs & Owned (millions)	$308	$299	$295	$300	$301	$298	$270	$245
[8]Total avoided costs PPAs & Owned ($/MWh)	$41.07	$41.16	$41.70	$42.65	$44.16	$44.77	$47.47	$45.49
Total RES Premium/Discount (millions)	$450	$436	$420	$393	$418	$420	$357	$330
Total RES Premium/Discount ($/MWh)	$60.05	$60.04	$59.35	$55.78	$61.34	$63.07	$62.75	$61.32
	Future Period							
Annualized RES Rate Impacts	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
NSP total retail sales (GWh)	40,214	40,758	40,644	40,784	40,816	41,262	41,457	41,781
% Retail Sales	100%	100%	100%	100%	100%	100%	100%	100%
NSP retail rate impact ($/MWh)	$11.19	$10.69	$10.33	$9.62	$10.25	$10.18	$8.60	$7.90
NSP retail rate impact (cents/kWh)	1.12¢	1.07¢	1.03¢	.96¢	1.03¢	1.02¢	.86¢	.79¢

Table 5: Annualized SES Rate Impact (2017-2026)[6]

	Historic Period			Future Period						
SES Generation	**2017**	**2018**	**2019**[9]	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Total SES Generation (GWh)	592	1,092	1,450	1,715	1,742	1,773	1,803	1,836	1,861	1,890
Costs associated with SES generation	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
SES Generation (millions)	$48	$110	$162	$201	$208	$215	$223	$231	$238	$246
SES attributable transmission (millions)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total SES Costs (millions)	$48	$110	$162	$201	$208	$215	$223	$231	$238	$246
[8]Total cost for SES generation ($/MWh)	$81	$101	$112	$117	$119	$121	$124	$126	$128	$130
Avoided Costs due to SES	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Avoided energy costs due to SES (millions)	$17	$35	$39	$57	$59	$61	$64	$66	$68	$71
Avoided capacity cost due to SES (millions)	$11	$15	$32	$0	$0	$0	$0	$0	$0	$0
Avoided transmission cost (millions)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Avoided emission cost due to SES (millions)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total avoided costs due to SES (millions)	$28	$49	$71	$57	$59	$61	$64	$66	$68	$71
[8]Total avoided costs SES ($/MWh)	$48	$45	$48.65	$33.36	$33.93	$34.61	$35.29	$36.09	$36.75	$37.46
Total SES Premium/Discount (millions)	$20	$61	$92	$144	$149	$154	$159	$165	$170	$175
Total SES Premium/Discount ($/MWh)	$33	$56	$63.23	$83.73	$85.31	$86.78	$88.25	$89.60	$91.11	$92.53
	Historic Period			**Future Period**						
Annualized SES Rate Impacts	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
NSP total retail sales (GWh)	40,793	41,896	40,555	40,607	40,318	40,284	40,151	40,171	40,010	40,024
% Retail Sales	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
NSP retail rate impact ($/MWh)	$0.48	$1.45	$2.26	$3.54	$3.69	$3.82	$3.96	$4.10	$4.24	$4.37
NSP retail rate impact (cents/kWh)	.05¢	.15¢	.23¢	.35¢	.37¢	.38¢	.40¢	.41¢	.42¢	.44¢

Table 6: Annualized SES Rate Impact (2027-2034)[6]

	Future Period							
SES Generation	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Total SES Generation (GWh)	1,919	1,952	1,976	2,004	2,032	2,065	2,086	2,112
Costs Associated with SES Generation	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
SES Generation (millions)	$254	$263	$270	$279	$288	$298	$307	$317
SES attributable transmission (millions)	$0	$0	$0	$0	$0	$0	$0	$0
Total SES Costs (millions)	$254	$263	$270	$279	$288	$298	$307	$317
[8]Total cost for SES generation ($/MWh)	$132	$134	$137	$139	$142	$144	$147	$150
Avoided Costs Due to SES	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Avoided energy costs due to SES (millions)	$73	$76	$79	$81	$84	$87	$90	$93
Avoided capacity cost due to SES (millions)	$0	$0	$0	$0	$0	$0	$0	$0
Avoided transmission cost (millions)	$0	$0	$0	$0	$0	$0	$0	$0
Avoided emission cost due to SES (millions)	$0	$0	$0	$0	-$1	$0	$0	$0
Total avoided costs due to SES (millions)	$73	$77	$79	$82	$83	$87	$90	$93
[8]Total avoided costs SES ($/MWh)	$38.29	$39.20	$39.79	$40.68	$41.06	$42.33	$43.04	$43.95
Total SES premium/discount (millions)	$180	$186	$191	$197	$204	$211	$217	$224
Total SES premium/discount ($/MWh)	$93.95	$95.26	$96.82	$98.32	$100.54	$101.99	$104.21	$106.27
	Future Period							
Annualized SES Rate Impacts	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
NSP total retail sales (GWh)	40,214	40,758	40,644	40,784	40,816	41,262	41,457	41,781
% Retail Sales	100%	100%	100%	100%	100%	100%	100%	100%
NSP retail rate impact ($/MWh)	$4.48	$4.56	$4.71	$4.83	$5.01	$5.10	$5.24	$5.37
NSP retail rate impact (cents/kWh)	.45¢	.46¢	.47¢	.48¢	.50¢	.51¢	.52¢	.54¢

Table 7: Levelized RES Rate Impact[6]

6.53% discount rate used in levelization calculations	Historic Period	Future Period
Levelized RES Generation	**2005-2019**	**2020-2034**
Total RES Generation (GWh)	6,395	7,916
Levelized Costs associated with RES generation	**2005-2019**	**2020-2034**
RES Generation (millions)	$337	$662
RES attributable transmission (millions)	$77	$59
Total RES Costs (millions)	$413	$720
[8]Total cost for RES generation ($/MWh)	$65	$91

Levelized Avoided Costs Due to RES	2005-2019	2020-2034
Avoided energy costs due to RES (millions)	$202	$281
Avoided capacity cost due to RES (millions)	$41	$4
Avoided transmission cost (millions)	$15	$19
Avoided emission cost due to RES (millions)	$0	$0
Total avoided costs due to RES (millions)	$258	$304
[8]Total avoided costs RES ($/MWh)	$40	$38
Levelized Total RES premium/discount (millions)	$156	$417
Levelized Total RES premium/discount ($/MWh)	$24	$53

	Historic Period	Future Period
Levelized RES Rate Impacts	**2005-2019**	**2020-2034**
NSP total retail sales (GWh)	41,870	40,519
NSP retail sales as % of total sales (%)	100%	100%
NSP retail rate impact ($/MWh)	$3.72	$10.28
NSP retail rate impact (cents/kWh)	.37¢	1.03¢

Table 8: Levelized SES Rate Impact[6]

6.53% Discount Rate Used in Levelization Calculations	Historic Period	Future Period
Levelized SES Generation	**2017-2019**	**2020-2034**
Total SES Generation (GWh)	1,027	1,884
Levelized Costs associated with SES generation	**2017-2019**	**2020-2034**
SES Generation (millions)	$104	$246
SES attributable transmission (millions)	$0	$0
Total SES Costs (millions)	$104	$246
[8]Total cost for SES generation ($/MWh)	$102	$131

Levelized Avoided Costs due to SES	**2017-2019**	**2020-2034**
Avoided energy costs due to SES (millions)	$30	$71
Avoided capacity cost due to SES (millions)	$19	$0
Avoided transmission cost (millions)	$0	$0
Avoided emission cost due to SES (millions)	$0	$0
Total avoided costs due to SES (millions)	$48	$71
[8]Total avoided costs SES ($/MWh)	$47	$38
Levelized Total SES Premium/Discount (millions)	$56	$175
Levelized Total SES Premium/Discount ($/MWh)	$54	$93

	Historic Period	**Future Period**
Levelized SES Rate Impacts	**2017-2019**	**2020-2034**
NSP total retail sales (GWh)	41,086	40,519
NSP retail sales as % of total sales (%)	100%	100%
NSP retail rate impact ($/MWh)	$1.36	$4.32
NSP retail rate impact (cents/kWh)	.14¢	.43¢

Table 9: Transmission Projects Attributable to the RES

2003 RCR	2004 RCR	2005 RCR	2007 TCR, RCR Compliance
M-02-474	M-03-1882	M-05-289	M-06-1505
425MW Throughput from SW MN	Chanarambie Substation and 115kV System Improvements Between Pipestone, Chanarambie, Lake Yankton, and Lyon County Substation	Alexandria to Douglas County 115kV	825 Wind Upgrade - Main Project
Split Rock / Lakefield Junction 345 kV	Black Dog Substation Transformer Replacement	Willmar to Kerkhoven Tap 115 kV	*Split Rock-Nobles Co- Lakefield Junction 345 kV line*
825MW Buffalo Ridge / White / Heron	345 kV Line Clearance Improvements from Wilmarth Substation to Lakefield junction Substation	Minnesota Valley to Franklin 115 kV	*Buffalo Ridge- Yankee- Brookings Co 115 kV line*
825MW Lyon / Franklin / Ft. Ridge	69 kV Line Upgrade from Bird Island Substation to Franklin Substation	Paynesville to Wakefield 115 kV	*Brookings Co- White 345 kV line*
825MW Reconductor Only	115 kV Line Upgrade from Summit Substation to Loon Tap to West Faribault Substation	Upgrades to Marshall Municipal Utilities 115 kV System	*Chanarambie- Fenton- Nobles Co 115 kV line*
	Troy Switching Substation	Lakefield Junction to Fox Lake 161 kVLine	*Red Wood Falls Junction- Franklin 115 kV upgrade*
	GM, LLC Project		*Brookings Co Substation*
	Wind Generator Interconnects on the 35 kV System in Southwestern Minnesota		*Split Rock Substation*
			Lakefield Junction Substation
			White Substation
			Nobles Co Substation
			Chanarambie Substation
			Buffalo Ridge Substation
			Yankee 200 MW Wind Generation Collector Station
			Fenton Wind Generation Collector Station
			Series Capacitor Station
			Nobles County Collector
			Rock County Collector

2008 TCR	2010 TCR	2011 TCR	2012 TCR
M-07-1156	M-09-1048	M-10-1064	M-12-050
BRIGO Transmission Lines	Blue Lake - Wilmarth - Lakefield Transmission	CAPX2020 - Brookings	161 kV Line Pleasant Valley Sub to Byron (SE MN - RIGO)
Spare Wind Transformer	Nobles Wind Farm Network Upgrade Transmission Project		

2016 TCR
LaCrosse - Madison
Big Stone - Brookings

Table 10: Transmission Project Costs Attributable to the RES
(70% of MPV Project Annual Revenue Requirements Assigned to RES)

Year	M-02-474	M-03-1882	M-05-289	M-06-1505	M-07-1156	M-09-1048	M-10-1064	M-12-050	2016 TCR	Total Project Revenue Requirements Assigned to RES
	All Costs in $ millions									
2005	$27.5	$6.8	$0.9	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	**$35.2**
2006	$43.6	$6.1	$1.7	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	**$51.4**
2007	$50.6	$5.9	$1.5	$18.4	$0.0	$0.0	$0.0	($0.0)	$0.0	**$76.4**
2008	$50.4	$5.7	$1.5	$28.4	$1.1	$0.0	$0.0	$0.0	$0.0	**$87.0**
2009	$48.8	$5.5	$1.4	$28.2	$6.1	$0.3	$0.0	$0.0	$0.0	**$90.4**
2010	$47.3	$5.4	$1.4	$27.2	$8.7	$1.4	$1.4	$0.0	$0.0	**$92.8**
2011	$45.8	$5.2	$1.3	$26.2	$8.3	$1.8	$2.4	$0.0	$0.0	**$91.1**
2012	$44.4	$5.1	$1.3	$25.3	$8.0	$1.8	$2.3	$0.5	$0.0	**$88.6**
2013	$43.1	$4.9	$1.2	$24.4	$7.7	$1.7	$2.2	$1.5	$0.0	**$86.7**
2014	$41.7	$4.7	$1.2	$23.6	$7.4	$1.7	$2.1	$2.9	$0.0	**$85.3**
2015	$40.4	$4.6	$1.1	$22.7	$7.2	$1.6	$2.0	$3.8	$0.0	**$83.4**
2016	$39.0	$4.4	$1.1	$21.9	$6.9	$1.6	$2.0	$3.7	$0.0	**$80.6**
2017	$37.7	$4.3	$1.0	$21.0	$6.6	$1.5	$1.9	$3.6	$0.1	**$77.7**
2018	$36.3	$4.1	$1.0	$20.2	$6.3	$1.5	$1.8	$3.5	$0.7	**$75.4**
2019	$35.0	$4.0	$0.9	$19.4	$6.1	$1.4	$1.7	$3.7	$2.5	**$74.6**
2020	$33.6	$3.8	$0.9	$18.5	$5.8	$1.4	$1.7	$3.3	$2.4	**$71.4**
2021	$32.3	$3.6	$0.9	$17.7	$5.5	$1.3	$1.6	$3.2	$2.3	**$68.4**
2022	$30.9	$3.5	$0.8	$16.9	$5.3	$1.3	$1.5	$3.1	$2.3	**$65.6**
2023	$29.7	$3.3	$0.8	$16.4	$5.0	$1.2	$1.4	$3.0	$2.2	**$63.1**
2024	$28.5	$3.2	$0.8	$16.1	$4.8	$1.2	$1.4	$2.9	$2.2	**$60.9**
2025	$27.4	$3.1	$0.7	$15.7	$4.7	$1.1	$1.3	$2.8	$2.2	**$59.1**
2026	$26.5	$3.0	$0.7	$15.4	$4.6	$1.1	$1.3	$2.7	$2.1	**$57.5**
2027	$25.8	$2.9	$0.7	$15.1	$4.4	$1.1	$1.2	$2.6	$2.1	**$56.1**
2028	$25.2	$2.9	$0.7	$14.8	$4.3	$1.1	$1.2	$2.5	$2.1	**$54.7**
2029	$24.6	$2.8	$0.7	$14.4	$4.2	$1.0	$1.2	$2.4	$2.1	**$53.4**
2030	$23.8	$2.7	$0.6	$14.0	$4.1	$1.0	$1.1	$2.3	$2.0	**$51.7**
2031	$23.0	$2.6	$0.6	$13.5	$4.0	$1.0	$1.1	$2.3	$1.9	**$50.0**
2032	$22.3	$2.5	$0.6	$13.1	$3.8	$0.9	$1.1	$2.2	$1.9	**$48.3**
2033	$21.5	$2.4	$0.6	$12.6	$3.7	$0.9	$1.0	$2.1	$1.8	**$46.7**
2034	$20.8	$2.3	$0.6	$12.2	$3.6	$0.9	$1.0	$2.1	$1.7	**$45.2**
Total (millions)	**$1,027.3**	**$121.4**	**$28.9**	**$533.3**	**$148.3**	**$32.8**	**$39.0**	**$63.0**	**$34.7**	**$2,028.8**

Table 11: MISO Data Used in RES Avoided Energy and Capacity Calculations

	Future Period							Future Period							
Avoided Capacity Cost Details	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
MISO Accredited Capacity of Renewables (MW)[10]	87	87	87	63	63	63	63	63	22	22	22	22	22	22	22
Avoided Capacity ($000/MW-Year)	$69	$71	$72	$74	$75	$77	$78	$80	$81	$83	$85	$86	$88	$90	$92
Total Avoided Capacity Costs due to RES (millions)	$6	$6	$6	$5	$5	$5	$5	$5	$2	$2	$2	$2	$2	$2	$2

Avoided Energy Cost Details	Future Avoided Energy Costs determined using Strategist model

[10] Only biomass is calculated for future avoided capacity costs, No avoided capacity costs calculated due to generic renewable costs being accounting for in avoided energy

Table 12: MISO Data Used in SES Avoided Energy and Capacity Calculations[6]

	Future Period							Future Period							
Avoided Capacity Cost Details	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
MISO Accredited Capacity of Renewables (MW)[11]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Avoided Capacity ($000/MW-Year)	$69	$71	$72	$74	$75	$77	$78	$80	$81	$83	$85	$86	$88	$90	$92
Total Avoided Capacity Costs due to SES (millions)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Avoided Energy Cost Details	Future Avoided Energy Costs determined using Strategist model

[11] No avoided capacity costs calculated due to generic renewable costs being accounted for in avoided energy

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May 31, 2019

—Via Electronic Filing—

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: ANNUAL REPORT
SOLAR ENERGY STANDARD
DOCKET NO. E999/M-19-276

Dear Mr. Wolf:

Enclosed for filing is the 2018 Annual Report on Progress in Achieving the Solar Energy Standard of Northern States Power Company, doing business as Xcel Energy, submitted in compliance with the Commission's April 25, 2014 Order in Docket No. E999/CI-13-542.

Please note that we have marked as "Non-Public" certain information identifying customer names, locations, energy usage or bill credits. This is considered to be private data pursuant to Minn. Stat. §13.02, Subd. 9, and is non-public pursuant to Minn. Stat.§ 13.37, Subd.2.

We have also marked as "Non-Public" capacity factor information relating to specific Purchase Power Agreements (PPAs). The terms of the Commission approved PPAs require that this information be non-public. Further, this is considered to be "nonpublic data" pursuant to Minn. Stat. §13.02, Subd.9, and is also "Trade Secret" information pursuant to Minn. Stat. §13.37, subd. 1(b) as it derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use.

We have electronically filed this document with the Minnesota Public Utilities Commission, and copies have been served on the parties on the attached service list. Please contact Amber Hedlund at amber.r.hedlund@xcelenergy.com or (612) 337-2268 or me at bria.e.shea@xcelenergy.com or (612) 330-6064 if you have any questions regarding this filing

Sincerely,

/s/

BRIA E. SHEA
DIRECTOR, REGULATORY & STRATEGIC ANALYSIS

Enclosures
c: Service List

Solar Energy Standard Annual Report

Due:	May 31, 2019
Reporting period:	January 1, 2018 – December 31, 2018
Statute/Rule reference:	216B.1691 Subd. 2f(g). (g) Beginning July 1, 2014, and each July 1 through 2020, each public utility shall file a report with the commission reporting its progress in achieving the solar energy standard established under this subdivision. Order, issued April 25 in Docket No. E-999/CI-13-542 Order, issued October 23, 2014 in Docket No. E-999/M-14-321 Order, issued November 28, 2016 in Docket No. E-999/M-16-342 Order, issued October 20, 2017 in Docket No. E-999/M-17-283 Order, issued September 21, 2018 in Docket No. E-999/M-18-205
Comments:	Please answer questions below and eFile as a PDF

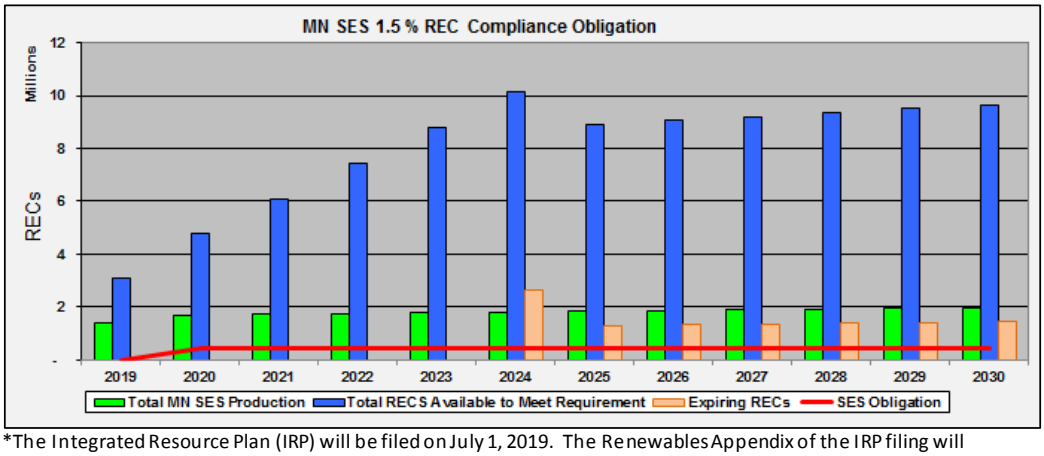
Report Year	2018
Date Submitted	5/31/2019
Filing Utility Information	
Company ID#	U12000
Company Name	Xcel Energy
Street Address Line 1	414 Nicollet Mall
Street Address Line 2	401-7
City	Minneapolis
State	MN
Zip Code	55401
Contact Information	
Contact Name	Amber Hedlund
Contact Title	Regulatory Case Specialist
Contact Telephone	612.337.2268
Contact Email	Regulatory.records@xcelenergy.com
Comments/Notes	

1. **Summary of ongoing efforts to obtain solar energy, including a brief summary of the anticipated mix of project sizes for SES compliance.**
Docket No. E999/CI-13-542, Commission Order (April 25, 2014), Order Point 4.H

For purposes of this Section 1, Solar Energy Standard (SES) compliance means the requirement set forth in Minn. Stat. § 216B.1691, Subd. 2f, whereby Xcel Energy, by the end of 2020, needs to generate or procure sufficient electricity generated by solar energy so that at least 1.5 percent of the Company's total retail electric sales to retail customers in Minnesota is generated by solar energy. The other requirement in Subd. 2f regarding systems of 40 kW (AC) or less is not addressed in the Company's response to Section 1 of this report, but instead is addressed in its response to Section 2 below.

The Company has developed a large portfolio of programs to provide renewable options to residential and commercial customers. Since the passage of the SES under the 2013 Energy Omnibus Bill, we have also grown our utility portfolio of solar resources to expand access to solar benefits to all customers while achieving compliance in 2020. The expected cumulative impact of the programs and efforts detailed below are graphically displayed below in Graph 1, and in the attached Excel file (Tab 5 – Additional Graphs). The Company expects to accumulate and exceed the amount of Solar RECs (SREC) required to satisfy the MN SES compliance requirements beginning in 2020 and continue well beyond 2030.

Graph 1*



*The Integrated Resource Plan (IRP) will be filed on July 1, 2019. The Renewables Appendix of the IRP filing will provide updated SES compliance graphs and resource related information.

A. Solar*Rewards (Second Generation) – For PV installations of 40 kW_{DC} or less

Our Solar*Rewards program offers customers installing solar photovoltaic (PV) systems sized 40 kW_{DC} or less an incentive based on the system's energy production. The program offers differing production incentives depending on the project for a 10-year period under a Solar*Rewards contract. The legislature under Minn. Stat. § 116C.77792 has authorized this program to be available for eight consecutive years at an annual budget of $5 million for the first four years, $15 million in the fifth year, $10 million in the sixth and seventh years and $5 million in the eighth year from the renewable development account beginning in August 2014. More details

about the results of the program are available in our Solar*Rewards Annual Report.[1] The RECs generated under the Solar*Rewards program are assigned to the Company for the first 10 years of each installation.[2]

B. Solar*Rewards (First Generation) – For PV installations of 40 kW_{DC} or less

Our SES compliance also includes RECs established under our first generation program (2010 – 2014). This program was part of the Company's Conservation Improvement Program and provided one-time incentives for projects sized 40 kW_{DC} or less. The program was discontinued when the second generation Solar*Rewards program was redeveloped in 2013 because of the passage of Minn. Stat. § 116C.7792. The program was closed for incoming applications in August 2014. Existing contracts remain in place for their contract term. These contracts have assigned the RECs to the Company for the 20-year contract term.

C. Made in Minnesota – For PV installations of 40 kW_{DC} or less

Established by legislation in 2013, the Made in Minnesota program provided incentives to systems manufactured in Minnesota that were up to 40 kW_{DC}, with the majority being over 20 kW_{DC}. The program was launched in 2014 and cancelled by the legislature in 2017 (Minn. Stat. § 216C.417). The program continues to be administered by the Department of Commerce. The RECs generated under this program by Company customers belong to the Company for 10 years from installation.

D. Buy-Back Option

Commission Staff suggested that the Company should continue to receive SRECs from these programs throughout the lifetime of the systems. Staff briefing papers on August 29, 2018 state:

> "The easiest way for Xcel to maintain control over the coveted small SRECs would be a tariff option allowing customers to elect to sell their SRECs to the company after the expiration of a Solar*Rewards contract. Xcel could then enroll interested customers in this new tariff offering and use the existing metering infrastructure to continue the uninterrupted transfer of SRECs for SES compliance."[3]

Staff's recommended approach is an option for the Company to consider and we will review the recommendation closer to 2024 when contracts begin expiring. If that is the desired approach, we will file a Petition requesting approval of this program or tariff change closer to that time. For transparency purposes, Graph 3 provided in part 2 below includes a compliance look at an assumed Solar*Rewards SREC buyback program based on an assumed participation level of 75 percent.

E. Solar*Rewards Community – For PV installations up to 1 MW

The Company launched its community solar garden program, called Solar*Rewards Community, in December 2014.[4] Solar gardens are shared PV arrays up to one MW that interconnect with the distribution grid under a 25-year contract term. Customers who subscribe to a solar garden receive a bill credit for their portion of the system's production and the Company receives the

[1] Annual Reports are filed on or around June 1 of every year beginning in 2015 in Docket No. E002/M-13-1015.
[2] Docket No. E002/M-13-1015, Solar*Rewards, Deputy Commissioner Decision, February 24, 2014.
[3] See Staff's briefing papers issued August 29, 2018 in Docket Nos. E999/M-13-542 & E999/M-18-205, Pages 3-4.
[4] See Docket No. E002/M-13-867.

RECs for the term of the contract.[5] There is no statutory budget or capacity limit for the Solar*Rewards Community program.

F. Universal Solar

Since the passage of the SES legislation, the Company has developed a portfolio of three universal scale solar projects. The Company has 162.25 MW of large-scale solar generation from two projects under Power Purchase Agreement (PPA) contracts, consisting of the North Star project (100 MW) and the Marshall Solar project (62.25 MW). These projects began operating in late 2016 and early 2017. These resources were approved by the Commission as part of a Solar Portfolio from a Request for Proposals process.[6] However, the Company has allotted as much as 25 percent of the expected output of the North Star facility to the Renewable*Connect program. The Company portfolio also includes the 100 MW Aurora Solar PPA which was approved through the Company's Competitive Acquisition Process proceeding[7]. This project is made up of multiple distributed generation solar sites. All phases of this project were in commercial operation by summer 2017. These projects will generate more than 400,000 SRECs annually.

G. Renewable Development Fund (RDF)

The 1994 Legislature mandated the creation of the RDF for the purpose of developing renewable sources of electricity, including solar. Recipients of RDF grant funds that install renewable energy generators are required to assign and transfer all RECs created from the facility's renewable energy production for the life of that facility. The Company currently has a total of 31 installed and operating solar RDF facilities, for a total of 9.962 MW of capacity. An additional 13 facilities are planned or under construction and will add an additional 3.522 MW of capacity. Legislation passed in 2017 made significant changes to the RDF statute (Minn. Stat. § 116C.779). These changes include the creation of the Renewable Development Account as a special account within the Minnesota treasury. Additional changes include the purposes for how funds may be expended and how projects are selected. Therefore it is not known at this time if any new RDF facilities will be installed which affect the SES.

[5] Prior to 2017, Garden Operators had the choice as to whether or not to receive the RECs directly. Currently, all community solar gardens have chosen to provide them to the Company.

[6] See Dockets No. E002/M-14-162, In the Matter of Xcel Energy's Petition for Approval of a Solar Portfolio to Meet Initial Solar Energy Standard.

[7] See Docket No. E002/CN-12/1240, In the Matter of the Petition of Northern States Power Company d/b/a Xcel Energy for Approval of Competitive Resource Acquisition Proposal and Certificate of Need.

Table 1: RDF/RDA Solar Facilities Through December 31, 2018*

Facility Size	Number	Capacity (MW)
Commissioned Facilities		
≤40 kW	14	0.187
>40 kW	17	9.755
Total Commissioned Facilities	**31**	**9.962**
Planned Facilities		
≤40 kW	3	0.120
>40 kW	10	3.402
Total Planned Facilities	**13**	**3.522**
TOTAL RDF FACILITIES	**44**	**13.483**

*Please note, the data provided in the "Table 1: RDF/RDA Solar Facilities through December 31, 2017" of our October 22, 2018 compliance filing incorrectly included a 2 MW wind project in the commissioned facilities totals. We have removed the wind project from Table 1 above.

2. Progress towards the 10% carve-out for systems 40 kW_{ac} or less, including the method by which the utility will meet the carve-out. ***Docket No. E999/CI-13-542, Commission Order (April 25, 2014), Order Point 4.I***

A subset of programs from Section 1 above, can be used towards our 10 percent small solar carve out. Table 2 describes these impacts. These are further detailed in this section.

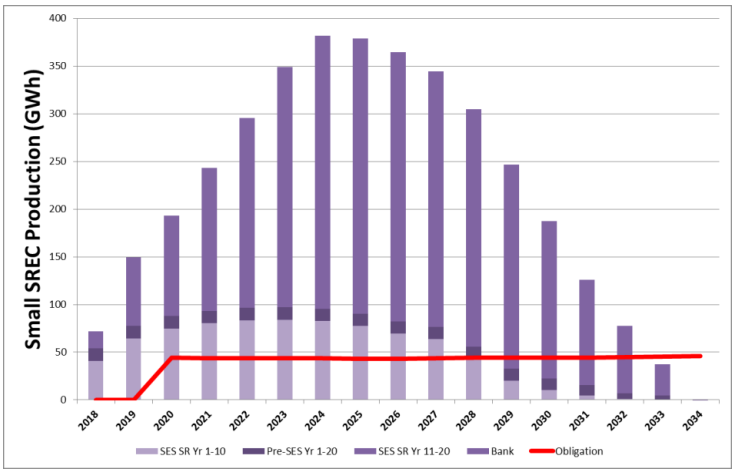
Table 2: Small Solar Carve Out – Programs

Program Name	Size (DC)*	Years Available
Solar*Rewards (First Generation)	**≤40 kW**	**2010 – August 2014**
Solar*Rewards (Second Generation)	**≤ 20 kW** **≤ 40 kW**	**August 2014 – May 2018** **June 2018 – 2021**
Made in Minnesota	**≤40 kW**	**2014 – 2017**

*Energy produced in DC goes through an inverter to get converted to AC. In this process there is energy loss, meaning that DC output results in a lower AC output.

Graph 2 below represents our current projection for REC compliance with the 10 percent small solar carve out. This chart shows the Company may be in compliance with the small solar carve out through 2032. However, this representation uses program assumptions and thus has embedded risk that the actual results could be significantly different than the forecast. The Company cannot predict what the market installation rate will be for small solar rooftop.

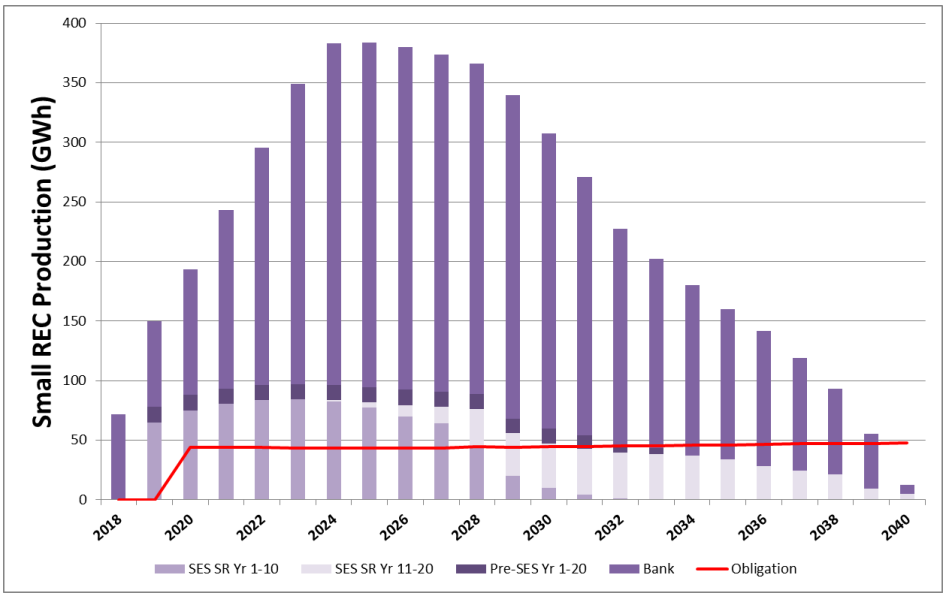
Graph 2
Small SREC Production with Solar*Rewards
Program Extension through 2021



The chart above assumes 100 percent of funds are awarded and that of these there will be an installation rate of 75 percent for the Solar*Rewards program. The Solar*Rewards program awarded 100 percent of the 2018 funding. If actual solar installations are lower than forecasted levels, the Company may not be able to meet the small solar carve-out requirements through 2032 as projected in the chart above.

Graph 3 below provides a projection for small solar carve out compliance with the addition of an assumed future buy-back option. The additional RECs would extend compliance with the small solar carve out until approximately 2039. The Company cannot predict customer participation in a future program; however, an assumption of 75 percent participation is made for this projection.

Graph 3
Small SREC Production with Solar*Rewards
Program Extension with Buy-Back Option

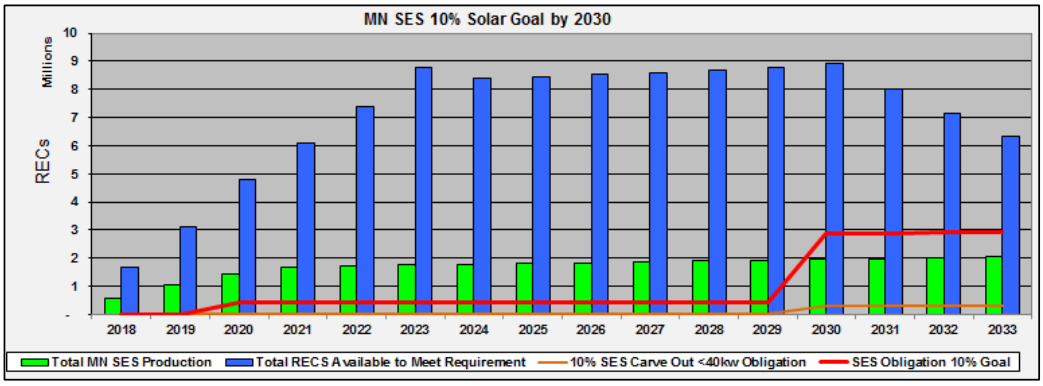


Also, the above analysis is based on the understanding that the nameplate capacity for purposes of this statute is measured in alternating current (AC). This is consistent with the definition of capacity in Minn. Stat. § 216B.164, Subd. 2a.(c)., as well as how capacity is used or interpreted under the following statutes: Minn. Stat. §§ 216B.1611, Subd.2(a), and Subd.3a(a)(1); 216B.1613; 216B.164, and Subd. 4c; 216B.1641 (b).

3. Discussion on the utilities' efforts to reach, by 2030, the energy goal that ten percent of the retail electric sales in Minnesota be generated by solar energy.
Docket Nos. E999/CI-13-542, E999/M-16-342, Commission Order (November 28, 2016)

The 10 percent by 2030 goal is an energy goal of the state of Minnesota. We understand this question to be requesting our efforts to reach our proportional share of the state's energy goal. As shown in Graph 4 below and in the attached Excel file (Tab 5 – Additional Graphs), the Company forecasts that we will meet the 10 percent by 2030 goal. The compliance fulfillment in those years will significantly be derived from the heavy use of our SREC bank that will have been accumulated up to that point. We expect to review the need of additional solar resources in a future resource plan.

Graph 4



4. Any additional comments or materials the utility may wish to include.

SES Cost Exclusion

No new SES exclusion applications were approved by the March 1, 2019, deadline for this report, and no applications are pending. We provide the production information and solar costs excluded for the two customers at six premises that became eligible for exclusion on June 1, 2017 in the attached Excel file (Tab 2 – Retail and Excluded). Per the exclusion process approved by the Commission in Docket No. E002/M-17-425, we issued bill credits in March 2019 to customers approved for exclusion for SES-eligible costs incurred between January 1 and December 31, 2018. See Tab 2 of the attached Excel file (Retail and Excluded) for the excluded customer sales and refund amount issued to each excluded premise.

Cost Recovery of 2018 SES Exclusion Amount

To recover the 2018 SES excluded costs from non-exempt customers, **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** was included in the May 2019 monthly fuel clause rate (Docket No. E002/AA-19-296; **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** was included in the CIP Rider tracker filed in Docket No. E002/M-19-258 on April 1, 2019; and **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** will be added to the RDF tracker to be filed with the Commission by October 1, 2019.

Future SES Cost Exclusion

In its January 16, 2018 Order in Docket No. E002/M-17-425, the Commission found that only those costs associated with SRECs that are retired for the purpose of meeting the requirements of Minn. Stat. § 216B.1691, subd. 2f, can be excluded from rates charged to exempt customers. We anticipate that all SRECs being generated at this time will be retired in order to meet the SES. At some point in the future, however, we may begin generating more SRECs than are needed for SES compliance. In a future annual report, we will discuss refinements to our SES cost exclusion methodology that will account for the fact that not all SRECs generated in a given year will be needed for SES compliance.

CERTIFICATE OF SERVICE

I, Paget Pengelly, hereby certify that I have this day served copies of the foregoing document on the attached list of persons.

xx by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States mail at Minneapolis, Minnesota

xx electronic filing

Docket No. E999/M-19-276

Dated this 31st day of May 2019

/s/

Paget Pengelly
Regulatory Administrator

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Minnesota Public Utilities Commission			
INFORMATION DOCKET E999/M-19-276		**Reporting Period:**	**January 1, 2018 - December 31, 2018**
Solar Energy Standard Annual Report		**Utility:**	**Xcel Energy**
Report Year:	2018	Date Submitted:	May 31, 2019

Filing Utility Information		Contact Information	
Company ID#	U12000	Contact Name	Amber Hedlund
Company Name	Xcel Energy	Contact Title	Regulatory Case Specialist
Street Address Line 1	414 Nicollet Mall	Contact Telephone	612.337.2268
Street Address Line 2	401-7	Contact Email	Regulatory.records@xcelenergy.com
City	Minneapolis		
State	MN		
Zip Code	55401		

Instructions
Due: June 1, 2019
Reporting Period: preceding calendar year
Complete the following worksheets and e-file in **Excel (XLS or XLSX)** format:
- Worksheet 1, Utility Info
- Worksheet 2, Retail and Excluded Sales
- Worksheet 3, Solar Generation
- Worksheet 4, Capacity Factors
- Worksheet 5, Additional graphs the utility may choose to provide

Also complete and efile the Solar Energy Standard Report PDF supplement
To e-file, login, or register, at: https://www.edockets.state.mn.us/EFiling/home.jsp
For directions on how to e-file, see: http://www.commerce.state.mn.us/eDocFile/eFilingHelp.html
For questions about the worksheets, send an email to: hanna.terwilliger@state.mn.us
For questions about e-filing, contact Karen Santori at 651-539-1530 or at karen.santori@state.mn.us .

Protected Data Shaded

PUBLIC DOCUMENT
NOT PUBLIC DATA HAS BEEN EXCISED

Minnesota Public Utilities Commission

INFORMATION DOCKET E999/M-19-276		**Reporting Period**	**January 1, 2018 - December 31, 2018**
Solar Energy Standard Annual Report		**Utility:**	**Xcel Energy**
Report Year:	2018	Date Submitted:	May 31, 2019

Annual Minnesota retail sales for the reporting year

Docket No. E999/CI-13-542, Commission Order (April 25, 2014), Order Points 4.A & 4.B

1. Annual MN retail sales for the reporting year	30,442,386 MWH
	[PROTECTED DATA BEGINS
2. Annual Excluded customer sales for the reporting year	
3. Annual Minnesota retail sales less exclusions	

PROTECTED DATA ENDS]

Customer requesting exclusion from the SES that have been approved by the utility

Docket Nos. E999/CI-13-542, E999/M-14-321, Commission Order (October 23, 2014), Order Point 2.a

Customer Name	Docket Granting Exclusion	Premise Number	Premise	NAICS	2018 kWh Usage	Refund ($s)
Previously approved excluded customers:						
[PROTECTED DATA BEGINS						
Total MN Sales for Excluded Customers						

PROTECTED DATA ENDS]

Customer Name	Docket	Premise Number	Premise	NAICS	2018 kWh Usage	Refund ($s)
New customers requesting exclusion:						
N/A - No additional customers have requested exclusion at this time.						

Minnesota Public Utilities Commission			
INFORMATION DOCKET E999/M-19-276	**Reporting Period:**		**January 1, 2018 - December 31, 2018**
Solar Energy Standard Annual Report	**Utility:**		**Xcel Energy**
Report Year:	2018	Date Submitted:	May 31, 2019

Solar generation on the utilities' system during the reporting period

Docket No. E999/CI-13-542, Commission Order (April 25, 2014), Order Point 4.E

	Number of Facilities on Utility System	Capacity (MW)	Number registered in M-RETS	Capacity registered in M-RETS (MW)	SRECs Generated
40kW or less	3,656	43.43	50	25.47	32,599
Greater than 40kW	582	776.52	562	752.42	1,027,277

Estimated amount of solar generation a utility would be required to obtain in 2020

Docket No. E999/CI-13-542, Commission Order (April 25, 2014), Order Points 4.F & 4.G

	Capacity (MW)	SRECs (MWh)
Entire 1.5% Standard	237	438,856
Small Scale Carve-Out (10% of 1.5%)	33	43,886
2030 Goal of 10%	1,694	2,943,808

Breakdown of S-RECS generated

Docket No. E999/CI-13-542, Commission Order (April 25, 2014), Order Point 5

	Balance at Beginning of Reporting Year[1]	Accrued in Reporting Year	Used in Reporting Year	Year End Balance
1. Utility-owned solar projects				
2. Solar Facilities that have entered into a PPA with the utility	440,418	452,534		892,952
3. Community Solar Gardens				
a. ARR	146,813	569,263		716,076
b. VOS				
c. Other compensation method				
6. Facilities receiving a VOS rate (not incuded above)				
7. Facilities under a net metering tariff				
a. Receiving an incentive (any type)	30,271	32,053		62,324
b. Not receiving an incentive				
8. Facilities receiving an incentive (not included above)				
9. Facilities that do not fall into any other category	4,399	6,026		10,425
Total	621,901	1,059,876	0	1,681,777

Purchases and sales of S-RECS to meet the SES

Docket No. E999/CI-13-542, Commission Order (April 25, 2014), Order Point 4.K

	SRECs Purchased	SRECs Sold
SES (>40W)	0	0
Small Scale Carve Out (<=40kW)	0	0
Total	0	0

1. Beginning of year REC balance includes current solar RECs held in NSP's REC bank. Beginning REC balance may differ from previous year's ending REC balance to accommmodate for adjustments made to REC classification, REC allocations, or registration details of qualified solar resources.

Protected Data Shaded

PUBLIC DOCUMENT
NOT PUBLIC DATA HAS BEEN EXCISED

Minnesota Public Utilities Commission

INFORMATION DOCKET E999/M-19-276		**Reporting Period:**	**January 1, 2018 - December 31, 2018**
Solar Energy Standard Annual Report		**Utility:**	**Xcel Energy**
Report Year:	2018	Date Submitted:	May 31, 2019

Additional information supporting assumed capacity factor, effective load carrying capability, and MISO capacity

Docket Nos. E999/CI-13-542, E999/M-14-321, Commission Order (October 23, 2014), Order Points 2.b & 2.d

Solar Project	Nameplate (MW)	Capacity Factor	Capacity Accreditation[1]	Project Status
		[PROTECTED DATA BEGINS		
Aurora Distributed Solar, LLC [2,6]	100 MW			existing
North Star Solar PV, LLC [2,7]	100 MW			existing
Marshall Solar, LLC [2,7]	62.25 MW			existing
			PROTECTED DATA ENDS]	
Community Solar Garden installations [2, 4, 5,8]	various	15-20%	60%	planned
Small Solar - RDF Projects	various	15-18%	58%	planned
Small Solar (<=40 kW)[8]	various	10-18%	BTMG[6]	planned

Information on Assumed Capacity Factor

8. Capacity factor reflects calendar year 2018, for the 90th to the 10th percentile. This includes all resources, not specific to 1st year production.

Information on effective load carrying capability and MISO Capacity Accreditation

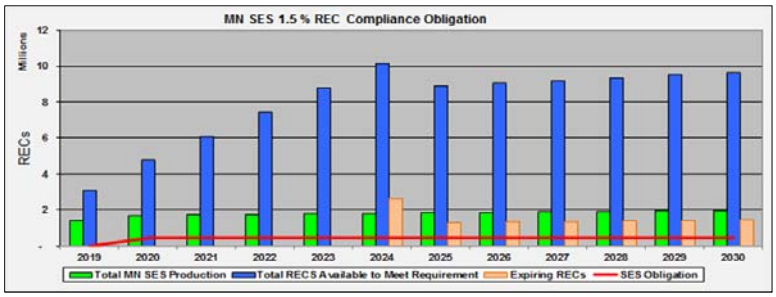
Capacity Accreditation represents an estimate of reliable resource capability during periods of system peak demand. The capacity accreditation is based on the reporting period of 1/1/2018 - 12/31/2018.

MISO has added Solar Accreditation practices to the Business Practice Manual for the 2018/19 Planning Year. For Year 1, solar resource accreditation will be 50% of nameplate rating; subsequent years the accreditation will be calculated based on historic operation data.

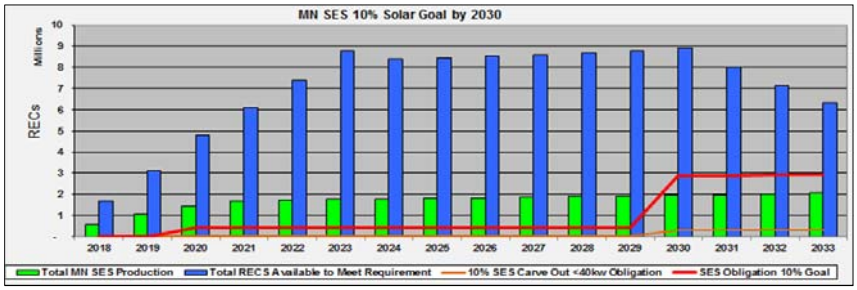
MISO BPM 11 - 4.2.3.1 Intermittent Generation and Dispatchable Intermittent Resources that are not powered by wind (example: run of river or solar) must supply MISO with the most recent consecutive three years of hourly net output (in MW) for hours ending 15, 16, and 17 EST from June, July and August. For new resources, or resources on qualified extended outage where data does not exist for some or all of the previous 36 historical months, a minimum of 30 consecutive days' worth of historical data during June, July or August for the hours ending 15, 16, and 17 EST must be provided prior to participating in the PRA.

1. The Company presumes that effective load carrying capability is addressed through the reporting of MISO's accreditation.
2. Capacity accreditation for Aurora Distributed Solar represents contractual agreement value. Capacity accreditation for other resources represent MISO first year of operation value.
4. Community Solar Garden installations are registered with MISO following COD.
5. Community Solar Garden and Solar Rewards installations continue to be added.
6. Behind the meter generation
7. Capacity accreditation based on MISO PY 2018/2019 (to include EOY 2018)
8. Capacity factor reflects calendar year 2018, for the 90th to the 10th percentile. This includes all resources, not specific to 1st year production.

1.5% by 2020

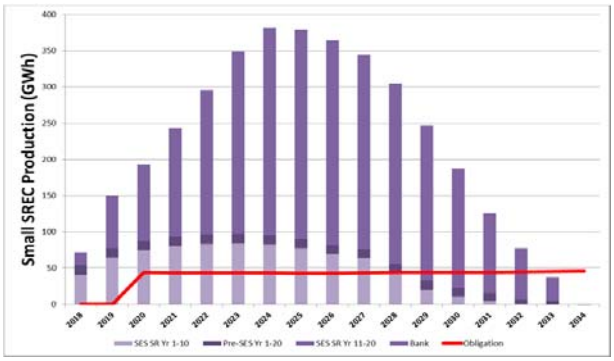


10% by 2030

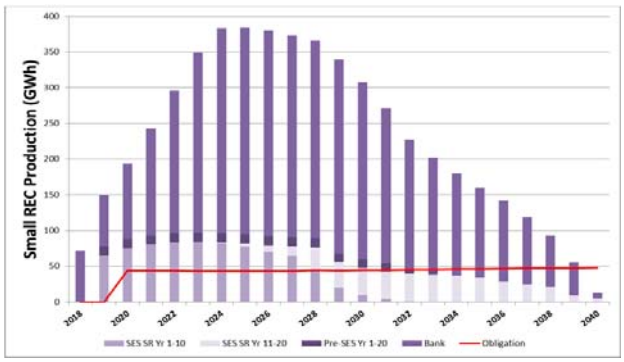


Carve Out

SREC Fullfillment and Bank w Add Pre-SES (2013), No RECs from Yrs 11-20



SREC Fullfilment and Bank w Add Pre-SES (2013), Add RECs from Yrs 11-20



June 14, 2019

—Via Electronic Filing—

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: MONTHLY UPDATE
COMMUNITY SOLAR GARDENS
DOCKET NO. E002/M-13-867

Dear Mr. Wolf:

Northern States Power Company, doing business as Xcel Energy, submits this Monthly Compliance Report to the Minnesota Public Utilities Commission. This Report provides the status of the Solar*Rewards Community program as of June 3, 2019.

We have electronically filed this document with the Minnesota Public Utilities Commission, and copies have been served on the parties on the attached service list. Please contact Jessica Peterson at jessica.k.peterson@xcelenergy.com or (612) 330-6850 if you have any questions regarding this filing.

Sincerely,

/s/

SHAWN WHITE
MANAGER, DSM & RENEWABLE REGULATORY STRATEGY AND PLANNING

Enclosures
c: Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Dan Lipschultz	Commissioner
Valerie Means	Commissioner
Matthew Schuerger	Commissioner
John Tuma	Commissioner

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY FOR APPROVAL OF ITS PROPOSED COMMUNITY SOLAR GARDENS PROGRAM	DOCKET NO. E002/M-13-867 **MONTHLY COMPLIANCE REPORT**

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, submits this Monthly Compliance Report to the Minnesota Public Utilities Commission (Commission) regarding our Solar*Rewards Community® program. This Monthly Compliance Report provides information current as of June 3, 2019 on the status of projects in the Solar*Rewards Community program as well as other compliance items such as engineering cost review and tariffed timelines.

MONTHLY REPORT

I. SOLAR*REWARDS COMMUNITY PROGRAM STATUS

Our June status report on the Solar*Rewards Community program finds 559 MW of connected solar generation online and over 200 projects completed. In May, there were a limited number of new applications.
On June 3, there were 287 project sites at various stages of development. We provide additional metrics regarding the queue in Tables 1 and 2 showing application status.

Table 1: Status of Applications

	Project Sites	MW (AC)	# of Co-Located Sites (>1 MW)
Active Applications	**287**	**332**	**17**
Commercial Operation (In-Service)	**201**	**559**	**118**
Withdrawn	NA	1,684	NA

Table 2: Active Applications: Progress Summary

	Project Sites	MW (AC)
Application	**18**	**17**
Initial Application	8	7
Applications in Review	10	10
Study	**95**	**97**
Waiting for Study Proposal	5	5
SOW Waiting for Developer	10	10
In process	47	47
Interconnection Agreement Issued	33	35
Design	**89**	**93**
Design	81	85
On Hold	8	8
Construction	**85**	**125**

The Company provides Attachment F, the Solar*Rewards Community Dashboard in addition to these details regarding program status.

II. ENGINEERING COST REVIEW

We provide the analysis of final bills provided to garden operators with a variance outside of +/- 20 percent within one of the required categories (substation or distribution) in Attachment A.[1] Ten projects were sent final interconnection bills in May. Variances continue to be observed for these projects. Whether it was omitted from the original IA or estimated higher than anticipated, many of the substation

[1] Attachment A is in compliance with ordering point 5 of the Commission's November 1, 2016 Order in this docket and does not include instances of which fall under this threshold.

variances are due to telemetry. Distribution variances were due to construction coming at a lower cost to developers for unneeded equipment, site conditions and changes from overhead to underground wiring.

III. COMPLETED PROJECTS

The Minnesota Solar*Rewards Community program has 559 MW in commercial operation. In this section, we provide specific details regarding completed projects.

A. Applications by County

Attachment B to this Report provides the application status of projects by county.[2] Completed projects are found in 41 separate counties with a significant amount of production located in Chisago which has over 50 MW of solar community installations.

B. Disconnected Gardens

Three operational gardens were disconnected (either voluntarily or by the Company) for violations in operation. Two CSG's were, in-part, disconnected due their failure to pass their open phase testing multiple times. Notices were submitted to the Commission. These projects remain disconnected as of the writing of this report. We will continue to provide further information as it becomes available.

C. Subscribers

Bill credits are provided to subscribers of completed community solar gardens. The compensation rate for these subscriptions is determined by when the garden operator completed its Solar*Rewards Community application and has been "deemed complete". At this time, most subscribers are receiving the Applicable Retail Rate for their compensation level. Table 3 provides further detail regarding the VOS bill credit rate vintage of projects in the pipeline today.

[2] Attachment B is in compliance with Order Point 3 of the Commission's February 13, 2015 Order addressing SoCore Energy's Petition for Clarification submitted in Docket E002/M-13-867.

Table 3: Active Project Sites - Bill Credit Vintage

	ARR	VOS 2017	VOS 2018	VOS 2019	Not yet Deemed Complete
Application Submitted	0	0	0	0	18
Study	3	1	69	22	0
Design and Construction	79	36	59	0	0
Commercial Operation	198	3	0	0	0
Total Sites	**280**	**40**	**128**	**22**	**18**

In June, there were two additional projects completed under the 2017 VOS; these two projects have not yet begun to receive bill credits. In total, there are now three projects constructed under the VOS. The one project receiving bill credits has seven subscriptions and has a 43 percent allocation to residential subscribers who hold less than 1 percent of the total capacity allocation to the CSG.

Bill credits begin to accrue the first day of the first full month of garden operation. Subscription information is collected when the bill credits begin to accrue.[3] There are over 15,000 subscriptions (or premises) in the community solar garden program. Residential customers make up 84 percent of the overall number of subscriptions (and 93 percent of subscribers), and 11 percent of the subscribed capacity. We offer further metrics in Table 4 below.

Table 4. April Subscription Metrics

	Residential	Small General Service	General Service	Other	Total
Number of Subscriptions	12,486	883	1180	366	14,915
% of Subscriptions	84%	6%	8%	2%	100%
Subscribers (Unique by Rate)	12,236	220	518	138	13,112
% of Subscribers	93%	2%	4%	1%	100%
DC Capacity Allocation (kW)	78,921	8,298	621,350	14,101	722,670
% of Subscription Capacity	11%	1%	86%	2%	100%
AC Monthly Production Allocation (kWh)	7,823,516	792,193	62,155,118	1,447,993	72,218,819
April Bill Credits	$ 1,222,899	$ 115,087	$ 7,710,971	$ 183,980	$ 9,232,938

[3] For purposes of the Report, the Company provides its subscription analysis for gardens receiving bill credits in April 2019.

In addition to subscribed energy there were 44 project sites with unsubscribed energy. These projects accounted for 384,517 kWh (AC) associated with unsubscribed energy payments in April (for March production). The payments to the Garden Operators for unsubscribed energy equaled $13,093 in bill credits during this timeframe.

IV. TARIFFED TIMELINES

Attachments C through E to this Report are provided in compliance with the Commission's August 6, 2015 Order at Order Point 2.[4]

We offer the following summary of compliance below:

- ***Application Completeness***[5]: The Company has met this timeline for ninety-five percent of all active applications; those that did not meet this timeline were generally sent the next business day.
- ***Statement of Work***[6]: Approximately ninety-eight percent of program SOWs for all active applications have been delivered within the timeframes outlined in Section 9 Tariff.
- ***Study Delivery***[7]: To determine whether this criterion has been met, the Company reviews the studies delivered to solar garden developers in 2019 and whether or not they were timely sent. Fifteen percent of program studies due in 2019 were timely delivered within the allocated timeframe. The remaining projects were delayed by an average of 21 days.

As noted in previous reports, recent study delays have occurred due to study resource issues, an increase in applications, a backlog of current projects, the complexity of studies at high penetration locations and continued focus on the quality of our study analysis. There have also been several instances in which the Company has received incorrect primary/secondary information impacting projects and those behind them in queue.

[4] Our Revised Tariff, effective on December 18, 2015, added new timeline requirements under our Electric Rate Book, Section 9. This timeline was added to these requirements.
[5] The Solar*Rewards Community tariff includes a 30-day timeline from the applicant submitting a complete application for the Company to advance projects into the interconnection process. Xcel Energy Electric Rate Book Section 9, beginning on Original Sheet No. 67
[6] This requirement was modified in our Revised Tariff dated December 18, 2015, at Original Sheet No. 68.3. Prior to this time, Section 10 governed this requirement at 15 business days.
[7] We note however, this metric has become increasingly more difficult to track given the amount of restudies completed over time and therefore may vary given the differing timeframes –currently we are only tracking the first delivery date in Attachment E.

The Company has contracted with additional resources to help meet upcoming deadlines. Forty-five percent of the studies due in May were submitted within tariffed timelines compared to 30 percent in previous months showing a decrease in study delays.

CONCLUSION

We appreciate the opportunity to report on the progress of the Solar*Rewards Community program. The Company will continue to report progress as projects move through the interconnection queue into commercial operation.

Dated: June 14, 2019

Northern States Power Company

Project #	Substation Costs				Distribution Costs				Total Cost				
	Indicative Cost	Actual Cost	Variance	Variance Explanation	Indicative Cost	Actual Cost	Variance	Variance Explanation	Indicative Cost	Detailed Design Cost	Actual Cost	Variance (Indicative/ Actual)	Variance (Detailed/ Actual)
1	$ 258,600	$ 195,109	-25%	Initial estimate included a satellite communication equipment that was not required any more as substation SCADA communication system was allowed to be used by Xcel Energy.	$ 311,500	$ 403,029	23%	Developer changed from OH to UG resulting in increased costs	$ 570,100	$ 549,600	$ 598,138	5%	9%
2	$ 61,426	$ 11,691	-81%	The feeder load monitoring in revised IA estimate was performed on another site on the feeder.	$ 475,450	$ 254,339	-87%	Developer changed to secondary metering resulting in less costs. - Developer changed scope of project resulting in less distribution material.	$ 536,876	$ 481,800	$ 266,030	-50%	-45%
3	$ 20,000	$ 11,691	-42%	Actual telemetry solution cost less than initial blanket estimate.	$ 166,000	$ 183,610	10%		$ 186,000	$ 294,200	$ 195,301	5%	-34%
4	$ 272,900	$ 330,262	21%	Telemetry was not included in the initial estimate.	$ 33,500	$ 41,479	19%	Muddy site conditions due to rain while building slowing construction down. Remobilization to the site by construction .	$ 306,400	$ 321,700	$ 371,741	21%	16%
5	$ -	$ 11,691	100%	Telemetry was not included in original estimate.	$ 83,631	$ 53,238	-57%	Less materials were used in detailed design & construction resulting lower costs.	$ 83,631	$ 81,700	$ 64,929	-22%	-21%
6	$ -	$ 45,408	100%	Transfer trip communication equipment was installed. Telemetry was not included in the initial estimate.	$ 127,126	$ 44,856	-183%	Metering costs were over-estimated in the IA.	$ 127,126	$ 68,700	$ 90,265	-29%	31%
7	$ -	$ 13,792	100%	Telemetry was not included in the initial estimate.	$ 95,495	$ 87,072	-10%	N/A	$ 95,495	$ 174,000	$ 100,865	6%	-42%
8	$ 20,000	$ 270,551	1253%	This garden moved from 2nd to 1st in queue absorbing reconductoring of feeder with voltage regulator and VSR.	$ 73,500	$ 77,575	5%	N/A	$ 93,500	$ 141,100	$ 348,126	272%	147%
9	$ -	$ -	0%	N/A	$ 14,305	$ 3,546	-303%	Garden was withdrawn by Developer after work had begun.	$ 14,305	$ 44,500	$ 3,546	-75%	-92%
10	$ -	$ 11,691	100%	Telemetry was not included in the initial estimate.	$ 162,047	$ 94,933	-71%	Recloser costs came in less than estimated. Detailed design determined fewer poles needed to be used.	$ 162,047	$ 159,300	$ 106,624	-34%	-33%

			Initial Applications		Application in Review		Applications Reviewed for Completeness		Design & Construction Phase		Completed Projects	
County	Active Applications	MW	Number of Applications	MW	Number of Applications	MW	Number of Applications	MW	Number of Applications	MW	Number of Applications	MW
Anoka	3	3			1	1.00	1	1.00	1	1.00		
Benton	31	31					6	6.00	3	3.00	22	21.95
Blue Earth	23	21					1	1.00	3	2.24	19	17.78
Carver	51	38							5	5.00	46	33.22
Chippewa	17	17			2	2.00	1	1.00	3	3.00	11	11.00
Chisago	83	82			1	1.00	17	17.00	9	9.00	56	55.39
Clay	5	5							5	5.00		
Dakota	62	61			1	0.20	2	2.00	15	15.00	44	43.40
Dodge	31	30			1	1.00	9	8.78	4	3.48	17	17.00
Douglas	8	8							3	3.00	5	5.00
Faribault	2	2									2	1.84
Freeborn	3	2							3	2.25		
Goodhue	51	49					11	11.00	13	12.59	27	25.66
Hennepin	22	17							8	5.91	14	11.06
Kandiyohi	7	7					2	2.00	1	1.00	4	4.00
Le Sueur	26	25					1	1.00	4	4.00	21	20.04
Lincoln	2	0									2	0.40
Lyon	5	5							1	1.00	4	4.00
McLeod	26	26	1	1.00	2	2.00	4	4.00	7	7.00	12	12.00
Meeker	4	4							3	3.00	1	0.76
Murray	2	2									2	2.00
Nicollet	13	13					3	3.00	4	4.00	6	6.00
Olmsted	11	11	1	1.00			2	2.00	3	3.00	5	5.00
Pipestone	13	13							1	1.00	12	11.70
Pope	29	29			1	1.00	6	6.00	6	6.00	16	16.00
Ramsey	3	1			1	0.50					2	0.67
Redwood	8	8							5	4.86	3	3.00
Renville	12	12					4	4.00	2	2.00	6	6.00
Rice	50	50			1	1.00	5	5.00	23	22.96	21	21.00
Scott	25	23					3	3.00	3	2.00	19	18.15
Sherburne	58	57					2	2.00	12	12.00	44	43.05
Sibley	6	5							6	5.25		
Stearns	87	85			4	4.00	8	8.00	26	25.60	49	47.07
Steele	8	7							2	2.00	6	5.40
Wabasha	12	12					1	1.00	3	3.00	8	7.85
Waseca	21	21			1	1.00	4	4.00	7	7.00	9	9.00
Washington	64	45					3	3.00	5	5.00	56	37.16
Watonwan	1	0									1	0.25
Winona	15	14					1	1.00	13	13.00	1	0.25
Wright	43	43							13	13.00	30	29.97
Yellow Medicine	5	5									5	5.00
Total	**948**	**891**	**2**	**2.00**	**16**	**14.70**	**97**	**96.78**	**225**	**218.13**	**608**	**559.01**

6.3.19

Solar Garden: Solar Garden ID	Site ID	Submission	Status	Sent to Engineering Review - Clock Start One	Comments Sent 1	Clock Restart 1	Comments Sent 2	Clock Restart 2	Comments Sent 3	Clock Restart 3	End of 30 day review clock	Applications Considered Complete	Data Pulled	Time lapse between requirement and date sent	Section 9 Requirement Met	Additional Information
SRC040945	15	7/14/2015	Step 6: Documents & Contract Submission	9/15/2015	10/19/2015	11/5/2015					12/6/2015	11/24/2015	6/3/2019	12	YES	
SRC040944	15	7/14/2015	Step 6: Documents & Contract Submission	9/15/2015	10/19/2015	11/5/2015					12/6/2015	11/24/2015	6/3/2019	12	YES	
SRC040943	15	7/14/2015	Step 6: Documents & Contract Submission	9/15/2015	10/19/2015	11/5/2015					12/6/2015	11/24/2015	6/3/2019	12	YES	
SRC040942	15	7/14/2015	Step 6: Documents & Contract Submission	9/15/2015	10/19/2015	11/5/2015					12/6/2015	11/24/2015	6/3/2019	12	YES	
SRC040946	15	7/14/2015	Step 6: Documents & Contract Submission	9/15/2015	10/19/2015	11/5/2015					12/6/2015	11/24/2015	6/3/2019	12	YES	
SRC041167	16	7/27/2015	Step 6: Documents & Contract Submission	9/16/2015	10/19/2015	9/29/2015		11/5/2015			12/6/2015	11/24/2015	6/3/2019	12	YES	
SRC041169	16	7/27/2015	Step 6: Documents & Contract Submission	9/16/2015	10/19/2015	9/29/2015		11/5/2015			12/6/2015	11/24/2015	6/3/2019	12	YES	
SRC041168	16	7/27/2015	Step 6: Documents & Contract Submission	9/16/2015	10/19/2015	9/29/2015		11/5/2015			12/6/2015	11/24/2015	6/3/2019	12	YES	
SRC041165	16	7/27/2015	Step 6: Documents & Contract Submission	9/16/2015	10/19/2015	9/29/2015		11/5/2015			12/6/2015	11/24/2015	6/3/2019	12	YES	
SRC041166	16	7/27/2015	Step 6: Documents & Contract Submission	9/16/2015	10/19/2015	9/29/2015		11/5/2015			12/6/2015	11/24/2015	6/3/2019	12	YES	
SRC040606	43	6/19/2015	Step 5: Design and Constructions	8/24/2015	9/24/2015	10/22/2015	11/6/2015	11/23/2015			12/24/2015	12/1/2015	6/3/2019	23	YES	
SRC040613	43	6/19/2015	Step 5: Design and Constructions	8/24/2015	9/24/2015	10/22/2015	11/6/2015	11/23/2015			12/24/2015	12/1/2015	6/3/2019	23	YES	
SRC040608	43	6/19/2015	Step 5: Design and Constructions	8/24/2015	9/24/2015	10/22/2015	11/6/2015	11/23/2015			12/24/2015	12/1/2015	6/3/2019	23	YES	
SRC040603	43	6/19/2015	Step 5: Design and Constructions	8/24/2015	9/24/2015	10/22/2015	11/6/2015	11/23/2015			12/24/2015	12/1/2015	6/3/2019	23	YES	
SRC040610	43	6/19/2015	Step 5: Design and Constructions	8/24/2015	9/24/2015	10/22/2015	11/6/2015	11/23/2015			12/24/2015	12/1/2015	6/3/2019	23	YES	
SRC039909	64	5/7/2015	Step 4: Engineering Scoping Study	6/3/2015	7/10/2015	7/27/2015					8/27/2015	8/27/2015	6/3/2019	0	YES	
SRC039911	64	5/7/2015	Step 4: Engineering Scoping Study	6/3/2015	7/10/2015	7/27/2015					8/27/2015	8/27/2015	6/3/2019	0	YES	
SRC039910	64	5/7/2015	Step 4: Engineering Scoping Study	6/3/2015	7/10/2015	7/27/2015					8/27/2015	8/27/2015	6/3/2019	0	YES	
SRC039758	108	5/1/2015	Step 5: Design and Constructions	6/10/2015	6/29/2015	7/1/2015	8/7/2015	1/5/2017	8/30/2015		2/5/2017	9/4/2016	6/3/2019	154	YES	Originally considered complete on 9/4/15. Required to re-enter review on 1/4/17. Comments sent 1/20/17
SRC039756	108	5/1/2015	Step 5: Design and Constructions	6/10/2015	6/29/2015	7/1/2015	8/7/2015	1/5/2017	8/30/2015		2/5/2017	9/4/2016	6/3/2019	154	YES	Originally considered complete on 9/4/15. Required to re-enter review on 1/4/17. Comments sent 1/20/17
SRC039757	108	5/1/2015	Step 5: Design and Constructions	6/10/2015	6/29/2015	7/1/2015	8/7/2015	1/5/2017	8/30/2015		2/5/2017	9/4/2016	6/3/2019	154	YES	Originally considered complete on 9/4/15. Required to re-enter review on 1/4/17. Comments sent 1/20/17
SRC039624	108	4/20/2015	Step 5: Design and Constructions	6/10/2015	6/29/2015	7/1/2015	8/7/2015	1/5/2017	8/30/2015		2/5/2017	9/4/2016	6/3/2019	154	YES	Originally considered complete on 9/4/15. Required to re-enter review on 1/4/17. Comments sent 1/20/17
SRC040034	118	5/28/2015	Step 5: Design and Constructions	7/6/2015	8/7/2015	8/30/2015					9/30/2015	9/4/2015	6/3/2019	26	YES	
SRC040036	118	5/28/2015	Step 5: Design and Constructions	7/6/2015	8/7/2015	8/30/2015					9/30/2015	9/4/2015	6/3/2019	26	YES	
SRC040038	118	5/28/2015	Step 5: Design and Constructions	7/6/2015	8/7/2015	8/30/2015					9/30/2015	9/4/2015	6/3/2019	26	YES	
SRC040035	118	5/28/2015	Step 5: Design and Constructions	7/6/2015	8/7/2015	8/30/2015					9/30/2015	9/4/2015	6/3/2019	26	YES	
SRC040037	118	5/28/2015	Step 5: Design and Constructions	7/6/2015	8/7/2015	8/30/2015					9/30/2015	9/4/2015	6/3/2019	26	YES	
SRC041078	153	7/24/2015	Step 5: Design and Constructions	9/28/2015	10/28/2015	9/15/2016	10/12/2016	10/17/2016	11/17/2016	2/21/2017	3/24/2017	3/24/2017	6/3/2019	0	YES	
SRC041079	153	7/24/2015	Step 5: Design and Constructions	9/28/2015	10/28/2015	9/15/2016	10/12/2016	10/17/2016	11/17/2016	2/21/2017	3/24/2017	3/24/2017	6/3/2019	0	YES	
SRC041077	153	7/24/2015	Step 5: Design and Constructions	9/28/2015	10/28/2015	9/15/2016	10/12/2016	10/17/2016	11/17/2016	2/21/2017	3/24/2017	3/24/2017	6/3/2019	0	YES	
SRC041080	153	7/24/2015	Step 5: Design and Constructions	9/28/2015	10/28/2015	9/15/2016	10/12/2016	12/29/2016	1/27/2017	2/21/2017	3/24/2017	3/24/2017	6/3/2019	0	YES	
SRC040824	154	6/24/2015	Step 5: Design and Constructions	9/28/2015	10/28/2015	9/13/2016	9/26/2016	10/17/2016	11/16/2016	2/21/2017	3/24/2017	3/22/2017	6/3/2019	2	YES	
SRC040823	154	6/24/2015	Step 5: Design and Constructions	9/28/2015	10/28/2015	9/13/2016	9/26/2016	10/17/2016	11/16/2016	2/21/2017	3/24/2017	3/22/2017	6/3/2019	2	YES	
SRC041085	157	7/24/2015	Step 5: Design and Constructions	9/28/2015	10/28/2015	2/3/2016	2/11/2016	12/3/2016	12/30/2016	2/21/2017	3/24/2017	3/24/2017	6/3/2019	0	YES	
SRC041082	157	7/24/2015	Step 5: Design and Constructions	9/28/2015	10/28/2015	12/18/2015	2/11/2016	1/29/2016	12/30/2016	2/21/2017	3/24/2017	3/24/2017	6/3/2019	0	YES	
SRC041084	157	7/24/2015	Step 5: Design and Constructions	9/28/2015	10/28/2015	2/3/2016	2/11/2016	12/3/2016	12/30/2016	2/21/2017	3/24/2017	3/24/2017	6/3/2019	0	YES	
SRC041083	157	7/24/2015	Step 5: Design and Constructions	9/28/2015	10/28/2015	1/29/2016	2/11/2016	9/15/2016	12/30/2016	2/21/2017	3/24/2017	3/24/2017	6/3/2019	0	YES	
SRC040316	158	6/3/2015	Step 5: Design and Constructions	9/28/2015	10/28/2015	9/13/2016	9/26/2016	10/17/2016	11/16/2016	3/23/2017	4/23/2017	4/4/2017	6/3/2019	19	YES	
SRC040353	158	6/8/2015	Step 5: Design and Constructions	9/28/2015	10/28/2015	9/13/2016	9/26/2016	10/17/2016	11/16/2016	3/23/2017	4/23/2017	4/4/2017	6/3/2019	19	YES	
SRC041087	158	7/24/2015	Step 5: Design and Constructions	9/28/2015	10/28/2015	2/3/2016	2/11/2016	12/29/2016	1/27/2017	3/30/2017	4/30/2017	4/4/2017	6/3/2019	26	YES	
SRC040813	158	6/24/2015	Step 5: Design and Constructions	9/28/2015	10/28/2015	12/29/2016	1/27/2017	2/21/2017	3/23/2017		4/23/2017	4/4/2017	6/3/2019	19	YES	
SRC040814	158	6/24/2015	Step 5: Design and Constructions	9/28/2015	10/28/2015	12/29/2016	1/27/2017	2/21/2017	3/23/2017		4/23/2017	4/4/2017	6/3/2019	19	YES	
SRC040897	166	7/7/2015	Step 6: Documents & Contract Submission	10/9/2015	11/6/2015	12/22/2015					1/22/2016	1/7/2016	6/3/2019	15	YES	
SRC040901	166	7/7/2015	Step 6: Documents & Contract Submission	10/9/2015	11/6/2015	12/22/2015					1/22/2016	1/7/2016	6/3/2019	15	YES	
SRC040898	166	7/7/2015	Step 6: Documents & Contract Submission	10/9/2015	11/6/2015	12/22/2015					1/22/2016	1/7/2016	6/3/2019	15	YES	

Solar Garden: Solar Garden ID	Site ID	Submission	Status	Sent to Engineering Review - Clock Start One	Comments Sent 1	Clock Restart 1	Comments Sent 2	Clock Restart 2	Comments Sent 3	Clock Restart 3	End of 30 day review clock	Applications Considered Complete	Data Pulled	Time lapse between requirement and date sent	Section 9 Requirement Met	Additional Information
SRC040900	166	7/7/2015	Step 6: Documents & Contract Submission	10/9/2015	11/6/2015	12/22/2015					1/22/2016	1/7/2016	6/3/2019	15	YES	
SRC040899	166	7/7/2015	Step 6: Documents & Contract Submission	10/9/2015	11/6/2015	12/22/2015					1/22/2016	1/7/2016	6/3/2019	15	YES	
SRC040667	222	6/19/2015	Step 5: Design and Constructions	9/24/2015	10/19/2015	10/22/2015	11/6/2015	11/23/2015			12/24/2015	12/1/2015	6/3/2019	23	YES	
SRC040669	222	6/19/2015	Step 5: Design and Constructions	9/24/2015	10/19/2015	10/22/2015	11/6/2015	11/23/2015			12/24/2015	12/1/2015	6/3/2019	23	YES	
SRC040668	222	6/19/2015	Step 5: Design and Constructions	9/24/2015	10/19/2015	10/22/2015	11/6/2015	11/23/2015			12/24/2015	12/1/2015	6/3/2019	23	YES	
SRC042655	235	9/24/2015	Step 5: Design and Constructions	11/18/2016	12/16/2016	1/11/2017					2/11/2017	2/9/2017	6/3/2019	2	YES	
SRC042652	235	9/24/2015	Step 5: Design and Constructions	11/18/2016	12/16/2016	1/11/2017					2/11/2017	2/9/2017	6/3/2019	2	YES	
SRC042662	235	9/24/2015	Step 5: Design and Constructions	11/18/2016	12/16/2016	1/11/2017					2/11/2017	2/9/2017	6/3/2019	2	YES	
SRC042659	235	9/24/2015	Step 5: Design and Constructions	11/18/2016	12/16/2016	1/11/2017					2/11/2017	2/9/2017	6/3/2019	2	YES	
SRC042667	235	9/24/2015	Step 5: Design and Constructions	11/18/2016	12/16/2016	1/11/2017					2/11/2017	2/9/2017	6/3/2019	2	YES	
SRC042333	251	9/18/2015	Step 5: Design and Constructions	10/5/2015	11/4/2015	11/20/2015					12/21/2015	12/21/2015	6/3/2019	0	YES	
SRC042400	255	9/21/2015	Step 5: Design and Constructions	10/5/2015	11/4/2015	11/23/2015					12/24/2015	12/21/2015	6/3/2019	3	YES	
SRC042467	258	9/22/2015	Step 6: Documents & Contract Submission	2/28/2017							3/31/2017	3/8/2017	6/3/2019	23	YES	
SRC042464	258	9/22/2015	Step 6: Documents & Contract Submission	2/28/2017							3/31/2017	3/8/2017	6/3/2019	23	YES	
SRC042465	258	9/22/2015	Step 6: Documents & Contract Submission	2/28/2017							3/31/2017	3/8/2017	6/3/2019	23	YES	
SRC042439	258	9/22/2015	Step 6: Documents & Contract Submission	2/28/2017							3/31/2017	3/8/2017	6/3/2019	23	YES	
SRC042725	284	9/24/2015	Step 5: Design and Constructions	3/13/2017							4/13/2017	4/10/2017	6/3/2019	3	YES	
SRC042727	284	9/24/2015	Step 5: Design and Constructions	3/13/2017							4/13/2017	4/10/2017	6/3/2019	3	YES	
SRC042722	284	9/24/2015	Step 5: Design and Constructions	3/13/2017							4/13/2017	4/10/2017	6/3/2019	3	YES	
SRC049639	467	10/13/2016	Step 5: Design and Constructions	11/4/2016	12/7/2016	1/31/2017	3/1/2017	3/14/2017	4/11/2017	4/12/2017	5/13/2017	4/13/2017	6/3/2019	30	YES	
SRC049640	468	10/13/2016	Step 5: Design and Constructions	11/4/2016							12/5/2016	12/2/2016	6/3/2019	3	YES	
SRC051585	493	11/15/2016	Step 5: Design and Constructions	12/23/2016	1/20/2017	1/30/2017	2/27/2017	3/20/2017			4/20/2017	4/7/2017	6/3/2019	13	YES	
SRC051587	495	11/15/2016	Step 5: Design and Constructions	12/23/2016	1/23/2017	1/30/2017	2/27/2017	3/20/2017			4/20/2017	4/7/2017	6/3/2019	13	YES	
SRC051589	497	11/15/2016	Step 5: Design and Constructions	12/23/2016	1/13/2017	1/30/2017	2/27/2017	3/20/2017			4/20/2017	4/7/2017	6/3/2019	13	YES	
SRC051594	502	11/15/2016	Step 5: Design and Constructions	12/23/2016	1/13/2017	1/30/2017	2/27/2017	3/20/2017			4/20/2017	4/7/2017	6/3/2019	13	YES	
SRC052244	516	12/5/2016	Step 5: Design and Constructions	2/3/2017	3/7/2017	3/14/2017					4/14/2017	3/23/2017	6/3/2019	22	YES	
SRC052806	518	12/28/2016	Step 5: Design and Constructions	2/1/2017	2/28/2017	3/14/2017	4/11/2017	4/12/2017			5/13/2017	4/13/2017	6/3/2019	30	YES	
SRC052809	523	12/28/2016	Step 5: Design and Constructions	2/1/2017	2/28/2017	3/14/2017					4/14/2017	3/17/2017	6/3/2019	28	YES	
SRC052763	527	12/29/2016	Step 5: Design and Constructions	1/31/2017	3/2/2017			3/20/2017			4/20/2017	4/7/2017	6/3/2019	13	YES	
SRC052762	529	12/29/2016	Step 5: Design and Constructions	1/31/2017	3/2/2017			3/20/2017			4/20/2017	4/7/2017	6/3/2019	13	YES	
SRC052305	530	12/9/2016	Step 5: Design and Constructions	1/10/2017							2/10/2017	2/3/2017	6/3/2019	7	YES	
SRC052799	535	12/29/2016	Step 6: Documents & Contract Submission	1/30/2017	2/27/2017	3/2/2017	3/7/2017	3/8/2017			4/8/2017	4/7/2017	6/3/2019	1	YES	
SRC052795	537	12/29/2016	Step 5: Design and Constructions	2/3/2017	3/7/2017	3/13/2017					4/13/2017	4/10/2017	6/3/2019	3	YES	
SRC052784	538	12/29/2016	Step 5: Design and Constructions	1/28/2017	2/27/2017	3/16/2017	4/10/2017	4/10/2017			5/11/2017	4/13/2017	6/3/2019	28	YES	
SRC052754	552	12/29/2016	Step 5: Design and Constructions	1/31/2017	3/2/2017			3/20/2017			4/20/2017	4/7/2017	6/3/2019	13	YES	
SRC052737	553	12/28/2016	Step 5: Design and Constructions	1/28/2017	2/27/2017	3/16/2017					4/16/2017	4/13/2017	6/3/2019	3	YES	
SRC052804	556	12/28/2016	Step 5: Design and Constructions	2/1/2017	3/1/2017	3/14/2017	4/11/2017	4/12/2017			5/13/2017	4/13/2017	6/3/2019	30	YES	
SRC052761	562	12/29/2016	Step 5: Design and Constructions	1/31/2017	3/2/2017			3/20/2017			4/20/2017	4/7/2017	6/3/2019	13	YES	
SRC052798	565	12/29/2016	Step 5: Design and Constructions	2/13/2017	3/7/2017	3/14/2017					4/14/2017	3/23/2017	6/3/2019	22	YES	
SRC052738	569	12/28/2016	Step 5: Design and Constructions	1/28/2017	2/27/2017	3/16/2017					4/16/2017	4/13/2017	6/3/2019	3	YES	
SRC052434	578	12/9/2016	Step 5: Design and Constructions	1/31/2017	3/2/2017			3/20/2017			4/20/2017	4/7/2017	6/3/2019	13	YES	
SRC052694	580	12/21/2016	Step 4: Engineering Scoping Study	2/22/2017	3/10/2017	3/17/2017	3/22/2017				4/22/2017	3/23/2017	6/3/2019	30	YES	
SRC052716	582	12/27/2016	Step 5: Design and Constructions	1/25/2017	2/24/2017	3/13/2017					4/13/2017	3/31/2017	6/3/2019	13	YES	
SRC052743	584	12/28/2016	Step 5: Design and Constructions	2/1/2017	3/1/2017	3/14/2017	4/11/2017	4/12/2017			5/13/2017	4/13/2017	6/3/2019	30	YES	
SRC052796	594	12/29/2016	Step 5: Design and Constructions	2/3/2017	3/7/2017	3/13/2017					4/13/2017	4/10/2017	6/3/2019	3	YES	
SRC052739	603	12/28/2016	Step 5: Design and Constructions	1/28/2017	2/27/2017	3/16/2017					4/16/2017	4/13/2017	6/3/2019	3	YES	
SRC052740	604	12/28/2016	Step 5: Design and Constructions	1/28/2017	3/2/2017	4/13/2017					5/14/2017	4/13/2017	6/3/2019	31	YES	
SRC052803	605	12/28/2016	Step 5: Design and Constructions	2/1/2017	2/28/2017	3/14/2017	4/11/2017	4/12/2017			5/13/2017	4/13/2017	6/3/2019	30	YES	
SRC052759	608	12/29/2016	Step 5: Design and Constructions	1/31/2017	3/2/2017			3/20/2017			4/20/2017	4/7/2017	6/3/2019	13	YES	
SRC052717	612	12/27/2016	Step 5: Design and Constructions	1/25/2017	2/27/2017	3/13/2017					4/13/2017	3/31/2017	6/3/2019	13	YES	
SRC052825	613	12/30/2016	Step 5: Design and Constructions	1/27/2017	2/23/2017	3/14/2017					4/14/2017	4/10/2017	6/3/2019	4	YES	
SRC052722	614	12/27/2016	Step 5: Design and Constructions	1/25/2017	2/27/2017	3/13/2017					4/13/2017	3/31/2017	6/3/2019	13	YES	
SRC052828	615	12/30/2016	Step 5: Design and Constructions	1/27/2017	2/22/2017	3/14/2017					4/14/2017	4/10/2017	6/3/2019	4	YES	
SRC052715	616	12/27/2016	Step 5: Design and Constructions	1/25/2017	2/27/2017	3/13/2017					4/13/2017	3/31/2017	6/3/2019	13	YES	
SRC052824	617	12/30/2016	Step 5: Design and Constructions	1/27/2017	2/23/2017	3/14/2017					4/14/2017	4/10/2017	6/3/2019	4	YES	
SRC052728	618	12/27/2016	Step 5: Design and Constructions	1/25/2017	2/24/2017	3/13/2017					4/13/2017	3/31/2017	6/3/2019	13	YES	
SRC052733	620	12/27/2016	Step 5: Design and Constructions	1/25/2017	2/24/2017	3/13/2017					4/13/2017	3/31/2017	6/3/2019	13	YES	
SRC052838	621	12/30/2016	Step 5: Design and Constructions	1/27/2017	2/23/2017	3/14/2017					4/14/2017	4/10/2017	6/3/2019	4	YES	
SRC052718	622	12/27/2016	Step 5: Design and Constructions	1/25/2017	2/24/2017	3/13/2017					4/13/2017	3/31/2017	6/3/2019	13	YES	
SRC052732	624	12/27/2016	Step 5: Design and Constructions	1/25/2017	2/27/2017	3/13/2017					4/13/2017	3/31/2017	6/3/2019	13	YES	
SRC052837	625	12/30/2016	Step 5: Design and Constructions	1/27/2017	2/23/2017	3/14/2017					4/14/2017	4/10/2017	6/3/2019	4	YES	
SRC052719	626	12/27/2016	Step 5: Design and Constructions	1/25/2017	2/24/2017	3/13/2017					4/13/2017	3/31/2017	6/3/2019	13	YES	
SRC052827	627	12/30/2016	Step 5: Design and Constructions	1/27/2017	2/23/2017	3/14/2017					4/14/2017	4/10/2017	6/3/2019	4	YES	
SRC052726	628	12/27/2016	Step 5: Design and Constructions	1/25/2017	2/27/2017	3/13/2017					4/13/2017	3/31/2017	6/3/2019	13	YES	
SRC052839	629	12/30/2016	Step 5: Design and Constructions	1/27/2017	2/23/2017	3/14/2017					4/14/2017	4/10/2017	6/3/2019	4	YES	
SRC052834	634	12/30/2016	Step 5: Design and Constructions	1/27/2017	2/23/2017	3/14/2017					4/14/2017	4/10/2017	6/3/2019	4	YES	
SRC052727	635	12/27/2016	Step 5: Design and Constructions	1/25/2017	2/24/2017	3/13/2017					4/13/2017	3/31/2017	6/3/2019	13	YES	
SRC052813	638	12/30/2016	Step 5: Design and Constructions	1/25/2017	2/24/2017	3/13/2017					4/13/2017	3/31/2017	6/3/2019	13	YES	

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SRC052814	639	12/30/2016	Step 5: Design and Constructions	1/27/2017	2/20/2017	3/14/2017					4/14/2017	4/10/2017	6/3/2019	4	YES	
SRC052721	640	12/27/2016	Step 5: Design and Constructions	1/25/2017	2/27/2017	3/13/2017					4/13/2017	3/31/2017	6/3/2019	13	YES	
SRC052832	641	12/30/2016	Step 5: Design and Constructions	1/27/2017	2/23/2017	3/14/2017					4/14/2017	4/10/2017	6/3/2019	4	YES	
SRC052725	642	12/27/2016	Step 5: Design and Constructions	1/25/2017	2/24/2017	3/13/2017					4/13/2017	3/31/2017	6/3/2019	13	YES	
SRC052831	643	12/30/2016	Step 5: Design and Constructions	1/27/2017	2/20/2017	3/14/2017					4/14/2017	4/10/2017	6/3/2019	4	YES	
SRC052724	644	12/27/2016	Step 5: Design and Constructions	1/25/2017	2/24/2017	3/13/2017					4/13/2017	3/31/2017	6/3/2019	13	YES	
SRC052830	645	12/30/2016	Step 5: Design and Constructions	1/27/2017	2/20/2017	3/14/2017					4/14/2017	4/10/2017	6/3/2019	4	YES	
SRC052723	646	12/27/2016	Step 5: Design and Constructions	1/25/2017	2/24/2017	3/13/2017					4/13/2017	3/31/2017	6/3/2019	13	YES	
SRC052829	647	12/30/2016	Step 5: Design and Constructions	1/27/2017	2/23/2017	3/14/2017					4/14/2017	4/10/2017	6/3/2019	4	YES	
SRC042081	648	9/13/2015	Step 5: Design and Constructions	7/11/2018	7/19/2018	7/23/2018	7/31/2018				8/31/2018	4/21/2016	6/3/2019	862	YES	Updated documents submitted
SRC042083	648	9/13/2015	Step 5: Design and Constructions	7/11/2018	7/19/2018	7/23/2018	7/31/2018				8/31/2018	4/21/2016	6/3/2019	862	YES	Updated documents submitted
SRC071169	648	9/13/2015	Step 5: Design and Constructions	7/11/2018	7/19/2018	7/23/2018	7/31/2018				8/31/2018	4/21/2016	6/3/2019	862	YES	Updated documents submitted
SRC061101	651	8/14/2017	Step 4: Engineering Scoping Study	1/3/2019	1/18/2019	2/8/2019	3/11/2019	3/20/2019			4/20/2019	4/1/2019	6/3/2019	19	YES	
SRC062754	652	10/12/2017	Step 5: Design and Constructions	12/13/2017							1/13/2018	1/11/2018	6/3/2019	2	YES	
SRC062797	653	10/12/2017	Step 5: Design and Constructions	12/13/2017							1/13/2018	1/11/2018	6/3/2019	2	YES	
SRC062798	654	10/12/2017	Step 5: Design and Constructions	12/13/2017							1/13/2018	1/11/2018	6/3/2019	2	YES	
SRC062799	655	10/12/2017	Step 5: Design and Constructions	12/13/2017							1/13/2018	1/11/2018	6/3/2019	2	YES	
SRC062800	656	10/12/2017	Step 5: Design and Constructions	12/13/2017							1/13/2018	1/11/2018	6/3/2019	2	YES	
SRC062801	657	10/12/2017	Step 5: Design and Constructions	12/13/2017							1/13/2018	1/11/2018	6/3/2019	2	YES	
SRC062802	658	10/12/2017	Step 5: Design and Constructions	12/13/2017							1/13/2018	1/11/2018	6/3/2019	2	YES	
SRC062803	659	10/12/2017	Step 5: Design and Constructions	12/13/2017							1/13/2018	1/11/2018	6/3/2019	2	YES	
SRC062804	660	10/12/2017	Step 5: Design and Constructions	12/13/2017							1/13/2018	1/11/2018	6/3/2019	2	YES	
SRC062805	661	10/12/2017	Step 5: Design and Constructions	12/13/2017							1/13/2018	1/11/2018	6/3/2019	2	YES	
SRC062807	662	10/12/2017	Step 5: Design and Constructions	12/13/2017							1/13/2018	1/11/2018	6/3/2019	2	YES	
SRC062809	663	10/12/2017	Step 5: Design and Constructions	12/13/2017							1/13/2018	1/11/2018	6/3/2019	2	YES	
SRC062810	664	10/12/2017	Step 5: Design and Constructions	3/13/2018	4/2/2018	4/4/2018					5/5/2018	4/9/2018	6/3/2019	26	YES	
SRC062811	665	10/12/2017	Step 5: Design and Constructions	12/13/2017							1/13/2018	1/11/2018	6/3/2019	2	YES	
SRC062812	666	10/12/2017	Step 5: Design and Constructions	12/13/2017							1/13/2018	1/11/2018	6/3/2019	2	YES	
SRC062814	668	10/12/2017	Step 5: Design and Constructions	12/13/2017							1/13/2018	1/11/2018	6/3/2019	2	YES	
SRC062815	669	10/12/2017	Step 5: Design and Constructions	12/13/2017							1/13/2018	1/11/2018	6/3/2019	2	YES	
SRC062816	670	10/12/2017	Step 5: Design and Constructions	12/13/2017							1/13/2018	1/11/2018	6/3/2019	2	YES	
SRC062817	671	10/12/2017	Step 5: Design and Constructions	12/13/2017							1/13/2018	1/11/2018	6/3/2019	2	YES	
SRC062818	672	10/12/2017	Step 5: Design and Constructions	12/13/2017							1/13/2018	1/11/2018	6/3/2019	2	YES	
SRC062819	673	10/12/2017	Step 5: Design and Constructions	12/13/2017							1/13/2018	1/11/2018	6/3/2019	2	YES	
SRC062820	674	10/12/2017	Step 5: Design and Constructions	12/13/2017							1/13/2018	1/11/2018	6/3/2019	2	YES	
SRC062821	675	10/12/2017	Step 4: Engineering Scoping Study	12/13/2017							1/13/2018	1/11/2018	6/3/2019	2	YES	
SRC062822	676	10/12/2017	Step 5: Design and Constructions	12/13/2017	1/11/2018	1/11/2018					2/11/2018	1/22/2018	6/3/2019	20	YES	
SRC062823	677	10/12/2017	Step 5: Design and Constructions	12/13/2017							1/13/2018	1/11/2018	6/3/2019	2	YES	
SRC063633	680	11/7/2017	Step 5: Design and Constructions	1/19/2018	2/1/2018	2/6/2018					3/9/2018	2/23/2018	6/3/2019	14	YES	
SRC063634	681	11/7/2017	Step 5: Design and Constructions	2/6/2018							3/9/2018	2/23/2018	6/3/2019	14	YES	
SRC063636	683	11/7/2017	Step 5: Design and Constructions	3/13/2018							4/13/2018	4/2/2018	6/3/2019	11	YES	
SRC063637	684	11/10/2017	Step 5: Design and Constructions	3/13/2018							4/13/2018	4/2/2018	6/3/2019	11	YES	
SRC063638	685	11/13/2017	Step 5: Design and Constructions	3/13/2018							4/13/2018	4/2/2018	6/3/2019	11	YES	
SRC063639	686	11/13/2017	Step 5: Design and Constructions	2/13/2018							3/16/2018	2/23/2018	6/3/2019	21	YES	
SRC063642	687	11/13/2017	Step 5: Design and Constructions	2/6/2018							3/9/2018	2/23/2018	6/3/2019	14	YES	
SRC063645	688	11/13/2017	Step 5: Design and Constructions	2/6/2018	2/26/2018	2/27/2018					3/30/2018	3/2/2018	6/3/2019	28	YES	
SRC063646	689	11/17/2017	Step 5: Design and Constructions	1/19/2018	2/1/2018	2/6/2018					3/9/2018	2/23/2018	6/3/2019	14	YES	
SRC063647	690	11/21/2017	Step 5: Design and Constructions	3/13/2018							4/13/2018	4/2/2018	6/3/2019	11	YES	
SRC064070	691	12/5/2017	Step 5: Design and Constructions	3/13/2018							4/13/2018	4/2/2018	6/3/2019	11	YES	
SRC064072	693	12/5/2017	Step 5: Design and Constructions	3/13/2018	4/2/2018	4/4/2018					5/5/2018	4/9/2018	6/3/2019	26	YES	
SRC064073	694	12/5/2017	Step 5: Design and Constructions	4/25/2018	5/14/2018	5/25/2018					6/25/2018	5/30/2018	6/3/2019	26	YES	
SRC064075	696	12/5/2017	Step 5: Design and Constructions	3/13/2018	4/2/2018	4/4/2018					5/5/2018	4/9/2018	6/3/2019	26	YES	
SRC064254	697	12/21/2017	Step 5: Design and Constructions	1/2/2018	1/11/2018	1/18/2018					2/18/2018	1/25/2018	6/3/2019	24	YES	
SRC064853	699	1/29/2018	Step 5: Design and Constructions	4/5/2018							5/6/2018	4/9/2018	6/3/2019	27	YES	
SRC065488	701	2/28/2018	Step 5: Design and Constructions	4/5/2018	4/9/2018	4/12/2018					5/13/2018	4/16/2018	6/3/2019	27	YES	
SRC065658	703	3/20/2018	Step 5: Design and Constructions	4/20/2018	5/14/2018	6/7/2018					7/8/2018	6/14/2018	6/3/2019	24	YES	
SRC065957	707	4/11/2018	Step 5: Design and Constructions	5/11/2018	5/23/2018	6/8/2018					7/9/2018	6/14/2018	6/3/2019	25	YES	
SRC065961	710	4/11/2018	Step 5: Design and Constructions	5/11/2018	5/23/2018	6/8/2018					7/9/2018	6/14/2018	6/3/2019	25	YES	
SRC065964	711	4/11/2018	Step 5: Design and Constructions	4/23/2018	5/9/2018	5/14/2018	5/21/2018	6/14/2018			7/15/2018	6/15/2018	6/3/2019	30	YES	
SRC066766	713	5/16/2018	Step 5: Design and Constructions	6/20/2018							7/21/2018	7/11/2018	6/3/2019	10	YES	
SRC067199	714	5/21/2018	Step 5: Design and Constructions	6/12/2018	6/14/2018	7/6/2018	7/9/2018	7/9/2018			8/9/2018	7/10/2018	6/3/2019	30	YES	
SRC067625	716	6/12/2018	Step 5: Design and Constructions	7/17/2018	7/31/2018	8/10/2018	8/14/2018	8/20/2018			9/20/2018	8/23/2018	6/3/2019	28	YES	
SRC067629	719	6/14/2018	Step 5: Design and Constructions	9/26/2018							10/27/2018	10/8/2018	6/3/2019	19	YES	
SRC067630	720	6/14/2018	Step 5: Design and Constructions	7/13/2018	7/19/2018	7/24/2018					8/24/2018	7/24/2018	6/3/2019	31	YES	
SRC067631	721	6/14/2018	Step 5: Design and Constructions	7/13/2018	7/19/2018	7/24/2018					8/24/2018	7/24/2018	6/3/2019	31	YES	
SRC067632	722	6/14/2018	Step 5: Design and Constructions	7/25/2018	7/31/2018	8/28/2018					9/28/2018	9/6/2018	6/3/2019	22	YES	
SRC067634	724	6/14/2018	Step 5: Design and Constructions	8/15/2018	8/23/2018	8/28/2018					9/28/2018	9/6/2018	6/3/2019	22	YES	
SRC067637	725	6/15/2018	Step 5: Design and Constructions	7/20/2018	7/31/2018	8/7/2018					9/7/2018	8/8/2018	6/3/2019	30	YES	
SRC067638	726	6/15/2018	Step 5: Design and Constructions	7/23/2018	7/26/2018	7/31/2018	8/2/2018	8/2/2018			9/2/2018	8/6/2018	6/3/2019	27	YES	
SRC067954	728	7/23/2018	Step 5: Design and Constructions	8/8/2018	8/10/2018	8/14/2018	8/23/2018				9/23/2018	8/31/2018	6/3/2019	23	YES	
SRC067963	729	7/24/2018	Step 4: Engineering Scoping Study	9/26/2018							10/27/2018	10/8/2018	6/3/2019	19	YES	
SRC068006	735	7/26/2018	Step 5: Design and Constructions	9/21/2018							10/22/2018	10/8/2018	6/3/2019	14	YES	
SRC068051	737	8/10/2018	Step 5: Design and Constructions	10/31/2018	11/27/2018	11/27/2018					12/28/2018	11/30/2018	6/3/2019	28	YES	

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SRC068220	738	8/20/2018	Step 5: Design and Constructions	10/8/2018	10/15/2018						11/15/2018	10/16/2018	6/3/2019	30	YES	
SRC068267	743	8/31/2018	Step 5: Design and Constructions	11/1/2018	11/5/2018	11/8/2018					12/9/2018	11/9/2018	6/3/2019	30	YES	
SRC068269	745	9/4/2018	Step 4: Engineering Scoping Study	10/30/2018	11/29/2018	11/30/2018					12/31/2018	12/31/2018	6/3/2019	0	YES	
SRC068270	746	9/4/2018	Step 4: Engineering Scoping Study	10/30/2018	11/29/2018	11/30/2018	1/2/2019				2/2/2019	1/2/2019	6/3/2019	31	YES	
SRC068443	749	9/13/2018	Step 5: Design and Constructions	10/30/2018							11/30/2018	11/27/2018	6/3/2019	3	YES	
SRC068444	750	9/13/2018	Step 5: Design and Constructions	10/30/2018							11/30/2018	11/5/2018	6/3/2019	25	YES	
SRC068445	751	9/13/2018	Step 5: Design and Constructions	10/30/2018	11/29/2018	11/30/2018					12/31/2018	12/31/2018	6/3/2019	0	YES	
SRC068446	752	9/13/2018	Step 5: Design and Constructions	10/29/2018							11/29/2018	11/5/2018	6/3/2019	24	YES	
SRC068447	753	9/13/2018	Step 5: Design and Constructions	10/30/2018							11/30/2018	11/27/2018	6/3/2019	3	YES	
SRC068448	754	9/13/2018	Step 5: Design and Constructions	10/30/2018	11/29/2018	11/30/2018					12/31/2018	12/31/2018	6/3/2019	0	YES	
SRC068440	757	9/13/2018	Step 5: Design and Constructions	10/30/2018	11/27/2018	11/27/2018					12/28/2018	11/30/2018	6/3/2019	28	YES	
SRC068577	759	9/20/2018	Step 5: Design and Constructions	10/11/2018	10/15/2018	10/18/2018					11/18/2018	10/19/2018	6/3/2019	30	YES	
SRC068639	760	9/21/2018	Step 5: Design and Constructions	10/15/2018	11/12/2018	11/12/2018	12/12/2018				1/12/2019	12/12/2018	6/3/2019	31	YES	
SRC068630	761	9/21/2018	Step 4: Engineering Scoping Study	12/3/2018	12/28/2018						1/28/2019	12/28/2018	6/3/2019	31	YES	
SRC068637	763	9/21/2018	Step 5: Design and Constructions	10/15/2018	10/19/2018						11/19/2018	10/29/2018	6/3/2019	21	YES	
SRC068919	766	10/2/2018	Step 4: Engineering Scoping Study	10/31/2018							12/1/2018	11/30/2018	6/3/2019	1	YES	
SRC068918	767	10/2/2018	Step 5: Design and Constructions	10/31/2018							12/1/2018	11/30/2018	6/3/2019	1	YES	
SRC068912	772	10/2/2018	Step 4: Engineering Scoping Study	11/8/2018							12/9/2018	11/30/2018	6/3/2019	9	YES	
SRC068911	773	10/2/2018	Step 5: Design and Constructions	11/6/2018							12/7/2018	11/30/2018	6/3/2019	7	YES	
SRC068910	774	10/2/2018	Step 4: Engineering Scoping Study	10/31/2018	11/30/2018	11/30/2018					12/31/2018	12/28/2018	6/3/2019	3	YES	
SRC068909	775	10/3/2018	Step 5: Design and Constructions	10/30/2018	11/27/2018	11/27/2018					12/28/2018	11/30/2018	6/3/2019	28	YES	
SRC068908	776	10/3/2018	Step 5: Design and Constructions	10/30/2018							11/30/2018	11/27/2018	6/3/2019	3	YES	
SRC068963	778	10/15/2018	Step 5: Design and Constructions	10/31/2018	11/8/2018	11/15/2018					12/16/2018	12/7/2018	6/3/2019	9	YES	
SRC068979	789	10/16/2018	Step 4: Engineering Scoping Study	11/29/2018	12/28/2018						1/28/2019	12/28/2018	6/3/2019	31	YES	
SRC068980	790	10/17/2018	Step 4: Engineering Scoping Study	11/12/2018	12/7/2018	12/19/2018					1/19/2019	12/28/2018	6/3/2019	22	YES	
SRC068981	791	10/16/2018	Step 4: Engineering Scoping Study	11/12/2018	12/7/2018	12/17/2018					1/17/2019	1/11/2019	6/3/2019	6	YES	
SRC068982	792	10/16/2018	Step 5: Design and Constructions	11/14/2018	12/7/2018	12/19/2018					1/19/2019	12/28/2018	6/3/2019	22	YES	
SRC068983	793	10/16/2018	Step 4: Engineering Scoping Study	11/12/2018	12/7/2018	12/17/2018					1/17/2019	1/11/2019	6/3/2019	6	YES	
SRC068984	794	10/16/2018	Step 4: Engineering Scoping Study	11/12/2018	12/7/2018	12/17/2018					1/17/2019	1/11/2019	6/3/2019	6	YES	
SRC068985	795	10/16/2018	Step 4: Engineering Scoping Study	11/12/2018	12/7/2018	12/17/2018					1/17/2019	1/11/2019	6/3/2019	6	YES	
SRC068986	796	10/16/2018	Step 4: Engineering Scoping Study	11/12/2018	12/7/2018	12/17/2018					1/17/2019	1/11/2019	6/3/2019	6	YES	
SRC068987	797	10/16/2018	Step 4: Engineering Scoping Study	11/12/2018	12/7/2018	1/3/2019					2/3/2019	1/11/2019	6/3/2019	23	YES	
SRC068988	798	10/18/2018	Step 5: Design and Constructions	11/1/2018	11/27/2018	11/29/2018	1/2/2019	1/3/2019			2/3/2019	1/3/2019	6/3/2019	31	YES	
SRC069414	799	10/29/2018	Step 4: Engineering Scoping Study	12/3/2018	12/28/2018	12/28/2018	1/11/2019				2/11/2019	1/11/2019	6/3/2019	31	YES	
SRC069415	800	10/29/2018	Step 4: Engineering Scoping Study	12/3/2018	12/28/2018	12/28/2018					1/28/2019	1/11/2019	6/3/2019	17	YES	
SRC069417	802	10/29/2018	Step 4: Engineering Scoping Study	12/3/2018	12/28/2018	12/28/2018					1/28/2019	1/11/2019	6/3/2019	17	YES	
SRC069419	804	10/29/2018	Step 5: Design and Constructions	11/6/2018							12/7/2018	11/30/2018	6/3/2019	7	YES	
SRC069420	805	10/29/2018	Step 4: Engineering Scoping Study	11/6/2018							12/7/2018	11/30/2018	6/3/2019	7	YES	
SRC069421	806	10/30/2018	Step 4: Engineering Scoping Study	12/3/2018	12/28/2018	12/28/2018					1/28/2019	1/11/2019	6/3/2019	17	YES	
SRC069422	807	10/30/2018	Step 4: Engineering Scoping Study	11/12/2018	12/7/2018	12/17/2018					1/17/2019	1/11/2019	6/3/2019	6	YES	
SRC069427	808	10/31/2018	Step 4: Engineering Scoping Study	12/3/2018	12/28/2018	12/28/2018					1/28/2019	1/11/2019	6/3/2019	17	YES	
SRC069433	814	10/31/2018	Step 4: Engineering Scoping Study	11/27/2018	12/28/2018	1/3/2019					2/3/2019	1/3/2019	6/3/2019	31	YES	
SRC069434	815	10/31/2018	Step 4: Engineering Scoping Study	11/27/2018	12/27/2018	1/3/2019					2/3/2019	1/3/2019	6/3/2019	31	YES	
SRC069435	816	10/31/2018	Step 4: Engineering Scoping Study	11/27/2018	12/27/2018	1/3/2019					2/3/2019	1/3/2019	6/3/2019	31	YES	
SRC069437	818	10/31/2018	Step 5: Design and Constructions	11/27/2018	12/28/2018	1/3/2019					2/3/2019	1/3/2019	6/3/2019	31	YES	
SRC069439	820	10/31/2018	Step 5: Design and Constructions	11/13/2018							12/14/2018	12/6/2018	6/3/2019	8	YES	
SRC069524	821	11/2/2018	Step 4: Engineering Scoping Study	11/14/2018	12/7/2018	12/19/2018					1/19/2019	12/28/2018	6/3/2019	22	YES	
SRC069525	822	11/2/2018	Step 4: Engineering Scoping Study	11/14/2018	12/7/2018	2/25/2019					3/28/2019	3/19/2019	6/3/2019	9	YES	
SRC069526	823	11/2/2018	Step 4: Engineering Scoping Study	11/14/2018	12/7/2018	12/17/2018					1/17/2019	1/11/2019	6/3/2019	6	YES	

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SRC069527	824	11/5/2018	Step 4: Engineering Scoping Study	11/27/2018	12/28/2018	1/3/2019					2/3/2019	1/3/2019	6/3/2019	31	YES	
SRC069528	825	11/5/2018	Step 5: Design and Constructions	11/19/2018	12/28/2018	12/18/2018		1/7/2019			2/7/2019	1/11/2019	6/3/2019	27	YES	
SRC069531	828	11/5/2018	Step 5: Design and Constructions	11/19/2018	12/17/2018	12/18/2018					1/18/2019	1/11/2019	6/3/2019	7	YES	
SRC069532	829	11/5/2018	Step 5: Design and Constructions	11/27/2018	12/28/2018	1/7/2019					2/7/2019	1/11/2019	6/3/2019	27	YES	
SRC069533	830	11/6/2018	Step 4: Engineering Scoping Study	12/3/2018	12/28/2018	12/28/2018					1/28/2019	1/11/2019	6/3/2019	17	YES	
SRC069871	832	11/9/2018	Step 5: Design and Constructions	11/19/2018	12/17/2018						1/17/2019	12/27/2018	6/3/2019	21	YES	
SRC069873	834	11/9/2018	Step 4: Engineering Scoping Study	11/19/2018	12/17/2018						1/17/2019	12/27/2018	6/3/2019	21	YES	
SRC069874	835	11/9/2018	Step 4: Engineering Scoping Study	11/19/2018	12/17/2018						1/17/2019	12/27/2018	6/3/2019	21	YES	
SRC069875	836	11/12/2018	Step 4: Engineering Scoping Study	12/10/2018							1/10/2019	12/28/2018	6/3/2019	13	YES	
SRC069876	837	11/12/2018	Step 4: Engineering Scoping Study	12/10/2018	12/31/2018	2/1/2019					3/4/2019	2/1/2019	6/3/2019	31	YES	
SRC069879	840	11/12/2018	Step 5: Design and Constructions	11/19/2018		12/3/2018					1/3/2019	1/2/2019	6/3/2019	1	YES	
SRC069880	841	11/12/2018	Step 4: Engineering Scoping Study	11/19/2018							12/20/2018	12/17/2018	6/3/2019	3	YES	
SRC069882	843	11/12/2018	Step 4: Engineering Scoping Study	11/19/2018							12/20/2018	12/17/2018	6/3/2019	3	YES	
SRC069884	845	11/12/2018	Step 4: Engineering Scoping Study	11/14/2018	12/7/2018	12/17/2018					1/17/2019	1/11/2019	6/3/2019	6	YES	
SRC069885	846	11/12/2018	Step 4: Engineering Scoping Study	11/14/2018	12/7/2018	12/17/2018					1/17/2019	1/11/2019	6/3/2019	6	YES	
SRC069887	848	11/12/2018	Step 5: Design and Constructions	11/28/2018	12/10/2018	12/17/2018					1/17/2019	1/11/2019	6/3/2019	6	YES	
SRC069888	849	11/12/2018	Step 4: Engineering Scoping Study	11/27/2018	12/10/2018	12/17/2018					1/17/2019	1/11/2019	6/3/2019	6	YES	
SRC069889	850	11/12/2018	Step 4: Engineering Scoping Study	11/14/2018	12/7/2018	12/17/2018					1/17/2019	1/11/2019	6/3/2019	6	YES	
SRC069890	851	11/12/2018	Step 4: Engineering Scoping Study	11/19/2018	12/17/2018						1/17/2019	12/27/2018	6/3/2019	21	YES	
SRC069891	852	11/12/2018	Step 5: Design and Constructions	11/19/2018	12/17/2018						1/17/2019	12/27/2018	6/3/2019	21	YES	
SRC069893	854	11/12/2018	Step 4: Engineering Scoping Study	11/27/2018							12/28/2018	12/17/2018	6/3/2019	11	YES	
SRC069894	855	11/12/2018	Step 4: Engineering Scoping Study	11/19/2018							12/20/2018	12/17/2018	6/3/2019	3	YES	
SRC069976	857	11/13/2018	Step 4: Engineering Scoping Study	11/27/2018	12/28/2018	1/7/2019					2/7/2019	1/11/2019	6/3/2019	27	YES	
SRC069977	858	11/14/2018	Step 5: Design and Constructions	11/27/2018	12/28/2018	1/7/2019					2/7/2019	1/11/2019	6/3/2019	27	YES	
SRC069978	859	11/13/2018	Step 4: Engineering Scoping Study	12/19/2018		1/3/2019					2/3/2019	1/11/2019	6/3/2019	23	YES	
SRC069983	864	11/16/2018	Step 4: Engineering Scoping Study	2/7/2019	3/11/2019	3/13/2019					4/13/2019	3/15/2019	6/3/2019	29	YES	
SRC069986	865	11/19/2018	Step 5: Design and Constructions	11/27/2018							12/28/2018	12/27/2018	6/3/2019	1	YES	
SRC069989	866	11/19/2018	Step 4: Engineering Scoping Study	11/28/2018	12/27/2018	1/18/2019	1/31/2019	2/1/2019			3/4/2019	2/1/2019	6/3/2019	31	YES	
SRC070201	867	11/20/2018	Step 4: Engineering Scoping Study	12/28/2018	1/11/2019	1/3/2019	1/18/2019	1/15/2019	1/24/2019	2/1/2019	3/4/2019	2/1/2019	6/3/2019	31	YES	
SRC070202	868	11/20/2018	Step 4: Engineering Scoping Study	12/28/2018	1/11/2019	1/3/2019					2/11/2019	1/15/2019	6/3/2019	27	YES	
SRC071533		2/1/2019	Step 4: Engineering Scoping Study	2/8/2019							3/11/2019	2/20/2019	6/3/2019	19	YES	
SRC071532		2/1/2019	Step 4: Engineering Scoping Study	2/8/2019							3/11/2019	2/18/2019	6/3/2019	21	YES	
SRC071534		2/1/2019	Step 4: Engineering Scoping Study	2/8/2019							3/11/2019	2/18/2019	6/3/2019	21	YES	
SRC072628		3/25/2019	Step 4: Engineering Scoping Study	4/11/2019							5/12/2019	4/16/2019	6/3/2019	26	YES	
SRC072630		3/25/2019	Step 4: Engineering Scoping Study	4/11/2019							5/12/2019	4/17/2019	6/3/2019	25	YES	
SRC072629		3/25/2019	Step 4: Engineering Scoping Study	4/11/2019							5/12/2019	4/17/2019	6/3/2019	25	YES	
SRC072631		3/25/2019	Step 4: Engineering Scoping Study	4/11/2019							5/12/2019	4/19/2019	6/3/2019	23	YES	
SRC071171		1/18/2019	Step 4: Engineering Scoping Study	2/15/2019	3/12/2019	3/13/2019					4/13/2019	3/15/2019	6/3/2019	29	YES	
SRC071175		1/18/2019	Step 4: Engineering Scoping Study	2/15/2019	3/12/2019	3/13/2019					4/13/2019	3/15/2019	6/3/2019	29	YES	
SRC071174		1/18/2019	Step 4: Engineering Scoping Study	2/1/2019							3/4/2019	2/28/2019	6/3/2019	4	YES	
SRC071173		1/18/2019	Step 4: Engineering Scoping Study	2/1/2019							3/4/2019	2/28/2019	6/3/2019	4	YES	
SRC072232		3/7/2019	Step 3: Initial Review	5/28/2019	6/3/2019						7/4/2019		6/3/2019	31	YES	
SRC071722		2/20/2019	Step 4: Engineering Scoping Study	3/21/2019							4/21/2019	3/26/2019	6/3/2019	26	YES	

Solar Garden: Solar Garden ID	Site ID	Submission	Status	Sent to Engineering Review - Clock Start One	Comments Sent 1	Clock Restart 1	Comments Sent 2	Clock Restart 2	Comments Sent 3	Clock Restart 3	End of 30 day review clock	Applications Considered Complete	Data Pulled	Time lapse between requirement and date sent	Section 9 Requirement Met	Additional Information
SRC072910		4/3/2019	Step 3: Initial Review	5/16/2019							6/16/2019		6/3/2019	13	YES	
SRC072911		4/3/2019	Step 3: Initial Review	5/16/2019							6/16/2019		6/3/2019	13	YES	
SRC071262		1/24/2019	Step 4: Engineering Scoping Study	2/18/2019							3/21/2019	3/20/2019	6/3/2019	1	YES	
SRC071263		1/24/2019	Step 4: Engineering Scoping Study	2/8/2019							3/11/2019	3/11/2019	6/3/2019	0	YES	
SRC071126		1/7/2019	Step 4: Engineering Scoping Study	2/1/2019							3/4/2019	2/28/2019	6/3/2019	4	YES	
SRC071404		1/25/2019	Step 4: Engineering Scoping Study	2/15/2019	3/14/2019	3/14/2019					4/14/2019	3/18/2019	6/3/2019	27	YES	
SRC071405		1/25/2019	Step 4: Engineering Scoping Study	2/27/2019	3/25/2019	4/3/2019					5/4/2019	4/4/2019	6/3/2019	30	YES	
SRC071809		2/26/2019	Step 4: Engineering Scoping Study	3/18/2019	3/25/2019	3/26/2019					4/26/2019	3/26/2019	6/3/2019	31	YES	
SRC071808		2/26/2019	Step 4: Engineering Scoping Study	3/18/2019	3/22/2019						4/22/2019	3/26/2019	6/3/2019	27	YES	
SRC070623		12/4/2018	Step 4: Engineering Scoping Study	2/5/2019							3/8/2019	3/5/2019	6/3/2019	3	YES	
SRC072569		3/21/2019	Step 4: Engineering Scoping Study	4/19/2019							5/20/2019	4/25/2019	6/3/2019	25	YES	
SRC072581		3/21/2019	Step 3: Initial Review	5/7/2019	5/14/2019	5/28/2019	5/30/2019				6/30/2019		6/3/2019	27	YES	
SRC072576		3/21/2019	Step 4: Engineering Scoping Study	5/7/2019	5/14/2019	5/21/2019					6/21/2019	5/23/2019	6/3/2019	29	YES	
SRC072570		3/21/2019	Step 4: Engineering Scoping Study	4/19/2019							5/20/2019	4/26/2019	6/3/2019	24	YES	
SRC071535		2/4/2019	Step 4: Engineering Scoping Study	2/8/2019							3/11/2019	2/18/2019	6/3/2019	21	YES	
SRC072814		4/1/2019	Step 4: Engineering Scoping Study	5/7/2019	5/14/2019	5/28/2019					6/28/2019	6/3/2019	6/3/2019	25	YES	
SRC072813		4/1/2019	Step 4: Engineering Scoping Study	5/7/2019	5/14/2019	5/28/2019					6/28/2019	6/3/2019	6/3/2019	25	YES	
SRC072585		3/21/2019	Step 4: Engineering Scoping Study	5/7/2019	5/14/2019	5/28/2019					6/28/2019	6/3/2019	6/3/2019	25	YES	
SRC072571		3/21/2019	Step 4: Engineering Scoping Study	4/19/2019							5/20/2019	4/26/2019	6/3/2019	24	YES	
SRC072574		3/21/2019	Step 4: Engineering Scoping Study	5/7/2019	5/14/2019	5/28/2019					6/28/2019	5/30/2019	6/3/2019	29	YES	
SRC072573		3/21/2019	Step 4: Engineering Scoping Study	5/7/2019	5/14/2019	5/21/2019					6/21/2019	5/23/2019	6/3/2019	29	YES	
SRC072580		3/21/2019	Step 4: Engineering Scoping Study	5/7/2019	5/14/2019	5/28/2019					6/28/2019	5/30/2019	6/3/2019	29	YES	
SRC072577		3/21/2019	Step 4: Engineering Scoping Study	5/7/2019	5/14/2019	5/21/2019					6/21/2019	5/23/2019	6/3/2019	29	YES	
SRC072579		3/21/2019	Step 3: Initial Review	5/7/2019	5/14/2019	5/28/2019	5/30/2019				6/30/2019		6/3/2019	27	YES	
SRC072578		3/21/2019	Step 4: Engineering Scoping Study	5/7/2019	5/14/2019	5/21/2019					6/21/2019	5/23/2019	6/3/2019	29	YES	
SRC072584		3/21/2019	Step 4: Engineering Scoping Study	5/7/2019	5/14/2019	5/28/2019					6/28/2019	5/30/2019	6/3/2019	29	YES	
SRC072583		3/21/2019	Step 4: Engineering Scoping Study	5/7/2019	5/14/2019	5/28/2019					6/28/2019	5/30/2019	6/3/2019	29	YES	
SRC072582		3/21/2019	Step 4: Engineering Scoping Study	5/7/2019	5/14/2019	5/28/2019					6/28/2019	5/30/2019	6/3/2019	29	YES	
SRC072572		3/22/2019	Step 4: Engineering Scoping Study	4/23/2019							5/24/2019	5/3/2019	6/3/2019	21	YES	
SRC070933		12/11/2018	Step 4: Engineering Scoping Study	1/14/2019							2/14/2019	1/18/2019	6/3/2019	27	YES	
SRC071104		12/21/2018	Step 4: Engineering Scoping Study	1/29/2019	2/1/2019	2/4/2019					3/7/2019	3/5/2019	6/3/2019	2	YES	
SRC072361		3/13/2019	Step 3: Initial Review	5/16/2019							6/16/2019		6/3/2019	13	YES	
SRC072362		3/13/2019	Step 3: Initial Review	5/16/2019							6/16/2019		6/3/2019	13	YES	
SRC072359		3/13/2019	Step 3: Initial Review	5/16/2019							6/16/2019		6/3/2019	13	YES	
SRC072360		3/13/2019	Step 3: Initial Review	5/16/2019							6/16/2019		6/3/2019	13	YES	
SRC070580		12/3/2018	Step 4: Engineering Scoping Study	1/14/2019	1/18/2019	1/21/2019	1/24/2019	1/24/2019	1/29/2019	2/1/2019	3/4/2019	2/1/2019	6/3/2019	31	YES	

Solar Garden: Solar Garden ID	Site ID	Status	Application Considered Complete	15 Business Days from Considered Complete Stage	10 Business Days from Considered Complete Stage (After 9/4/15)	SOW for Study Sent to Developer	Data Pulled	Use 15 day Requirement	15 Day Requirement Met	Use 10 day Requirement	10 Day Requirement Met	SOW Requirement Met	Time lapse between requirement and date sent	Additional Information
SRC040942	15	Step 6: Documents & Contract Submission	11/24/2015		12/17/2015	12/15/2015	6/3/2019	NO		YES	YES	YES	N/A	
SRC040943	15	Step 6: Documents & Contract Submission	11/24/2015		12/17/2015	12/15/2015	6/3/2019	NO		YES	YES	YES	N/A	
SRC040944	15	Step 6: Documents & Contract Submission	11/24/2015		12/17/2015	12/15/2015	6/3/2019	NO		YES	YES	YES	N/A	
SRC040945	15	Step 6: Documents & Contract Submission	11/24/2015		12/17/2015	12/15/2015	6/3/2019	NO		YES	YES	YES	N/A	
SRC040946	15	Step 6: Documents & Contract Submission	11/24/2015		12/17/2015	12/15/2015	6/3/2019	NO		YES	YES	YES	N/A	
SRC041165	16	Step 6: Documents & Contract Submission	11/24/2015		12/17/2015	12/15/2015	6/3/2019	NO		YES	YES	YES	N/A	
SRC041166	16	Step 6: Documents & Contract Submission	11/24/2015		12/17/2015	12/15/2015	6/3/2019	NO		YES	YES	YES	N/A	
SRC041167	16	Step 6: Documents & Contract Submission	11/24/2015		12/17/2015	12/15/2015	6/3/2019	NO		YES	YES	YES	N/A	
SRC041168	16	Step 6: Documents & Contract Submission	11/24/2015		12/17/2015	12/15/2015	6/3/2019	NO		YES	YES	YES	N/A	
SRC041169	16	Step 6: Documents & Contract Submission	11/24/2015		12/17/2015	12/15/2015	6/3/2019	NO		YES	YES	YES	N/A	
SRC040603	43	Step 5: Design and Constructions	12/1/2015		12/23/2015	12/22/2015	6/3/2019	NO		YES	YES	YES	N/A	
SRC040606	43	Step 5: Design and Constructions	12/1/2015		12/23/2015	12/22/2015	6/3/2019	NO		YES	YES	YES	N/A	
SRC040608	43	Step 5: Design and Constructions	12/1/2015		12/23/2015	12/22/2015	6/3/2019	NO		YES	YES	YES	N/A	
SRC040610	43	Step 5: Design and Constructions	12/1/2015		12/23/2015	12/22/2015	6/3/2019	NO		YES	YES	YES	N/A	
SRC040613	43	Step 5: Design and Constructions	12/1/2015		12/23/2015	12/22/2015	6/3/2019	NO		YES	YES	YES	N/A	
SRC039909	64	Step 4: Engineering Scoping Study	8/27/2015	9/21/2015		9/18/2015	6/3/2019	YES	YES	NO		YES	N/A	
SRC039910	64	Step 4: Engineering Scoping Study	8/27/2015	9/21/2015		9/18/2015	6/3/2019	YES	YES	NO		YES	N/A	
SRC039911	64	Step 4: Engineering Scoping Study	8/27/2015	9/21/2015		9/18/2015	6/3/2019	YES	YES	NO		YES	N/A	
SRC039624	108	Step 5: Design and Constructions	9/4/2016		9/26/2016	9/25/2015	6/3/2019	NO		YES	YES	YES	N/A	
SRC039756	108	Step 5: Design and Constructions	9/4/2016		9/26/2016	9/25/2015	6/3/2019	NO		YES	YES	YES	N/A	
SRC039757	108	Step 5: Design and Constructions	9/4/2016		9/26/2016	9/25/2015	6/3/2019	NO		YES	YES	YES	N/A	
SRC039758	108	Step 5: Design and Constructions	9/4/2016		9/26/2016	9/25/2015	6/3/2019	NO		YES	YES	YES	N/A	
SRC040034	118	Step 5: Design and Constructions	9/4/2015	9/28/2015		9/18/2015	6/3/2019	YES	YES	NO		YES	N/A	
SRC040035	118	Step 5: Design and Constructions	9/4/2015	9/28/2015		9/18/2015	6/3/2019	YES	YES	NO		YES	N/A	
SRC040036	118	Step 5: Design and Constructions	9/4/2015	9/28/2015		9/18/2015	6/3/2019	YES	YES	NO		YES	N/A	
SRC040037	118	Step 5: Design and Constructions	9/4/2015	9/28/2015		9/18/2015	6/3/2019	YES	YES	NO		YES	N/A	
SRC040038	118	Step 5: Design and Constructions	9/4/2015	9/28/2015		9/18/2015	6/3/2019	YES	YES	NO		YES	N/A	
SRC041077	153	Step 5: Design and Constructions	3/24/2017		4/14/2017	3/24/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC041078	153	Step 5: Design and Constructions	3/24/2017		4/14/2017	3/24/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC041079	153	Step 5: Design and Constructions	3/24/2017		4/14/2017	3/24/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC041080	153	Step 5: Design and Constructions	3/24/2017		4/14/2017	3/24/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC040823	154	Step 5: Design and Constructions	3/22/2017		4/13/2017	3/23/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC040824	154	Step 5: Design and Constructions	3/22/2017		4/13/2017	3/23/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC041082	157	Step 5: Design and Constructions	3/24/2017		4/14/2017	3/27/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC041083	157	Step 5: Design and Constructions	3/24/2017		4/14/2017	3/27/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC041084	157	Step 5: Design and Constructions	3/24/2017		4/14/2017	3/27/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC041085	157	Step 5: Design and Constructions	3/24/2017		4/14/2017	3/27/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC040316	158	Step 5: Design and Constructions	4/4/2017		4/26/2017	4/11/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC040353	158	Step 5: Design and Constructions	4/4/2017		4/26/2017	4/11/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC040813	158	Step 5: Design and Constructions	4/4/2017		4/26/2017	4/11/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC040814	158	Step 5: Design and Constructions	4/4/2017		4/26/2017	4/11/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC041087	158	Step 5: Design and Constructions	4/4/2017		4/26/2017	4/11/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC040897	166	Step 6: Documents & Contract Submission	1/7/2016		2/1/2016	1/14/2016	6/3/2019	NO		YES	YES	YES	N/A	
SRC040898	166	Step 6: Documents & Contract Submission	1/7/2016		2/1/2016	1/14/2016	6/3/2019	NO		YES	YES	YES	N/A	
SRC040899	166	Step 6: Documents & Contract Submission	1/7/2016		2/1/2016	1/14/2016	6/3/2019	NO		YES	YES	YES	N/A	
SRC040900	166	Step 6: Documents & Contract Submission	1/7/2016		2/1/2016	1/14/2016	6/3/2019	NO		YES	YES	YES	N/A	
SRC040901	166	Step 6: Documents & Contract Submission	1/7/2016		2/1/2016	1/14/2016	6/3/2019	NO		YES	YES	YES	N/A	
SRC040667	222	Step 5: Design and Constructions	12/1/2015		12/23/2015	12/22/2015	6/3/2019	NO		YES	YES	YES	N/A	
SRC040668	222	Step 5: Design and Constructions	12/1/2015		12/23/2015	12/22/2015	6/3/2019	NO		YES	YES	YES	N/A	
SRC040669	222	Step 5: Design and Constructions	12/1/2015		12/23/2015	12/22/2015	6/3/2019	NO		YES	YES	YES	N/A	
SRC042652	235	Step 5: Design and Constructions	2/9/2017		3/6/2017	2/21/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC042655	235	Step 5: Design and Constructions	2/9/2017		3/6/2017	2/21/2017	6/3/2019	NO		YES	YES	YES	N/A	

Solar Garden: Solar Garden ID	Site ID	Status	Application Considered Complete	15 Business Days from Considered Complete Stage	10 Business Days from Considered Complete Stage (After 9/4/15)	SOW for Study Sent to Developer	Data Pulled	Use 15 day Requirement	15 Day Requirement Met	Use 10 day Requirement	10 Day Requirement Met	SOW Requirement Met	Time lapse between requirement and date sent	Additional Information
SRC042659	235	Step 5: Design and Constructions	2/9/2017		3/6/2017	2/21/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC042662	235	Step 5: Design and Constructions	2/9/2017		3/6/2017	2/21/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC042667	235	Step 5: Design and Constructions	2/9/2017		3/6/2017	2/21/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC042333	251	Step 5: Design and Constructions	12/21/2015		1/14/2016	12/30/2015	6/3/2019	NO		YES	YES	YES	N/A	
SRC042400	255	Step 5: Design and Constructions	12/21/2015		1/14/2016	12/29/2015	6/3/2019	NO		YES	YES	YES	N/A	
SRC042439	258	Step 6: Documents & Contract Submission	3/8/2017		3/30/2017	3/10/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC042464	258	Step 6: Documents & Contract Submission	3/8/2017		3/30/2017	3/10/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC042465	258	Step 6: Documents & Contract Submission	3/8/2017		3/30/2017	3/10/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC042467	258	Step 6: Documents & Contract Submission	3/8/2017		3/30/2017	3/10/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC042722	284	Step 5: Design and Constructions	4/10/2017		5/2/2017	4/19/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC042725	284	Step 5: Design and Constructions	4/10/2017		5/2/2017	4/19/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC042727	284	Step 5: Design and Constructions	4/10/2017		5/2/2017	4/19/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC042628	349	Step 6: Documents & Contract Submission	11/28/2016		12/20/2016	12/6/2016	6/3/2019	NO		YES	YES	YES	N/A	
SRC042632	349	Step 6: Documents & Contract Submission	11/28/2016		12/20/2016	12/6/2016	6/3/2019	NO		YES	YES	YES	N/A	
SRC042675	349	Step 6: Documents & Contract Submission	11/28/2016		12/20/2016	12/6/2016	6/3/2019	NO		YES	YES	YES	N/A	
SRC042677	349	Step 6: Documents & Contract Submission	11/28/2016		12/20/2016	12/6/2016	6/3/2019	NO		YES	YES	YES	N/A	
SRC042680	349	Step 6: Documents & Contract Submission	11/28/2016		12/20/2016	12/6/2016	6/3/2019	NO		YES	YES	YES	N/A	
SRC049572	442	Step 5: Design and Constructions	1/13/2017		2/6/2017	1/31/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC049639	467	Step 5: Design and Constructions	4/13/2017		5/5/2017	4/27/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC049640	468	Step 5: Design and Constructions	12/2/2016		12/23/2016	12/22/2016	6/3/2019	NO		YES	YES	YES	N/A	
SRC051585	493	Step 5: Design and Constructions	4/7/2017		4/28/2017	4/17/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC051587	495	Step 5: Design and Constructions	4/7/2017		4/28/2017	4/13/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC051589	497	Step 5: Design and Constructions	4/7/2017		4/28/2017	4/12/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC051594	502	Step 5: Design and Constructions	4/7/2017		4/28/2017	4/12/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC052244	516	Step 5: Design and Constructions	3/23/2017		4/14/2017	3/23/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC052806	518	Step 5: Design and Constructions	4/13/2017		5/5/2017	4/27/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC052809	523	Step 5: Design and Constructions	3/17/2017		4/7/2017	3/23/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC052763	527	Step 5: Design and Constructions	4/7/2017		4/28/2017	4/13/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC052762	529	Step 5: Design and Constructions	4/7/2017		4/28/2017	4/13/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC052305	530	Step 5: Design and Constructions	2/3/2017		2/27/2017	2/15/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC052799	535	Step 6: Documents & Contract Submission	4/7/2017		4/28/2017	9/9/1999	6/3/2019	NO		YES	YES	YES	N/A	
SRC052795	537	Step 5: Design and Constructions	4/10/2017		5/2/2017	4/19/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC052784	538	Step 5: Design and Constructions	4/13/2017		5/5/2017	4/27/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC052769	542	Step 4: Engineering Scoping Study	4/7/2017		4/28/2017	10/17/2017	6/3/2019	NO		YES	NO	NO	(123)	Application restudied after relocation
SRC052770	543	Step 5: Design and Constructions	4/7/2017		4/28/2017	4/18/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC052797	550	Step 5: Design and Constructions	4/10/2017		5/2/2017	4/19/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC052754	552	Step 5: Design and Constructions	4/7/2017		4/28/2017	4/13/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC052737	553	Step 5: Design and Constructions	4/13/2017		5/5/2017	4/27/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC052765	554	Step 5: Design and Constructions	6/20/2017		7/13/2017	7/5/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC052804	556	Step 5: Design and Constructions	4/13/2017		5/5/2017	4/27/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC052781	561	Step 5: Design and Constructions	4/7/2017		4/28/2017	4/13/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC052761	562	Step 5: Design and Constructions	4/7/2017		4/28/2017	10/17/2017	6/3/2019	NO		YES	NO	NO	(123)	Application restudied after relocation
SRC052798	565	Step 5: Design and Constructions	3/23/2017		4/14/2017	3/23/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC052738	569	Step 5: Design and Constructions	4/13/2017		5/5/2017	4/27/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC052434	578	Step 5: Design and Constructions	4/7/2017		4/28/2017	4/17/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC052694	580	Step 4: Engineering Scoping Study	3/23/2017		4/14/2017	3/27/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC052716	582	Step 5: Design and Constructions	3/31/2017		4/21/2017	4/10/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC052743	584	Step 5: Design and Constructions	4/13/2017		5/5/2017	4/27/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC052796	594	Step 5: Design and Constructions	4/10/2017		5/2/2017	4/19/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC052739	603	Step 5: Design and Constructions	4/13/2017		5/5/2017	4/28/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC052740	604	Step 5: Design and Constructions	4/13/2017		5/5/2017	4/28/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC052803	605	Step 5: Design and Constructions	4/13/2017		5/5/2017	4/27/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC052759	608	Step 5: Design and Constructions	4/7/2017		4/28/2017	4/13/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC052717	612	Step 5: Design and Constructions	3/31/2017		4/21/2017	4/10/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC052825	613	Step 5: Design and Constructions	4/10/2017		5/2/2017	4/19/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC052722	614	Step 5: Design and Constructions	3/31/2017		4/21/2017	4/10/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC052828	615	Step 5: Design and Constructions	4/10/2017		5/2/2017	4/19/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC052715	616	Step 5: Design and Constructions	3/31/2017		4/21/2017	4/10/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC052824	617	Step 5: Design and Constructions	4/10/2017		5/2/2017	4/19/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC052728	618	Step 5: Design and Constructions	3/31/2017		4/21/2017	4/10/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC052733	620	Step 5: Design and Constructions	3/31/2017		4/21/2017	4/10/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC052838	621	Step 5: Design and Constructions	4/10/2017		5/2/2017	4/19/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC052718	622	Step 5: Design and Constructions	3/31/2017		4/21/2017	4/10/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC052732	624	Step 5: Design and Constructions	3/31/2017		4/21/2017	4/10/2017	6/3/2019	NO		YES	YES	YES	N/A	

Solar Garden: Solar Garden ID	Site ID	Status	Application Considered Complete	15 Business Days from Considered Complete Stage	10 Business Days from Considered Complete Stage (After 9/4/15)	SOW for Study Sent to Developer	Data Pulled	Use 15 day Requirement	15 Day Requirement Met	Use 10 day Requirement	10 Day Requirement Met	SOW Requirement Met	Time lapse between requirement and date sent	Additional Information
SRC052837	625	Step 5: Design and Constructions	4/10/2017		5/2/2017	4/19/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC052719	626	Step 5: Design and Constructions	3/31/2017		4/21/2017	4/10/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC052827	627	Step 5: Design and Constructions	4/10/2017		5/2/2017	4/19/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC052726	628	Step 5: Design and Constructions	3/31/2017		4/21/2017	4/10/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC052839	629	Step 5: Design and Constructions	4/10/2017		5/2/2017	4/19/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC052834	634	Step 5: Design and Constructions	4/10/2017		5/2/2017	4/19/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC052727	635	Step 5: Design and Constructions	3/31/2017		4/21/2017	4/10/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC052813	638	Step 5: Design and Constructions	3/31/2017		4/21/2017	4/10/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC052814	639	Step 5: Design and Constructions	4/10/2017		5/2/2017	4/19/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC052721	640	Step 5: Design and Constructions	3/31/2017		4/21/2017	4/10/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC052832	641	Step 5: Design and Constructions	4/10/2017		5/2/2017	4/19/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC052725	642	Step 5: Design and Constructions	3/31/2017		4/21/2017	4/10/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC052831	643	Step 5: Design and Constructions	4/10/2017		5/2/2017	4/19/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC052724	644	Step 5: Design and Constructions	3/31/2017		4/21/2017	4/10/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC052830	645	Step 5: Design and Constructions	4/10/2017		5/2/2017	4/19/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC052723	646	Step 5: Design and Constructions	3/31/2017		4/21/2017	4/10/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC052829	647	Step 5: Design and Constructions	4/10/2017		5/2/2017	4/19/2017	6/3/2019	NO		YES	YES	YES	N/A	
SRC042081	648	Step 5: Design and Constructions	4/21/2016		5/13/2016	7/31/2018	6/3/2019	NO		YES	NO	NO	(578)	Project resubmitted at new location after initial site was cancelled- Deemed Complete and Expedited Ready dates maintained based on agreement with developer.
SRC042083	648	Step 5: Design and Constructions	4/21/2016		5/13/2016	7/31/2018	6/3/2019	NO		YES	NO	NO	(578)	Project resubmitted at new location after initial site was cancelled- Deemed Complete and Expedited Ready dates maintained based on agreement with developer.
SRC071169	648	Step 5: Design and Constructions	4/21/2016		5/13/2016	7/31/2018	6/3/2019	NO		YES	NO	NO	(578)	Project resubmitted at new location after initial site was cancelled- Deemed Complete and Expedited Ready dates maintained based on agreement with developer.
SRC061101	651	Step 4: Engineering Scoping Study	4/1/2019		4/23/2019	4/10/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC062754	652	Step 5: Design and Constructions	1/11/2018		2/5/2018	1/16/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC062797	653	Step 5: Design and Constructions	1/11/2018		2/5/2018	1/16/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC062798	654	Step 5: Design and Constructions	1/11/2018		2/5/2018	1/16/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC062799	655	Step 5: Design and Constructions	1/11/2018		2/5/2018	1/16/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC062800	656	Step 5: Design and Constructions	1/11/2018		2/5/2018	1/16/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC062801	657	Step 5: Design and Constructions	1/11/2018		2/5/2018	1/16/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC062802	658	Step 5: Design and Constructions	1/11/2018		2/5/2018	1/16/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC062803	659	Step 5: Design and Constructions	1/11/2018		2/5/2018	1/16/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC062804	660	Step 5: Design and Constructions	1/11/2018		2/5/2018	1/16/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC062805	661	Step 5: Design and Constructions	1/11/2018		2/5/2018	1/16/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC062807	662	Step 5: Design and Constructions	1/11/2018		2/5/2018	1/16/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC062809	663	Step 5: Design and Constructions	1/11/2018		2/5/2018	1/16/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC062810	664	Step 5: Design and Constructions	4/9/2018		5/1/2018	4/10/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC062811	665	Step 5: Design and Constructions	1/11/2018		2/5/2018	1/16/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC062812	666	Step 5: Design and Constructions	1/11/2018		2/5/2018	1/16/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC062814	668	Step 5: Design and Constructions	1/11/2018		2/5/2018	1/16/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC062815	669	Step 5: Design and Constructions	1/11/2018		2/5/2018	1/16/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC062816	670	Step 5: Design and Constructions	1/11/2018		2/5/2018	1/16/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC062817	671	Step 5: Design and Constructions	1/11/2018		2/5/2018	1/16/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC062818	672	Step 5: Design and Constructions	1/11/2018		2/5/2018	1/16/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC062819	673	Step 5: Design and Constructions	1/11/2018		2/5/2018	1/16/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC062820	674	Step 5: Design and Constructions	1/11/2018		2/5/2018	1/16/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC062821	675	Step 4: Engineering Scoping Study	1/11/2018		2/5/2018	1/16/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC062822	676	Step 5: Design and Constructions	1/22/2018		2/13/2018	1/22/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC062823	677	Step 5: Design and Constructions	1/11/2018		2/5/2018	1/16/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC063633	680	Step 5: Design and Constructions	2/23/2018		3/16/2018	2/27/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC063634	681	Step 5: Design and Constructions	2/23/2018		3/16/2018	2/27/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC063636	683	Step 5: Design and Constructions	4/2/2018		4/24/2018	4/17/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC063637	684	Step 5: Design and Constructions	4/2/2018		4/24/2018	4/17/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC063638	685	Step 5: Design and Constructions	4/2/2018		4/24/2018	4/17/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC063639	686	Step 5: Design and Constructions	2/23/2018		3/16/2018	2/27/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC063642	687	Step 5: Design and Constructions	2/23/2018		3/16/2018	2/27/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC063645	688	Step 5: Design and Constructions	3/2/2018		3/23/2018	3/2/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC063646	689	Step 5: Design and Constructions	2/23/2018		3/16/2018	2/27/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC063647	690	Step 5: Design and Constructions	4/2/2018		4/24/2018	4/17/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC064070	691	Step 5: Design and Constructions	4/2/2018		4/24/2018	4/17/2018	6/3/2019	NO		YES	YES	YES	N/A	

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SRC064072	693	Step 5: Design and Constructions	4/9/2018		5/1/2018	4/10/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC064073	694	Step 5: Design and Constructions	5/30/2018		6/21/2018	5/30/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC064075	696	Step 5: Design and Constructions	4/9/2018		5/1/2018	4/10/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC064254	697	Step 5: Design and Constructions	1/25/2018		2/16/2018	1/25/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC064853	699	Step 5: Design and Constructions	4/9/2018		5/1/2018	4/10/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC065488	701	Step 5: Design and Constructions	4/16/2018		5/8/2018	5/1/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC065658	703	Step 5: Design and Constructions	6/14/2018		7/9/2018	6/25/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC065957	707	Step 5: Design and Constructions	6/14/2018		7/9/2018	6/25/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC065961	710	Step 5: Design and Constructions	6/14/2018		7/9/2018	6/25/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC065964	711	Step 5: Design and Constructions	6/15/2018		7/9/2018	6/18/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC066766	713	Step 5: Design and Constructions	7/11/2018		8/2/2018	7/16/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC067199	714	Step 5: Design and Constructions	7/10/2018		8/1/2018	7/16/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC067624	715	Step 4: Engineering Scoping Study	10/31/2018		11/22/2018	11/5/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC067625	716	Step 5: Design and Constructions	8/23/2018		9/17/2018	8/28/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC067629	719	Step 5: Design and Constructions	10/8/2018		10/30/2018	10/12/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC067630	720	Step 5: Design and Constructions	7/24/2018		8/15/2018	7/25/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC067631	721	Step 5: Design and Constructions	7/24/2018		8/15/2018	7/25/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC067632	722	Step 5: Design and Constructions	9/6/2018		9/28/2018	9/7/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC067634	724	Step 5: Design and Constructions	9/6/2018		9/28/2018	9/7/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC067637	725	Step 5: Design and Constructions	8/8/2018		8/30/2018	8/10/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC067638	726	Step 5: Design and Constructions	8/6/2018		8/28/2018	8/6/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC067954	728	Step 5: Design and Constructions	8/31/2018		9/24/2018	10/5/2018	6/3/2019	NO		YES	NO	NO	(10)	PMO delay
SRC067963	729	Step 4: Engineering Scoping Study	10/8/2018		10/30/2018	10/12/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC067962	730	Step 5: Design and Constructions	10/31/2018		11/22/2018	11/5/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC067961	731	Step 4: Engineering Scoping Study	1/2/2019		1/24/2019	1/3/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC067960	732	Step 4: Engineering Scoping Study	10/31/2018		11/22/2018	11/1/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC067959	733	Step 4: Engineering Scoping Study	10/31/2018		11/22/2018	11/1/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC067955	734	Step 5: Design and Constructions	10/31/2018		11/22/2018	11/1/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC068006	735	Step 5: Design and Constructions	10/8/2018		10/30/2018	10/26/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC068051	737	Step 5: Design and Constructions	11/30/2018		12/21/2018	12/3/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC068220	738	Step 5: Design and Constructions	10/16/2018		11/7/2018	10/19/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC068265	741	Step 5: Design and Constructions	11/19/2018		12/12/2018	11/27/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC068266	742	Step 5: Design and Constructions	11/19/2018		12/12/2018	11/27/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC068267	743	Step 5: Design and Constructions	11/9/2018		12/3/2018	11/19/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC068269	745	Step 4: Engineering Scoping Study	12/31/2018		1/22/2019	1/3/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC068270	746	Step 4: Engineering Scoping Study	1/2/2019		1/24/2019	1/3/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC068443	749	Step 5: Design and Constructions	11/27/2018		12/19/2018	11/30/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC068444	750	Step 5: Design and Constructions	11/5/2018		11/28/2018	11/19/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC068445	751	Step 5: Design and Constructions	12/31/2018		1/22/2019	1/3/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC068446	752	Step 5: Design and Constructions	11/5/2018		11/28/2018	11/9/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC068447	753	Step 5: Design and Constructions	11/27/2018		12/19/2018	11/30/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC068448	754	Step 5: Design and Constructions	12/31/2018		1/22/2019	1/3/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC068440	757	Step 5: Design and Constructions	11/30/2018		12/21/2018	12/3/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC068577	759	Step 5: Design and Constructions	10/19/2018		11/9/2018	10/26/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC068639	760	Step 5: Design and Constructions	12/12/2018		1/4/2019	12/12/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC068630	761	Step 4: Engineering Scoping Study	12/28/2018		1/18/2019	1/2/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC068637	763	Step 5: Design and Constructions	10/29/2018		11/20/2018	11/5/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC068919	766	Step 4: Engineering Scoping Study	11/30/2018		12/21/2018	12/3/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC068918	767	Step 5: Design and Constructions	11/30/2018		12/21/2018	12/3/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC068912	772	Step 4: Engineering Scoping Study	11/30/2018		12/21/2018	12/3/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC068911	773	Step 5: Design and Constructions	11/30/2018		12/21/2018	12/3/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC068910	774	Step 4: Engineering Scoping Study	12/28/2018		1/18/2019	1/2/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC068909	775	Step 5: Design and Constructions	11/30/2018		12/21/2018	12/3/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC068908	776	Step 5: Design and Constructions	11/27/2018		12/19/2018	11/30/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC068963	778	Step 5: Design and Constructions	12/7/2018		12/31/2018	12/13/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC068979	789	Step 4: Engineering Scoping Study	12/28/2018		1/18/2019	1/2/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC068980	790	Step 4: Engineering Scoping Study	12/28/2018		1/18/2019	1/2/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC068981	791	Step 4: Engineering Scoping Study	1/11/2019		2/1/2019	1/17/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC068982	792	Step 5: Design and Constructions	12/28/2018		1/18/2019	1/2/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC068983	793	Step 4: Engineering Scoping Study	1/11/2019		2/1/2019	1/17/2019	6/3/2019	NO		YES	YES	YES	N/A	

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SRC068984	794	Step 4: Engineering Scoping Study	1/11/2019		2/1/2019	1/17/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC068985	795	Step 4: Engineering Scoping Study	1/11/2019		2/1/2019	1/17/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC068986	796	Step 4: Engineering Scoping Study	1/11/2019		2/1/2019	1/17/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC068987	797	Step 4: Engineering Scoping Study	1/11/2019		2/1/2019	1/17/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC068988	798	Step 5: Design and Constructions	1/3/2019		1/25/2019	1/14/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC069414	799	Step 4: Engineering Scoping Study	1/11/2019		2/1/2019	1/23/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC069415	800	Step 4: Engineering Scoping Study	1/11/2019		2/1/2019	1/23/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC069417	802	Step 4: Engineering Scoping Study	1/11/2019		2/1/2019	1/23/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC069419	804	Step 5: Design and Constructions	11/30/2018		12/21/2018	12/3/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC069420	805	Step 4: Engineering Scoping Study	11/30/2018		12/21/2018	12/3/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC069421	806	Step 4: Engineering Scoping Study	1/11/2019		2/1/2019	1/23/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC069422	807	Step 4: Engineering Scoping Study	1/11/2019		2/1/2019	1/17/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC069427	808	Step 4: Engineering Scoping Study	1/11/2019		2/1/2019	1/23/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC069433	814	Step 4: Engineering Scoping Study	1/3/2019		1/25/2019	1/14/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC069434	815	Step 4: Engineering Scoping Study	1/3/2019		1/25/2019	1/14/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC069435	816	Step 4: Engineering Scoping Study	1/3/2019		1/25/2019	1/14/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC069437	818	Step 5: Design and Constructions	1/3/2019		1/25/2019	1/14/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC069439	820	Step 5: Design and Constructions	12/6/2018		12/31/2018	12/19/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC069524	821	Step 4: Engineering Scoping Study	12/28/2018		1/18/2019	1/2/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC069525	822	Step 4: Engineering Scoping Study	3/19/2019		4/10/2019	4/1/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC069526	823	Step 4: Engineering Scoping Study	1/11/2019		2/1/2019	1/17/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC069527	824	Step 4: Engineering Scoping Study	1/3/2019		1/25/2019	1/14/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC069528	825	Step 5: Design and Constructions	1/11/2019		2/1/2019	1/17/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC069531	828	Step 5: Design and Constructions	1/11/2019		2/1/2019	1/17/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC069532	829	Step 5: Design and Constructions	1/11/2019		2/1/2019	1/17/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC069533	830	Step 4: Engineering Scoping Study	1/11/2019		2/1/2019	1/23/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC069871	832	Step 5: Design and Constructions	12/27/2018		1/18/2019	1/2/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC069873	834	Step 4: Engineering Scoping Study	12/27/2018		1/18/2019	1/2/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC069874	835	Step 4: Engineering Scoping Study	12/27/2018		1/18/2019	1/2/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC069875	836	Step 4: Engineering Scoping Study	12/28/2018		1/18/2019	1/2/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC069876	837	Step 4: Engineering Scoping Study	2/1/2019		2/22/2019	2/11/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC069879	840	Step 5: Design and Constructions	1/2/2019		1/24/2019	1/3/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC069880	841	Step 4: Engineering Scoping Study	12/17/2018		1/9/2019	12/27/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC069882	843	Step 4: Engineering Scoping Study	12/17/2018		1/9/2019	12/27/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC069884	845	Step 4: Engineering Scoping Study	1/11/2019		2/1/2019	1/17/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC069885	846	Step 4: Engineering Scoping Study	1/11/2019		2/1/2019	1/17/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC069887	848	Step 5: Design and Constructions	1/11/2019		2/1/2019	1/17/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC069888	849	Step 4: Engineering Scoping Study	1/11/2019		2/1/2019	1/17/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC069889	850	Step 4: Engineering Scoping Study	1/11/2019		2/1/2019	1/17/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC069890	851	Step 4: Engineering Scoping Study	12/27/2018		1/18/2019	1/2/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC069891	852	Step 5: Design and Constructions	12/27/2018		1/18/2019	1/2/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC069893	854	Step 4: Engineering Scoping Study	12/17/2018		1/9/2019	12/27/2018	6/3/2019	NO		YES	YES	YES	N/A	
SRC069894	855	Step 4: Engineering Scoping Study	12/17/2018		1/9/2019	12/27/2018	6/3/2019	NO		YES	YES	YES	N/A	

Solar Garden: Solar Garden ID	Site ID	Status	Application Considered Complete	15 Business Days from Considered Complete Stage	10 Business Days from Considered Complete Stage (After 9/4/15)	SOW for Study Sent to Developer	Data Pulled	Use 15 day Requirement	15 Day Requirement Met	Use 10 day Requirement	10 Day Requirement Met	SOW Requirement Met	Time lapse between requirement and date sent	Additional Information
SRC069976	857	Step 4: Engineering Scoping Study	1/11/2019		2/1/2019	1/17/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC069977	858	Step 5: Design and Constructions	1/11/2019		2/1/2019	1/17/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC069978	859	Step 4: Engineering Scoping Study	1/11/2019		2/1/2019	1/23/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC069983	864	Step 4: Engineering Scoping Study	3/15/2019		4/5/2019	3/22/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC069986	865	Step 5: Design and Constructions	12/27/2018		1/18/2019	1/2/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC069989	866	Step 4: Engineering Scoping Study	2/1/2019		2/22/2019	2/11/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC070201	867	Step 4: Engineering Scoping Study	2/1/2019		2/22/2019	2/11/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC070202	868	Step 4: Engineering Scoping Study	1/15/2019		2/6/2019	1/21/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC070580		Step 4: Engineering Scoping Study	2/1/2019		2/22/2019	2/11/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC070623		Step 4: Engineering Scoping Study	3/5/2019		3/27/2019	3/18/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC070888		Step 4: Engineering Scoping Study	2/1/2019		2/22/2019	2/11/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC070933		Step 4: Engineering Scoping Study	1/18/2019		2/8/2019	1/21/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC071104		Step 4: Engineering Scoping Study	3/5/2019		3/27/2019	3/18/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC071126		Step 4: Engineering Scoping Study	2/28/2019		3/22/2019	3/4/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC071171		Step 4: Engineering Scoping Study	3/15/2019		4/5/2019	3/22/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC071173		Step 4: Engineering Scoping Study	2/28/2019		3/22/2019	3/4/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC071174		Step 4: Engineering Scoping Study	2/28/2019		3/22/2019	3/4/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC071175		Step 4: Engineering Scoping Study	3/15/2019		4/5/2019	3/22/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC071262		Step 4: Engineering Scoping Study	3/20/2019		4/11/2019	4/1/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC071263		Step 4: Engineering Scoping Study	3/11/2019		4/2/2019	3/18/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC071404		Step 4: Engineering Scoping Study	3/18/2019		4/9/2019	4/1/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC071405		Step 4: Engineering Scoping Study	4/4/2019		4/26/2019	4/10/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC071532		Step 4: Engineering Scoping Study	2/18/2019		3/12/2019	3/4/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC071533		Step 4: Engineering Scoping Study	2/20/2019		3/14/2019	3/4/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC071534		Step 4: Engineering Scoping Study	2/18/2019		3/12/2019	3/4/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC071535		Step 4: Engineering Scoping Study	2/18/2019		3/12/2019	3/4/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC071722		Step 4: Engineering Scoping Study	3/26/2019		4/17/2019	3/27/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC071808		Step 4: Engineering Scoping Study	3/26/2019		4/17/2019	3/27/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC071809		Step 4: Engineering Scoping Study	3/26/2019		4/17/2019	3/27/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC072569		Step 4: Engineering Scoping Study	4/25/2019		5/17/2019	5/2/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC072570		Step 4: Engineering Scoping Study	4/26/2019		5/17/2019	5/2/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC072571		Step 4: Engineering Scoping Study	4/26/2019		5/17/2019	5/2/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC072572		Step 4: Engineering Scoping Study	5/3/2019		5/24/2019	5/6/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC072573		Step 4: Engineering Scoping Study	5/23/2019		6/14/2019	5/31/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC072574		Step 4: Engineering Scoping Study	5/30/2019		6/21/2019		6/3/2019	NO		YES	YES	YES	N/A	
SRC072576		Step 4: Engineering Scoping Study	5/23/2019		6/14/2019	5/31/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC072577		Step 4: Engineering Scoping Study	5/23/2019		6/14/2019	5/31/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC072578		Step 4: Engineering Scoping Study	5/23/2019		6/14/2019	5/31/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC072580		Step 4: Engineering Scoping Study	5/30/2019		6/21/2019		6/3/2019	NO		YES	YES	YES	N/A	

Solar Garden: Solar Garden ID	Site ID	Status	Application Considered Complete	15 Business Days from Considered Complete Stage	10 Business Days from Considered Complete Stage (After 9/4/15)	SOW for Study Sent to Developer	Data Pulled	Use 15 day Requirement	15 Day Requirement Met	Use 10 day Requirement	10 Day Requirement Met	SOW Requirement Met	Time lapse between requirement and date sent	Additional Information
SRC072582		Step 4: Engineering Scoping Study	5/30/2019		6/21/2019		6/3/2019	NO		YES	YES	YES	N/A	
SRC072583		Step 4: Engineering Scoping Study	5/30/2019		6/21/2019		6/3/2019	NO		YES	YES	YES	N/A	
SRC072584		Step 4: Engineering Scoping Study	5/30/2019		6/21/2019		6/3/2019	NO		YES	YES	YES	N/A	
SRC072585		Step 4: Engineering Scoping Study	6/3/2019		6/25/2019		6/3/2019	NO		YES	YES	YES	N/A	
SRC072628		Step 4: Engineering Scoping Study	4/16/2019		5/8/2019	4/16/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC072629		Step 4: Engineering Scoping Study	4/17/2019		5/9/2019	4/17/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC072630		Step 4: Engineering Scoping Study	4/17/2019		5/9/2019	4/17/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC072631		Step 4: Engineering Scoping Study	4/19/2019		5/10/2019	4/22/2019	6/3/2019	NO		YES	YES	YES	N/A	
SRC072813		Step 4: Engineering Scoping Study	6/3/2019		6/25/2019		6/3/2019	NO		YES	YES	YES	N/A	
SRC072814		Step 4: Engineering Scoping Study	6/3/2019		6/25/2019		6/3/2019	NO		YES	YES	YES	N/A	

Solar Garden: Solar Garden ID	Site ID	Status	Data Pulled	SOW for Study Executed/Paid	Expedited Ready	40 Calendar Days into Study	50 Working Days into Study	90 Working Days into Study	Original Study Results Due	Study Results Sent to Developer (Original Date)	Study Delivery Requirement Met	Time lapse between requirement and date sent	Additional Information
SRC040942	15	Step 6: Documents & Contract Submission	6/3/2019	1/5/2016	1/5/2016	2/14/2016	3/15/2016	5/10/2016	3/17/2016	5/19/2016	NO	(45)	Capacity Limit
SRC040943	15	Step 6: Documents & Contract Submission	6/3/2019	1/5/2016	1/5/2016	2/14/2016	3/15/2016	5/10/2016	3/17/2016	5/19/2016	NO	(45)	Capacity Limit
SRC040944	15	Step 6: Documents & Contract Submission	6/3/2019	1/5/2016	1/5/2016	2/14/2016	3/15/2016	5/10/2016	3/17/2016	5/19/2016	NO	(45)	Capacity Limit
SRC040945	15	Step 6: Documents & Contract Submission	6/3/2019	1/5/2016	1/5/2016	2/14/2016	3/15/2016	5/10/2016	3/17/2016	5/19/2016	NO	(45)	Capacity Limit
SRC040946	15	Step 6: Documents & Contract Submission	6/3/2019	1/5/2016	1/5/2016	2/14/2016	3/15/2016	5/10/2016	3/17/2016	5/19/2016	NO	(45)	Capacity Limit
SRC041165	16	Step 6: Documents & Contract Submission	6/3/2019	1/5/2016	1/5/2016	2/14/2016	3/15/2016	5/10/2016	3/17/2016	5/19/2016	NO	(45)	Restudy (withdrawn project ahead in queue) Original results due 3/17/2016 and capacity limit notice sent 5/19. Restudy results sent 11/30/2016 and 12/4/2017
SRC041166	16	Step 6: Documents & Contract Submission	6/3/2019	1/5/2016	1/5/2016	2/14/2016	3/15/2016	5/10/2016	3/17/2016	5/19/2016	NO	(45)	Restudy (withdrawn project ahead in queue) Original results due 3/17/2016 and capacity limit notice sent 5/19. Restudy results 11/30/2016 and 12/4/2017
SRC041167	16	Step 6: Documents & Contract Submission	6/3/2019	1/5/2016	1/5/2016	2/14/2016	3/15/2016	5/10/2016	3/17/2016	5/19/2016	NO	(45)	Restudy (withdrawn project ahead in queue) Original results due 3/17/2016 and capacity limit notice sent 5/19. Restudy results 11/30/2016 and 12/4/2017
SRC041168	16	Step 6: Documents & Contract Submission	6/3/2019	1/5/2016	1/5/2016	2/14/2016	3/15/2016	5/10/2016	3/17/2016	5/19/2016	NO	(45)	Restudy (withdrawn project ahead in queue) Original results due 3/17/2016 and capacity limit notice sent 5/19. Restudy results 11/30/2016 and 12/4/2017
SRC041169	16	Step 6: Documents & Contract Submission	6/3/2019	1/5/2016	1/5/2016	2/14/2016	3/15/2016	5/10/2016	3/17/2016	5/19/2016	NO	(45)	Restudy (withdrawn project ahead in queue) Original results due 3/17/2016 and capacity limit notice sent 5/19. Restudy results sent 11/30/2016 and 12/4/17
SRC040603	43	Step 5: Design and Constructions	6/3/2019	1/4/2016	1/5/2016	2/13/2016	3/14/2016	5/9/2016	3/17/2016	3/21/2016	NO	(2)	
SRC040606	43	Step 5: Design and Constructions	6/3/2019	1/4/2016	1/5/2016	2/13/2016	3/14/2016	5/9/2016	3/17/2016	3/21/2016	NO	(2)	
SRC040608	43	Step 5: Design and Constructions	6/3/2019	1/4/2016	1/5/2016	2/13/2016	3/14/2016	5/9/2016	3/17/2016	3/21/2016	NO	(2)	
SRC040610	43	Step 5: Design and Constructions	6/3/2019	1/4/2016	1/5/2016	2/13/2016	3/14/2016	5/9/2016	3/17/2016	3/21/2016	NO	(2)	
SRC040613	43	Step 5: Design and Constructions	6/3/2019	1/4/2016	1/5/2016	2/13/2016	3/14/2016	5/9/2016	3/17/2016	3/21/2016	NO	(2)	
SRC039909	64	Step 4: Engineering Scoping Study	6/3/2019	11/18/2015	1/5/2016	12/28/2015	1/27/2016	3/23/2016	3/17/2016	2/19/2016	YES	N/A	Updated results sent on 5/18; Updated results sent on 6/23
SRC039910	64	Step 4: Engineering Scoping Study	6/3/2019	11/18/2015	1/5/2016	12/28/2015	1/27/2016	3/23/2016	3/17/2016	2/19/2016	YES	N/A	Updated results sent on 5/18; Updated results sent on 6/23
SRC039911	64	Step 4: Engineering Scoping Study	6/3/2019	11/18/2015	1/5/2016	12/28/2015	1/27/2016	3/23/2016	3/17/2016	2/19/2016	YES	N/A	Updated results sent on 5/18; Updated results sent on 6/23
SRC040034	118	Step 5: Design and Constructions	6/3/2019	9/25/2015	1/5/2016	11/4/2015	12/4/2015	1/29/2016	10/13/2016	11/4/2016	NO	(16)	Flicker Restudy Original results due 2/8/2016 and sent on 2/10/2016
SRC040035	118	Step 5: Design and Constructions	6/3/2019	9/25/2015	1/5/2016	11/4/2015	12/4/2015	1/29/2016	10/13/2016	11/4/2016	NO	(16)	Flicker Restudy Original results due 2/8/2016 and sent on 2/10/2016
SRC040036	118	Step 5: Design and Constructions	6/3/2019	9/25/2015	1/5/2016	11/4/2015	12/4/2015	1/29/2016	10/13/2016	11/4/2016	NO	(16)	Flicker Restudy Original results due 2/8/2016 and sent on 2/10/2016
SRC040037	118	Step 5: Design and Constructions	6/3/2019	9/25/2015	1/5/2016	11/4/2015	12/4/2015	1/29/2016	10/13/2016	11/4/2016	NO	(16)	Flicker Restudy Original results due 2/8/2016 and sent on 2/10/2016
SRC040038	118	Step 5: Design and Constructions	6/3/2019	9/25/2015	1/5/2016	11/4/2015	12/4/2015	1/29/2016	10/13/2016	11/4/2016	NO	(16)	Flicker Restudy Original results due 2/8/2016 and sent on 2/10/2016
SRC041077	153	Step 5: Design and Constructions	6/3/2019	4/20/2017	6/21/2017	5/30/2017	6/29/2017	8/24/2017	9/1/2017	8/31/2017	YES	N/A	
SRC041078	153	Step 5: Design and Constructions	6/3/2019	4/20/2017	6/21/2017	5/30/2017	6/29/2017	8/24/2017	9/1/2017	8/31/2017	YES	N/A	
SRC041079	153	Step 5: Design and Constructions	6/3/2019	4/20/2017	6/21/2017	5/30/2017	6/29/2017	8/24/2017	9/1/2017	8/31/2017	YES	N/A	
SRC041080	153	Step 5: Design and Constructions	6/3/2019	4/20/2017	6/21/2017	5/30/2017	6/29/2017	8/24/2017	9/1/2017	8/31/2017	YES	N/A	
SRC040823	154	Step 5: Design and Constructions	6/3/2019	4/20/2017	6/21/2017	5/30/2017	6/29/2017	8/24/2017	9/1/2017	8/31/2017	YES	N/A	
SRC040824	154	Step 5: Design and Constructions	6/3/2019	4/20/2017	6/21/2017	5/30/2017	6/29/2017	8/24/2017	9/1/2017	8/31/2017	YES	N/A	
SRC041082	157	Step 5: Design and Constructions	6/3/2019	4/20/2017	6/21/2017	5/30/2017	6/29/2017	8/24/2017	9/1/2017	9/7/2017	NO	(4)	Developer required to provide Grounding Calculations prior to study
SRC041083	157	Step 5: Design and Constructions	6/3/2019	4/20/2017	6/21/2017	5/30/2017	6/29/2017	8/24/2017	9/1/2017	9/7/2017	NO	(4)	Developer required to provide Grounding Calculations prior to study

Solar Garden: Solar Garden ID	Site ID	Status	Data Pulled	SOW for Study Executed/Paid	Expedited Ready	40 Calendar Days into Study	50 Working Days into Study	90 Working Days into Study	Original Study Results Due	Study Results Sent to Developer (Original Date)	Study Delivery Requirement Met	Time lapse between requirement and date sent	Additional Information
SRC041084	157	Step 5: Design and Constructions	6/3/2019	4/20/2017	6/21/2017	5/30/2017	6/29/2017	8/24/2017	9/1/2017	9/7/2017	NO	(4)	Developer required to provide Grounding Calculations prior to study
SRC041085	157	Step 5: Design and Constructions	6/3/2019	4/20/2017	6/21/2017	5/30/2017	6/29/2017	8/24/2017	9/1/2017	9/7/2017	NO	(4)	Developer required to provide Grounding Calculations prior to study
SRC040316	158	Step 5: Design and Constructions	6/3/2019	4/20/2017	6/21/2017	5/30/2017	6/29/2017	8/24/2017	9/1/2017	8/30/2017	YES	N/A	
SRC040353	158	Step 5: Design and Constructions	6/3/2019	4/20/2017	6/21/2017	5/30/2017	6/29/2017	8/24/2017	9/1/2017	8/30/2017	YES	N/A	
SRC040813	158	Step 5: Design and Constructions	6/3/2019	4/20/2017	6/21/2017	5/30/2017	6/29/2017	8/24/2017	9/1/2017	8/30/2017	YES	N/A	
SRC040814	158	Step 5: Design and Constructions	6/3/2019	4/20/2017	6/21/2017	5/30/2017	6/29/2017	8/24/2017	9/1/2017	8/30/2017	YES	N/A	
SRC041087	158	Step 5: Design and Constructions	6/3/2019	4/20/2017	6/21/2017	5/30/2017	6/29/2017	8/24/2017	9/1/2017	8/30/2017	YES	N/A	
SRC040897	166	Step 6: Documents & Contract Submission	6/3/2019	1/25/2016	1/25/2016	3/5/2016	4/4/2016	5/30/2016	4/6/2016	4/6/2016	YES	N/A	
SRC040898	166	Step 6: Documents & Contract Submission	6/3/2019	1/25/2016	1/25/2016	3/5/2016	4/4/2016	5/30/2016	4/6/2016	4/6/2016	YES	N/A	
SRC040899	166	Step 6: Documents & Contract Submission	6/3/2019	1/25/2016	1/25/2016	3/5/2016	4/4/2016	5/30/2016	4/6/2016	4/6/2016	YES	N/A	
SRC040900	166	Step 6: Documents & Contract Submission	6/3/2019	1/25/2016	1/25/2016	3/5/2016	4/4/2016	5/30/2016	4/6/2016	4/6/2016	YES	N/A	
SRC040901	166	Step 6: Documents & Contract Submission	6/3/2019	1/25/2016	1/25/2016	3/5/2016	4/4/2016	5/30/2016	4/6/2016	4/6/2016	YES	N/A	
SRC040667	222	Step 5: Design and Constructions	6/3/2019	1/4/2016	1/5/2016	2/13/2016	3/14/2016	5/9/2016	3/17/2016	2/12/2016	YES	N/A	
SRC040668	222	Step 5: Design and Constructions	6/3/2019	1/4/2016	1/5/2016	2/13/2016	3/14/2016	5/9/2016	3/17/2016	2/12/2016	YES	N/A	
SRC040669	222	Step 5: Design and Constructions	6/3/2019	1/4/2016	1/5/2016	2/13/2016	3/14/2016	5/9/2016	3/17/2016	2/12/2016	YES	N/A	
SRC042652	235	Step 5: Design and Constructions	6/3/2019	3/21/2017	3/21/2017	4/30/2017	5/30/2017	7/25/2017	6/1/2017	5/26/2017	YES	N/A	
SRC042655	235	Step 5: Design and Constructions	6/3/2019	3/21/2017	3/21/2017	4/30/2017	5/30/2017	7/25/2017	6/1/2017	5/26/2017	YES	N/A	
SRC042659	235	Step 5: Design and Constructions	6/3/2019	3/21/2017	3/21/2017	4/30/2017	5/30/2017	7/25/2017	6/1/2017	5/26/2017	YES	N/A	
SRC042662	235	Step 5: Design and Constructions	6/3/2019	3/21/2017	3/21/2017	4/30/2017	5/30/2017	7/25/2017	6/1/2017	5/26/2017	YES	N/A	
SRC042667	235	Step 5: Design and Constructions	6/3/2019	3/21/2017	3/21/2017	4/30/2017	5/30/2017	7/25/2017	6/1/2017	5/26/2017	YES	N/A	
SRC042333	251	Step 5: Design and Constructions	6/3/2019	1/7/2016	1/7/2016	2/16/2016	3/17/2016	5/12/2016	3/21/2016	3/25/2016	NO	(4)	
SRC042400	255	Step 5: Design and Constructions	6/3/2019	12/28/2016	12/28/2016	2/6/2017	3/8/2017	5/3/2017	3/14/2017	3/14/2017	YES	N/A	Study SOW not paid initially - sent email on 12/13/16 with updated SOW and need to execute by 12/28/2016. Paid and Executed 12/28/16
SRC042439	258	Step 6: Documents & Contract Submission	6/3/2019	5/1/2017	5/1/2017	6/10/2017	7/10/2017	9/4/2017	7/13/2017	7/14/2017	NO	(1)	Next Business Day
SRC042464	258	Step 6: Documents & Contract Submission	6/3/2019	5/1/2017	5/1/2017	6/10/2017	7/10/2017	9/4/2017	7/13/2017	7/14/2017	NO	(1)	Next Business Day
SRC042465	258	Step 6: Documents & Contract Submission	6/3/2019	5/1/2017	5/1/2017	6/10/2017	7/10/2017	9/4/2017	7/13/2017	7/14/2017	NO	(1)	Next Business Day
SRC042467	258	Step 6: Documents & Contract Submission	6/3/2019	5/1/2017	5/1/2017	6/10/2017	7/10/2017	9/4/2017	7/13/2017	7/14/2017	NO	(1)	Next Business Day
SRC042722	284	Step 5: Design and Constructions	6/3/2019	6/26/2017	6/27/2017	8/5/2017	9/4/2017	10/30/2017	9/8/2017	9/7/2017	YES	N/A	
SRC042725	284	Step 5: Design and Constructions	6/3/2019	6/27/2017	6/26/2017	8/6/2017	9/5/2017	10/31/2017	9/8/2017	9/7/2017	YES	N/A	
SRC042727	284	Step 5: Design and Constructions	6/3/2019	6/26/2017	6/27/2017	8/5/2017	9/4/2017	10/30/2017	9/8/2017	9/7/2017	YES	N/A	
SRC042628	349	Step 6: Documents & Contract Submission	6/3/2019	12/15/2016	12/15/2016	1/24/2017	2/23/2017	4/20/2017	3/2/2017	2/28/2017	YES	N/A	
SRC042632	349	Step 6: Documents & Contract Submission	6/3/2019	12/15/2016	12/15/2016	1/24/2017	2/23/2017	4/20/2017	3/2/2017	2/28/2017	YES	N/A	
SRC042675	349	Step 6: Documents & Contract Submission	6/3/2019	12/15/2016	12/15/2016	1/24/2017	2/23/2017	4/20/2017	3/2/2017	2/28/2017	YES	N/A	
SRC042677	349	Step 6: Documents & Contract Submission	6/3/2019	12/15/2016	12/15/2016	1/24/2017	2/23/2017	4/20/2017	3/2/2017	2/28/2017	YES	N/A	
SRC042680	349	Step 6: Documents & Contract Submission	6/3/2019	12/15/2016	12/15/2016	1/24/2017	2/23/2017	4/20/2017	3/2/2017	2/28/2017	YES	N/A	
SRC049572	442	Step 5: Design and Constructions	6/3/2019	3/8/2017	3/9/2017	4/17/2017	5/17/2017	7/12/2017	5/19/2017	5/19/2017	YES	N/A	
SRC049639	467	Step 5: Design and Constructions	6/3/2019	5/8/2017	5/8/2017	6/17/2017	7/17/2017	9/11/2017	7/20/2017	7/20/2017	YES	N/A	
SRC049640	468	Step 5: Design and Constructions	6/3/2019	2/1/2017	2/1/2017	3/13/2017	4/12/2017	6/7/2017	4/14/2017	4/17/2017	NO	(1)	SOW Paid 1/4/17. Waiting for Executed SOW to be uploaded
SRC051585	493	Step 5: Design and Constructions	6/3/2019	4/19/2017	4/19/2017	5/29/2017	6/28/2017	8/23/2017	6/30/2017	6/27/2017	YES	N/A	
SRC051587	495	Step 5: Design and Constructions	6/3/2019	4/14/2017	4/14/2017	5/24/2017	6/23/2017	8/18/2017	6/27/2017	6/19/2017	YES	N/A	
SRC051589	497	Step 5: Design and Constructions	6/3/2019	4/14/2017	4/14/2017	5/24/2017	6/23/2017	8/18/2017	6/27/2017	6/20/2017	YES	N/A	
SRC051594	502	Step 5: Design and Constructions	6/3/2019	4/14/2017	4/14/2017	5/24/2017	6/23/2017	8/18/2017	6/27/2017	6/23/2017	YES	N/A	
SRC052244	516	Step 5: Design and Constructions	6/3/2019	4/24/2017	4/25/2017	6/3/2017	7/3/2017	8/28/2017	7/7/2017	7/28/2017	NO	(15)	Developer Requested Change in site size- provided new IA for lower capacity.
SRC052806	518	Step 5: Design and Constructions	6/3/2019	5/8/2017	5/8/2017	6/17/2017	7/17/2017	9/11/2017	7/20/2017	7/28/2017	NO	(6)	

Solar Garden: Solar Garden ID	Site ID	Status	Data Pulled	SOW for Study Executed/Paid	Expedited Ready	40 Calendar Days into Study	50 Working Days into Study	90 Working Days into Study	Original Study Results Due	Study Results Sent to Developer (Original Date)	Study Delivery Requirement Met	Time lapse between requirement and date sent	Additional Information
SRC052809	523	Step 5: Design and Constructions	6/3/2019	3/31/2017	3/31/2017	5/10/2017	6/9/2017	8/4/2017	6/13/2017	6/5/2017	YES	N/A	
SRC052763	527	Step 5: Design and Constructions	6/3/2019	4/14/2017	4/14/2017	5/24/2017	6/23/2017	8/18/2017	6/27/2017	6/26/2017	YES	N/A	
SRC052762	529	Step 5: Design and Constructions	6/3/2019	4/14/2017	4/14/2017	5/24/2017	6/23/2017	8/18/2017	6/27/2017	6/27/2017	YES	N/A	
SRC052305	530	Step 5: Design and Constructions	6/3/2019	3/3/2017	3/3/2017	4/12/2017	5/12/2017	7/7/2017	5/15/2017	5/23/2017	NO	(6)	
SRC052799	535	Step 6: Documents & Contract Submission	6/3/2019	9/9/1999	4/20/2017	10/19/1999	11/18/1999	1/13/2000	7/3/2017	6/22/2017	YES	N/A	Developer needed to provide Grounding Calcs before achieving Expedited Ready. Study results sent on 6/16 required correction, to be re-sent
SRC052795	537	Step 5: Design and Constructions	6/3/2019	5/12/2017	5/12/2017	6/21/2017	7/21/2017	9/15/2017	7/26/2017	7/25/2017	YES	N/A	
SRC052784	538	Step 5: Design and Constructions	6/3/2019	6/14/2017	6/15/2017	7/24/2017	8/23/2017	10/18/2017	8/28/2017	8/30/2017	NO	(2)	Grounding calcs need correction for Feeder voltage prior to study
SRC052769	542	Step 4: Engineering Scoping Study	6/3/2019	10/17/2017	10/17/2017	11/26/2017	12/26/2017	2/20/2018	12/29/2017	1/15/2018	NO	(11)	No Capacity Received
SRC052770	543	Step 5: Design and Constructions	6/3/2019	4/18/2017	4/18/2017	5/28/2017	6/27/2017	8/22/2017	6/29/2017	6/23/2017	YES	N/A	Updated study results provided 8/10/18
SRC052797	550	Step 5: Design and Constructions	6/3/2019	5/12/2017	5/12/2017	6/21/2017	7/21/2017	9/15/2017	7/26/2017	7/25/2017	YES	N/A	
SRC052754	552	Step 5: Design and Constructions	6/3/2019	4/14/2017	4/14/2017	5/24/2017	6/23/2017	8/18/2017	6/27/2017	6/27/2017	YES	N/A	
SRC052737	553	Step 5: Design and Constructions	6/3/2019	6/14/2017	6/15/2017	7/24/2017	8/23/2017	10/18/2017	8/28/2017	8/15/2017	YES	N/A	Need feeder voltage confirmed for grounding calcs
SRC052765	554	Step 5: Design and Constructions	6/3/2019	7/7/2017	7/7/2017	8/16/2017	9/15/2017	11/10/2017	9/19/2017	9/14/2017	YES	N/A	First went into study 5/16 then updated documents 5/30 and returned to initial review 6/16.
SRC052804	556	Step 5: Design and Constructions	6/3/2019	5/8/2017	5/8/2017	6/17/2017	7/17/2017	9/11/2017	7/20/2017	7/28/2017	NO	(6)	
SRC052781	561	Step 5: Design and Constructions	6/3/2019	4/14/2017	4/14/2017	5/24/2017	6/23/2017	8/18/2017	6/27/2017	6/23/2017	YES	N/A	Updated Study results provided 8/10 (notification on 8/16/18)
SRC052761	562	Step 5: Design and Constructions	6/3/2019	10/17/2017	10/17/2017	11/26/2017	12/26/2017	2/20/2018	12/29/2017	12/22/2017	YES	N/A	
SRC052798	565	Step 5: Design and Constructions	6/3/2019	6/8/2017	7/12/2017	7/18/2017	8/17/2017	10/12/2017	9/22/2017	9/12/2017	YES	N/A	SOW paid 6/8. Developer requested to hold off on study until after July 10th
SRC052738	569	Step 5: Design and Constructions	6/3/2019	6/14/2017	6/15/2017	7/24/2017	8/23/2017	10/18/2017	8/28/2017	9/12/2017	NO	(11)	Grounding calcs need correction for Feeder voltage prior to study
SRC052694	580	Step 4: Engineering Scoping Study	6/3/2019	4/17/2017	4/17/2017	5/27/2017	6/26/2017	8/21/2017	6/28/2017	6/29/2017	NO	(1)	No Capacity
SRC052716	582	Step 5: Design and Constructions	6/3/2019	5/30/2017	7/7/2017	7/9/2017	8/8/2017	10/3/2017	11/10/2017	12/4/2017	NO	(16)	Delayed due to restudies ahead in queue
SRC052743	584	Step 5: Design and Constructions	6/3/2019	5/8/2017	5/8/2017	6/17/2017	7/17/2017	9/11/2017	7/20/2017	7/20/2017	YES	N/A	
SRC052796	594	Step 5: Design and Constructions	6/3/2019	5/12/2017	5/12/2017	6/21/2017	7/21/2017	9/15/2017	7/26/2017	7/28/2017	NO	(2)	
SRC052739	603	Step 5: Design and Constructions	6/3/2019	6/14/2017	6/15/2017	7/24/2017	8/23/2017	10/18/2017	8/28/2017	8/28/2017	YES	N/A	Grounding calcs need correction for Feeder voltage prior to study
SRC052740	604	Step 5: Design and Constructions	6/3/2019	6/14/2017	6/15/2017	7/24/2017	8/23/2017	10/18/2017	8/28/2017	9/12/2017	NO	(11)	Grounding calcs need correction for Feeder voltage prior to study
SRC052803	605	Step 5: Design and Constructions	6/3/2019	5/8/2017	5/8/2017	6/17/2017	7/17/2017	9/11/2017	7/20/2017	7/20/2017	YES	N/A	
SRC052759	608	Step 5: Design and Constructions	6/3/2019	4/14/2017	4/14/2017	5/24/2017	6/23/2017	8/18/2017	6/27/2017	6/20/2017	YES	N/A	IA sent 6/20/17, issue with substation required review. Finalized 7/18/17. After restudy IA was sent, error was recognized and updated again on 5/25/18
SRC052717	612	Step 5: Design and Constructions	6/3/2019	6/12/2017	7/7/2017	7/22/2017	8/21/2017	10/16/2017	9/19/2017	9/20/2017	NO	(1)	Grounding Calcs required prior to Expedited Ready
SRC052825	613	Step 5: Design and Constructions	6/3/2019	1/8/2018	1/8/2018	2/17/2018	3/19/2018	5/14/2018	3/19/2018	2/13/2018	YES	N/A	Need Grounding calcs prior to study
SRC052722	614	Step 5: Design and Constructions	6/3/2019	6/12/2017	7/7/2017	7/22/2017	8/21/2017	10/16/2017	9/19/2017	10/6/2017	NO	(13)	
SRC052828	615	Step 5: Design and Constructions	6/3/2019	1/8/2018	1/8/2018	2/17/2018	3/19/2018	5/14/2018	3/19/2018	2/21/2018	YES	N/A	Need Grounding calcs prior to study
SRC052715	616	Step 5: Design and Constructions	6/3/2019	6/12/2017	7/7/2017	7/22/2017	8/21/2017	10/16/2017	9/19/2017	9/12/2017	YES	N/A	Grounding Calcs required prior to Expedited Ready
SRC052824	617	Step 5: Design and Constructions	6/3/2019	1/8/2018	1/8/2018	2/17/2018	3/19/2018	5/14/2018	3/19/2018	3/16/2018	YES	N/A	Need Grounding calcs prior to study
SRC052728	618	Step 5: Design and Constructions	6/3/2019	6/12/2017	7/7/2017	7/22/2017	8/21/2017	10/16/2017	9/19/2017	9/12/2017	YES	N/A	Grounding calcs required prior to Expedited Ready
SRC052733	620	Step 5: Design and Constructions	6/3/2019	6/12/2017	7/7/2017	7/22/2017	8/21/2017	10/16/2017	9/19/2017	9/13/2017	YES	N/A	Grounding calcs required prior to Expedited Ready
SRC052838	621	Step 5: Design and Constructions	6/3/2019	1/8/2018	1/8/2018	2/17/2018	3/19/2018	5/14/2018	3/19/2018	3/15/2018	YES	N/A	Need Grounding calcs prior to study
SRC052718	622	Step 5: Design and Constructions	6/3/2019	6/12/2017	7/7/2017	7/22/2017	8/21/2017	10/16/2017	9/19/2017	9/20/2017	NO	(1)	Grounding Calcs required prior to Expedited Ready
SRC052732	624	Step 5: Design and Constructions	6/3/2019	6/12/2017	7/7/2017	7/22/2017	8/21/2017	10/16/2017	9/19/2017	10/2/2017	NO	(9)	
SRC052837	625	Step 5: Design and Constructions	6/3/2019	1/8/2018	1/8/2018	2/17/2018	3/19/2018	5/14/2018	3/19/2018	3/20/2018	NO	(1)	
SRC052719	626	Step 5: Design and Constructions	6/3/2019	6/12/2017	7/7/2017	7/22/2017	8/21/2017	10/16/2017	9/19/2017	9/20/2017	NO	(1)	Grounding Calcs required prior to Expedited Ready
SRC052827	627	Step 5: Design and Constructions	6/3/2019	1/8/2018	1/8/2018	2/17/2018	3/19/2018	5/14/2018	3/19/2018	3/19/2018	YES	N/A	
SRC052726	628	Step 5: Design and Constructions	6/3/2019	6/12/2017	7/7/2017	7/22/2017	8/21/2017	10/16/2017	9/19/2017	9/13/2017	YES	N/A	Grounding Calcs required prior to Expedited Ready. Developer paid to be restudied for a site move on 9/5/18 and confirmed documents on 9/6
SRC052839	629	Step 5: Design and Constructions	6/3/2019	1/8/2018	1/8/2018	2/17/2018	3/19/2018	5/14/2018	3/19/2018	3/19/2018	YES	N/A	No Capacity Notice sent on 3/19/18
SRC052834	634	Step 5: Design and Constructions	6/3/2019	1/8/2018	1/8/2018	2/17/2018	3/19/2018	5/14/2018	3/19/2018	3/15/2018	YES	N/A	Need Grounding calcs prior to study
SRC052727	635	Step 5: Design and Constructions	6/3/2019	6/12/2017	7/7/2017	7/22/2017	8/21/2017	10/16/2017	9/19/2017	9/12/2017	YES	N/A	Grounding calcs required prior to Expedited Ready

Solar Garden: Solar Garden ID	Site ID	Status	Data Pulled	SOW for Study Executed/Paid	Expedited Ready	40 Calendar Days into Study	50 Working Days into Study	90 Working Days into Study	Original Study Results Due	Study Results Sent to Developer (Original Date)	Study Delivery Requirement Met	Time lapse between requirement and date sent	Additional Information
SRC052813	638	Step 5: Design and Constructions	6/3/2019	6/12/2017	7/7/2017	7/22/2017	8/21/2017	10/16/2017	9/12/2018	9/25/2018	NO	(9)	Developer required to demonstrate land rights before study due to conflict with existing site. Developer moved site per request and updated site plan allowed for study start on 7/2/2018 (after verification that there were no more concerns)
SRC052814	639	Step 5: Design and Constructions	6/3/2019	1/8/2018	1/8/2018	2/17/2018	3/19/2018	5/14/2018	9/18/2018	10/9/2018	NO	(15)	Need Grounding calcs and then updated Site Plan prior to study (Developer moved site per request after conflict with ahead in queue was discovered). Developer provided and then verified new plan to begin study on 7/9.
SRC052721	640	Step 5: Design and Constructions	6/3/2019	6/12/2017	7/7/2017	7/22/2017	8/21/2017	10/16/2017	9/19/2017	9/12/2017	YES	N/A	Grounding Calcs required prior to Expedited Ready
SRC052832	641	Step 5: Design and Constructions	6/3/2019	1/8/2018	1/8/2018	2/17/2018	3/19/2018	5/14/2018	3/19/2018	3/19/2018	YES	N/A	
SRC052725	642	Step 5: Design and Constructions	6/3/2019	6/12/2017	7/7/2017	7/22/2017	8/21/2017	10/16/2017	9/19/2017	9/29/2017	NO	(8)	Restudy ahead in queue
SRC052831	643	Step 5: Design and Constructions	6/3/2019	1/8/2018	1/8/2018	2/17/2018	3/19/2018	5/14/2018	3/19/2018	3/19/2018	YES	N/A	
SRC052724	644	Step 5: Design and Constructions	6/3/2019	6/12/2017	7/7/2017	7/22/2017	8/21/2017	10/16/2017	9/19/2017	9/26/2017	NO	(5)	Grounding Calcs required prior to Expedited Ready
SRC052830	645	Step 5: Design and Constructions	6/3/2019	1/8/2018	1/8/2018	2/17/2018	3/19/2018	5/14/2018	3/19/2018	3/16/2018	YES	N/A	Need Grounding calcs prior to study
SRC052723	646	Step 5: Design and Constructions	6/3/2019	6/12/2017	7/7/2017	7/22/2017	8/21/2017	10/16/2017	9/19/2017	9/20/2017	NO	(1)	Grounding Calcs required prior to Expedited Ready
SRC052829	647	Step 5: Design and Constructions	6/3/2019	1/8/2018	1/8/2018	2/17/2018	3/19/2018	5/14/2018	3/19/2018	2/21/2018	YES	N/A	Need Grounding calcs prior to study
SRC042081	648	Step 5: Design and Constructions	6/3/2019	7/31/2018	8/10/2016	9/9/2018	10/9/2018	12/4/2018	10/11/2018	11/1/2018	NO	(15)	Project resubmitted at new location after initial site was cancelled- Deemed Complete and Expedited Ready dates maintained based on agreement with developer. New Study results due 10/11/18
SRC042083	648	Step 5: Design and Constructions	6/3/2019	7/31/2018	8/10/2016	9/9/2018	10/9/2018	12/4/2018	10/11/2018	11/1/2018	NO	(15)	Project resubmitted at new location after initial site was cancelled- Deemed Complete and Expedited Ready dates maintained based on agreement with developer. New Study results due 10/11/18
SRC071169	648	Step 5: Design and Constructions	6/3/2019	8/1/2018	8/10/2016	9/10/2018	10/10/2018	12/5/2018	10/11/2018	11/1/2018	NO	(15)	Project resubmitted at new location after initial site was cancelled- Deemed Complete and Expedited Ready dates maintained based on agreement with developer. New Study results due 10/11/18
SRC061101	651	Step 4: Engineering Scoping Study	6/3/2019	4/29/2019	5/3/2019	6/8/2019	7/8/2019	9/2/2019	7/16/2019		TBD	TBD	
SRC062754	652	Step 5: Design and Constructions	6/3/2019	3/12/2018	3/12/2018	4/21/2018	5/21/2018	7/16/2018	5/22/2018	6/21/2018	NO	(22)	Internal review discovered issues with the study- needed to restudy before sending.
SRC062797	653	Step 5: Design and Constructions	6/3/2019	3/12/2018	3/12/2018	4/21/2018	5/21/2018	7/16/2018	5/22/2018	5/22/2018	YES	N/A	
SRC062798	654	Step 5: Design and Constructions	6/3/2019	3/12/2018	3/12/2018	4/21/2018	5/21/2018	7/16/2018	5/22/2018	6/8/2018	NO	(13)	Study results sent by 5/22 but developer was not notified
SRC062799	655	Step 5: Design and Constructions	6/3/2019	3/12/2018	3/12/2018	4/21/2018	5/21/2018	7/16/2018	5/22/2018	5/10/2018	YES	N/A	
SRC062800	656	Step 5: Design and Constructions	6/3/2019	3/12/2018	3/12/2018	4/21/2018	5/21/2018	7/16/2018	5/22/2018	5/22/2018	YES	N/A	
SRC062801	657	Step 5: Design and Constructions	6/3/2019	3/12/2018	3/12/2018	4/21/2018	5/21/2018	7/16/2018	5/22/2018	5/22/2018	YES	N/A	
SRC062802	658	Step 5: Design and Constructions	6/3/2019	3/12/2018	3/12/2018	4/21/2018	5/21/2018	7/16/2018	5/22/2018	6/6/2018	NO	(11)	
SRC062803	659	Step 5: Design and Constructions	6/3/2019	3/12/2018	3/12/2018	4/21/2018	5/21/2018	7/16/2018	5/22/2018	5/22/2018	YES	N/A	
SRC062804	660	Step 5: Design and Constructions	6/3/2019	3/12/2018	3/12/2018	4/21/2018	5/21/2018	7/16/2018	5/22/2018	5/10/2018	YES	N/A	
SRC062805	661	Step 5: Design and Constructions	6/3/2019	3/12/2018	3/12/2018	4/21/2018	5/21/2018	7/16/2018	5/22/2018	6/5/2018	NO	(10)	
SRC062807	662	Step 5: Design and Constructions	6/3/2019	3/12/2018	3/12/2018	4/21/2018	5/21/2018	7/16/2018	5/21/2018	5/17/2018	YES	N/A	
SRC062809	663	Step 5: Design and Constructions	6/3/2019	3/12/2018	3/12/2018	4/21/2018	5/21/2018	7/16/2018	5/22/2018	5/22/2018	YES	N/A	
SRC062810	664	Step 5: Design and Constructions	6/3/2019	6/8/2018	6/8/2018	7/18/2018	8/17/2018	10/12/2018	8/20/2018	8/15/2018	YES	N/A	Potential issues discovered with study results- developer notified and extension for payment allowed until issues are resolved
SRC062811	665	Step 5: Design and Constructions	6/3/2019	3/12/2018	3/12/2018	4/21/2018	5/21/2018	7/16/2018	5/22/2018	6/5/2018	NO	(10)	
SRC062812	666	Step 5: Design and Constructions	6/3/2019	3/12/2018	3/12/2018	4/21/2018	5/21/2018	7/16/2018	5/22/2018	6/11/2018	NO	(14)	Study Results sent 5/1/2018 but no notification provided to developer until 6/11.
SRC062814	668	Step 5: Design and Constructions	6/3/2019	3/12/2018	3/12/2018	4/21/2018	5/21/2018	7/16/2018	5/22/2018	7/26/2018	NO	(47)	Voltage/grounding issue with SLD provided by developer. Required developer to provide updated SLD before IA could be provided.
SRC062815	669	Step 5: Design and Constructions	6/3/2019	3/12/2018	3/12/2018	4/21/2018	5/21/2018	7/16/2018	5/22/2018	5/21/2018	YES	N/A	Missed initial notification to developer
SRC062816	670	Step 5: Design and Constructions	6/3/2019	3/12/2018	3/12/2018	4/21/2018	5/21/2018	7/16/2018	5/22/2018	6/4/2018	NO	(9)	
SRC062817	671	Step 5: Design and Constructions	6/3/2019	3/12/2018	3/12/2018	4/21/2018	5/21/2018	7/16/2018	5/22/2018	5/2/2018	YES	N/A	
SRC062818	672	Step 5: Design and Constructions	6/3/2019	3/12/2018	3/12/2018	4/21/2018	5/21/2018	7/16/2018	5/22/2018	5/2/2018	YES	N/A	
SRC062819	673	Step 5: Design and Constructions	6/3/2019	3/13/2018	3/13/2018	4/22/2018	5/22/2018	7/17/2018	5/23/2018	6/6/2018	NO	(10)	
SRC062820	674	Step 5: Design and Constructions	6/3/2019	3/12/2018	3/12/2018	4/21/2018	5/21/2018	7/16/2018	5/22/2018	10/17/2018	NO	(106)	Delays due to conflicting site plans ahead in queue preventing the prior in queue sites from being studied.
SRC062821	675	Step 4: Engineering Scoping Study	6/3/2019	3/12/2018	3/12/2018	4/21/2018	5/21/2018	7/16/2018	5/22/2018	7/2/2018	NO	(29)	Project dropping ahead required restudy

Solar Garden: Solar Garden ID	Site ID	Status	Data Pulled	SOW for Study Executed/Paid	Expedited Ready	40 Calendar Days into Study	50 Working Days into Study	90 Working Days into Study	Original Study Results Due	Study Results Sent to Developer (Original Date)	Study Delivery Requirement Met	Time lapse between requirement and date sent	Additional Information
SRC062822	676	Step 5: Design and Constructions	6/3/2019	3/12/2018	3/12/2018	4/21/2018	5/21/2018	7/16/2018	5/22/2018	6/5/2018	NO	(10)	
SRC062823	677	Step 5: Design and Constructions	6/3/2019	3/12/2018	3/12/2018	4/21/2018	5/21/2018	7/16/2018	5/22/2018	6/8/2018	NO	(13)	
SRC063633	680	Step 5: Design and Constructions	6/3/2019	3/2/2018	3/2/2018	4/11/2018	5/11/2018	7/6/2018	5/11/2018	5/10/2018	YES	N/A	
SRC063634	681	Step 5: Design and Constructions	6/3/2019	3/2/2018	3/2/2018	4/11/2018	5/11/2018	7/6/2018	5/11/2018	5/7/2018	YES	N/A	
SRC063636	683	Step 5: Design and Constructions	6/3/2019	5/30/2018	5/30/2018	7/9/2018	8/8/2018	10/3/2018	8/9/2018	8/6/2018	YES	N/A	
SRC063637	684	Step 5: Design and Constructions	6/3/2019	5/30/2018	5/30/2018	7/9/2018	8/8/2018	10/3/2018	8/9/2018	9/9/2018	NO	(21)	
SRC063638	685	Step 5: Design and Constructions	6/3/2019	6/8/2018	6/8/2018	7/18/2018	8/17/2018	10/12/2018	8/20/2018	10/10/2018	NO	(37)	Contractor delays
SRC063639	686	Step 5: Design and Constructions	6/3/2019	3/2/2018	3/2/2018	4/11/2018	5/11/2018	7/6/2018	5/11/2018	5/10/2018	YES	N/A	Updated Study Results provided 8/1/2018 based on additional substation information discovered.
SRC063642	687	Step 5: Design and Constructions	6/3/2019	3/2/2018	3/2/2018	4/11/2018	5/11/2018	7/6/2018	5/11/2018	5/2/2018	YES	N/A	
SRC063645	688	Step 5: Design and Constructions	6/3/2019	3/5/2018	3/5/2018	4/14/2018	5/14/2018	7/9/2018	5/14/2018	5/7/2018	YES	N/A	
SRC063646	689	Step 5: Design and Constructions	6/3/2019	3/2/2018	3/2/2018	4/11/2018	5/11/2018	7/6/2018	5/11/2018	5/10/2018	YES	N/A	
SRC063647	690	Step 5: Design and Constructions	6/3/2019	5/30/2018	5/30/2018	7/9/2018	8/8/2018	10/3/2018	8/9/2018	8/7/2018	YES	N/A	No changes needed to IA from restudy. IA not reissued.
SRC064070	691	Step 5: Design and Constructions	6/3/2019	5/30/2018	5/30/2018	7/9/2018	8/8/2018	10/3/2018	8/9/2018	11/1/2018	NO	(60)	Delays due to conflicting site plans ahead in queue preventing the prior in queue sites from being studied.
SRC064072	693	Step 5: Design and Constructions	6/3/2019	6/8/2018	6/8/2018	7/18/2018	8/17/2018	10/12/2018	8/20/2018	8/23/2018	NO	(3)	
SRC064073	694	Step 5: Design and Constructions	6/3/2019	7/31/2018	7/31/2018	9/9/2018	10/9/2018	12/4/2018	10/11/2018	12/10/2018	NO	(42)	Contractor delays
SRC064075	696	Step 5: Design and Constructions	6/3/2019	6/8/2018	6/8/2018	7/18/2018	8/17/2018	10/12/2018	8/20/2018	8/14/2018	YES	N/A	
SRC064254	697	Step 5: Design and Constructions	6/3/2019	1/29/2018	1/29/2018	3/10/2018	4/9/2018	6/4/2018	4/9/2018	4/13/2018	NO	(4)	
SRC064853	699	Step 5: Design and Constructions	6/3/2019	6/8/2018	6/8/2018	7/18/2018	8/17/2018	10/12/2018	8/20/2018	8/21/2018	NO	(1)	
SRC065488	701	Step 5: Design and Constructions	6/3/2019	6/22/2018	6/25/2018	8/1/2018	8/31/2018	10/26/2018	9/5/2018	10/25/2018	NO	(36)	Contractor delays
SRC065658	703	Step 5: Design and Constructions	6/3/2019	8/14/2018	8/15/2018	9/23/2018	10/23/2018	12/18/2018	10/26/2018	1/16/2019	NO	(58)	Contractor delays
SRC065957	707	Step 5: Design and Constructions	6/3/2019	7/30/2018	7/30/2018	9/8/2018	10/8/2018	12/3/2018	12/20/2018	3/4/2019	NO	(52)	project original due date of 10/10/18. Project withdrew ahead of queue, restudy results due on 12/20/18.
SRC065961	710	Step 5: Design and Constructions	6/3/2019	7/30/2018	7/30/2018	9/8/2018	10/8/2018	12/3/2018	4/16/2019	4/22/2019	NO	(4)	Prior in queue dispute. Original Due date 10/10/2018. New deadline is 4/16/19
SRC065964	711	Step 5: Design and Constructions	6/3/2019	7/16/2018	7/16/2018	8/25/2018	9/24/2018	11/19/2018	9/25/2018	8/27/2018	YES	N/A	
SRC066766	713	Step 5: Design and Constructions	6/3/2019	7/25/2018	7/25/2018	9/3/2018	10/3/2018	11/28/2018	10/4/2018	11/5/2018	NO	(22)	
SRC067199	714	Step 5: Design and Constructions	6/3/2019	8/13/2018	8/13/2018	9/22/2018	10/22/2018	12/17/2018	10/24/2018	12/12/2018	NO	(35)	Contractor delays
SRC067624	715	Step 4: Engineering Scoping Study	6/3/2019	11/19/2018	11/19/2018	12/29/2018	1/28/2019	3/25/2019	2/1/2019	3/14/2019	NO	(29)	Contractor delays
SRC067625	716	Step 5: Design and Constructions	6/3/2019	9/6/2018	9/6/2018	10/16/2018	11/15/2018	1/10/2019	11/19/2018	11/27/2018	NO	(6)	
SRC067629	719	Step 5: Design and Constructions	6/3/2019	10/29/2018	10/29/2018	12/8/2018	1/7/2019	3/4/2019	1/11/2019	3/14/2019	NO	(44)	Contractor delays
SRC067630	720	Step 5: Design and Constructions	6/3/2019	8/27/2018	8/27/2018	10/6/2018	11/5/2018	12/31/2018	11/7/2018	9/10/2018	YES	N/A	
SRC067631	721	Step 5: Design and Constructions	6/3/2019	9/18/2018	9/18/2018	10/28/2018	11/27/2018	1/22/2019	11/30/2018	3/13/2019	NO	(73)	Contractor delays
SRC067632	722	Step 5: Design and Constructions	6/3/2019	9/24/2018	9/24/2018	11/3/2018	12/3/2018	1/28/2019	12/6/2018	1/15/2019	NO	(28)	Contractor delays
SRC067634	724	Step 5: Design and Constructions	6/3/2019	11/1/2018	11/1/2018	12/11/2018	1/10/2019	3/7/2019	1/16/2019	3/12/2019	NO	(39)	Contractor delays
SRC067637	725	Step 5: Design and Constructions	6/3/2019	9/12/2018	9/12/2018	10/22/2018	11/21/2018	1/16/2019	11/26/2018	12/10/2018	NO	(10)	
SRC067638	726	Step 5: Design and Constructions	6/3/2019	9/12/2018	9/12/2018	10/22/2018	11/21/2018	1/16/2019	11/26/2018	11/27/2018	NO	(1)	
SRC067954	728	Step 5: Design and Constructions	6/3/2019	10/5/2018	10/5/2018	11/14/2018	12/14/2018	2/8/2019	12/19/2018	11/27/2018	YES	N/A	
SRC067963	729	Step 4: Engineering Scoping Study	6/3/2019	10/29/2018	10/29/2018	12/8/2018	1/7/2019	3/4/2019	1/11/2019	5/20/2019	NO	(91)	Contractor delays; 1st IA sent 3/21/2019 contained errors on cost and conductoring to be corrected
SRC067962	730	Step 5: Design and Constructions	6/3/2019	11/13/2018	11/13/2018	12/23/2018	1/22/2019	3/19/2019	1/28/2019	3/13/2019	NO	(32)	Contractor delays.
SRC067961	731	Step 4: Engineering Scoping Study	6/3/2019	1/8/2019	1/8/2019	2/17/2019	3/19/2019	5/14/2019	3/21/2019	3/29/2019	NO	(6)	
SRC067960	732	Step 4: Engineering Scoping Study	6/3/2019	11/13/2018	11/13/2018	12/23/2018	1/22/2019	3/19/2019	1/28/2019	3/20/2019	NO	(37)	Contractor delays
SRC067959	733	Step 4: Engineering Scoping Study	6/3/2019	11/13/2018	11/13/2018	12/23/2018	1/22/2019	3/19/2019	1/28/2019	3/20/2019	NO	(37)	Contractor delays
SRC067955	734	Step 5: Design and Constructions	6/3/2019	11/13/2018	11/13/2018	12/23/2018	1/22/2019	3/19/2019	1/28/2019	3/13/2019	NO	(32)	Contractor delays
SRC068006	735	Step 5: Design and Constructions	6/3/2019	11/19/2018	11/19/2018	12/29/2018	1/28/2019	3/25/2019	2/1/2019	3/28/2019	NO	(39)	Contractor delays
SRC068051	737	Step 5: Design and Constructions	6/3/2019	12/6/2018	12/6/2018	1/15/2019	2/14/2019	4/11/2019	2/20/2019	3/18/2019	NO	(18)	Contractor delays
SRC068220	738	Step 5: Design and Constructions	6/3/2019	11/1/2018	11/1/2018	12/11/2018	1/10/2019	3/7/2019	1/16/2019	1/16/2019	YES	N/A	
SRC068265	741	Step 5: Design and Constructions	6/3/2019	12/18/2018	12/18/2018	1/27/2019	2/26/2019	4/23/2019	3/4/2019	3/28/2019	NO	(18)	
SRC068266	742	Step 5: Design and Constructions	6/3/2019	12/18/2018	12/18/2018	1/27/2019	2/26/2019	4/23/2019	3/4/2019	3/19/2019	NO	(11)	Contractor delays
SRC068267	743	Step 5: Design and Constructions	6/3/2019	12/3/2018	12/3/2018	1/12/2019	2/11/2019	4/8/2019	2/14/2019	3/29/2019	NO	(31)	Contractor delays
SRC068269	745	Step 4: Engineering Scoping Study	6/3/2019	1/7/2019	1/7/2019	2/16/2019	3/18/2019	5/13/2019	3/20/2019	4/8/2019	NO	(13)	Contractor delays
SRC068270	746	Step 4: Engineering Scoping Study	6/3/2019	1/7/2019	1/7/2019	2/16/2019	3/18/2019	5/13/2019	3/20/2019	1/15/2019	YES	N/A	
SRC068443	749	Step 5: Design and Constructions	6/3/2019	1/17/2019	1/17/2019	2/26/2019	3/28/2019	5/23/2019	4/1/2019	4/16/2019	NO	(11)	Contractor delays
SRC068444	750	Step 5: Design and Constructions	6/3/2019	12/31/2018	12/31/2018	2/9/2019	3/11/2019	5/6/2019	3/14/2019	3/29/2019	NO	(11)	
SRC068445	751	Step 5: Design and Constructions	6/3/2019	1/7/2019	1/7/2019	2/16/2019	3/18/2019	5/13/2019	3/20/2019	4/8/2019	NO	(13)	Contractor delays
SRC068446	752	Step 5: Design and Constructions	6/3/2019	12/6/2018	12/6/2018	1/15/2019	2/14/2019	4/11/2019	2/20/2019	3/11/2019	NO	(13)	
SRC068447	753	Step 5: Design and Constructions	6/3/2019	12/6/2018	12/6/2018	1/15/2019	2/14/2019	4/11/2019	2/20/2019	3/8/2019	NO	(12)	Contractor delays
SRC068448	754	Step 5: Design and Constructions	6/3/2019	1/7/2019	1/7/2019	2/16/2019	3/18/2019	5/13/2019	3/20/2019	4/16/2019	NO	(19)	Contractor delays

Solar Garden: Solar Garden ID	Site ID	Status	Data Pulled	SOW for Study Executed/Paid	Expedited Ready	40 Calendar Days into Study	50 Working Days into Study	90 Working Days into Study	Original Study Results Due	Study Results Sent to Developer (Original Date)	Study Delivery Requirement Met	Time lapse between requirement and date sent	Additional Information
SRC068440	757	Step 5: Design and Constructions	6/3/2019	12/6/2018	12/6/2018	1/15/2019	2/14/2019	4/11/2019	2/20/2019	3/19/2019	NO	(19)	Contractor delays
SRC068577	759	Step 5: Design and Constructions	6/3/2019	12/6/2018	12/6/2018	1/15/2019	2/14/2019	4/11/2019	2/20/2019	4/15/2019	NO	(38)	Contractor delays
SRC068639	760	Step 5: Design and Constructions	6/3/2019	12/17/2018	12/17/2018	1/26/2019	2/25/2019	4/22/2019	3/1/2019	3/29/2019	NO	(20)	
SRC068630	761	Step 4: Engineering Scoping Study	6/3/2019	2/28/2019	2/28/2019	4/9/2019	5/9/2019	7/4/2019	5/9/2019	5/20/2019	NO	(7)	Contractor delays
SRC068637	763	Step 5: Design and Constructions	6/3/2019	11/19/2018	11/19/2018	12/29/2018	1/28/2019	3/25/2019	2/1/2019	3/15/2019	NO	(30)	Contractor delays
SRC068919	766	Step 4: Engineering Scoping Study	6/3/2019	12/18/2018	12/18/2018	1/27/2019	2/26/2019	4/23/2019	3/4/2019	4/2/2019	NO	(21)	Contractor delays; restudy - loading value error
SRC068918	767	Step 5: Design and Constructions	6/3/2019	12/18/2018	12/18/2018	1/27/2019	2/26/2019	4/23/2019	3/4/2019	4/22/2019	NO	(35)	Contractor delays. Moved to new substation and feeder.
SRC068912	772	Step 4: Engineering Scoping Study	6/3/2019	12/18/2018	12/18/2018	1/27/2019	2/26/2019	4/23/2019	3/4/2019		NO	TBD	Contractor delays; restudy - steady state overvoltage
SRC068911	773	Step 5: Design and Constructions	6/3/2019	12/18/2018	12/18/2018	1/27/2019	2/26/2019	4/23/2019	3/4/2019	4/11/2019	NO	(28)	Contractor delays
SRC068910	774	Step 4: Engineering Scoping Study	6/3/2019	1/14/2019	1/14/2019	2/23/2019	3/25/2019	5/20/2019	3/27/2019		NO	TBD	
SRC068909	775	Step 5: Design and Constructions	6/3/2019	12/6/2018	12/6/2018	1/15/2019	2/14/2019	4/11/2019	2/20/2019	3/8/2019	NO	(12)	Contractor delays
SRC068908	776	Step 5: Design and Constructions	6/3/2019	12/6/2018	12/6/2018	1/15/2019	2/14/2019	4/11/2019	2/20/2019	3/29/2019	NO	(27)	
SRC068963	778	Step 5: Design and Constructions	6/3/2019	12/14/2018	12/14/2018	1/23/2019	2/22/2019	4/19/2019	2/28/2019	3/8/2019	NO	(6)	Contractor delays
SRC068979	789	Step 4: Engineering Scoping Study	6/3/2019	2/28/2019	2/28/2019	4/9/2019	5/9/2019	7/4/2019	5/9/2019	5/6/2019	YES	N/A	N/A
SRC068980	790	Step 4: Engineering Scoping Study	6/3/2019	1/14/2019	1/14/2019	2/23/2019	3/25/2019	5/20/2019	3/27/2019	4/16/2019	NO	(14)	Contractor delays; restudy - min loading values
SRC068981	791	Step 4: Engineering Scoping Study	6/3/2019	2/14/2019	2/18/2019	3/26/2019	4/25/2019	6/20/2019	4/29/2019	5/28/2019	NO	(21)	Contractor delays
SRC068982	792	Step 5: Design and Constructions	6/3/2019	1/14/2019	1/14/2019	2/23/2019	3/25/2019	5/20/2019	3/27/2019	4/22/2019	NO	(18)	Contractor delays
SRC068983	793	Step 4: Engineering Scoping Study	6/3/2019	1/25/2019	2/18/2019	3/6/2019	4/5/2019	5/31/2019	4/29/2019		NO	TBD	
SRC068984	794	Step 4: Engineering Scoping Study	6/3/2019	1/25/2019	2/18/2019	3/6/2019	4/5/2019	5/31/2019	4/29/2019		NO	TBD	
SRC068985	795	Step 4: Engineering Scoping Study	6/3/2019	1/25/2019	2/18/2019	3/6/2019	4/5/2019	5/31/2019	4/29/2019		NO	TBD	
SRC068986	796	Step 4: Engineering Scoping Study	6/3/2019	1/25/2019	2/18/2019	3/6/2019	4/5/2019	5/31/2019	4/29/2019	5/28/2019	NO	(21)	Contractor delays
SRC068987	797	Step 4: Engineering Scoping Study	6/3/2019	2/15/2019	2/18/2019	3/27/2019	4/26/2019	6/21/2019	4/29/2019		NO	TBD	
SRC068988	798	Step 5: Design and Constructions	6/3/2019	1/29/2019	1/29/2019	3/10/2019	4/9/2019	6/4/2019	4/10/2019	4/26/2019	NO	(12)	Contractor delays
SRC069414	799	Step 4: Engineering Scoping Study	6/3/2019	3/14/2019	3/14/2019	4/23/2019	5/23/2019	7/18/2019	5/23/2019	5/28/2019	NO	(3)	Contractor delays
SRC069415	800	Step 4: Engineering Scoping Study	6/3/2019	3/14/2019	3/14/2019	4/23/2019	5/23/2019	7/18/2019	5/23/2019		NO	TBD	
SRC069417	802	Step 4: Engineering Scoping Study	6/3/2019	3/14/2019	3/14/2019	4/23/2019	5/23/2019	7/18/2019	5/23/2019		NO	TBD	
SRC069419	804	Step 5: Design and Constructions	6/3/2019	12/18/2018	12/18/2018	1/27/2019	2/26/2019	4/23/2019	3/4/2019	4/3/2019	NO	(22)	Contractor delays
SRC069420	805	Step 4: Engineering Scoping Study	6/3/2019	12/18/2018	12/18/2018	1/27/2019	2/26/2019	4/23/2019	3/4/2019	4/1/2019	NO	(20)	Contractor delays
SRC069421	806	Step 4: Engineering Scoping Study	6/3/2019	3/14/2019	3/14/2019	4/23/2019	5/23/2019	7/18/2019	5/23/2019		NO	TBD	
SRC069422	807	Step 4: Engineering Scoping Study	6/3/2019	1/25/2019	2/18/2019	3/6/2019	4/5/2019	5/31/2019	4/29/2019		NO	TBD	
SRC069427	808	Step 4: Engineering Scoping Study	6/3/2019	3/14/2019	3/14/2019	4/23/2019	5/23/2019	7/18/2019	5/23/2019	5/30/2019	NO	(5)	Contractor delays; 1 day delay from PMO
SRC069433	814	Step 4: Engineering Scoping Study	6/3/2019	1/23/2019	1/23/2019	3/4/2019	4/3/2019	5/29/2019	4/4/2019	4/22/2019	NO	(12)	Contractor delays.
SRC069434	815	Step 4: Engineering Scoping Study	6/3/2019	1/23/2019	1/23/2019	3/4/2019	4/3/2019	5/29/2019	4/4/2019	4/22/2019	NO	(12)	Contractor delays.
SRC069435	816	Step 4: Engineering Scoping Study	6/3/2019	2/12/2019	2/12/2019	3/24/2019	4/23/2019	6/18/2019	4/24/2019	5/13/2019	NO	(13)	Contractor delays
SRC069437	818	Step 5: Design and Constructions	6/3/2019	1/23/2019	1/23/2019	3/4/2019	4/3/2019	5/29/2019	4/4/2019	3/4/2019	YES	N/A	
SRC069439	820	Step 5: Design and Constructions	6/3/2019	12/27/2018	12/27/2018	2/5/2019	3/7/2019	5/2/2019	3/12/2019	4/16/2019	NO	(25)	Contractor delays
SRC069524	821	Step 4: Engineering Scoping Study	6/3/2019	1/14/2019	1/14/2019	2/23/2019	3/25/2019	5/20/2019	3/27/2019		NO	TBD	
SRC069525	822	Step 4: Engineering Scoping Study	6/3/2019	4/8/2019	4/9/2019	5/18/2019	6/17/2019	8/12/2019	6/19/2019		TBD	TBD	Ahead in queue restudies (loading value errors)
SRC069526	823	Step 4: Engineering Scoping Study	6/3/2019	2/14/2019	2/18/2019	3/26/2019	4/25/2019	6/20/2019	4/29/2019		NO	TBD	
SRC069527	824	Step 4: Engineering Scoping Study	6/3/2019	1/23/2019	1/23/2019	3/4/2019	4/3/2019	5/29/2019	4/4/2019	5/7/2019	NO	(23)	Contractor delays. No capacity.
SRC069528	825	Step 5: Design and Constructions	6/3/2019	1/29/2019	1/29/2019	3/10/2019	4/9/2019	6/4/2019	4/10/2019	3/12/2019	YES	N/A	
SRC069531	828	Step 5: Design and Constructions	6/3/2019	1/29/2019	1/29/2019	3/10/2019	4/9/2019	6/4/2019	4/10/2019	4/2/2019	YES	N/A	
SRC069532	829	Step 5: Design and Constructions	6/3/2019	1/29/2019	1/29/2019	3/10/2019	4/9/2019	6/4/2019	4/10/2019	3/22/2019	YES	N/A	
SRC069533	830	Step 4: Engineering Scoping Study	6/3/2019	3/14/2019	3/14/2019	4/23/2019	5/23/2019	7/18/2019	5/23/2019		NO	TBD	
SRC069871	832	Step 5: Design and Constructions	6/3/2019	1/29/2019	1/29/2019	3/10/2019	4/9/2019	6/4/2019	4/10/2019	4/10/2019	YES	N/A	
SRC069873	834	Step 4: Engineering Scoping Study	6/3/2019	1/29/2019	1/29/2019	3/10/2019	4/9/2019	6/4/2019	4/10/2019	5/24/2019	NO	(32)	Contractor delays
SRC069874	835	Step 4: Engineering Scoping Study	6/3/2019	1/29/2019	1/29/2019	3/10/2019	4/9/2019	6/4/2019	4/10/2019	5/24/2019	NO	(32)	Contractor delays
SRC069875	836	Step 4: Engineering Scoping Study	6/3/2019	1/29/2019	1/29/2019	3/10/2019	4/9/2019	6/4/2019	4/10/2019		NO	TBD	
SRC069876	837	Step 4: Engineering Scoping Study	6/3/2019	4/3/2019	4/3/2019	5/13/2019	6/12/2019	8/7/2019	6/13/2019	5/2/2019	YES	N/A	N/A - No capacity
SRC069879	840	Step 5: Design and Constructions	6/3/2019	1/8/2019	1/8/2019	2/17/2019	3/19/2019	5/14/2019	3/21/2019	3/22/2019	NO	(1)	One day delay
SRC069880	841	Step 4: Engineering Scoping Study	6/3/2019	1/8/2019	1/8/2019	2/17/2019	3/19/2019	5/14/2019	3/21/2019		NO	TBD	Contractor delays; restudy - stdy st overvoltage
SRC069882	843	Step 4: Engineering Scoping Study	6/3/2019	1/8/2019	1/8/2019	2/17/2019	3/19/2019	5/14/2019	3/21/2019	3/29/2019	NO	(6)	
SRC069884	845	Step 4: Engineering Scoping Study	6/3/2019	2/14/2019	2/18/2019	3/26/2019	4/25/2019	6/20/2019	4/29/2019	4/24/2019	YES	N/A	N/A
SRC069885	846	Step 4: Engineering Scoping Study	6/3/2019	1/25/2019	2/18/2019	3/6/2019	4/5/2019	5/31/2019	4/29/2019		NO	TBD	
SRC069887	848	Step 5: Design and Constructions	6/3/2019	2/14/2019	2/18/2019	3/26/2019	4/25/2019	6/20/2019	4/29/2019	4/24/2019	YES	N/A	N/A
SRC069888	849	Step 4: Engineering Scoping Study	6/3/2019	2/28/2019	2/28/2019	4/9/2019	5/9/2019	7/4/2019	5/9/2019		NO	TBD	Was "On Hold" due to developer providing site map showing location on top of another garden. John Harlander to provide # of days. Off hold 5/2/19.
SRC069889	850	Step 4: Engineering Scoping Study	6/3/2019	1/25/2019	2/18/2019	3/6/2019	4/5/2019	5/31/2019	4/29/2019		NO	TBD	
SRC069890	851	Step 4: Engineering Scoping Study	6/3/2019	2/7/2019	2/7/2019	3/19/2019	4/18/2019	6/13/2019	4/19/2019	5/20/2019	NO	(21)	Contractor delays
SRC069891	852	Step 5: Design and Constructions	6/3/2019	1/29/2019	1/29/2019	3/10/2019	4/9/2019	6/4/2019	4/10/2019	4/26/2019	NO	(12)	Contractor delays
SRC069893	854	Step 4: Engineering Scoping Study	6/3/2019	1/18/2019	1/18/2019	2/27/2019	3/29/2019	5/24/2019	4/2/2019	4/19/2019	NO	(13)	Contractor delays

Solar Garden: Solar Garden ID	Site ID	Status	Data Pulled	SOW for Study Executed/Paid	Expedited Ready	40 Calendar Days into Study	50 Working Days into Study	90 Working Days into Study	Original Study Results Due	Study Results Sent to Developer (Original Date)	Study Delivery Requirement Met	Time lapse between requirement and date sent	Additional Information
SRC069894	855	Step 4: Engineering Scoping Study	6/3/2019	1/8/2019	1/8/2019	2/17/2019	3/19/2019	5/14/2019	3/21/2019	3/29/2019	NO	(6)	
SRC069976	857	Step 4: Engineering Scoping Study	6/3/2019	1/29/2019	1/29/2019	3/10/2019	4/9/2019	6/4/2019	4/10/2019		NO	TBD	Was "On Hold" due to developer providing site map showing location on top of another garden. John Harlander to provide # of days. Off hold 5/2/19.
SRC069977	858	Step 5: Design and Constructions	6/3/2019	1/29/2019	1/29/2019	3/10/2019	4/9/2019	6/4/2019	4/10/2019	3/12/2019	YES	N/A	
SRC069978	859	Step 4: Engineering Scoping Study	6/3/2019	3/14/2019	3/14/2019	4/23/2019	5/23/2019	7/18/2019	5/23/2019	5/29/2019	NO	(4)	Contractor delays
SRC069983	864	Step 4: Engineering Scoping Study	6/3/2019	5/3/2019	5/3/2019	6/12/2019	7/12/2019	9/6/2019	7/16/2019		TBD	TBD	
SRC069986	865	Step 5: Design and Constructions	6/3/2019	1/14/2019	1/14/2019	2/23/2019	3/25/2019	5/20/2019	3/27/2019	4/8/2019	NO	(8)	Contractor delays
SRC069989	866	Step 4: Engineering Scoping Study	6/3/2019	4/2/2019	4/2/2019	5/12/2019	6/11/2019	8/6/2019	6/12/2019		TBD	TBD	
SRC070201	867	Step 4: Engineering Scoping Study	6/3/2019	4/15/2019	4/15/2019	5/25/2019	6/24/2019	8/19/2019	6/25/2019		TBD	TBD	
SRC070202	868	Step 4: Engineering Scoping Study	6/3/2019	3/25/2019	3/25/2019	5/4/2019	6/3/2019	7/29/2019	6/4/2019		TBD	TBD	
SRC070580		Step 4: Engineering Scoping Study	6/3/2019	4/15/2019	4/15/2019	5/25/2019	6/24/2019	8/19/2019	6/25/2019		TBD	TBD	
SRC070623		Step 4: Engineering Scoping Study	6/3/2019	5/6/2019	5/6/2019	6/15/2019	7/15/2019	9/9/2019	7/17/2019		TBD	TBD	
SRC070888		Step 4: Engineering Scoping Study	6/3/2019	4/3/2019	4/3/2019	5/13/2019	6/12/2019	8/7/2019	6/13/2019		TBD	TBD	
SRC070933		Step 4: Engineering Scoping Study	6/3/2019	3/20/2019	3/20/2019	4/29/2019	5/29/2019	7/24/2019	5/30/2019		NO	TBD	
SRC071104		Step 4: Engineering Scoping Study	6/3/2019	5/6/2019	5/6/2019	6/15/2019	7/15/2019	9/9/2019	7/17/2019		TBD	TBD	
SRC071126		Step 4: Engineering Scoping Study	6/3/2019	4/30/2019	4/30/2019	6/9/2019	7/9/2019	9/3/2019	7/11/2019		TBD	TBD	
SRC071171		Step 4: Engineering Scoping Study	6/3/2019	5/3/2019	5/3/2019	6/12/2019	7/12/2019	9/6/2019	7/16/2019		TBD	TBD	
SRC071173		Step 4: Engineering Scoping Study	6/3/2019	4/30/2019	4/30/2019	6/9/2019	7/9/2019	9/3/2019	7/11/2019		TBD	TBD	
SRC071174		Step 4: Engineering Scoping Study	6/3/2019	4/30/2019	4/30/2019	6/9/2019	7/9/2019	9/3/2019	7/11/2019		TBD	TBD	
SRC071175		Step 4: Engineering Scoping Study	6/3/2019	5/3/2019	5/3/2019	6/12/2019	7/12/2019	9/6/2019	7/16/2019		TBD	TBD	
SRC071262		Step 4: Engineering Scoping Study	6/3/2019	4/11/2019	4/11/2019	5/21/2019	6/20/2019	8/15/2019	6/21/2019		TBD	TBD	
SRC071263		Step 4: Engineering Scoping Study	6/3/2019	5/13/2019	5/13/2019	6/22/2019	7/22/2019	9/16/2019	7/24/2019		TBD	TBD	
SRC071404		Step 4: Engineering Scoping Study	6/3/2019	5/28/2019	5/28/2019	7/7/2019	8/6/2019	10/1/2019	8/7/2019		TBD	TBD	
SRC071532		Step 4: Engineering Scoping Study	6/3/2019	3/28/2019	3/28/2019	5/7/2019	6/6/2019	8/1/2019	6/7/2019	5/31/2019	YES	N/A	N/A
SRC071533		Step 4: Engineering Scoping Study	6/3/2019	3/28/2019	3/28/2019	5/7/2019	6/6/2019	8/1/2019	6/7/2019	5/31/2019	YES	N/A	N/A
SRC071534		Step 4: Engineering Scoping Study	6/3/2019	3/28/2019	3/28/2019	5/7/2019	6/6/2019	8/1/2019	6/7/2019		TBD	TBD	
SRC071535		Step 4: Engineering Scoping Study	6/3/2019	3/28/2019	3/28/2019	5/7/2019	6/6/2019	8/1/2019	6/7/2019		TBD	TBD	
SRC071722		Step 4: Engineering Scoping Study	6/3/2019	5/28/2019	5/28/2019	7/7/2019	8/6/2019	10/1/2019	8/7/2019		TBD	TBD	
SRC071808		Step 4: Engineering Scoping Study	6/3/2019	5/28/2019	5/28/2019	7/7/2019	8/6/2019	10/1/2019	8/7/2019		TBD	TBD	
SRC071809		Step 4: Engineering Scoping Study	6/3/2019	5/28/2019	5/28/2019	7/7/2019	8/6/2019	10/1/2019	8/7/2019		TBD	TBD	

Minnesota Solar*Rewards Community®

Status Report | June 2019

PROJECT STATUS

- New Applications (2019) = 75 (*49 remain active*)
- Total No. of Applications under the VOS = 208

June 3, 2019	Project Sites	MW
TOTAL	488	891
Completed Projects	201	559
Active Applications	287	332
↓ PROGRESS SUMMARY ↓		
Application Stage	18	17
Study Phase	95	97
In process	61	61
Interconnection Agreement Issued	33	35
Restudies in Progress	*1*	*1*
Design & Construction Phase	174	218

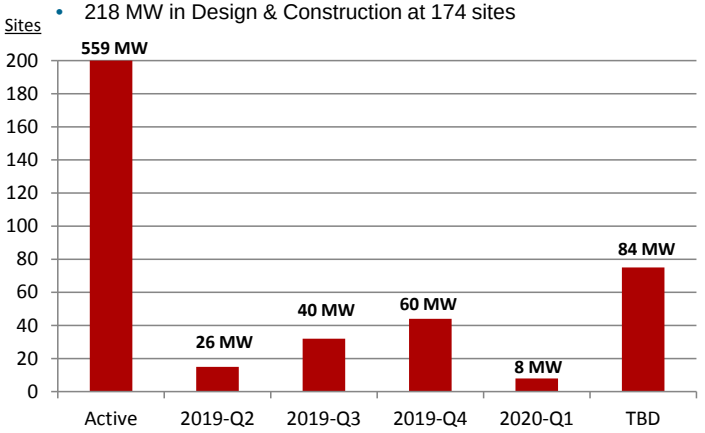
PROJECT SITES BY STAGE

PROGRAM UPDATE

- The next SRC Implementation Workgroup meeting will be 7/31/19 with a focus on the VOS calculation.
- MN DIP goes into effect as of June 17, 2019.
- Summer and fall construction work is underway; contact SRCMN@xcelenergy.com immediately if you have not yet set your in-service date.
- New study providers are quickly becoming adept and correction delays are decreasing. 45% of studies due in May were delivered on time.

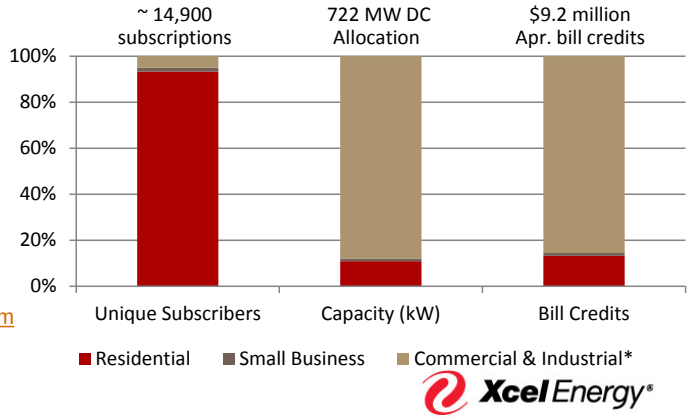
SOLAR GARDENS IN DESIGN & CONSTRUCTION

- 218 MW in Design & Construction at 174 sites



ACTIVE SOLAR GARDENS

- $114.8 million – Bill Credits paid (full production months through Apr 2019)
- Details below are as of April 2019



Xcel Energy®

CERTIFICATE OF SERVICE

I, Jim Erickson, hereby certify that I have this day served copies of the foregoing document on the attached list of persons.

xx by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States mail at Minneapolis, Minnesota; or

xx by electronic filing.

Docket No.: E002/M-13-867

Dated this 14th day of June.

/s/

Jim Erickson
Regulatory Administrator

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Michael	Allen	michael.allen@allenergysolar.com	All Energy Solar	721 W 26th st Suite 211 Minneapolis, Minnesota 55405	Electronic Service	No	OFF_SL_13-867_Official
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Arthur	Crowell	Crowell.arthur@yahoo.com	A Work of Art Solar	14333 Orchard Rd. Minnetonka, MN 55345	Electronic Service	No	OFF_SL_13-867_Official

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Daniel P	Wolf	dan.wolf@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_13-867_Official

414 Nicollet Mall
Minneapolis, MN 55401

December 1, 2017

—Via Electronic Filing—

Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: PETITION
2019-2021 TRIENNIAL NUCLEAR PLANT DECOMMISSIONING STUDY & ASSUMPTIONS
DOCKET NO. E002/M-17-828

Dear Dr. Haar:

Northern States Power Company, doing business as Xcel Energy, submits a Petition for approval of our 2019-2021 Triennial Nuclear Decommissioning Study & Assumptions, along with supporting materials.

We have electronically filed this Petition and supporting materials with the Minnesota Public Utilities Commission, and copies have been served on the parties on the attached service list. In addition, a one page summary of the filing has been provided to persons on the attached service list. The one-page summary provided also contains directions on how to access an electronic copy of the full filing via the Commission's website. Please contact me at (612) 215-4663 or aakash.chandarana@xcelenergy.com or Lisa Perkett at (612) 330-6950 or lisa.h.perkett@xcelenergy.com if you have any questions regarding this filing.

Sincerely,

/s/

AAKASH H. CHANDARANA
REGIONAL VICE PRESIDENT
RATES AND REGULATORY AFFAIRS

Enclosures
c: Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Nancy Lange	Chair
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IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY FOR APPROVAL OF THE 2019-2021 TRIENNIAL NUCLEAR DECOMMISSIONING STUDY & ASSUMPTIONS

DOCKET NO. E002/M-17-828

PETITION

OVERVIEW

Pursuant to Minn. Stat. § 216B.11 and § 216B.2445 and Minn. R. 7825.0500 through 7825.0800, and prior Minnesota Public Utilities Commission (Commission) Orders, Northern States Power Company, doing business as Xcel Energy, submits our Petition for approval of the 2019-2021 Nuclear Decommissioning Study and Assumptions.

The objective of a decommissioning docket is to arrive at a reasonable cost estimate for decontamination and removal of nuclear facilities at the end of their operating lives and to set an accrual to accumulate funds sufficient to pay those decommissioning costs. This triennial filing is unique in that it closely precedes our 2019 Integrated Resource Plan (2019 IRP), in which we—along with the Commission, the Department, and other stakeholders—will consider the long-term future of our nuclear plants because, among other things, all three of our units will reach the end of their respective license life during the fifteen-year planning period.[1] We anticipate discussions in the upcoming 2019 IRP related to several alternatives for our nuclear fleet, including the continued operation of the units through the end of their licensed lives, possible early retirements of one or more units, and/or possible life extensions. In this way, decisions coming out of the 2019 IRP are likely to have a substantial impact on our decommissioning analysis and accrual calculation.

[1] *In the Matter of Xcel Energy's 2016–2030 Integrated Resource Plan,* Docket No. E002/RP-15-21, ORDER APPROVING PLAN WITH MODIFICATIONS AND ESTABLISHING REQUIREMENTS FOR FUTURE RESOURCE PLAN FILINGS (January 11, 2017)

The order of these two dockets—with the 2019 IRP coming approximately a year after our triennial—makes planning for decommissioning in this docket a challenge. It also has the potential of introducing substantial swings in the accrual calculation, as any accrual set in this docket could soon be inaccurate as a result of decisions made in the 2019 IRP. For these reasons, we recommend (1) using the information provided in this docket to inform upcoming discussions in the 2019 IRP; (2) maintaining the accrual set in the 2014 Triennial Nuclear Decommissioning filing (2014 Filing), Docket No. E002/M-14-761 until a decision is reached in the 2019 IRP; and (3) allowing the Company to file its next decommissioning petition shortly following a decision in the 2019 IRP. This will allow the Company, Commission, and stakeholders to make decisions regarding the future of our nuclear fleet first (and with the benefit of updated decommissioning data provided in this filing) and then turn to a discussion regarding decommission planning and accrual setting in light of decisions made in the 2019 IRP.

To that end and in compliance with the Commission's Order in the 2014 Filing, we have analyzed a number of decommissioning scenarios and calculated a number of different accruals as part of this filing. The resulting accrual calculations range from negative $16.0 million (meaning we are over-funded today) for scenarios involving life extensions of our plants to positive $115.9 million (meaning we are under-funded today) for scenarios involving the early retirement of our plants by five years. In general, when compared to the 2014 Filing and using of the same assumptions regarding decommissioning alternatives and operating lives, accrual calculations have risen. For example, if we assume that immediate decommissioning will occur following the end of each plant license (consistent with our 2014 Filing), the accrual for 2019 would be approximately $45 million.

These increases in some of the accrual calculations are driven almost entirely by forward-looking expected returns, which in turn are largely driven by the lower current treasury interest rate relative to the interest rate expected from the 2014 Filing valuation. In other words, because the long-term treasury rate is a fundamental building block for our forward-looking return forecast and because that rate is lower today than it was in 2014, we now anticipate lower long-term investment growth in the future than we did in the 2014 Filing. This change in our projections is consistent with the investment industry as a whole. And given the very long duration of the Nuclear Decommissioning Trust (NDT) and decommissioning, even modest changes in forward looking expected return assumptions can have a substantial effect on the accrual. More detail can be found in Schedule D.

That said, some accrual calculations provided in this filing are substantially lower than $45 million. Changing from immediate decommissioning to SAFSTOR alone cuts the accrual nearly in half, resulting in an accrual of $24.9 million. And as already discussed, if we were to extend one or more of the plant licenses, the accruals decrease considerably and become negative in scenarios involving extensions at both plants. In light of this, our recommendation is to hold the accrual at the present $14.0 million until our 2019 IRP is resolved.

We recognize that this request deviates from the normal triennial procedure, but we believe it will allow for a complete and thorough review of this Petition while also ensuring that the 2019 accrual year remains consistent with what was included in the currently effective 2015 Multi Year Rate Plan (MYRP) filed under Docket No. E002/GR-15-826. In addition, it will provide an opportunity to reassess the accrual on the basis of updated assumptions from the 2019 IRP.

To be sure, if our previous assumption of running the plants through the end of their licensed lives is affirmed in the 2019 IRP, the decision to hold the accrual constant in this docket will result in a greater increase in the accrual post-2019 IRP. To mitigate these effects, we propose that Department of Energy (DOE) settlement funds be held for potential allocation to the NDT, which is consistent with some previous applications of these funds and is consistent with the Commission's Order in Docket No. E002/M-11-939, dated December 4, 2012. In combination with the current $14.0 million accrual, we believe these funds would allow the Commission to see the 2019 IRP process through before finalizing plans with respect to decommissioning and changing the accrual to reflect those plans.

For these reasons, the Company respectfully requests the Commission:

- Approve our decommissioning study and assumptions as compliant with the Company's obligations under Minnesota statutes, Commission rules, and prior precedent;
- Continue the current approved annual accrual of $14.0 million, to meet the needs of the Company's 60-year spent fuel scenario with no re-casking of the fuel, continuing for 2019 through 2021 while strategic decisions about the future of our nuclear units are decided in our 2019 IRP;
- Approve an annual accrual of $2.0 million for end-of-life (EOL) nuclear fuel for the calendar year 2019 through 2021; and
- Permit the Company to hold settlement payments received from the DOE in an interest-bearing account until the 2019 IRP is resolved, at which time the Commission can decide whether to apply those funds to the NDT or refund them to customers.

Additionally, and consistent with prior triennial filings, the Company is requesting Commission approval of changes in investment assumptions and targets. Specifically, the Company requests Commission approval of the following two changes in order to improve the expected earnings of the investment portfolio and ensure that decommissioning funding needs are met without excess costs to customers:

- Transitioning investments to bonds five years before decommissioning cash flows rather than the six years as previously assumed; and
- Changing the investment mix to reduce allocations to certain alternative asset classes and increase allocations to fixed income investments, as described later in this Petition.

I. SUMMARY OF FILING

A one-paragraph summary of the filing accompanies this Petition pursuant to Minn. R. 7829.1300, subp. 1.

II. SERVICE ON OTHER PARTIES

Pursuant to Minn. Stat. § 216.17, subd.3, Xcel Energy has electronically filed this document. A summary of the filing has been served on all parties on the attached service list

III. GENERAL FILING INFORMATION

Pursuant to Minn. R. 7825.3200, 7825.3500, and 7829.1300, subp. 3. Xcel Energy provides the following required information:

A. Name, Address, and Telephone Number of Utility

Northern States Power Company
Xcel Energy
414 Nicollet Mall
Minneapolis, MN 55401
(612) 330-5500

B. Name, Address, and Telephone Number of Utility Attorney

Ryan J. Long
Principal Attorney

Xcel Energy
414 Nicollet Mall, 401 – 8th Floor
Minneapolis, MN 55401
(612) 215-4659

C. Date of Filing

This Petition is being filed December 1, 2017.

D. Statute Controlling Schedule for Processing the Filing

Under Minn. R. 7829.0100, subp. 11, this request for approval of decommissioning accrual is a "miscellaneous" filing because no determination of the Xcel Energy general revenue requirements is necessary. There is no specific statute that prescribes the amount of time the Commission has to rule on this Petition.

E. Utility Employee Responsible for the Filing

Aakash H. Chandarana
Regional V. P., Rates and Regulatory Affairs
Xcel Energy
414 Nicollet Mall, 401 – 7th Floor
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IV. COMPANY PROPOSAL

As already discussed, this filing differs from past triennial dockets in a couple of significant ways. First, it comes shortly before our 2019 IRP, in which we and our stakeholders will consider the long-term future of our nuclear fleet because all three of our nuclear units will reach the end of their respective license life during the fifteen-year IRP planning period. Moreover, the Commission specifically ordered that the Company describe in its next IRP "its plans and possible scenarios for cost-effective and orderly retirement of its aging baseload fleet, including Sherco, King, Monticello, and Prairie Island."[2]

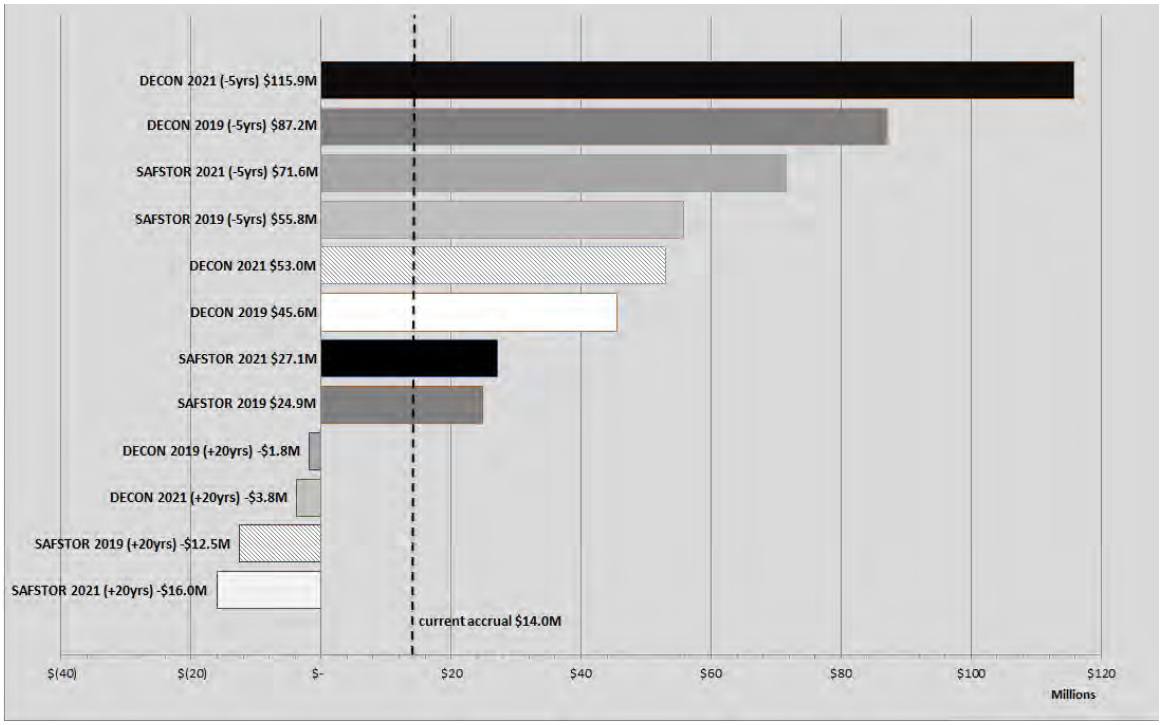
We therefore anticipate discussions in the upcoming 2019 IRP related to several alternatives for our nuclear fleet, including the continued operation of the units through the end of their licensed lives, possible early retirements of one or more units,

[2] Dkt. No. E002/RP-15-21 (January 11, 2017 Order at 12.)

and/or possible life extensions. In connection with these scenarios, we also expect to discuss alternative decommissioning scenarios, including both immediate decommissioning (DECON[3]) as well as the SAFSTOR[4] alternative. In fact, the Department raised SAFSTOR as an alternative in our 2015 IRP, noting that it would allow the decommissioning funds to accrue interest following retirement of the plants.[5]

These two decision points—how long to run the plants and how to decommission them—could have a dramatic impact on the accrual calculation for the NDT. The following table shows the potential 60-year accrual calculations using a variety of assumptions related to operating lives and decommissioning alternatives. It also shows accrual calculations for changes occurring in 2019 versus 2021 to reflect the potential impact of waiting to change the accrual until after the 2019 IRP.

Table 1 – Nuclear Decommissioning Triennial Accrual Alternatives (60 Year, No Recasking)



[3] DECON is defined by the NRC as, "[a] method of decommissioning in which the equipment, structures, and portions of a facility and site containing radioactive contaminants are removed and safely buried in a low-level radioactive waste landfill or decontaminated to a level that permits the property to be released for unrestricted use shortly after cessation of operations."
[4] SAFSTOR is defined by the NRC as, "[a] method of decommissioning in which a nuclear facility is placed and maintained in a condition that allows the facility to be safely stored and subsequently decontaminated (deferred decontamination) to levels that permit release for unrestricted use."
[5] Dkt. No. E002/RP-15-21 (Department's July 8, 2016 Comments at 37-38).

This table shows the wide range of potential accrual outcomes that could result from decisions that will need to be made in the 2019 IRP. The accrual could range from negative $16 million to positive $115 million depending on decisions about possible life extensions and/or early retirements. This is not inconsistent with the previous life extensions for our nuclear plants, which also had a significant impact on the accrual. Looking back to 2005, the accrual was approximately $61 million; then from 2006-2008, it was approximately $32 million; and once the licenses were extended, it dropped to $0 from 2009-2012.

This triennial is also unique because it is the first one to have been made during the term of the MYRP. Typically in the past, triennial filings and rate cases proceeded either in tandem or in quick succession so that base rates could be modified to reflect any changes that are necessary to the accrual to fully fund the NDT. Here, by contrast, the Company recently entered into a four-year MYRP that prevents it from filing another case until 2019, which would then not affect rates until 2020. As a result, any changes made to the accrual in this docket could not be reflected in base rates in 2019 consistent with past practice.

The overall goal of the decommissioning accrual schedule is designed to ensure that the customers who benefit from nuclear power pay the costs associated with that power at the time it is generated. We believe our proposal to maintain the current accrual level while the future of our nuclear units is decided in the 2019 IRP is reasonable due to the wide range of scenarios (and therefore, accrual levels) that could result from the 2019 IRP. Our proposal is also in the public interest as it does not collect speculative costs from customers in advance of a 2019 IRP decision, nor does it penalize the Company for the timing of the 2019 IRP by changing the accrual during the MYRP. Once the 2019 IRP is resolved, we propose to file an updated decommissioning petition, so that an accrual could be set based on the decisions that were made in the 2019 IRP as well as updated cost, inflation, escalation, and investment growth assumptions.[6]

Although we do not recommend a change to the accrual in this petition, we do want the Commission and our stakeholders to be fully informed with respect to our current assumptions related to our decommissioning cost estimate, inflation, escalation, and investment growth. We believe this information is important both for purposes of evaluating this petition and also to inform discussions in the upcoming 2019 IRP. We

[6] While these financial assumptions will not necessarily change as a result of any decision made in the 2019 IRP, they may change due to the passage of time and changes in market conditions.

have therefore analyzed a number of decommissioning scenarios and calculated a number of different accruals for the Commission. We also walk through all of the information that is required by the relevant statutes, Commission rules, and past Commission Orders in Section V below.

To be clear, if the 2019 IRP does not lead to any changes with respect to operational lives or decommissioning plans for the nuclear units, the decision to hold the accrual constant in this docket will result in a greater increase in the accrual after the 2019 IRP. That is why we are proposing to hold the DOE settlement funds in order to potentially mitigate these effects. More specifically, we propose to hold the DOE funds in an interest bearing account until the 2019 IRP is resolved, at which time the Commission can decide whether to add the funds to the NDT or refund them to customers in light of the 2019 IRP outcome in our next triennial filing with updated decommissioning assumptions. And while we cannot be certain as to the amounts we will receive as part of our settlement with the DOE in future years, we note that our 2017 payment was approximately $15 million (on a total company basis) and will continue to be significant over the coming years.[7] This use of the DOE funds is also consistent with some previous applications of these funds and with the Commission's Order in Docket No. E002/M-11-939, dated December 4, 2012.

We believe this proposal is reasonable and represents the best path forward in light of the unique circumstances at play in this triennial for all of the reasons discussed above. In the balance of this Petition, we present the information and analyses that are required by statute, Commission rules, and past Commission Orders for triennial filings.

V. REQUIRED DECOMMISSIONING INFORMATION

A. Scenarios Evaluated

Consistent with previous filings, the Company examines the impact of assumptions in (1) the engineering cost estimate; (2) costs associated with spent fuel storage following plant shutdown; (3) inflation and escalation; (4) earnings rates; (5) fund investment structure; and (6) recovery period.

As required by Minn. Stat. § 216B.2445, the Company provides scenarios assuming spent fuel will be stored in the State for 60 years, 100 years, and 200 years following cessation of operations at the plant. We include a 60-year scenario without recasking of the dry cask storage units as our base case because the Nuclear Regulatory

[7] We will soon make a filing with the Commission addressing the 2017 payment.

Commission (NRC) assumes that casks can be used for 100 years. We discuss this assumption further in Part C.1.b.iii below. However, pursuant to the Commission's Order in our previous Triennial Nuclear Decommissioning Accrual filing, we have also provided 60-year, 100-year, and 200-year scenarios that include the cost of switching out the dry cask storage units every 50 years.[8] In addition, we are including a scenario that assumes spent fuel will be stored in the state for only 32 years. This scenario is based on the Blue Ribbon Commission on America's Nuclear Future (BRC) report recommendations for the prompt development of centralized interim storage. The scenarios discussed above have been provided using the prompt removal and dismantling (*i.e.*, DECON) scenario for decommissioning, which is consistent with what was provided in the 2014 Filing. In addition to these five DECON scenarios, the Company has provided 32-year and 60-year (with no recasking) delayed removal and dismantling (*i.e.*, SAFSTOR) scenarios. These two alternatives are discussed in Schedule A, which lays out the annual cash flows, as well as the cost estimate report provided by TLG Services, Inc. (TLG) in Schedule L for Monticello and Schedule M for Prairie Island.

The decommissioning accrual is an annuity calculation based on the yearly expenditures, in nominal dollars, provided for each cost estimate scenario. The cost estimate is jurisdictionalized for Minnesota retail customers using 73.4886 percent as presented in the current Minnesota rate case.[9] The escalation rate is used to inflate the jurisdictional cost estimate to future years and the earnings rate is used to present value those future dollars back to the start of decommissioning. Then an annuity payment is calculated such that when added to the current fund balance and grown at the forward looking after tax expected return, will result in this present value required at decommissioning.

In total, the Company has presented 20 accrual scenarios. Fourteen are based on the DECON assumption. Six are based on the SAFSTOR assumption. They include various scenarios for a 32-year, 60-year (with and without re-casking), 100-year, and 200-year dry cask storage operational period. Some of the scenarios assume the accrual change starts in 2019 and the remaining scenarios assume a change in 2021. While most scenarios assume the current license shutdown, several alter the license termination date to be either 5 years before the current license date or 20 years after. The accrual scenarios are presented in Schedule F.

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[8] *In the Matter of Northern States Power Company's for Approval of the 2016-2018 Triennial Nuclear Plant Decommissioning Accrual*, Docket No. E002/M-14-761, ORDER APPROVING NUCLEAR DECOMMISSIONING STUDY, ASSUMPTIONS, AND ANNUAL ACCRUAL, AND SETTING FILING REQUIREMENTS (October 5, 2015).
[9] Minnesota Electric Retail Rate Case, filed November 4, 2013, Docket No. E002/GR-15-826.

B. Primary Factors Changed Since 2014 Filing

The decommissioning analysis is comprised of three discrete steps. The first is to determine a decommissioning cost estimate for a chosen scenario.[10] The second is to determine the forward looking expected return estimate for the Nuclear Decommissioning Trust based on the investment mix over the relevant period of time. This includes an analysis of the expected returns on various asset classes and changing investment strategies based on when liquidity would be needed to cover decommissioning costs. The third step is to calculate an annual accrual necessary to fully fund the costs of decommissioning for each site based on the earnings estimates developed for the chosen scenario.

This Section of the Petition examines the three primary drivers that contribute to changes in the amounts needed for decommissioning at the expiration of the plants' current operating licenses:

- *Changes to the engineering and other cost estimates.* We revised the engineering cost estimates, using multiple dismantling and fuel storage duration scenarios. The DECON decommissioning scenario was prepared with five fuel storage scenarios. Two of the fuel storage scenarios assume no re-casking of the fuel and three fuel storage scenarios assume replacement of spent fuel storage dry casks every 50 years. The SAFSTOR scenario was prepared with two fuel storage scenarios with no re-casking assumed for either scenario.
- *Changes in assumptions about escalation/inflation of costs over time.* We utilized two escalation/inflation rates: one for the labor cash flows and one for the non-labor cash flows;
- *Revisions to the forward looking expected returns.* We applied multiple earnings rates. For each scenario, we applied one earnings rate for the operation period and another for the post shutdown period.

A detailed discussion of each of these primary drivers is provided below.

1. Engineering and Other Cost Estimates

Our consultant, TLG Services, Inc. (TLG), performed site-specific cost estimates for the 20 scenarios noted above (14 fuel scenarios for DECON and six fuel scenarios for SAFSTOR for each of the two sites). Schedules A.1-A14 show TLG's schedules of annual expenditures for each of the scenarios individually. A more complete

[10] In all scenarios, it is assumed that the site is fully dismantled, radiologically decontaminated, and restored.

comparison between the cost estimates from the previous filing to this one is provided in Schedule A.

In addition to the cost estimates from TLG, the Company also has provided a calculation of the NRC minimum funding amount applicable to Xcel Energy's facilities in Schedule A. The NRC minimum is a calculation of a generic cost to decommission based on the output of a unit and is calculated using a formula specified by the NRC. It is not intended to be a site-specific estimate of decommissioning, as it does not address specific site issues. The NRC uses this as a gauge of the minimum level of funding a licensee must have to meet the NRC's funding assurance requirements of future decommissioning. Consistent with prior filings, the Company does not use the NRC minimum when analyzing the need for future decommissioning funding, but it provides it as an additional data point for analysis. All the cost estimates from TLG in total are greater than the NRC minimum calculations, thus we are funding for more than the NRC minimum.

The decommissioning cost estimate is driven by two primary factors: the choice of decommissioning alternative for the radiological removal of the plant and the duration of fuel storage on site after operations. We discuss each in turn below.

a. Decommissioning Alternatives for Radiological Removal

The alternative chosen for the removal and decontamination of the radiological components of the nuclear plant can vary the timing of when the costs are incurred from early in the decommissioning timeframe for DECON to almost 50 years after operations cease for SAFSTOR. The annual costs associated with the radiological decommissioning alternative are similar across all the different spent fuel storage scenarios that are provided. For example, with the DECON method, the radiological removal costs are the same for the 32-year, the two 60-year, the 100-year, and the 200-year spent fuel storage scenarios. Thus, the duration for storing spent fuel remaining on site does not affect the annual costs for the radiological decommissioning.

The Company has decided to evaluate and provide SAFSTOR scenarios—in addition to DECON scenarios—in light of a growing number of plants using this method. Indeed, the industry is currently in the midst of change with respect to decommissioning, as a majority of plants shutting down in recent years are electing to use SAFSTOR. Of the 20 nuclear plants currently in decommissioning across the United States, 14 are utilizing SAFSTOR. Many of these plants have stated, however, they do not intend to take the full 60 years, but will finish decommissioning when economically viable.

The primary driver of this shift to SAFSTOR is the increased earnings in the fund when a large majority of the expenditures are pushed further out into the future. This allows for smaller annual accruals during operation. That is, to the extent that the after-tax return of the fund outpaces the sum of the annual escalation and costs to maintain the facility during dormancy, the required contributions by customers will decrease relative to a DECON method.

Regardless of decommissioning option, we anticipate the plant will put all of the used fuel into dry storage containers and move it to the Independent Spent Fuel Storage Installation (ISFSI) within the first five years following shutdown. This could occur even faster as technology continues to evolve, and we note that the Kewaunee plant recently completed moving all fuel to ISFSI within two years of shut down.

With either method, once the fuel has been moved to dry casks, the spent fuel pool and supporting systems can be dismantled, meaning that that the pool can be drained and supporting equipment can be de-energized and secured. For SAFSTOR, the plant is then left intact during the dormancy period. During this time, there is a 24-hour security force, and maintenance of security systems along with lighting, building maintenance, ventilation and radiation monitoring programs. This dormancy period allows for an eventual reduction in worker dose rates during decommissioning as systems are allowed to decay before full dismantlement. It also results in a reduction in radioactive waste volumes at time of full dismantlement, which results in cost savings.

b. Period that Spent Fuel Could Potentially Remain On Site

The second issue that influences the overall cost estimate is the duration of fuel storage after shutdown and the procedures in place for the handling of spent fuel. These include the period spent fuel remains in the pool, the period the fuel is stored onsite, and whether the fuel has to be moved to a second cask while stored onsite.[11]

As with all decommissioning cost estimates, the dismantlement and removal of contaminated structures cannot be completed until all spent fuel has been removed from the reactors and storage pools and placed in dry storage containers in the ISFSI. Final release of the site from all licenses will occur once all the fuel is removed from

[11] In our last triennial nuclear decommissioning filing, the Commission ordered that the Company provide a more detailed break out of "spent fuel management" costs in future decommissioning filings. In reference to this request the Company first notes that the engineering cost estimate provided in this filing contains tables 3.1-3.7 containing the costs assigned to spent fuel management by cost category and year for all seven scenarios. The cost estimates also provide a narrative discussion regarding what these costs include in section 2.1.4.

the onsite storage facility and the storage facility itself has been removed. The differences between the 32-year, the two 60-year, the 100-year, and the 200-year scenarios are all related to the storage facility operational period and whether the fuel storage scenario included costs to replace spent fuel dry storage casks every 50 years (*i.e.*, recasking). In our spent fuel scenarios, the 32-year and one of the 60-year scenarios do not include recasking. The second 60-year scenario as well as the 100-year and 200-year scenarios include recasking every 50 years.[12] Our recasking assumptions are discussed further in Part c below.

As part of the engineering cost estimate in the 2014 Filing, it was assumed that a federal off-site storage or disposal facility would be available in 2025 allowing spent fuel to be removed from Xcel Energy's nuclear plant sites by 2065 at Prairie Island and 2066 at Monticello. It was also assumed that all spent fuel would be removed from the storage pools at both plants after approximately 15 years to meet cool down requirements before being placed in dry storage. In the current engineering cost study, the assumptions for the removal of the fuel from the storage pools were changed to account for emerging cask technology that will allow spent fuel to be removed from the storage pools within the first five years of decommissioning. However, while the fuel can be placed into the ISFSI much earlier in the decommissioning timeframe compared to the 2014 engineering cost estimate, the ISFSI operating durations were not altered by this change.

Consistent with our 2014 Filing, we have evaluated a scenario that assumes a centralized interim storage facility will begin operation in 2025, allowing shipments from the Prairie Island and Monticello sites to begin in 2027 with all spent fuel being removed from Minnesota by 2064. [13] Based on the current status support for centralized interim storage (discussed further below), we believe this 32-year scenario may represent a realistic length of time for all spent fuel to be shipped off-site to a federal facility following the shutdown of Monticello and Prairie Island, assuming that

[12] The Commission's Order from the 2014 Filing directed the Company to "develop a 60, 100 and 200-year plan for the City of Red Wing to enable Xcel to build, improve, communicate, and share an understanding of the long-term safety-related costs of spent fuel storage on host communities." We provide this information in Schedule B.

[13] The NRC has resumed work on its review of the proposed Yucca Mountain repository as directed by the U.S. Court of Appeals. In October 2014, the NRC issued its Safety Evaluation Report Related to Disposal of High-Level Radioactive Wastes in a Geologic Repository at Yucca Mountain, Nevada: Repository Safety after Permanent Closure (NUREG-1949, Volume 3). Since the last filing, the Yucca Mountain supplemental Environmental Impact Statement (EIS) was issued in May, 2016. A final licensing decision could come after hearings, and full NRC adjudicatory review of contentions filed by project opponents.

the federal facility will be capable of receiving 3,000 metric-tons heavy metal each year from all nuclear power plants nationwide.[14]

In developing the strategy for spent fuel shipping for the 60-year, 100-year, and 200-year scenarios, a key assumption is that all fuel would be shipped from one site first (Prairie Island) followed by the second site (Monticello). Allocations of space for shipping to a federal facility are provided on a company-wide basis, and Xcel Energy has the discretion to ship spent fuel from either site first, or both sites at the same time. If spent fuel were shipped from both sites at the same time, both ISFSIs would have to operate for the entire time period following shutdown, *i.e.* 60 years, 100 years, or 200 years. By completing shipping from one site first, overall costs would be lowered because the costs of operating and securing the first site's ISFSI are eliminated approximately 13 years earlier.

However, the 32-year scenario assumes shipping from both sites simultaneously, resulting in the Prairie Island ISFSI operating until 2064 (31 years after plant shutdown) and the Monticello ISFSI operating until 2062 (32 years after plant shutdown). This is due to a need to cool the spent fuel following discharge from the reactor for a minimum of 30 years prior to shipping. Table 1 below depicts the years that spent fuel shipping will begin and finish for the 32-year, 60-year, 100-year, and 200-year scenarios. The fuel shipping commencement and completion dates do not change because of the decommissioning alternative chosen or whether recasking is performed.

[14] For more information pertaining to the DOE's progress toward its removal of spent nuclear fuel from Minnesota's nuclear plants, see the Company's most recent Annual Nuclear Waste Management Report at Docket No. E002/CN-09-36 filed on August 10, 2017.

Table 2 – Spent Fuel Shipping Schedules

Plant	Year Shipping Begins	Year Shipping Finishes
32-year Scenario		
Prairie Island	2027	2064
Monticello	2042	2062
60-year Scenario (recasking or no recasking)		
Prairie Island	2053	2077
Monticello	2078	2090
100-year Scenario		
Prairie Island	2093	2117
Monticello	2118	2130
200-year Scenario		
Prairie Island	2193	2217
Monticello	2218	2230

These shipping schedules are informed by two sets of activities that are occurring at the national level. The first is the DOE's Strategy for the Management and Disposal of Used Nuclear Fuel and High-Level Radioactive Waste published in January 2013, and the second is the NRC's Continued Storage of Spent Nuclear Fuel rule which went into effect on October 20, 2014.[15] Each is discussed in greater detail below.

i. BRC Report and DOE's Implementation Strategy

The BRC issued its report, entitled "Report to the Secretary of Energy" on January 26, 2012.[16] The report recommended, "Prompt efforts to develop a New Geologic Disposal Facility," in order to provide the needed facilities to safely dispose of spent fuel permanently.[17] In tandem with the development of a geologic disposal facility, the report also recommended, "Prompt efforts to develop one or more consolidated storage facilities," which, "would allow the federal government to begin the orderly transfer of spent fuel from reactor sites to safe and secure centralized facilities independent of the schedule for operating a permanent repository."[18]

On January 11, 2013, in response to the BRC report, then-Secretary Chu issued the DOE's "Strategy for the Management and Disposal of Used Nuclear Fuel and High-

[15] A copy of the Federal Register Notice which published the final NRC rule entitled, "Continued Storage of Spent Nuclear Fuel" dated September 19, 2014 can be found at the following web location: http://www.gpo.gov/fdsys/pkg/FR-2014-09-19/pdf/2014-22215.pdf

[16] "Blue Ribbon Commission on America's Nuclear Future, Report to the Secretary of Energy", http://cybercemetery.unt.edu/archive/brc/20120620220235/http://brc.gov/sites/default/files/documents/brc_finalreport_jan2012.pdf, January 26, 2012

[17] Ibid, Pg. xi

[18] Ibid, Pg. xii

Level Radioactive Waste."[19] The Strategy is intended to serve as a statement of Administration policy on nuclear waste and represents an initial basis for discussions among the Administration, Congress and other stakeholders. As the DOE report summarizes, "The Administration currently plans to implement a program over the next 10 years that:

- Sites, designs and licenses, constructs and begins operations of a pilot interim storage facility by 2021 with an initial focus on accepting used nuclear fuel from shut-down reactor sites;
- Advances toward the siting and licensing of a larger interim storage facility to be available by 2025 that will have sufficient capacity to provide flexibility in the waste management system and allows for acceptance of enough used nuclear fuel to reduce expected government liabilities; and
- Makes demonstrable progress on the siting and characterization of repository sites to facilitate the availability of a geologic repository by 2048."[20]

Full implementation of this program will require legislation to enable the timely deployment of the system elements noted above. In the meantime, the DOE is undertaking activities within its existing authorization to plan for the eventual transportation, storage, and disposal of used nuclear fuel. Activities range from examining waste management system design concepts, to developing plans for consent-based siting processes, to conducting research and development on the suitability of various geologies for a repository.

Based on these two reports, it is feasible that some facility, whether a centralized interim storage facility or permanent geologic disposal facility, could reasonably be sited, constructed and begin receiving fuel by 2025. The projected 2025 timeframe allows time for Congress to enact any required legislative changes, and for the facility to be sited, licensed and constructed. Transportation planning to the centralized interim facility would be accomplished in parallel with the siting and construction activities. The year 2025 is the earliest that spent fuel might be moved from Minnesota nuclear power plants.

Below we provide further details regarding the status of federal storage initiatives.

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[19] *Strategy for the Management and Disposal of Used Nuclear Fuel and High-Level Radioactive Waste*, United States Department of Energy, http://www.energy.gov/sites/prod/files/Strategy%20for%20the%20Management%20and%20Disposal%20of%20Used%20Nuclear%20Fuel%20and%20High%20Level%20Radioactive%20Waste.pdf, January 11, 2013

[20] Ibid, Pg. 2

ii. Status of Federal Storage Initiatives, Permanent or Temporary.

Licensing of Yucca Mountain. Public hearings before the NRC Atomic Safety and Licensing Boards were underway in May 2010 when the DOE sought to withdraw the Yucca Mountain application. An Atomic Safety and Licensing Board denied DOE's motion in June 2010 and the NRC Commission ruled that it was evenly divided on whether to overturn or uphold the Licensing Board decision.

In August 2013, the U.S. Court of Appeals for the District of Columbia Circuit ordered the NRC to continue with the licensing process unless or until Congress ruled otherwise or the NRC exhausted its appropriated funds. Subsequent to that decision, the NRC Staff completed its technical and environmental reviews of the Yucca Mountain application. As of May, 2016, the NRC has completed both the technical and environmental reviews of DOE's application for the proposed Yucca Mountain facility. The public hearings have not, however, been restarted

In March 2017, the Administration's Office of Management and Budget published its Budget Blueprint for Fiscal Year 2018 which proposed $120 million in appropriations "to restart licensing activities for the Yucca Mountain nuclear waste repository and initiate a robust interim storage program." The DOE budget request submitted to Congress on May 23, 2017, included $120 million for Yucca Mountain and interim storage. The NRC budget request, also submitted on May 23, 2017, sought $30 million for Yucca Mountain licensing. The House on July 27, 2017 passed the Fiscal Year 2018 appropriations for DOE and NRC, providing $120 million intended for DOE's Yucca Mountain licensing, and $30 million for NRC Yucca Mountain licensing costs. On August 8, 2017, the NRC announced that it would use $110,000 in existing Nuclear Waste Fund appropriations for information gathering activities relating to potential venues for a restarted Yucca Mountain hearing and the Yucca Mountain electronic database.

Consolidated Interim Storage. There are currently two private initiatives to develop away-from-reactor dry storage facilities. One project, Waste Control Specialists (WCS), is a proposed Consolidated Interim Storage Facility (CISF) at a site in Andrews County, Texas, adjacent to WCS's existing low-level radioactive waste and hazardous waste storage and disposal facilities. In April 2016, WCS filed an application with the NRC for the CISF. In April 2017, WCS asked the NRC to suspend the review of this application. Since that time, a federal judge ruled against the EnergySolutions $367 million acquisition of WCS, saying it would create a monopoly in nuclear waste disposal. It is unknown if another company will purchase WCS or if WCS will choose to move forward with licensing. Holtec

International has proposed a similar facility for a site in Eddy and Lea Counties in southeastern New Mexico. Holtec filed an application with the NRC for this facility on March 30, 2017. Both companies are reportedly considering how their projects could be used to meet the DOE obligation to accept spent nuclear fuel under the Standard Contracts.

It is feasible that some facility, whether it is a centralized interim storage facility or permanent geologic disposal facility, could reasonably be sited, constructed, and begins receiving fuel by 2025. The projected 2025 timeframe allows time for Congress to enact any required legislative changes, and for the facility to be sited, licensed and constructed. The year 2025 is the earliest that spent fuel might be moved from Minnesota nuclear power plants.

iii. Continued Storage of Spent Nuclear Fuel Rule

Historically, Waste Confidence has been the NRC's generic determination regarding the environmental impacts of storing spent nuclear fuel beyond the licensed life for operation of a nuclear power plant. This generic analysis has been incorporated into the NRC's reviews under the National Environmental Policy Act for new reactor licenses, license renewals, and ISFSI licenses through the Waste Confidence Rule. On June 8, 2012, the U.S. Court of Appeals for the DC Circuit found that some aspects of the Waste Confidence Rule did not satisfy the NRC's National Environmental Policy Act obligations and vacated the rulemaking.[21] The court indicated that in making either a Finding of No Significant Impact based on an Environmental Assessment or in an Environmental Impact Statement, the NRC needed to add additional discussions concerning the impacts of failing to secure permanent disposal for spent nuclear fuel, and concerning the impacts of certain aspects of potential spent fuel pool leaks and spent fuel pool fires.

In response to the court's decision, the NRC suspended final licensing decisions on new reactors, reactor license renewals, and spent fuel storage facility renewals. The NRC subsequently directed its staff to develop a new rule within 24 months.

On Sept. 6, 2012, the NRC Commission directed NRC staff to proceed with a Generic Environmental Impact Statement (GEIS) to analyze the environmental impacts of continued storage, address the issues raised in the Court's decision, and update the rule in accordance with the analysis in the GEIS. The final rule and GEIS was renamed from "waste confidence" to "continued storage of spent nuclear fuel" in response to public comment to more accurately reflect the nature and content of the

[21] *New York v. NRC,* 681 F.3d 471 (D.C. Cir. 2012)

rule. The GEIS and final rule effective October 20, 2014, implemented the Commission's direction.

The rule does not authorize, license or otherwise permit nuclear power plant licensees to store spent fuel for any length of time. Rather, the continued storage rule adopts the findings of the GEIS regarding the environmental impacts of storing spent fuel at any reactor site after the reactor's licensed period of operations. As a result, those generic impacts do not need to be re-analyzed in the environmental reviews for individual licenses. The GEIS analyzes the environmental impact of storing spent fuel beyond the licensed operating life of reactors over three timeframes: for 60 years (short-term), 100 years after the short-term scenario (long-term) and indefinitely. However, availability of a deep geologic repository within 60 years is commented on by the NRC in the Federal Register Notice of the Rule where it states on page 56254:

> *The United States national policy remains disposal of spent fuel in a geologic repository, and, as stated in the GEIS, the NRC believes that the most likely scenario is that a repository will become available by the end of the short-term timeframe (60 years beyond the licensed life for operation of a reactor).*

The possibility of even longer service times is supported by the evaluations performed in the NRCs NUREG-2157, Generic Environmental Impact Statement for Continued Storage of Spent Nuclear Fuel. Under the renewed ISFSI licenses, cask monitoring and maintenance activities are reviewed and approved by the NRC and provide reasonable assurance the casks will continue to store used nuclear fuel safely for a minimum of 60 years.

In NUREG- 2157, "The NRC assumes the replacement of dry casks after 100 years of service life, however, replacement times will depend on actual degradation observed during continued regulatory oversight for maintain safety during continued storage."

c. Recasking Assumptions

The Commission Order in the 2014 Filing required the Company to "re-examine its 50-year model recasking cost assumption and analysis, by providing two scenarios—one based on the same recasking assumptions used in this filing, and one assuming the need to replace all casks prior to being turned over to the custody of the federal government."[22] In compliance with that Order, the Company is providing two 60-

[22] Order Point 12(e). Additionally, we note that Order Point 12(g) directed the Company to "provide a detailed discussion of the status of Nuclear Regulatory Commission relicensing of casks, on the anticipated

year fuel storage scenarios—one that includes recasking after 50 years and one that does not. Additionally, both the 100-year and 200-year scenarios include recasking costs. Under all recasking scenarios, the first spent fuel canister would be replaced in 2045 at Prairie Island and 2058 at Monticello.

We believe it is reasonable and appropriate to assume that no recasking will be necessary for either the 32-year or 60-year scenarios. Recent activities by the NRC indicate that cask life is at least 60 years and might be 100 years, or longer. This is supported by the NRC's recent actions to process the renewal of the licenses of multiple ISFSIs,[23] including for Prairie Island, a total operation period of 60 years (a 20-year initial license plus a 40-year renewal) of operation. Under the renewed ISFSI licenses, cask monitoring and maintenance activities are reviewed and approved by the NRC and provide reasonable assurance that the casks will continue to store used nuclear fuel safely for a minimum of 60 years.

In addition, in the Generic Environmental Impact Statement for Continued Storage of Spent Fuel published in NUREG-2157 in September 2014, the NRC states, "The NRC assumes replacement of dry casks after 100 years of service life; however, replacement times will depend on actual degradation observed during continued regulatory oversight for maintaining safety during continued storage." Taken together, we believe these findings support our assumption that no recasking will be necessary under the 60-year scenario. We further note that the large step up in the accrual for any scenarios with recasking is primarily due to the recasking assumption that is included in the cost estimate.

The Prairie Island site specific ISFSI license (SNM-2506), which permits storage of the TN-40 casks, was issued in 1993 for a 20-year period. The associated Safety Analysis Report (SAR) described a minimum design life of 25 years. Xcel Energy subsequently applied for, and the NRC granted, a renewal of license SNM-2506 for an additional 40 years through 2053. As part of the license renewal process, a review of Time-Limited Aging Analyses (TLAA) and the Aging Management Review (AMR) of the ISFSI systems, structures, and components were conducted. TLAA reviews identified analyses that were required to be performed to demonstrate intended functions would be maintained during the period of extended operation. AMRs identified aging effects/mechanisms that could adversely affect the ability of the systems, structures, and components to perform their safety functions during the

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life of the casks used by Xcel, manufacturer and contractor warranties and liability obligations for the casks, the technical and regulatory barriers associated with transporting the casks used and the status of any federal storage initiatives whether permanent or temporary.

period of extended operation and the application identifies an acceptable aging management program to be implemented prior to the period of extended operation at the site. The NRC Staff reviewed the AMRs and the Aging Management Programs proposed by Xcel Energy and added additional license conditions reflecting the Aging Management Programs.

The Monticello ISFSI casks are authorized by Certificate of Compliance 72-1004 which permits the use of each cask for 20 years from the date it is placed into service. The associated SAR described a service life of 50 years. The general license holder (TN Americas LLC) has subsequently applied for a renewal of Certificate of Compliance 1004 for an additional 40 years. This application is pending NRC approval. As part of the license renewal process, a review of Time-Limited Aging Analyses (TLAA) and the AMR of the ISFSI systems, structures, and components was conducted. TLAA reviews identified analyses that were required to be performed to demonstrate intended functions would be maintained during the period of extend operation. AMRs identified aging effects/mechanisms that could adversely affect the ability of the systems, structures, and components to perform their safety functions during the period of extended operation and the application identifies an acceptable aging management program to be implemented prior to the period of extended operation at the site. The application included SAR markups to modify the service life to 60 years.[24]

Based on TLAA and AMRs that have been performed, experience to date and continuation of approved aging management programs to ensure that monitoring and maintenance are adequately performed, Xcel Energy believes it is reasonable to assume the licenses and Certificates of Compliance may eventually be renewed for an additional 40 years, or longer.

d. Technical and Regulatory Barriers to Transporting Spent Fuel

There are no technical or regulatory barriers to transporting spent fuel. The NRC regulates the transportation of commercial spent nuclear fuel in accordance with 10 CFR Part 71 – Packaging and Transport of Radioactive Material. Over the past 30 years, the DOE, NRC and the nuclear industry have safely completed approximately 3,000 shipments of spent nuclear fuel and high-level waste. There is also extensive worldwide experience with spent nuclear fuel transportation: more than 70,000 metric tons of uranium of spent nuclear fuel has been safely shipped in the past 25 years.

[24] The manufacture warranty states the design of the casks shall conform and comply with the applicable NRC requirements for 20 years. The warranty on the material and services typically applies for 2- 5 years from the date of services or material delivery.

This is equal to the amount the DOE will ship to a permanent repository as authorized in the Nuclear Waste Policy Act. Barriers at this time are largely political and at a state level along the proposed transportation routes. DOE continues to provide funding to work on the potential transportation barriers such as public education and emergency planning along the transportation routes.

Under contract with DOE, nuclear plant operators are required to prepare spent fuel for shipment to DOE. To ship spent fuel the nuclear plant operators are required to place the fuel in NRC approved containers for transportation. The casks used for storage at Monticello and Prairie Island also will be used for transportation and there will not be a need to move spent fuel from their current storage container prior to transport. The actual transportation will be the responsibility of DOE. To accomplish this title and liability for the spent fuel will be transferred to DOE when the spent fuel transportation container crosses the nuclear plant site boundary and is in the possession of DOE.

2. Escalation/Inflation Rate

The second primary driver of the decommissioning estimate is an updated set of assumptions regarding escalation and inflation. Goldman Sachs Asset Management (GSAM), our investment advisor for the NDT, provided the forecast analysis for the escalation/inflation rates used in this filing's accrual calculations. A more comprehensive narrative of this analysis and accompanying graphs are included in Schedule C, which includes a discussion of the economic and inflation factors, including gross national product growth, labor productivity, and other considerations utilized in estimating long-term inflation rates.

The Company recommends a 4.05 percent escalation rate for the labor component of decommissioning and a 2.85 percent escalation rate for the non-labor components. The 1.2 percent difference in this escalation rate for non-labor reflects the fact that increases in labor productivity will not have an impact on escalation of non-labor costs. These two rates were factored into the calculation of the future costs of nuclear decommissioning. However, the Prairie Island Indian Community payments were not escalated as they remain constant each year until the fuel is removed from the site.

3. Forecast Earnings Rate

GSAM also provided the analysis for the forecasted earnings rate, which was reviewed internally for reasonableness. A more comprehensive narrative of this analysis and accompanying graphs are included in Schedule D, which includes a discussion of the analytical framework used by GSAM to arrive at the forward looking expected

returns. It also includes a discussion regarding our investment strategy, investment and economic assumptions, and the expected returns for the various classes of investments that are currently a part of the fund.

While there is inherent uncertainty in any forward looking expected return and escalation/inflation forecasts, the longer it takes to complete the decommissioning, the more time the fund has to compound earnings on the amounts contributed. At the same time, however, a longer decommissioning period also subjects the fund to more risk that the estimated earnings will not be realized as expected.

Consistent with our past triennial filings, the Company recommends a stratification of the earnings rate between the operational period and the decommissioning period. We also recommend two earnings rates for each facility to better match the earnings rates with the individual cost estimates and to better replicate the separation in the Qualified Trusts within the NDT. Each unit has its own set of earnings rates due to the difference in the timing of cash flows and different decommissioning start dates. Table 2 below shows the expected after-tax returns that are representative of the analysis detailed in Schedule D.

Table 3 – Earnings Rates Forecast

	60-Year Scenario			
	2014 Rates		2017 Rates	
Nuclear Unit	Operations	Decom.	Operations	Decom.
Monticello	6.20%	5.51%	5.00%	4.43%
Prairie Island Unit 1	6.24%	5.35%	4.99%	4.15%
Prairie Island Unit 2	6.30%	5.23%	5.04%	4.09%

The decrease in the expected after-tax returns is largely the result of lower forward looking expected returns for multiple asset classes.

C. Trust Structure & Investment Strategy

Per the Commission's October 5th, 2015 Order in Docket E002/M-14-761, the NDT investments are contained in three Qualified Trusts, which are a standard decommissioning fund that cannot be refunded to customers until all decommissioning activities are completed. The Company has established an individual Qualified Trust for each nuclear operating unit to hold the decommissioning funds required by the NRC.

Below we discuss our investment strategy for the NDT as well as changes to our liquidity assumptions for the trust.

1. Investment Strategy

As discussed in previous triennial dockets, the Company's NDT Committee routinely evaluates both the NDT's performance and the overall investment strategy for the fund (including its asset allocation), and it revises both the strategy and allocation as necessary. Following a hearing on the Company's 2016 Annual Informational Report, the Commission issued an order in February 2017 requiring Xcel Energy to re-evaluate the investment mix for the NDT with the purpose of reducing the NDT's investment management fees and increasing the annual return on its investment portfolio.

As part of this Triennial Nuclear Decommissioning Accrual filing, the Company undertook a comprehensive review of our investment allocations to evaluate portfolio changes that would be effective over the next triennial period. The process of determining the portfolio's asset mix is called asset allocation optimization. Different mixes of assets can produce hundreds, or even thousands, of alternative combinations of risk and returns. As a result, asset allocation techniques are used in practice to evaluate the various possible asset mixes and determine those combinations that are likely to deliver optimal performance in terms of risk and return.

We have used this process to perform a long-term optimization of the asset allocation for the NDT's investments. With any investment, there is always a trade-off between risk and the expected rate of return on that investment. Typically, strategies with higher expected returns also come with higher risk and vice versa. The goal is to optimize the trade-off between risk and return over the long term. If on one hand too little risk is taken, then there is a significant chance that the trust remains underfunded, necessitating very large contributions into the trust in later years. If on the other hand too much risk is taken, there is a risk of significant underfunding of the trust in the future, or of overfunding of the trust, which because of the difficulty of removing assets from the Qualified Trust is also undesirable.

In addition to this analysis, the Company also considered portfolio options that shifted fund objectives slightly from liability matching characteristics such as inflation sensitivity to instead focus on lower cost, more traditional investments. To that end, the NDT's investment in commodities was removed from the portfolio. The Company also re-evaluated the diversifying assets included in the portfolio, such as the hedge fund investments. Consistent with the objective of reducing investment manager fees and simplifying the portfolio, hedge funds were also removed.

Following the Company's full analysis of multiple investment portfolios, we recommend the following investment mix shown in Table 3 below. We note that the

development of this recommendation followed a process deemed prudent by the independent investment review required by the Commission's February 27, 2017 Order in Docket No. E002/M-14-761. That review also concluded that the Company "has found an appropriate balance to achieving a reasonable risk adjusted return" and that its asset allocation is "properly diversified amongst a reasonable amount of non-correlated assets classes."

Table 4 – Recommended Investment Mix

Portfolio Line Item	2016 Target	Updated 2017 Target
Total Equity	60.0%	60.0%
Private Equity	10.0%	10.0%
Public Equity	50.0%	50.0%
US All Cap Equity	26.0%	25.8%
Non-US Developed Equity	14.0%	14.1%
Emerging Markets Equity	10.0%	10.1%
Fixed Income	17.5%	30.0%
Investment Grade Fixed Income	5.0%	12.1%
High Yield Fixed Income	8.5%	10.0%
Emerging Market Debt	4.0%	7.9%
Hedge Funds	7.5%	0.0%
Private Real Estate	10.0%	10.0%
Real Assets (Commodities)	5.0%	0.0%
Cash	0.0%	0.0%
Total	**100.0%**	**100.0%**

Consistent with prior triennial filings, we request that the Commission approve this asset allocation, which we believe results in an optimized trade-off between risk and return over the long term on a forward looking basis. That said, the Company will continue to analyze the portfolio asset mix and make updates and changes as necessary. In other words, the portfolio mix identified in this filing is a snapshot of a point in time and could change between now and the next triennial filing.

A more detailed discussion of the recommended target asset mix for the decommissioning fund, along with an analysis of the forward looking expected returns is included in Schedule D.

a. Change in Liquidity Assumptions

The Company's 2014 analysis of forward looking expected returns assumed a reallocation of investments equivalent to the respective cash outflow to bonds six

years before that cash flow was needed for decommissioning. This was done to follow a principal called "the Two-Fund Separation Theorem," which states that an efficient portfolio can be constructed of both a growth portfolio and efficient low-risk portfolio. For 2017, the Company's analysis is continuing to use this Two-Fund Separation Theorem as a guide when making future investment assumptions. However, the Company is proposing a change from reallocation six years before cash flows to five years before cash flows.

Our analysis assumes that the funds are invested in bonds as a cash outlay is approached. For each expected annual outgoing cash flow, assets are converted to bonds ahead of time to give more certainty to the ability to make the payment. Not all funds are converted to bonds – only enough to cover each annual cash outflow. For example, if the conversion is at a five year period, the first outflows expected in 2030 are converted to bonds in 2025; then in 2026, enough cash is converted to bonds to match the 2031 expected outflow.

Since expected bond returns are lower than the expected growth portfolio returns, the earlier the transition to bonds, the greater the certainty (lower the risk) but also the lower expected return. And because a later conversion to bonds for each cash flow increases the overall expected return, the assumed conversion period has been reduced from six years to five years as indicated above. We believe any risk of the shorter period is mitigated by the transfer to bonds each year for the associated cash flow (rather than all at once), so cycles have a chance to 'average out."

In short, the Company believes that making this change will provide greater returns without adding significant additional risk. Additional details regarding this change are provided in Schedule D.

D. Current Fund Balances

Annually, the Company reports the balances in the various funds in either this petition or a separate letter. The balances for both the Qualified Trust for the MN Jurisdiction are discussed below. The Escrow Fund was transferred to the Qualified Trust after the last decommissioning filing and thus, Escrow Fund no longer exists.

1. Qualified Trust

As of June 30, 2017, the Qualified Trust book value balance for all three operating units was a total of $1,151 million for the MN Jurisdiction, with a total market value of $1,467 million. The difference between the book value and the market value is the

unrealized gains and losses. Table 4 below shows the book and market values by unit. A detailed presentation of each unit's balances is presented in Schedule E.

Table 5 – Qualified Trust Balance as of June 30, 2017

Unit	Book Value	Market Value
Monticello	$514,771,426	$641,884,228
Prairie Island Unit 1	298,347,569	388,313,263
Prairie Island Unit 2	337,452,778	436,807,122
Total	$1,150,571,773	$1,467,004,613

The Qualified Trust is maintained by retail and wholesale jurisdictions. The retail jurisdictions are Minnesota, North Dakota, South Dakota, and Wisconsin. The wholesale jurisdictions are Minnesota and Wisconsin. Since 2014, there are no longer any full requirements wholesale customers; the Company contacted the FERC for the possibility of redistributing the two wholesale jurisdictional balances to the four retail jurisdictions. Before we can do this transfer within the Qualified Trust, we must first file with the FERC for their approval.

While we cannot physically transfer the funds with in the Qualified Trust, and regardless of whether the FERC grants us approval to do so, the amount of funds assigned to these two wholesale jurisdictions need to be factored into the Minnesota retail accrual calculation. The reason we believe that we have to factor a portion of the wholesale balance into the accrual calculation relates to the allocation of the cost estimate to each jurisdiction. One hundred percent of the cost estimate is allocated to the retail jurisdictions as these customers carry the burden of funding the remaining amount for decommissioning. If we did not include a portion of the wholesale balance in the accrual calculation, the accrual calculations for each retail jurisdiction will over recover the amount needed by the wholesale balance. Thus, for the accrual calculation we must account for the Minnesota jurisdictional amount of the Minnesota and Wisconsin wholesale balance when calculating the accrual.

The book value balance for the Minnesota and Wisconsin wholesale jurisdictions in total was $45.3 million and for the market value is was $56.7 million at June 30, 2017. The proposed distribution of these balances using the rate case demand allocators, assigned 73.4886 percent of the total to the Minnesota Retail jurisdiction, or $33.3 million additional book value balance and $41.7 million in market value balance. The allocation of the wholesale jurisdiction balances is included in Schedule E. Including the Minnesota Retail portion of the wholesale jurisdiction balances to the June 30, 2017 balances, results in the adjusted balances used in this filing as follows in Table 5:

Table 6 – Adjusted Qualified Trust Balance as of June 30, 2017

Unit	Book Value	Market Value
Monticello	$529,148,381	$660,140,345
Prairie Island Unit 1	308,078,761	399,941,696
Prairie Island Unit 2	346,627,064	448,597,551
Total	$1,183,854,206	$1,508,679,592

2. Beginning Fund Balance for Annuity Calculation

The 2014 Filing was submitted using the fund's market values, per the Commission order, and the 2017 filing continues to use the market value as a basis for the accrual. Using the adjusted market value is consistent with forward looking market conditions and will provide the most justifiable and proper accrual estimate at this time. The adjusted funds currently have a $324.8 million unrealized net gain. However, not all of this unrealized gain is available to fund decommissioning costs because taxes will have to be paid on the gains when they are realized. Therefore, the June 30, 2017 adjusted market value was dampened by $90.4 million for the estimated tax that can be expected be paid when the unrealized gain is realized. The Company calculated the tax effect on the June 30, 2017 adjusted market value based on the unrealized gains and losses in the portfolio. This tax effect calculation is shown with each accrual calculation in Schedule F.

3. Escrow Fund

In the 2014 Filing, the Commission approved the discontinuance of the Escrow Fund and approved the transfer (pour-over) to the Qualified Trust. The Company completed this pour-over in 2016 and reported a zero balance in the Escrow Fund with the 2017 compliance filing to 2014 Filing.

VI. EFFECT OF CHANGE UPON XCEL ENERGY REVENUE

Subdivision 1 (b) of Minn. Stat. §216B.2445 requires the inclusion of an estimated customer impact for each of the assumed periods. For this petition we calculated the rate impact to each of the customer classes on a $/kWh increase. This was done by allocating the estimated accruals for the various scenarios presented in Schedule F to the customer classes using the most recent Class Cost of Service Study.

The class allocation process used the same stratification methodology approved by the Commission in Docket No. E002/M-11-807 to return the DOE Settlement dollars to customers. This included an approximate 19.3 percent weight to capacity and an 80.7

percent weight to energy usage from Docket No E002/GR-15-826. The accrual was then divided by the energy each class forecasted to be used over a 12-month period ending December 31, 2017, also from Docket No. E002/GR-15-826, to determine a $/kWh that would be required for that class to collect its portion of the accrual. Schedule G provides the result of this calculation for all accruals provided in Schedule F.

VII. EOL NUCLEAR FUEL

At the time each nuclear unit is shutdown, there will be nuclear fuel remaining in the reactor that has not been fully utilized. We refer to this unused fuel as end-of-life (EOL) nuclear fuel. The unused fuel cannot be transferred to another facility, and the amortization expense for said fuel would have to be taken at the end of operations at each unit. To avoid this spike in amortization at the end of the useful life of each unit, the Company estimates the expected cost of unused fuel at the end of operations and amortizes the expense over the remaining life of each unit. This is done using a sinking fund method.

The Company recommends a decrease to the annual internal accrual for EOL nuclear fuel for this triennial filing. The Company is proposing to change the 2019 accrual based on the new EOL nuclear fuel factors discussed in Schedule H. The Minnesota jurisdictional annual accrual for 2019 is requested to be $2,040,887. This is a decrease of $372,402 over the accrual based on the factors approved in the 2014 Filing.

This recommended decrease stems mainly from an update in the estimates of the cost of the final fuel at shutdown. The estimated amount to be recovered decreased approximately $4 million from the estimate used in the 2014 Filing. The decrease was primarily the result of lower projected nuclear fuel commodity prices in the future, and the enrichment assumptions used in the estimate for Monticello. The 2021 accrual worksheet detailing the calculation is included in Schedule H. We have included the 2019 and 2020 data as well, for comparison purposes. The internal rate of return has been revised for the 2021 accrual to coincide with the new authorized rate of return from the MYRP.

VIII. PREMATURE RISK INVESTIGATION

In previous Orders, the Commission has directed that the Company to provide an investigation of premature risk in its Triennial Nuclear Decommissioning Accrual

filings.[25] Consistent with the Commission's prior orders, our investigation included the following aspects of the risks of premature decommissioning:

- The availability of commercial insurance.
- The availability of electric industry co-insurance.
- Any programs, which may be proposed, mandated, or administered by the NRC or any other United States Government agency.
- Specific detailed information pertaining to any steps Xcel Energy has taken to minimize any possible loss, which may occur as a result of premature decommissioning.
- Xcel Energy's ability to withstand possible economic and financial trauma, which may be associated with premature decommissioning.

Schedule I contains the regular response to that request. It addresses accident and non-accident related premature decommissioning of nuclear generating facilities. Presently, insurance is unavailable for non-accident related premature decommissioning such as those caused by regulatory directives. Therefore, the insurance analysis deals with accidents.

Xcel Energy property insurance coverage of $2.25 billion would largely offset the potential impact of an accident-related decommissioning. Although accident-related decommissioning expenses are significant, the length of time involved in a clean-up process, insurance payments, tax deductibility of expenses, and related rate relief would affect the yearly expense. Although accident related premature decommissioning would affect both the Company and its customers, it is anticipated that, with acceptable regulatory decisions, the financial integrity of the Company would be maintained.

IX. ASSET RETIREMENT OBLIGATION

The implementation of the Statement of Financial Accounting Standards No. 143 (SFAS 143), *Accounting for Asset Retirement Obligations* (ARO) in January of 2003 brought some changes to the accrual accounting for decommissioning. Financial Accounting Standards Board (FASB) Interpretation No. 47 (FIN 47), *Accounting for Conditional Asset Retirement Obligations* was released in March 2005. These statements are both included within the FASB Accounting Standards Codification (ASC) 410 *Asset Retirement and Environmental Obligations*. This Interpretation of the conditionality of an ARO has resulted in some additional accounting analysis for many of the fixed assets

[25] *In the Matter of the Petition of Northern States Power Company d/b/a Xcel Energy for Approval of the 2012-2014 Triennial Nuclear Plant Decommissioning Accrual,* Docket No. E002/M-11-939, Order Approving Decommissioning Plan and Modifying Refund Plan, (Dec. 4, 2012).

at Xcel Energy. Nuclear decommissioning was never assumed to be conditional in nature, thus the ARO accounting for nuclear decommissioning established in 2003 is unaffected by this Interpretation. Nonetheless, a summary of the ARO accounting for nuclear decommissioning is included in Schedule J for reference. This section is provided in response to the Commission's Order Point 12.a. from the 2014 Filing.

X. COMPLIANCE MATRIX AND REQUESTED AUTHORIZATION

The Company has provided Schedule K, a Compliance Matrix, to assist in referencing specific order points from the Commission Order from the 2014 Filing to the discussion in this petition.

XI. MISCELLANEOUS INFORMATION

Pursuant to Minn. R. 7829.0700, subpt. 2, Xcel Energy requests that the following persons be placed on the Commission's official service list for this matter:

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Any information requests in this proceeding should be submitted to Mr. Cronin at the Regulatory Records email address above.

XII. SUPPORTING DOCUMENTS

The following supporting schedules and studies have been included for filing requirement purposes and consistent with past practice:

Supporting Schedules

A	Cost Estimate Summary
B	Red Wing Plan
C	Escalation Analysis
D	Portfolio Analysis
E	Qualified Trust Statements

Supporting Schedules

F	Decommissioning Accrual Analysis
G	Customer Rate Impact Calculation
H	EOL Accrual
I	Premature Risk Investigation
J	Asset Retirement Obligation
K	Compliance Matrix
L	Decommissioning Cost Analysis for the Monticello Nuclear Generating Plant
M	Decommissioning Cost Analysis for the Prairie Island Nuclear Generating Plant

CONCLUSION

Xcel Energy respectfully requests the Commission approve our Petition for Approval of the 2019-2021 Nuclear Decommissioning Accrual. As described in this filing, we specifically request Commission approval of:

- Approve our decommissioning study and assumptions as compliant with the Company's obligations under Minnesota statutes, Commission rules, and prior precedent;
- Continue the current approved annual accrual of $14.0 million, to meet the needs of the Company's 60-year spent fuel scenario with no re-casking of the fuel, continuing for 2019 through 2021 while strategic decisions about the future of our nuclear units are decided in our 2019 IRP;
- Approve an annual accrual of $2.0 million for EOL nuclear fuel for the calendar year 2019 through 2021; and
- Permit the Company to hold settlement payments received from the DOE in an interest-bearing account until the 2019 IRP is resolved, at which time the Commission can decide whether to apply those funds to the NDT or refund them to customers.

Additionally, and consistent with prior triennial filings, the Company is requesting Commission approval of changes in investment transition assumption and investment mix targets. Specifically, the Company requests Commission approval of the following two changes in order to improve the expected earnings of the investment portfolio and ensure that decommissioning funding needs are met without excess costs to customers:

- Transitioning investments to bonds five years before decommissioning cash flows rather than the six years as previously assumed; and
- Changing the investment mix to reduce allocations to certain alternative asset classes and increase allocations to fixed income investments, thereby reducing the expected fees and increasing the forward looking expected return.

The next decommissioning filing would be for the calendar years 2022 through 2024 with the submittal due December 1, 2020.

Dated: December 1, 2017

Northern States Power Company

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Nancy Lange	Chair
Dan Lipschultz	Commissioner
Matthew Schuerger	Commissioner
Katie J. Sieben	Commissioner
John A. Tuma	Commissioner

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY FOR APPROVAL OF THE 2019-2021 TRIENNIAL NUCLEAR DECOMMISSIONING STUDY & ASSUMPTIONS

DOCKET NO. E002/M-17-828

SUMMARY

SUMMARY OF FILING

Please take notice that on December 1, 2017, Northern States Power Company, doing business as Xcel Energy, filed with the Minnesota Public Utilities Commission its Petition for approval of its Triennial Nuclear Decommissioning Study and Assumptions. In this Petition the Company analyzed a number of decommissioning scenarios and calculated a number of different accruals The resulting accrual calculations range from negative $16.0 million (meaning we are over-funded today) for scenarios involving life extensions of our plants to positive $115.9 million (meaning we are under-funded today) for scenarios involving the early retirement of our plants by five years.

The full version of this filing can be found via the Commission's website at http://mn.gov/puc/. Select "Search eDockets," enter the year (17) and the docket number (828), then select "Search."

The cost estimates developed and presented in this decommissioning filing are based on numerous fundamental assumptions, including regulatory requirements, project contingencies, low-level radioactive waste disposal practices, high-level radioactive waste management options, and site restoration requirements. Thus, there are seven cost estimates for each facility provided with this filing. There are five fuel storage options and two dismantiling options presented.

As required by Minnesota statutes, a variety of cost studies were created, in order to address the possibility of delays in the DOE acceptance of spent fuel. The Company is required by statute to submit at least three cost scenarios, 60-year, 100-year, and 200-year scenarios. The length of these scenarios is the longest period of time measured from the start of shutdown until all spent fuel is removed from the locations, for all scenarios that is for the Monticello plant. The 60-year, scenario has been provided with a no-re-casking assumption as well as one that assumes that spent fuel storage dry casks will be replaced every 50 years. The 100-year and the 200-year dry cask operational period scenarios assume that the fuel will be re-casked every 50-years. The Company has provided Schedule P in order to clarify its position and the basis for disagreement with the need to recask the spent fuel every 50 years.

In the 2014 Filing, the Company provided all scenarios using the DECON decommissioning alternative. This alternative is discussed below, and also elaborated on in TLG's executive summary to the cost estimate. In addition to the standard DECON scenarios presented, this filing also provides two SAFSTOR alternative scenarios for consideration. Over the last several years SAFSTOR has become a more popular decommissioning alternative as nuclear facilities have begun shutting down. The Company last presented a SAFSTOR its 2002 filing, as well as the 2003 update to reflect license extention at Priarie Island. Both of these decommissioning alternatives are discussed below.

For this filing, the Company assumed approximately five years of wet storage based on a conservative estimate of the capabilitieis of casks currently on the market. For the remainder of this period, the fuel will be stored in dry storage and the pool will no longer be required. This results in a significant decrease in the amount of security staff required at the site.

As a basis for these cost estimates, TLG uses a systems and structural inventory database, which in 1999, was revised for both nuclear facilities. The Company has reviewed and made minor changes to this inventory in the current filing. Other items provided as input are property and sales tax assumptions, insurance levels, burial rates, recycling practices, license termination dates, department budgets,

purchased power and oil costs, incidental costs and meteorological data. These are all input to a process that will estimate the total dollar amount for decontaminating, removing, packaging, shipping, and disposing of the two nuclear sites. These cost estimates include labor rates for both salaried staff and union craft people. All labor is provided with loadings such as pension, unemployment, workers compensation, and medical where applicable. An estimate for employee retention costs also was included in the estimate to account for the additional expense the Company expects to incur in order to insure it retains the staffing required for the plant in the early post shutdown stage while fuel remains in the pool. Xcel Energy also reviewed the organizational structure and numbers of employees for the salaried staff input.

Briefly, the decommissioning process is broken down into several main categories of work that are performed in various periods throughout the decommissioning depending on the dismantling method and the fuel storage assumptions, as follows:

Preparation – Site preparation, engineering and planning of detailed procedures, performing various surveys, implementing the staffing transition plan, organizing the staff required to manage the intended decommissioning activities from available plant staff and outside resources, and submitting filings to regulatory entities.

Fuel Storage – Packaging the fuel in dry cask canisters, loading the canisters to the storage pad, building a fuel transfer facility, re-casking every 50 years for some cost estimates

Dormancy – For SAFSTOR only, this is the period following unit shutdown where structures and systems not necessary for the operation or support of spent fuel pool and site security and surveilience are drained, de-energized, and securired. Minimal maintenance, sanitation, and sealing is performed to allow the facility to be maintained in an inactive state until delayed decommissioning activities commence. Only inspection, maintenance and security/surveilience activities are occurring during this period.

Decommissioning operations – a constructing additional facilities for cask storage, transferring all spent fuel to dry casks, modifications to site structures and facilities, decontamination, removal, packaging, shipping, and burial of all contaminated and activated components and structures. By the end of this work all radioactive or

contaminated material from the plant has been removed, but the fuel may still be onsite.

Site Restoration – The demolition of remaining structures, site restoration, and license termination.

All cost estimate numbers are provided in instant dollars, which means that costs for the same activity from one year to the next do not increase due to inflation. For example, the salary for an engineer is the same in the first year and all subsequent years. The time value impact of inflation is brought into the equation in the accrual calculation worksheet.

In Summary, the Company has computed variousdecommissioning accruals using the DECON scenario assuming a 32-year, 60-year (no re-casking), 60-year (recasking), 100-year (with re-casking), and 200-year (with re-casking) dry cask storage operational period. Additional decommissioning accruals have been computed using the SAFSTOR scenario with the 32-year and 60-year (no re-casking) dry cask storage operational period.

SAFSTOR Method of Decommissioning

SAFSTOR is defined in the U.S. Code of Federal Regulations, Title 10, Parts 30, 40, 50, 51, 70, and 72, as "the alternative in which the nuclear facility is placed and maintained in a condition that allows the nuclear facility to be safely stored and subsequently decontaminated (deferred decontamination) to levels that permit release for unrestricted use." Under this cost estimate decommissioning activities will commence about 50 years after the cessation of operations and will be completed within 60 years. Many plants entering SAFSTOR have stated they do not intend to take the full 60 years but will finish decommissioning when economically viable.

SAFSTOR has begun to be pursued by a number of plant operators as they have entered shutdown. The primary reason for this shift is the increased earnings in the fund when a large majority of the expenditures are pushed further out into the future, which allows for smaller annual accruals during operation. To the extent that the after-tax return of the fund out paces the sum of the annual escalation and costs to tend the facility during dormancy, the required contributions by rate payers will be decreased over a DECON method. Over a 50 year dormancy period, this impact becomes substantial based upon current estimates.

The salaried staff presented in the cost estimate is not necessarily assumed to be the staff of Xcel Energy. This assumption is due to the length of the wait period, now being 50 years, and the fact that the employees with nuclear experience currently employed within Xcel Energy will be enjoying retirement and not available for decommissioning work. Thus, the cost estimate assumes a Decommissioning Operations Contractor (DOC), which is an independent entity that oversees the decommissioning work and provides the required salaried employees.

A more detailed description of the cost estimation process is included in the accompanying two volumes. TLG has provided a written outline of the procedures as well as worksheets that delineate the costs per activity, per period. The 2017 cost estimate results from TLG for SAFSTOR are provided for the 32 year and 60 year no-recasking scenarios.

DECON Method of Decommissioning

DECON is defined in the U.S. Code of Federal Regulations, Title 10, Parts 30, 40, 50, 51, 70, and 72, as "the alternative in which the equipment, structures, and portions of a facility and site containing radioactive contaminants are removed or decontaminated to a level that permits the property to be released for unrestricted use shortly after cessation of operations."

Under this cost estimate decommissioning activities will commence as soon as possible after the cessation of operations. The last fuel assemblies will be sufficiently cooled and can be removed from the spent fuel pool and placed in dry casks after about five years.

DECON has been the preferred method of decommissioning for most situations. It is generally favorable because it eliminates the costs for caretaking, other than those related to the ISFSI. The cost estimate places most of the major expenditures more towards the front end of the decommissioning schedule. This is a major advantage because the individuals familiar with the operation of the facility are available to support the dismantling effort, plant systems and services are fully functional, structural integrity is intact, and licensee has a comprehensive management organization available to oversee and conduct the orderly decommissioning and decontamination.

The 2017 cost estimate results from TLG Services for DECON are provided for the 32-year, 60-year (no re-casking), 60-year (recasking), 100-year, and 200-year

spent fuel removal scenarios. The 100-year and the 200-year spent fuel scenarios also assume a 50 year recasking schedule.

Comparison to 2014 Filing

An extended time period of spent fuel management has multiple impacts including a significant increase in labor costs and extends the period of cost escalation, which creates a higher risk over time. The Company has escalated the 60-year cost estimate from the 2014 Filing in the Table 1 below and compared it to the 2017 cost estimate simply to show that the cost estimates were similar and in line with the changes expected from inflaltion. The comparison table inflates the 2014 Filing cost estimate using the last approved escalation rate for radiological activities of 4.36 percent along with the 3.36 percent approved for the ISFSI operating periods.

Table 1
Comparison of Current No-Recasking Cost Estimate to Previous Filing
60-Year Scenario

	2014 Study in 2017 Dollars	2017 Cost Estimate
Monticello	$1,478,122,368	$1,515,849,676
Prairie Island Unit 1	891,516,617	997,041,305
Prairie Island Unit 2	1,038,396,636	998,642,807
	$3,408,035,641	$3,511,533,789

There have been a number of differences in the cost estimate assumptions that factor into the comparison of the cash flows. One of the largest increases was in the security staffing levels for the plants. This is the first filing where the Company has provided a detailed site specific estimate of security staffing levels rather than using generic estimates that did not fully incorporate current NRC requirements of 10CFR73.55. This was substantially offset by a decrease in the amount of time the Company anticipates needing to operate the spent fuel pool after shutdown from15 years to 5 years. This was driven by the emergence of new cask technology capable of storing hotter fuel, which allows the Company to empty the pool somewhat faster than prior estimates. This results in decreased operating and security costs for the plant. Also new to this cost estimate was the inclusion of certain retention payments, removal of all structures below grade in compliance

with Minnesota Pollution Control Agency (MPCA) rules[1], and the continuation of PIIC payments throughout the decommissioning period as long as fuel remains on the Prairie Island site. Given the increases and decreases, the current estimate is slightly increased, but remains approximately in line with the inflated 2014 Filing cost estimate.

Table 2 shows the attachments that provide the yearly cost estimate detail for the seven cost estimates for each facility. Theses summaries show the costs for the radiological decommissioning, the spent fuel management costs, site restoration, and the ISFSI decommissioning. The entire TLG cost estimate documentation is provided in Schedule L for Monticello and Schedule M for Prairie Island.

Table 2
Cost Estimate Cash Flow Summary Schedules

A.1	Monticello Schedule of Annual Expenditures – DECON 32-Year Schedule
A.2	Monticello Schedule of Annual Expenditures – DECON 60-Year No-Recasking Schedule
A.3	Monticello Schedule of Annual Expenditures – DECON 60-Year with Recasking Schedule
A.4	Monticello Schedule of Annual Expenditures – DECON 100-Year Schedule
A.5	Monticello Schedule of Annual Expenditures – DECON 200-Year Schedule
A.6	Monticello Schedule of Annual Expenditures – SAFSTOR 32-Year Schedule
A.7	Monticello Schedule of Annual Expenditures – SAFSTOR 60-Year No-Recasking Schedule
A.8	Prairie Island Schedule of Annual Expenditures – DECON 32-Year Schedule

[1] MPCA interpretation and clarification of rule 7035.0400

A.9	Prairie Island Schedule of Annual Expenditures – DECON 60-Year Schedule
A.10	Prairie Island Schedule of Annual Expenditures – DECON 60-Year with Recasking Schedule
A.11	Prairie Island Schedule of Annual Expenditures – DECON 100-Year Schedule
A.12	Prairie Island Schedule of Annual Expenditures – DECON 200-Year Schedule
A.13	Prairie Island Schedule of Annual Expenditures – SAFSTOR 32-Year Schedule
A.14	Prairie Island Schedule of Annual Expenditures – SAFSTOR 60-Year No-Recasking Schedule

NRC Minimum

The NRC minimum required funding amounts, based upon the new information from NUREG-1307, Revision 16, and the most recent statistics for comparison to the new cost estimates have been calculated. Under the NRC minimum calculation requirements, the Company must show that it will meet the minimum cost calculated under at least one of the two burial options allowed: Direct Burial and Blended Burial. Both of the NRC minimum calculations are less than all scenarios of our 2017 cost estimates in total. Table 3 shows lists the support schedules for the information for the calculation of the NRC minimum.

Table 3
NRC Minimum Calculation Supporting Schedules

A.15	NRC Minimum Historical Escalation
A.16	NRC Minimum Calculation

Property Taxes Included in Cost Estimates

Taxation of utility property is fundamentally different than taxation of the property owned by any other business. Like other businesses, we pay property taxes on the value of the land we own, the buildings attached thereto, and rights-of-way. This property is all assessed at the local level. Unlike other businesses, however, we are also assessed property taxes on personal property. Specifically, we are required to pay property taxes on Operating Property, which is defined as "any tangible property that is owned or leased, except land, which is directly associated with the generation, transmission, or distribution of electricity [or] natural gas…." Minn. R. 8100.0100, subp. 11.

In Minnesota, the Department of Revenue (DOR) values all of the Company's operating property in Minnesota, as well as its gas and electric operating property that extends into North Dakota and South Dakota. Each type of property is valued as one integrated system, or unit. When the system value for each type (electric or natural gas) is determined, an allocation is then made to reflect how much of the system value is attributable to Minnesota. Allocation is based on a combination of original cost of the property in Minnesota to total system cost, as well as gross revenue in Minnesota to total system revenue.

Deductions are then made to subtract property locally assessed (land and some buildings) and exemptions (e.g., sliding scale exemption for generation efficiency, pollution control, etc.). The resulting value is then apportioned to the various taxing districts based on the original cost of the property located in those districts.

Local taxing districts then combine the market value apportioned to them with the value of the Company's locally assessed property to arrive at our tax base within the taxing district's jurisdiction. Finally, each jurisdiction then applies its own individual property tax rate to our tax base to determine our property tax liability in that jurisdiction.

As we make new investments in personal property throughout our integrated system, the market value upon which property taxes are assessed increases. This increased market value is then apportioned to the local jurisdictions that host our Monticello and Prairie Island plants. In 2012, the Company paid $8.9 million in real and personal property taxes related to Monticello and $11.9 million for Prairie Island. In 2013, the Company paid $13.1 million in property taxes related to Monticello and $13.9 million for Prairie Island. When operations at these nuclear plants cease, the operating property will be removed from the sites and will no longer be included in the DOR's market valuation. This will result in a reduction

in property taxes paid when operations cease, but the property for the ISFSI will continue to be locally assessed. For the decommissioning cost estimates, the land, structures, and the dry cask portion of the operating property taxes were assumed to continue with the structures component lasting until the structures are decommissioned and removed.

The property tax amounts for Monticello and Prairie Island provided in the decommissioning cost estimate were based on the actual liabilities for 2014 paid in 2016. The Company's consultant developed the future property tax estimates for after plant shut down based on the actual 2014 accruals for the Prairie Island ($21.4 million) and Monticello ($17.5 million) locations as reflected on the property tax statements received and paid in 2016. Table 3 shows the change in property taxes from operations to decommissioning.

Table 4
Property Tax Estimates

	During Operations	Plant Shutdown	Plant Structures Removed
Prairie Island			
Land	$212,258	$212,258	$212,258
Structure	4,552,444	4,552,444	0
Substation	345,235	0	0
ISFSI	1,885,006	1,885,006	1,885,006
Generation Machinery	14,378,986	0	0
Total	$21,373,930	$6,649,708	$2,097,264
Monticello			
Land	$535,724	$535,724	$535,724
Structure	2,524,272	2,524,272	0
Substation	287,654	0	0
ISFSI	149,311	149,311	149,311
Generation Machinery	13,959,453	0	0
Total	$17,456,414	$3,209,307	$685,035

The process used in the current property tax cost estimates is the same as the method used in our 2014 Filing. In addition, we note that there is no double recovery of property taxes between the decommissioning accrual and those included in current rates. The collection of funds from customers today for the payment of future tax obligations does not relate to the current year property tax expense.

Xcel Energy
Cost Estimate Summary

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Schedule A.0
Page 10 of 10

Spent Fuel Management Costs

The cost estimates include the operating and maintenance of the ISFSI from shutdown through when all the fuel has been removed from the site. Schedules A.1 through A.14 show the annual costs in total spent fuel management costs by unit. Schedule A.17 breaks the spent fuel management costs down into its cost components such as utility staff, property taxes, and operating costs.

Table 5
Cost Breakdown Schedule

A.17	Spent Fuel Management Cost Breakdown – 60-year DECON

Xcel Energy **Docket No. E002/M-17-828**
Schedule of Annual Expenditures **Schedule A.1**
32-Year Decommissioning Period **Page 1 of 1**

SCHEDULE OF TOTAL ANNUAL EXPENDITURES
Monticello Nuclear Generating Plant

Year	Radiological	Spent Fuel	Site Restoration	ISFSI Radiological	Yearly Total
2030	$27,622,702	$9,158,323	$158,156	$0	$36,939,181
2031	109,411,318	5,290,419	609,481	0	115,311,218
2032	175,717,482	4,766,180	189,516	0	180,673,177
2033	151,858,587	24,566,464	27,458	0	176,452,509
2034	101,337,190	3,866,462	5,028	0	105,208,680
2035	95,996,598	103,960,455	3,444	0	199,960,497
2036	63,844,950	7,084,520	0	0	70,929,470
2037	9,093,107	8,146,118	31,514,417	0	48,753,642
2038	112,108	8,637,491	35,879,589	0	44,629,189
2039	0	8,242,615	0	0	8,242,615
2040	0	8,265,197	0	0	8,265,197
2041	0	8,242,615	0	0	8,242,615
2042	0	8,625,360	0	0	8,625,360
2043	0	9,390,851	0	0	9,390,851
2044	0	9,030,688	0	0	9,030,688
2045	0	9,008,105	0	0	9,008,105
2046	0	10,539,088	0	0	10,539,088
2047	0	10,156,343	0	0	10,156,343
2048	0	12,833,504	0	0	12,833,504
2049	0	10,156,343	0	0	10,156,343
2050	0	9,390,851	0	0	9,390,851
2051	0	9,008,105	0	0	9,008,105
2052	0	9,413,433	0	0	9,413,433
2053	0	9,008,105	0	0	9,008,105
2054	0	9,008,105	0	0	9,008,105
2055	0	9,390,851	0	0	9,390,851
2056	0	9,030,688	0	0	9,030,688
2057	0	9,008,105	0	0	9,008,105
2058	0	9,390,851	0	0	9,390,851
2059	0	9,773,597	0	0	9,773,597
2060	0	9,030,688	0	0	9,030,688
2061	0	9,773,597	0	0	9,773,597
2062	0	9,773,597	0	0	9,773,597
2063	9,484,743	15,411	2,888,351	14,814,819	27,203,324
	$744,478,784	$400,983,117	$71,275,439		$1,231,552,159

Xcel Energy **Docket No. E002/M-17-828**
Schedule of Annual Expenditures **Schedule A.2**
60-Year Decommissioning Period **Page 1 of 2**

SCHEDULE OF TOTAL ANNUAL EXPENDITURES
Monticello Nuclear Generating Plant

Year	Radiological	Spent Fuel	Site Restoration	ISFSI Radiological	Yearly Total
2030	$27,622,702	$2,258,324	$158,156	$0	$30,039,182
2031	109,411,318	5,356,796	609,481	0	115,377,595
2032	175,717,487	4,832,543	189,516	0	180,739,546
2033	151,858,609	26,932,825	27,458	0	178,818,892
2034	101,337,239	3,932,827	5,028	0	105,275,094
2035	95,996,631	104,026,819	3,444	0	200,026,894
2036	63,844,950	7,150,891	0	0	70,995,841
2037	9,093,107	8,212,486	31,514,417	0	48,820,010
2038	112,108	8,688,760	35,879,589	0	44,680,457
2039	0	8,112,178	0	0	8,112,178
2040	0	8,134,221	0	0	8,134,221
2041	0	8,112,178	0	0	8,112,178
2042	0	8,112,178	0	0	8,112,178
2043	0	8,112,178	0	0	8,112,178
2044	0	8,134,221	0	0	8,134,221
2045	0	8,112,178	0	0	8,112,178
2046	0	8,112,178	0	0	8,112,178
2047	0	8,112,178	0	0	8,112,178
2048	0	10,788,801	0	0	10,788,801
2049	0	8,112,178	0	0	8,112,178
2050	0	14,084,983	0	0	14,084,983
2051	0	14,084,983	0	0	14,084,983
2052	0	17,557,026	0	0	17,557,026
2053	0	20,122,483	0	0	20,122,483
2054	0	14,947,483	0	0	14,947,483
2055	0	19,259,983	0	0	19,259,983
2056	0	21,007,026	0	0	21,007,026
2057	0	8,045,814	0	0	8,045,814
2058	0	8,045,814	0	0	8,045,814
2059	0	8,045,814	0	0	8,045,814
2060	0	8,067,857	0	0	8,067,857
2061	0	8,045,814	0	0	8,045,814
2062	0	8,045,814	0	0	8,045,814
2063	0	8,045,814	0	0	8,045,814
2064	0	8,067,857	0	0	8,067,857
2065	0	8,045,814	0	0	8,045,814
2066	0	8,045,814	0	0	8,045,814
2067	0	8,045,814	0	0	8,045,814
2068	0	8,067,857	0	0	8,067,857
2069	0	8,045,814	0	0	8,045,814
2070	0	8,045,814	0	0	8,045,814
2071	0	8,045,814	0	0	8,045,814

Xcel Energy **Docket No. E002/M-17-828**
Schedule of Annual Expenditures **Schedule A.2**
60-Year Decommissioning Period **Page 2 of 2**

SCHEDULE OF TOTAL ANNUAL EXPENDITURES
Monticello Nuclear Generating Plant

Year	Radiological	Spent Fuel	Site Restoration	ISFSI Radiological	Yearly Total
2072	0	8,067,857	0	0	8,067,857
2073	0	8,045,814	0	0	8,045,814
2074	0	8,045,814	0	0	8,045,814
2075	0	8,045,814	0	0	8,045,814
2076	0	8,067,857	0	0	8,067,857
2077	0	8,045,814	0	0	8,045,814
2078	0	9,944,210	0	0	9,944,210
2079	0	10,326,955	0	0	10,326,955
2080	0	9,966,212	0	0	9,966,212
2081	0	9,944,210	0	0	9,944,210
2082	0	9,944,210	0	0	9,944,210
2083	0	10,326,955	0	0	10,326,955
2084	0	9,966,212	0	0	9,966,212
2085	0	9,944,210	0	0	9,944,210
2086	0	9,944,210	0	0	9,944,210
2087	0	10,326,955	0	0	10,326,955
2088	0	12,620,790	0	0	12,620,790
2089	0	9,944,210	0	0	9,944,210
2090	0	8,795,973	0	0	8,795,973
2091	9,198,906	0	2,936,846	14,854,149	26,989,900
	$744,193,057	$685,478,537	$71,323,933	$14,854,149	$1,515,849,676

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SCHEDULE OF TOTAL ANNUAL EXPENDITURES
Monticello Nuclear Generating Plant

Year	Radiological	Spent Fuel	Site Restoration	ISFSI Radiological	Yearly Total
2030	$27,622,702	$2,258,324	$158,156	$0	$30,039,182
2031	109,411,312	5,356,786	609,481	0	115,377,579
2032	175,717,484	18,411,741	189,516	0	194,318,741
2033	151,858,609	26,932,825	27,458	0	178,818,892
2034	101,337,239	3,932,827	5,028	0	105,275,094
2035	95,996,631	104,026,819	3,444	0	200,026,894
2036	63,844,950	7,150,891	0	0	70,995,841
2037	9,093,107	8,212,486	31,514,417	0	48,820,010
2038	112,108	8,688,760	35,879,589	0	44,680,457
2039	0	8,112,179	0	0	8,112,179
2040	0	8,134,222	0	0	8,134,222
2041	0	8,112,179	0	0	8,112,179
2042	0	8,112,179	0	0	8,112,179
2043	0	8,112,179	0	0	8,112,179
2044	0	8,134,222	0	0	8,134,222
2045	0	8,112,179	0	0	8,112,179
2046	0	8,112,179	0	0	8,112,179
2047	0	8,112,179	0	0	8,112,179
2048	0	10,788,804	0	0	10,788,804
2049	0	8,112,176	0	0	8,112,176
2050	0	14,084,983	0	0	14,084,983
2051	0	14,084,983	0	0	14,084,983
2052	0	17,557,026	0	0	17,557,026
2053	0	20,122,483	0	0	20,122,483
2054	0	14,947,483	0	0	14,947,483
2055	0	19,259,983	0	0	19,259,983
2056	0	21,007,026	0	0	21,007,026
2057	0	8,045,815	0	0	8,045,815
2058	0	32,431,354	0	0	32,431,354
2059	0	8,045,815	0	0	8,045,815
2060	0	8,067,858	0	0	8,067,858
2061	0	8,045,815	0	0	8,045,815
2062	0	8,045,815	0	0	8,045,815
2063	0	8,045,815	0	0	8,045,815
2064	0	8,067,858	0	0	8,067,858
2065	0	8,045,815	0	0	8,045,815
2066	0	22,677,139	0	0	22,677,139
2067	0	8,045,815	0	0	8,045,815
2068	0	42,207,613	0	0	42,207,613
2069	0	8,045,815	0	0	8,045,815
2070	0	8,045,815	0	0	8,045,815
2071	0	8,045,815	0	0	8,045,815

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SCHEDULE OF TOTAL ANNUAL EXPENDITURES
Monticello Nuclear Generating Plant

Year	Radiological	Spent Fuel	Site Restoration	ISFSI Radiological	Yearly Total
2072	0	8,067,858	0	0	8,067,858
2073	0	8,045,815	0	0	8,045,815
2074	0	8,045,815	0	0	8,045,815
2075	0	8,045,815	0	0	8,045,815
2076	0	8,067,858	0	0	8,067,858
2077	0	8,045,815	0	0	8,045,815
2078	0	9,944,210	0	0	9,944,210
2079	0	10,326,955	0	0	10,326,955
2080	0	9,966,212	0	0	9,966,212
2081	0	9,944,210	0	0	9,944,210
2082	0	9,944,210	0	0	9,944,210
2083	0	10,326,955	0	0	10,326,955
2084	0	9,966,212	0	0	9,966,212
2085	0	9,944,210	0	0	9,944,210
2086	0	9,944,210	0	0	9,944,210
2087	0	10,326,955	0	0	10,326,955
2088	0	12,620,790	0	0	12,620,790
2089	0	9,944,210	0	0	9,944,210
2090	9,198,906	8,795,973	0	0	17,994,879
2091	0	0	2,937,361	14,928,557	17,865,917
	$744,193,049	$772,214,374	$71,324,448	$14,928,557	$1,602,660,427

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SCHEDULE OF TOTAL ANNUAL EXPENDITURES
Monticello Nuclear Generating Plant

Year	Radiological	Spent Fuel	Site Restoration	ISFSI Radiological	Yearly Total
2030	$27,622,702	$2,258,324	$158,156	$0	$30,039,182
2031	109,411,312	5,356,786	609,481	0	115,377,579
2032	175,717,484	18,411,741	189,516	0	194,318,741
2033	151,858,609	26,932,825	27,458	0	178,818,892
2034	101,337,239	3,932,827	5,028	0	105,275,094
2035	95,996,631	104,026,819	3,444	0	200,026,894
2036	63,844,950	7,150,891	0	0	70,995,841
2037	9,093,107	8,247,094	31,612,405	0	48,952,606
2038	112,108	8,818,492	35,991,150	0	44,921,751
2039	0	9,289,712	0	0	9,289,712
2040	0	9,314,982	0	0	9,314,982
2041	0	9,289,712	0	0	9,289,712
2042	0	9,289,712	0	0	9,289,712
2043	0	9,289,712	0	0	9,289,712
2044	0	9,314,982	0	0	9,314,982
2045	0	9,289,712	0	0	9,289,712
2046	0	9,289,712	0	0	9,289,712
2047	0	9,289,712	0	0	9,289,712
2048	0	11,969,561	0	0	11,969,561
2049	0	9,289,712	0	0	9,289,712
2050	0	15,262,516	0	0	15,262,516
2051	0	15,262,516	0	0	15,262,516
2052	0	15,287,786	0	0	15,287,786
2053	0	15,262,516	0	0	15,262,516
2054	0	15,262,516	0	0	15,262,516
2055	0	15,262,516	0	0	15,262,516
2056	0	15,287,786	0	0	15,287,786
2057	0	15,262,516	0	0	15,262,516
2058	0	39,648,055	0	0	39,648,055
2059	0	15,262,516	0	0	15,262,516
2060	0	15,287,786	0	0	15,287,786
2061	0	15,262,516	0	0	15,262,516
2062	0	15,262,516	0	0	15,262,516
2063	0	15,262,516	0	0	15,262,516
2064	0	15,287,786	0	0	15,287,786
2065	0	15,262,516	0	0	15,262,516
2066	0	29,893,840	0	0	29,893,840
2067	0	15,262,516	0	0	15,262,516
2068	0	49,427,541	0	0	49,427,541
2069	0	15,262,516	0	0	15,262,516
2070	0	15,262,516	0	0	15,262,516
2071	0	15,262,516	0	0	15,262,516

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SCHEDULE OF TOTAL ANNUAL EXPENDITURES
Monticello Nuclear Generating Plant

Year	Radiological	Spent Fuel	Site Restoration	ISFSI Radiological	Yearly Total
2072	0	15,287,786	0	0	15,287,786
2073	0	15,262,516	0	0	15,262,516
2074	0	15,262,516	0	0	15,262,516
2075	0	15,262,516	0	0	15,262,516
2076	0	15,287,786	0	0	15,287,786
2077	0	15,262,516	0	0	15,262,516
2078	0	15,262,516	0	0	15,262,516
2079	0	15,262,516	0	0	15,262,516
2080	0	15,287,786	0	0	15,287,786
2081	0	15,262,516	0	0	15,262,516
2082	0	15,262,516	0	0	15,262,516
2083	0	15,262,516	0	0	15,262,516
2084	0	15,287,786	0	0	15,287,786
2085	0	15,262,516	0	0	15,262,516
2086	0	15,262,516	0	0	15,262,516
2087	0	15,262,516	0	0	15,262,516
2088	0	17,942,366	0	0	17,942,366
2089	0	15,262,516	0	0	15,262,516
2090	0	15,262,516	0	0	15,262,516
2091	0	15,262,516	0	0	15,262,516
2092	0	18,737,786	0	0	18,737,786
2093	0	21,300,016	0	0	21,300,016
2094	0	16,125,016	0	0	16,125,016
2095	0	114,858,721	0	0	114,858,721
2096	0	22,187,786	0	0	22,187,786
2097	0	9,223,347	0	0	9,223,347
2098	0	9,223,347	0	0	9,223,347
2099	0	9,223,347	0	0	9,223,347
2100	0	9,223,347	0	0	9,223,347
2101	0	9,223,347	0	0	9,223,347
2102	0	9,223,347	0	0	9,223,347
2103	0	9,223,347	0	0	9,223,347
2104	0	9,248,617	0	0	9,248,617
2105	0	9,223,347	0	0	9,223,347
2106	0	9,223,347	0	0	9,223,347
2107	0	9,223,347	0	0	9,223,347
2108	0	33,634,157	0	0	33,634,157
2109	0	9,223,347	0	0	9,223,347
2110	0	9,223,347	0	0	9,223,347
2111	0	9,223,347	0	0	9,223,347
2112	0	9,248,617	0	0	9,248,617
2113	9,198,906	9,223,347	0	0	18,422,253

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SCHEDULE OF TOTAL ANNUAL EXPENDITURES
Monticello Nuclear Generating Plant

Year	Radiological	Spent Fuel	Site Restoration	ISFSI Radiological	Yearly Total
2114	0	9,223,347	0	0	9,223,347
2115	0	9,223,347	0	0	9,223,347
2116	0	23,879,941	0	0	23,879,941
2117	0	9,223,347	0	0	9,223,347
2118	0	44,083,965	0	0	44,083,965
2119	0	10,326,955	0	0	10,326,955
2120	0	9,966,212	0	0	9,966,212
2121	0	9,944,210	0	0	9,944,210
2122	0	9,944,210	0	0	9,944,210
2123	0	10,326,955	0	0	10,326,955
2124	0	9,966,212	0	0	9,966,212
2125	0	9,944,210	0	0	9,944,210
2126	0	9,944,210	0	0	9,944,210
2127	0	10,326,955	0	0	10,326,955
2128	0	12,620,790	0	0	12,620,790
2129	0	9,944,210	0	0	9,944,210
2130	0	8,795,973	0	0	8,795,973
2131	0	0	3,088,487	3,962,165	7,050,652
	$744,193,048	$1,599,295,243	$71,685,125	$3,962,165	$2,419,135,581

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SCHEDULE OF TOTAL ANNUAL EXPENDITURES
Monticello Nuclear Generating Plant

Year	Radiological	Spent Fuel	Site Restoration	ISFSI Radiological	Yearly Total
2030	$27,622,702	$2,258,324	$158,156	$0	$30,039,182
2031	109,411,312	5,356,786	609,481	0	115,377,579
2032	175,717,484	18,411,740	189,516	0	194,318,740
2033	151,858,609	26,932,822	27,458	0	178,818,889
2034	101,337,239	3,932,823	5,028	0	105,275,090
2035	95,996,631	104,026,817	3,444	0	200,026,892
2036	63,844,950	7,150,892	0	0	70,995,842
2037	9,093,107	8,247,092	31,612,405	0	48,952,604
2038	112,108	8,815,549	35,991,150	0	44,918,808
2039	0	9,251,355	0	0	9,251,355
2040	0	9,276,526	0	0	9,276,526
2041	0	9,251,355	0	0	9,251,355
2042	0	9,251,355	0	0	9,251,355
2043	0	9,251,355	0	0	9,251,355
2044	0	9,276,526	0	0	9,276,526
2045	0	9,251,355	0	0	9,251,355
2046	0	9,251,355	0	0	9,251,355
2047	0	9,251,355	0	0	9,251,355
2048	0	11,931,106	0	0	11,931,106
2049	0	9,251,355	0	0	9,251,355
2050	0	15,224,175	0	0	15,224,175
2051	0	15,224,175	0	0	15,224,175
2052	0	15,249,336	0	0	15,249,336
2053	0	15,224,175	0	0	15,224,175
2054	0	15,224,175	0	0	15,224,175
2055	0	15,224,175	0	0	15,224,175
2056	0	15,249,336	0	0	15,249,336
2057	0	15,224,175	0	0	15,224,175
2058	0	39,609,705	0	0	39,609,705
2059	0	15,224,175	0	0	15,224,175
2060	0	15,249,336	0	0	15,249,336
2061	0	15,224,175	0	0	15,224,175
2062	0	15,224,175	0	0	15,224,175
2063	0	15,224,175	0	0	15,224,175
2064	0	15,249,336	0	0	15,249,336
2065	0	15,224,175	0	0	15,224,175
2066	0	29,855,495	0	0	29,855,495
2067	0	15,224,175	0	0	15,224,175
2068	0	49,389,086	0	0	49,389,086
2069	0	15,224,175	0	0	15,224,175
2070	0	15,224,175	0	0	15,224,175
2071	0	15,224,175	0	0	15,224,175

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SCHEDULE OF TOTAL ANNUAL EXPENDITURES
Monticello Nuclear Generating Plant

Year	Radiological	Spent Fuel	Site Restoration	ISFSI Radiological	Yearly Total
2072	0	15,249,336	0	0	15,249,336
2073	0	15,224,175	0	0	15,224,175
2074	0	15,224,175	0	0	15,224,175
2075	0	15,224,175	0	0	15,224,175
2076	0	15,249,336	0	0	15,249,336
2077	0	15,224,175	0	0	15,224,175
2078	0	15,224,175	0	0	15,224,175
2079	0	15,224,175	0	0	15,224,175
2080	0	15,249,336	0	0	15,249,336
2081	0	15,224,175	0	0	15,224,175
2082	0	15,224,175	0	0	15,224,175
2083	0	15,224,175	0	0	15,224,175
2084	0	15,249,336	0	0	15,249,336
2085	0	15,224,175	0	0	15,224,175
2086	0	15,224,175	0	0	15,224,175
2087	0	15,224,175	0	0	15,224,175
2088	0	17,903,906	0	0	17,903,906
2089	0	15,224,175	0	0	15,224,175
2090	0	15,224,175	0	0	15,224,175
2091	0	15,224,175	0	0	15,224,175
2092	0	15,249,336	0	0	15,249,336
2093	0	15,224,175	0	0	15,224,175
2094	0	15,224,175	0	0	15,224,175
2095	0	109,645,371	0	0	109,645,371
2096	0	15,249,336	0	0	15,249,336
2097	0	15,224,175	0	0	15,224,175
2098	0	15,224,175	0	0	15,224,175
2099	0	15,224,175	0	0	15,224,175
2100	0	15,224,175	0	0	15,224,175
2101	0	15,224,175	0	0	15,224,175
2102	0	15,224,175	0	0	15,224,175
2103	0	15,224,175	0	0	15,224,175
2104	0	15,249,336	0	0	15,249,336
2105	0	15,224,175	0	0	15,224,175
2106	0	15,224,175	0	0	15,224,175
2107	0	15,224,175	0	0	15,224,175
2108	0	39,634,866	0	0	39,634,866
2109	0	15,224,175	0	0	15,224,175
2110	0	15,224,175	0	0	15,224,175
2111	0	15,224,175	0	0	15,224,175
2112	0	15,249,336	0	0	15,249,336
2113	0	15,224,175	0	0	15,224,175

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SCHEDULE OF TOTAL ANNUAL EXPENDITURES
Monticello Nuclear Generating Plant

Year	Radiological	Spent Fuel	Site Restoration	ISFSI Radiological	Yearly Total
2114	0	15,224,175	0	0	15,224,175
2115	0	15,224,175	0	0	15,224,175
2116	0	29,880,656	0	0	29,880,656
2117	0	15,224,175	0	0	15,224,175
2118	0	49,363,915	0	0	49,363,915
2119	0	15,224,175	0	0	15,224,175
2120	0	15,249,336	0	0	15,249,336
2121	0	15,224,175	0	0	15,224,175
2122	0	15,224,175	0	0	15,224,175
2123	0	15,224,175	0	0	15,224,175
2124	0	15,249,336	0	0	15,249,336
2125	0	15,224,175	0	0	15,224,175
2126	0	15,224,175	0	0	15,224,175
2127	0	15,224,175	0	0	15,224,175
2128	0	17,903,906	0	0	17,903,906
2129	0	15,224,175	0	0	15,224,175
2130	0	15,224,175	0	0	15,224,175
2131	0	15,224,175	0	0	15,224,175
2132	0	15,249,336	0	0	15,249,336
2133	0	15,224,175	0	0	15,224,175
2134	0	15,224,175	0	0	15,224,175
2135	0	15,224,175	0	0	15,224,175
2136	0	15,249,336	0	0	15,249,336
2137	0	15,224,175	0	0	15,224,175
2138	0	15,224,175	0	0	15,224,175
2139	0	15,224,175	0	0	15,224,175
2140	0	15,249,336	0	0	15,249,336
2141	0	15,224,175	0	0	15,224,175
2142	0	15,224,175	0	0	15,224,175
2143	0	15,224,175	0	0	15,224,175
2144	0	15,249,336	0	0	15,249,336
2145	0	100,573,555	0	0	100,573,555
2146	0	15,224,175	0	0	15,224,175
2147	0	15,224,175	0	0	15,224,175
2148	0	15,249,336	0	0	15,249,336
2149	0	15,224,175	0	0	15,224,175
2150	0	15,224,175	0	0	15,224,175
2151	0	15,224,175	0	0	15,224,175
2152	0	15,249,336	0	0	15,249,336
2153	0	15,224,175	0	0	15,224,175
2154	0	15,224,175	0	0	15,224,175
2155	0	15,224,175	0	0	15,224,175

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SCHEDULE OF TOTAL ANNUAL EXPENDITURES
Monticello Nuclear Generating Plant

Year	Radiological	Spent Fuel	Site Restoration	ISFSI Radiological	Yearly Total
2156	0	15,249,336	0	0	15,249,336
2157	0	15,224,175	0	0	15,224,175
2158	0	39,609,705	0	0	39,609,705
2159	0	15,224,175	0	0	15,224,175
2160	0	15,249,336	0	0	15,249,336
2161	0	15,224,175	0	0	15,224,175
2162	0	15,224,175	0	0	15,224,175
2163	0	15,224,175	0	0	15,224,175
2164	0	15,249,336	0	0	15,249,336
2165	0	15,224,175	0	0	15,224,175
2166	0	29,855,495	0	0	29,855,495
2167	0	15,224,175	0	0	15,224,175
2168	0	52,043,666	0	0	52,043,666
2169	0	15,224,175	0	0	15,224,175
2170	0	15,224,175	0	0	15,224,175
2171	0	15,224,175	0	0	15,224,175
2172	0	15,249,336	0	0	15,249,336
2173	0	15,224,175	0	0	15,224,175
2174	0	15,224,175	0	0	15,224,175
2175	0	15,224,175	0	0	15,224,175
2176	0	15,249,336	0	0	15,249,336
2177	0	15,224,175	0	0	15,224,175
2178	0	15,224,175	0	0	15,224,175
2179	0	15,224,175	0	0	15,224,175
2180	0	15,249,336	0	0	15,249,336
2181	0	15,224,175	0	0	15,224,175
2182	0	15,224,175	0	0	15,224,175
2183	0	15,224,175	0	0	15,224,175
2184	0	15,249,336	0	0	15,249,336
2185	0	15,224,175	0	0	15,224,175
2186	0	15,224,175	0	0	15,224,175
2187	0	15,224,175	0	0	15,224,175
2188	0	15,249,336	0	0	15,249,336
2189	0	15,224,175	0	0	15,224,175
2190	0	15,224,175	0	0	15,224,175
2191	0	15,224,175	0	0	15,224,175
2192	0	18,699,336	0	0	18,699,336
2193	0	21,261,665	0	0	21,261,665
2194	0	16,086,665	0	0	16,086,665
2195	0	105,748,555	0	0	105,748,555
2196	0	22,149,336	0	0	22,149,336
2197	0	9,184,995	0	0	9,184,995

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SCHEDULE OF TOTAL ANNUAL EXPENDITURES
Monticello Nuclear Generating Plant

Year	Radiological	Spent Fuel	Site Restoration	ISFSI Radiological	Yearly Total
2198	0	9,184,995	0	0	9,184,995
2199	0	9,184,995	0	0	9,184,995
2200	0	9,184,995	0	0	9,184,995
2201	0	9,184,995	0	0	9,184,995
2202	0	9,184,995	0	0	9,184,995
2203	0	9,184,995	0	0	9,184,995
2204	0	9,210,166	0	0	9,210,166
2205	0	9,184,995	0	0	9,184,995
2206	0	9,184,995	0	0	9,184,995
2207	0	9,184,995	0	0	9,184,995
2208	0	36,250,286	0	0	36,250,286
2209	0	9,184,995	0	0	9,184,995
2210	0	9,184,995	0	0	9,184,995
2211	0	9,184,995	0	0	9,184,995
2212	0	9,210,166	0	0	9,210,166
2213	9,198,904	9,184,995	0	0	18,383,899
2214	0	9,184,995	0	0	9,184,995
2215	0	9,184,995	0	0	9,184,995
2216	0	23,841,486	0	0	23,841,486
2217	0	9,184,995	0	0	9,184,995
2218	0	44,083,968	0	0	44,083,968
2219	0	10,326,948	0	0	10,326,948
2220	0	9,966,221	0	0	9,966,221
2221	0	9,944,218	0	0	9,944,218
2222	0	9,944,218	0	0	9,944,218
2223	0	10,326,948	0	0	10,326,948
2224	0	9,966,221	0	0	9,966,221
2225	0	9,944,218	0	0	9,944,218
2226	0	9,944,218	0	0	9,944,218
2227	0	10,326,948	0	0	10,326,948
2228	0	9,966,221	0	0	9,966,221
2229	0	9,944,218	0	0	9,944,218
2230	0	8,795,978	0	0	8,795,978
2231	0	0	3,088,487	3,962,165	7,050,652
	$744,193,046	$3,441,603,346	$71,685,125	$3,962,165	$4,261,443,682

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SCHEDULE OF TOTAL ANNUAL EXPENDITURES
Monticello Nuclear Generating Plant

Year	Radiological	Spent Fuel	Site Restoration	ISFSI Radiological	Yearly Total
2030	$24,264,597	$9,158,323	$0	$0	$33,422,920
2031	104,697,554	5,290,416	0	0	109,987,970
2032	42,642,743	9,353,482	0	0	51,996,225
2033	33,328,022	30,185,144	0	0	63,513,166
2034	33,328,022	9,485,139	0	0	42,813,161
2035	25,036,146	106,966,023	0	0	132,002,168
2036	7,029,533	5,909,632	0	0	12,939,165
2037	7,010,327	5,893,486	0	0	12,903,813
2038	7,010,327	5,893,486	0	0	12,903,813
2039	7,010,327	5,893,486	0	0	12,903,813
2040	7,029,533	5,909,632	0	0	12,939,165
2041	7,010,327	5,893,486	0	0	12,903,813
2042	7,010,327	6,276,232	0	0	13,286,559
2043	7,010,327	7,041,722	0	0	14,052,049
2044	7,029,533	6,675,123	0	0	13,704,656
2045	7,010,327	6,658,977	0	0	13,669,304
2046	7,010,327	8,189,959	0	0	15,200,286
2047	7,010,327	7,807,214	0	0	14,817,541
2048	7,029,533	10,477,939	0	0	17,507,472
2049	7,010,327	7,807,218	0	0	14,817,545
2050	7,010,327	7,041,722	0	0	14,052,049
2051	7,010,327	6,658,977	0	0	13,669,304
2052	7,029,533	7,057,868	0	0	14,087,401
2053	7,010,327	6,658,977	0	0	13,669,304
2054	7,010,327	6,658,977	0	0	13,669,304
2055	7,010,327	7,041,722	0	0	14,052,049
2056	7,029,533	6,675,123	0	0	13,704,656
2057	7,010,327	6,658,977	0	0	13,669,304
2058	7,010,327	7,041,722	0	0	14,052,049
2059	7,010,327	7,424,469	0	0	14,434,796
2060	7,029,533	6,675,123	0	0	13,704,656
2061	7,010,327	7,424,469	0	0	14,434,796
2062	7,010,327	7,424,469	0	0	14,434,796
2063	5,756,546	269,160	0	0	6,025,706
2064	5,772,318	269,898	0	0	6,042,215
2065	5,756,546	269,160	0	0	6,025,706
2066	5,756,546	269,160	0	0	6,025,706
2067	5,756,546	269,160	0	0	6,025,706
2068	5,772,318	269,898	0	0	6,042,215
2069	5,756,546	269,160	0	0	6,025,706
2070	5,756,546	269,160	0	0	6,025,706
2071	5,756,546	269,160	0	0	6,025,706

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SCHEDULE OF TOTAL ANNUAL EXPENDITURES
Monticello Nuclear Generating Plant

Year	Radiological	Spent Fuel	Site Restoration	ISFSI Radiological	Yearly Total
2072	5,772,318	269,898	0	0	6,042,215
2073	5,756,546	269,160	0	0	6,025,706
2074	5,756,546	269,160	0	0	6,025,706
2075	5,756,546	269,160	0	0	6,025,706
2076	5,772,318	269,898	0	0	6,042,215
2077	5,756,546	269,160	0	0	6,025,706
2078	5,756,546	269,160	0	0	6,025,706
2079	5,756,546	269,160	0	0	6,025,706
2080	5,772,318	269,898	0	0	6,042,215
2081	5,756,546	269,160	0	0	6,025,706
2082	5,756,546	269,160	0	0	6,025,706
2083	5,756,546	269,160	0	0	6,025,706
2084	5,772,318	269,898	0	0	6,042,215
2085	50,934,209	269,160	514,522	0	51,717,891
2086	93,208,075	269,160	459,492	0	93,936,727
2087	129,612,126	269,160	31,860	756,671	130,669,817
2088	68,997,281	269,898	4,638	7,287,935	76,559,751
2089	68,037,066	269,160	4,308	6,770,213	75,080,747
2090	39,517,410	184,356	11,609,433	0	51,311,199
2091	333,567	0	36,847,332	0	37,180,900
2092	139,824	0	15,445,594	0	15,585,418
	$1,030,228,552	$364,665,558	$64,917,180	$14,814,818	$1,474,626,109

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SCHEDULE OF TOTAL ANNUAL EXPENDITURES
Monticello Nuclear Generating Plant

Year	Radiological	Spent Fuel	Site Restoration	ISFSI Radiological	Yearly Total
2030	$24,264,597	$2,258,324	$0	$0	$26,522,921
2031	104,697,554	5,356,786	0	0	110,054,340
2032	42,642,743	9,419,837	0	0	52,062,580
2033	33,328,022	32,551,504	0	0	65,879,526
2034	33,328,022	9,551,500	0	0	42,879,522
2035	25,036,130	107,032,385	0	0	132,068,514
2036	7,029,482	5,975,998	0	0	13,005,479
2037	7,010,276	5,959,851	0	0	12,970,127
2038	7,010,276	5,959,851	0	0	12,970,127
2039	7,010,276	5,959,851	0	0	12,970,127
2040	7,029,482	5,975,998	0	0	13,005,479
2041	7,010,276	5,959,851	0	0	12,970,127
2042	7,010,276	5,959,851	0	0	12,970,127
2043	7,010,276	5,959,851	0	0	12,970,127
2044	7,029,482	5,975,998	0	0	13,005,479
2045	7,010,276	5,959,851	0	0	12,970,127
2046	7,010,276	5,959,851	0	0	12,970,127
2047	7,010,276	5,959,851	0	0	12,970,127
2048	7,029,482	8,630,580	0	0	15,660,061
2049	7,010,276	5,959,848	0	0	12,970,124
2050	7,010,276	11,932,656	0	0	18,942,932
2051	7,010,276	11,932,656	0	0	18,942,932
2052	7,029,482	15,398,803	0	0	22,428,284
2053	7,010,276	17,970,156	0	0	24,980,432
2054	7,010,276	12,795,156	0	0	19,805,432
2055	7,010,276	17,107,656	0	0	24,117,932
2056	7,029,482	18,848,803	0	0	25,878,284
2057	7,010,276	5,893,486	0	0	12,903,762
2058	7,010,276	5,893,486	0	0	12,903,762
2059	7,010,276	5,893,486	0	0	12,903,762
2060	7,029,482	5,909,634	0	0	12,939,115
2061	7,010,276	5,893,486	0	0	12,903,762
2062	7,010,276	5,893,486	0	0	12,903,762
2063	7,010,276	5,893,486	0	0	12,903,762
2064	7,029,482	5,909,634	0	0	12,939,115
2065	7,010,276	5,893,486	0	0	12,903,762
2066	7,010,276	5,893,486	0	0	12,903,762
2067	7,010,276	5,893,486	0	0	12,903,762
2068	7,029,482	5,909,634	0	0	12,939,115
2069	7,010,276	5,893,486	0	0	12,903,762
2070	7,010,276	5,893,486	0	0	12,903,762
2071	7,010,276	5,893,486	0	0	12,903,762

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SCHEDULE OF TOTAL ANNUAL EXPENDITURES
Monticello Nuclear Generating Plant

Year	Radiological	Spent Fuel	Site Restoration	ISFSI Radiological	Yearly Total
2072	7,029,482	5,909,634	0	0	12,939,115
2073	7,010,276	5,893,486	0	0	12,903,762
2074	7,010,276	5,893,486	0	0	12,903,762
2075	7,010,276	5,893,486	0	0	12,903,762
2076	7,029,482	5,909,634	0	0	12,939,115
2077	7,010,276	5,893,486	0	0	12,903,762
2078	7,010,276	7,807,214	0	0	14,817,490
2079	7,010,276	8,189,960	0	0	15,200,236
2080	7,029,482	7,823,361	0	0	14,852,842
2081	7,010,276	7,807,214	0	0	14,817,490
2082	7,010,276	7,807,214	0	0	14,817,490
2083	7,010,276	8,189,960	0	0	15,200,236
2084	7,029,482	7,823,361	0	0	14,852,842
2085	55,527,077	2,398,613	514,522	0	58,440,212
2086	97,934,142	2,182,890	459,492	0	100,576,524
2087	134,336,182	2,565,634	31,860	758,680	137,692,356
2088	73,716,944	4,838,206	4,638	7,307,283	85,867,070
2089	72,779,970	2,182,889	4,308	6,788,186	81,755,354
2090	43,102,581	949,842	11,616,490	0	55,668,913
2091	333,568	0	36,869,728	0	37,203,297
2092	139,825	0	15,454,982	0	15,594,807
	$1,084,920,548	$552,723,605	$64,956,020	$14,854,148	$1,717,454,322

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SCHEDULE OF TOTAL ANNUAL EXPENDITURES
Prairie Island Nuclear Generating Plant Unit 1

Year	Radiological	Spent Fuel	Site Restoration	ISFSI Radiological	Yearly Total
2033	$31,076,470	$1,703,879	$242,314	$0	$33,022,663
2034	92,781,597	3,989,771	1,032,687	0	97,804,055
2035	141,808,053	5,695,988	1,628,670	0	149,132,711
2036	119,073,013	4,339,400	1,957,412	0	125,369,825
2037	71,373,222	3,984,135	1,467,374	0	76,824,731
2038	19,230,849	3,487,240	0	0	22,718,089
2039	24,730,499	88,498,905	0	0	113,229,405
2040	43,794,068	3,337,688	0	0	47,131,756
2041	11,680,880	5,934,875	13,436,852	0	31,052,607
2042	99,306	7,481,318	20,693,886	0	28,274,510
2043	46,796	6,977,384	9,751,640	0	16,775,820
2044	0	6,716,138	0	0	6,716,138
2045	0	6,698,833	0	0	6,698,833
2046	0	6,316,088	0	0	6,316,088
2047	0	6,316,088	0	0	6,316,088
2048	0	6,333,392	0	0	6,333,392
2049	0	6,316,088	0	0	6,316,088
2050	0	6,698,833	0	0	6,698,833
2051	0	6,698,833	0	0	6,698,833
2052	0	6,716,138	0	0	6,716,138
2053	0	6,698,833	0	0	6,698,833
2054	0	6,698,833	0	0	6,698,833
2055	0	6,698,833	0	0	6,698,833
2056	0	6,716,138	0	0	6,716,138
2057	0	6,698,833	0	0	6,698,833
2058	0	6,698,833	0	0	6,698,833
2059	0	6,698,833	0	0	6,698,833
2060	0	6,716,138	0	0	6,716,138
2061	0	6,698,833	0	0	6,698,833
2062	0	6,698,833	0	0	6,698,833
2063	0	6,698,833	0	0	6,698,833
2064	11,829,180	6,516,025	0	0	18,345,206
2065	0	0	850,564	4,455,736	5,306,300
	$567,523,934	$274,478,813	$51,061,399	$4,455,736	$897,519,882

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SCHEDULE OF TOTAL ANNUAL EXPENDITURES
Prairie Island Nuclear Generating Plant Unit 2

Year	Radiological	Spent Fuel	Site Restoration	ISFSI Radiological	Yearly Total
2034	$12,643,372	$800,696	$45,733	$0	$13,489,801
2035	77,326,219	6,861,449	340,602	0	84,528,271
2036	149,360,187	4,454,324	2,013,863	0	155,828,374
2037	136,609,791	4,139,962	2,528,578	0	143,278,331
2038	74,882,873	3,727,465	1,290,832	0	79,901,170
2039	30,330,603	88,498,906	0	0	118,829,509
2040	50,102,437	3,337,688	0	0	53,440,125
2041	14,229,327	5,934,875	18,268,894	0	38,433,096
2042	42,463	7,481,318	28,135,639	0	35,659,420
2043	20,010	6,977,384	13,258,438	0	20,255,832
2044	0	6,716,138	0	0	6,716,138
2045	0	6,698,833	0	0	6,698,833
2046	0	6,316,088	0	0	6,316,088
2047	0	6,316,088	0	0	6,316,088
2048	0	6,333,392	0	0	6,333,392
2049	0	6,316,088	0	0	6,316,088
2050	0	6,698,833	0	0	6,698,833
2051	0	6,698,833	0	0	6,698,833
2052	0	6,716,138	0	0	6,716,138
2053	0	6,698,833	0	0	6,698,833
2054	0	6,698,833	0	0	6,698,833
2055	0	6,698,833	0	0	6,698,833
2056	0	6,716,138	0	0	6,716,138
2057	0	6,698,833	0	0	6,698,833
2058	0	6,698,833	0	0	6,698,833
2059	0	6,698,833	0	0	6,698,833
2060	0	6,716,138	0	0	6,716,138
2061	0	6,698,833	0	0	6,698,833
2062	0	6,698,833	0	0	6,698,833
2063	0	6,698,833	0	0	6,698,833
2064	11,829,180	6,516,025	0	0	18,345,206
2065	0	0	850,564	4,455,736	5,306,300
	$557,376,463	$271,262,295	$66,733,143	$4,455,736	$899,827,638

Xcel Energy
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SCHEDULE OF TOTAL ANNUAL EXPENDITURES
Prairie Island Nuclear Generating Plant Unit 1

Year	Radiological	Spent Fuel	Site Restoration	ISFSI Radiological	Yearly Total
2033	$31,357,118	$1,703,879	$242,314	$0	$33,303,311
2034	93,207,409	3,989,769	1,032,687	0	98,229,866
2035	141,808,060	4,930,496	1,628,670	0	148,367,226
2036	119,073,016	3,573,906	1,957,412	0	124,604,334
2037	71,373,223	3,410,020	1,467,374	0	76,250,618
2038	19,230,853	14,221,752	0	0	33,452,605
2039	24,738,914	89,023,669	0	0	113,762,582
2040	43,775,251	2,759,911	0	0	46,535,162
2041	11,590,520	5,183,123	13,493,548	0	30,267,191
2042	99,306	6,907,459	20,693,886	0	27,700,652
2043	46,524	6,545,657	9,694,944	0	16,287,125
2044	0	6,243,809	0	0	6,243,809
2045	0	6,226,749	0	0	6,226,749
2046	0	6,226,749	0	0	6,226,749
2047	0	6,226,749	0	0	6,226,749
2048	0	6,243,809	0	0	6,243,809
2049	0	6,226,749	0	0	6,226,749
2050	0	6,226,749	0	0	6,226,749
2051	0	6,226,749	0	0	6,226,749
2052	0	6,243,809	0	0	6,243,809
2053	0	6,609,495	0	0	6,609,495
2054	0	6,992,240	0	0	6,992,240
2055	0	6,992,240	0	0	6,992,240
2056	0	7,200,673	0	0	7,200,673
2057	0	6,800,868	0	0	6,800,868
2058	0	7,374,985	0	0	7,374,985
2059	0	6,800,868	0	0	6,800,868
2060	0	6,626,554	0	0	6,626,554
2061	0	6,992,240	0	0	6,992,240
2062	0	6,992,240	0	0	6,992,240
2063	0	6,800,868	0	0	6,800,868
2064	0	7,009,299	0	0	7,009,299
2065	0	6,992,240	0	0	6,992,240
2066	0	6,800,868	0	0	6,800,868
2067	0	6,992,240	0	0	6,992,240
2068	0	7,009,299	0	0	7,009,299
2069	0	6,800,868	0	0	6,800,868
2070	0	6,992,240	0	0	6,992,240
2071	0	6,992,240	0	0	6,992,240
2072	0	7,009,299	0	0	7,009,299
2073	0	6,992,240	0	0	6,992,240
2074	0	6,992,240	0	0	6,992,240
2075	0	8,319,530	0	0	8,319,530
2076	0	7,009,299	0	0	7,009,299
2077	11,827,000	6,813,749	0	0	18,640,749
2078	0	0	962,042	4,490,764	5,452,806
	$568,127,196	$373,250,469	$51,172,876	$4,490,764	$997,041,305

Xcel Energy
Schedule of Annual Expenditures
60-Year Decommissioning Period

Docket No. E002/M-17-828
Schedule A.9

SCHEDULE OF TOTAL ANNUAL EXPENDITURES
Prairie Island Nuclear Generating Plant Unit 2

Year	Radiological	Spent Fuel	Site Restoration	Site Restoration	Yearly Total
2034	$12,643,370	$800,696	$45,733	$0	$13,489,800
2035	77,326,211	6,095,954	340,602	0	83,762,768
2036	149,360,181	3,688,831	2,013,863	0	155,062,875
2037	136,609,788	3,565,838	2,528,578	0	142,704,204
2038	74,882,873	14,461,972	1,290,832	0	90,635,677
2039	30,342,574	89,023,668	0	0	119,366,242
2040	50,100,768	2,759,911	0	0	52,860,679
2041	14,118,612	5,183,123	18,345,978	0	37,647,713
2042	42,462	6,907,459	28,135,639	0	35,085,561
2043	19,893	6,545,657	13,181,354	0	19,746,904
2044	0	6,243,809	0	0	6,243,809
2045	0	6,226,749	0	0	6,226,749
2046	0	6,226,749	0	0	6,226,749
2047	0	6,226,749	0	0	6,226,749
2048	0	6,243,809	0	0	6,243,809
2049	0	6,226,749	0	0	6,226,749
2050	0	6,226,749	0	0	6,226,749
2051	0	6,226,749	0	0	6,226,749
2052	0	6,243,809	0	0	6,243,809
2053	0	6,609,496	0	0	6,609,496
2054	0	6,992,240	0	0	6,992,240
2055	0	6,992,240	0	0	6,992,240
2056	0	7,200,673	0	0	7,200,673
2057	0	6,800,868	0	0	6,800,868
2058	0	7,374,985	0	0	7,374,985
2059	0	6,800,868	0	0	6,800,868
2060	0	6,626,554	0	0	6,626,554
2061	0	6,992,240	0	0	6,992,240
2062	0	6,992,240	0	0	6,992,240
2063	0	6,800,868	0	0	6,800,868
2064	0	7,009,299	0	0	7,009,299
2065	0	6,992,240	0	0	6,992,240
2066	0	6,800,868	0	0	6,800,868
2067	0	6,992,240	0	0	6,992,240
2068	0	7,009,299	0	0	7,009,299
2069	0	6,800,868	0	0	6,800,868
2070	0	6,992,240	0	0	6,992,240
2071	0	6,992,240	0	0	6,992,240
2072	0	7,009,299	0	0	7,009,299
2073	0	6,992,240	0	0	6,992,240
2074	0	6,992,240	0	0	6,992,240
2075	0	8,319,530	0	0	8,319,530
2076	0	7,009,299	0	0	7,009,299
2077	11,826,750	6,813,749	0	0	18,640,498
2078	0	0	962,042	4,490,764	5,452,806
	$557,273,484	$370,033,938	$66,844,621	$4,490,764	$998,642,807

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Schedule of Annual Expenditures **Schedule A.10**
60-Year Decommissioning Period with Recasking **Page 1 of 2**

SCHEDULE OF TOTAL ANNUAL EXPENDITURES
Prairie Island Nuclear Generating Plant Unit 1

Year	Radiological	Spent Fuel	Site Restoration	ISFSI Radiological	Yearly Total
2033	$31,076,470	$1,703,879	$242,314	$0	$33,022,663
2034	92,781,598	3,989,769	1,032,687	0	97,804,054
2035	141,808,060	4,930,496	1,628,670	0	148,367,226
2036	119,073,016	3,573,905	1,957,412	0	124,604,333
2037	71,373,222	10,199,620	1,467,374	0	83,040,216
2038	19,230,849	14,221,751	0	0	33,452,600
2039	24,738,910	89,023,669	0	0	113,762,578
2040	43,775,251	2,759,911	0	0	46,535,162
2041	11,594,057	5,183,123	13,490,012	0	30,267,191
2042	104,729	6,907,459	20,688,463	0	27,700,652
2043	49,065	6,545,657	9,692,403	0	16,287,125
2044	0	6,243,809	0	0	6,243,809
2045	0	15,454,214	0	0	15,454,214
2046	0	12,378,392	0	0	12,378,392
2047	0	12,378,392	0	0	12,378,392
2048	0	6,243,809	0	0	6,243,809
2049	0	12,378,392	0	0	12,378,392
2050	0	15,454,214	0	0	15,454,214
2051	0	14,678,390	0	0	14,678,390
2052	0	15,471,275	0	0	15,471,275
2053	0	6,609,495	0	0	6,609,495
2054	0	6,992,240	0	0	6,992,240
2055	0	16,219,704	0	0	16,219,704
2056	0	13,352,316	0	0	13,352,316
2057	0	15,252,511	0	0	15,252,511
2058	0	7,374,986	0	0	7,374,986
2059	0	6,800,868	0	0	6,800,868
2060	0	6,626,554	0	0	6,626,554
2061	0	6,992,240	0	0	6,992,240
2062	0	6,992,240	0	0	6,992,240
2063	0	6,800,868	0	0	6,800,868
2064	0	7,009,300	0	0	7,009,300
2065	0	6,992,240	0	0	6,992,240
2066	0	6,800,868	0	0	6,800,868
2067	0	6,992,240	0	0	6,992,240
2068	0	7,009,300	0	0	7,009,300
2069	0	6,800,868	0	0	6,800,868
2070	0	6,992,240	0	0	6,992,240
2071	0	6,992,240	0	0	6,992,240
2072	0	7,009,300	0	0	7,009,300
2073	0	6,992,240	0	0	6,992,240
2074	0	6,992,240	0	0	6,992,240
2075	0	8,319,531	0	0	8,319,531
2076	0	7,009,300	0	0	7,009,300
2077	11,829,300	6,811,206	0	0	18,640,505
2078	0	0	1,243,387	4,888,392	6,131,779
	$567,434,526	$458,457,246	$51,442,722	$4,888,392	$1,082,222,885

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Schedule of Annual Expenditures **Schedule A.10**
60-Year Decommissioning Period with Recasking **Page 2 of 2**

SCHEDULE OF TOTAL ANNUAL EXPENDITURES
Prairie Island Nuclear Generating Plant Unit 2

Year	Radiological	Spent Fuel	Site Restoration	Site Restoration	Yearly Total
2034	$12,643,370	$800,696	$45,733	$0	$13,489,800
2035	77,326,211	6,095,954	340,602	0	83,762,768
2036	149,360,181	3,688,802	2,013,863	0	155,062,846
2037	136,609,788	10,355,441	2,528,578	0	149,493,807
2038	74,882,873	14,461,973	1,290,832	0	90,635,678
2039	30,342,574	89,023,668	0	0	119,366,242
2040	50,100,768	2,759,911	0	0	52,860,679
2041	14,118,612	5,183,123	18,345,978	0	37,647,713
2042	42,462	6,907,459	28,135,639	0	35,085,561
2043	19,893	6,545,657	13,181,354	0	19,746,904
2044	0	6,243,809	0	0	6,243,809
2045	0	15,454,214	0	0	15,454,214
2046	0	12,378,392	0	0	12,378,392
2047	0	12,378,392	0	0	12,378,392
2048	0	6,243,809	0	0	6,243,809
2049	0	12,378,392	0	0	12,378,392
2050	0	15,454,214	0	0	15,454,214
2051	0	14,678,392	0	0	14,678,392
2052	0	15,471,273	0	0	15,471,273
2053	0	6,609,495	0	0	6,609,495
2054	0	6,992,240	0	0	6,992,240
2055	0	16,219,704	0	0	16,219,704
2056	0	13,352,316	0	0	13,352,316
2057	0	15,252,511	0	0	15,252,511
2058	0	7,374,986	0	0	7,374,986
2059	0	6,800,868	0	0	6,800,868
2060	0	6,626,554	0	0	6,626,554
2061	0	6,992,240	0	0	6,992,240
2062	0	6,992,240	0	0	6,992,240
2063	0	6,800,868	0	0	6,800,868
2064	0	7,009,300	0	0	7,009,300
2065	0	6,992,240	0	0	6,992,240
2066	0	6,800,868	0	0	6,800,868
2067	0	6,992,240	0	0	6,992,240
2068	0	7,009,300	0	0	7,009,300
2069	0	6,800,868	0	0	6,800,868
2070	0	6,992,240	0	0	6,992,240
2071	0	6,992,240	0	0	6,992,240
2072	0	7,009,300	0	0	7,009,300
2073	0	6,992,240	0	0	6,992,240
2074	0	6,992,240	0	0	6,992,240
2075	0	8,319,531	0	0	8,319,531
2076	0	7,009,300	0	0	7,009,300
2077	11,829,300	6,811,206	0	0	18,640,505
2078	0	0	1,243,387	4,888,392	6,131,779
	$557,276,034	$455,240,691	$67,125,966	$4,888,392	$1,084,531,083

Xcel Energy
Schedule of Annual Expenditures
100-Year Decommissioning Period

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Schedule A.11
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SCHEDULE OF TOTAL ANNUAL EXPENDITURES
Prairie Island Nuclear Generating Plant Unit 2

Year	Radiological	Spent Fuel	Site Restoration	ISFSI Radiological	Yearly Total
2034	$12,643,370	$800,696	$45,733	$0	$13,489,800
2035	77,326,211	6,095,954	340,602	0	83,762,768
2036	149,360,181	3,688,830	2,013,863	0	155,062,874
2037	136,609,788	10,355,438	2,528,578	0	149,493,804
2038	74,882,873	14,461,970	1,290,832	0	90,635,675
2039	30,251,654	87,824,337	0	0	118,075,990
2040	49,584,357	3,276,321	0	0	52,860,678
2041	13,941,273	5,691,564	18,068,179	0	37,701,016
2042	42,463	7,415,243	27,709,603	0	35,167,309
2043	19,894	7,090,649	12,981,759	0	20,092,302
2044	0	6,823,180	0	0	6,823,180
2045	0	16,032,001	0	0	16,032,001
2046	0	12,956,180	0	0	12,956,180
2047	0	12,956,180	0	0	12,956,180
2048	0	6,823,180	0	0	6,823,180
2049	0	12,956,180	0	0	12,956,180
2050	0	16,032,001	0	0	16,032,001
2051	0	15,256,180	0	0	15,256,180
2052	0	16,050,644	0	0	16,050,644
2053	0	6,804,537	0	0	6,804,537
2054	0	6,804,537	0	0	6,804,537
2055	0	16,032,001	0	0	16,032,001
2056	0	12,974,822	0	0	12,974,822
2057	0	12,956,180	0	0	12,956,180
2058	0	6,804,537	0	0	6,804,537
2059	0	12,180,358	0	0	12,180,358
2060	0	12,974,822	0	0	12,974,822
2061	0	12,956,180	0	0	12,956,180
2062	0	6,804,537	0	0	6,804,537
2063	0	25,259,465	0	0	25,259,465
2064	0	18,350,644	0	0	18,350,644
2065	0	12,956,180	0	0	12,956,180
2066	0	6,804,537	0	0	6,804,537
2067	0	6,804,537	0	0	6,804,537
2068	0	19,126,465	0	0	19,126,465
2069	0	16,032,001	0	0	16,032,001
2070	0	6,804,537	0	0	6,804,537
2071	0	6,804,537	0	0	6,804,537
2072	0	21,426,465	0	0	21,426,465
2073	0	6,804,537	0	0	6,804,537
2074	0	6,804,537	0	0	6,804,537
2075	0	23,510,934	0	0	23,510,934
2076	0	6,823,180	0	0	6,823,180

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100-Year Decommissioning Period **Page 2 of 2**

SCHEDULE OF TOTAL ANNUAL EXPENDITURES
Prairie Island Nuclear Generating Plant Unit 2

Year	Radiological	Spent Fuel	Site Restoration	ISFSI Radiological	Yearly Total
2077	0	6,804,537	0	0	6,804,537
2078	0	22,183,644	0	0	22,183,644
2079	0	6,804,537	0	0	6,804,537
2080	0	6,823,180	0	0	6,823,180
2081	0	6,804,537	0	0	6,804,537
2082	0	20,632,001	0	0	20,632,001
2083	0	6,804,537	0	0	6,804,537
2084	0	6,823,180	0	0	6,823,180
2085	0	6,804,537	0	0	6,804,537
2086	0	6,804,537	0	0	6,804,537
2087	0	6,804,537	0	0	6,804,537
2088	0	6,823,180	0	0	6,823,180
2089	0	99,402,533	0	0	99,402,533
2090	0	8,738,968	0	0	8,738,968
2091	0	6,804,537	0	0	6,804,537
2092	0	6,823,180	0	0	6,823,180
2093	0	6,270,663	0	0	6,270,663
2094	0	6,653,405	0	0	6,653,405
2095	0	15,880,869	0	0	15,880,869
2096	0	13,012,552	0	0	13,012,552
2097	0	12,613,676	0	0	12,613,676
2098	0	7,036,150	0	0	7,036,150
2099	0	6,462,033	0	0	6,462,033
2100	0	15,498,124	0	0	15,498,124
2101	0	15,880,869	0	0	15,880,869
2102	0	15,880,869	0	0	15,880,869
2103	0	6,462,033	0	0	6,462,033
2104	0	6,669,536	0	0	6,669,536
2105	0	15,880,869	0	0	15,880,869
2106	0	12,613,676	0	0	12,613,676
2107	0	12,805,048	0	0	12,805,048
2108	0	6,669,536	0	0	6,669,536
2109	0	12,613,676	0	0	12,613,676
2110	0	12,776,342	0	0	12,776,342
2111	0	12,747,636	0	0	12,747,636
2112	0	6,612,124	0	0	6,612,124
2113	0	25,050,921	0	0	25,050,921
2114	0	18,899,278	0	0	18,899,278
2115	0	14,074,926	0	0	14,074,926
2116	11,656,078	6,612,124	0	0	18,268,202
2117	0	6,581,641	0	0	6,581,641
2118	0	0	1,547,368	1,795,353	3,342,721
	$556,318,142	$1,079,136,533	$66,526,518	$1,795,353	$1,703,776,546

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Schedule of Annual Expenditures **Schedule A.12**
200-Year Decommissioning Period **Page 1 of 5**

SCHEDULE OF TOTAL ANNUAL EXPENDITURES
Prairie Island Nuclear Generating Plant Unit 1

Year	Radiological	Spent Fuel	Site Restoration	ISFSI Radiological	Yearly Total
2033	$31,076,470	$1,703,879	$242,314	$0	$33,022,663
2034	92,781,598	3,989,769	1,032,687	0	97,804,054
2035	141,808,060	4,930,504	1,628,670	0	148,367,234
2036	119,073,016	3,573,906	1,957,412	0	124,604,334
2037	71,373,222	10,199,623	1,467,374	0	83,040,219
2038	19,230,849	14,221,750	0	0	33,452,599
2039	24,647,989	87,824,337	0	0	112,472,326
2040	43,258,846	3,276,324	0	0	46,535,170
2041	11,413,185	5,691,565	13,215,752	0	30,320,501
2042	99,305	7,415,240	20,267,855	0	27,782,400
2043	46,524	7,052,463	9,495,351	0	16,594,338
2044	0	6,751,147	0	0	6,751,147
2045	0	15,960,165	0	0	15,960,165
2046	0	12,884,335	0	0	12,884,335
2047	0	12,884,335	0	0	12,884,335
2048	0	6,751,147	0	0	6,751,147
2049	0	12,884,335	0	0	12,884,335
2050	0	15,960,165	0	0	15,960,165
2051	0	15,184,335	0	0	15,184,335
2052	0	15,978,607	0	0	15,978,607
2053	0	6,732,695	0	0	6,732,695
2054	0	6,732,695	0	0	6,732,695
2055	0	15,960,165	0	0	15,960,165
2056	0	12,902,787	0	0	12,902,787
2057	0	12,884,335	0	0	12,884,335
2058	0	6,732,695	0	0	6,732,695
2059	0	12,108,525	0	0	12,108,525
2060	0	12,902,787	0	0	12,902,787
2061	0	12,884,335	0	0	12,884,335
2062	0	6,732,695	0	0	6,732,695
2063	0	25,187,635	0	0	25,187,635
2064	0	18,278,607	0	0	18,278,607
2065	0	12,884,335	0	0	12,884,335
2066	0	6,732,695	0	0	6,732,695
2067	0	6,732,695	0	0	6,732,695
2068	0	19,054,427	0	0	19,054,427
2069	0	15,960,165	0	0	15,960,165
2070	0	6,732,695	0	0	6,732,695
2071	0	6,732,695	0	0	6,732,695
2072	0	21,354,427	0	0	21,354,427
2073	0	6,732,695	0	0	6,732,695
2074	0	6,732,695	0	0	6,732,695

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SCHEDULE OF TOTAL ANNUAL EXPENDITURES
Prairie Island Nuclear Generating Plant Unit 1

Year	Radiological	Spent Fuel	Site Restoration	ISFSI Radiological	Yearly Total
2075	0	23,439,095	0	0	23,439,095
2076	0	6,751,147	0	0	6,751,147
2077	0	6,732,695	0	0	6,732,695
2078	0	22,111,805	0	0	22,111,805
2079	0	6,732,695	0	0	6,732,695
2080	0	6,751,147	0	0	6,751,147
2081	0	6,732,695	0	0	6,732,695
2082	0	20,560,165	0	0	20,560,165
2083	0	6,732,695	0	0	6,732,695
2084	0	6,751,147	0	0	6,751,147
2085	0	6,732,695	0	0	6,732,695
2086	0	6,732,695	0	0	6,732,695
2087	0	6,732,695	0	0	6,732,695
2088	0	6,751,147	0	0	6,751,147
2089	0	101,230,098	0	0	101,230,098
2090	0	6,732,695	0	0	6,732,695
2091	0	6,732,695	0	0	6,732,695
2092	0	6,751,147	0	0	6,751,147
2093	0	6,732,695	0	0	6,732,695
2094	0	6,732,695	0	0	6,732,695
2095	0	15,960,165	0	0	15,960,165
2096	0	12,902,787	0	0	12,902,787
2097	0	12,884,335	0	0	12,884,335
2098	0	6,732,695	0	0	6,732,695
2099	0	6,732,695	0	0	6,732,695
2100	0	15,960,165	0	0	15,960,165
2101	0	15,960,165	0	0	15,960,165
2102	0	15,960,165	0	0	15,960,165
2103	0	6,732,695	0	0	6,732,695
2104	0	6,751,147	0	0	6,751,147
2105	0	15,960,165	0	0	15,960,165
2106	0	12,884,335	0	0	12,884,335
2107	0	12,884,335	0	0	12,884,335
2108	0	6,751,147	0	0	6,751,147
2109	0	12,884,335	0	0	12,884,335
2110	0	12,884,335	0	0	12,884,335
2111	0	12,884,335	0	0	12,884,335
2112	0	6,751,147	0	0	6,751,147
2113	0	25,187,635	0	0	25,187,635
2114	0	19,035,985	0	0	19,035,985
2115	0	14,211,635	0	0	14,211,635
2116	0	6,751,147	0	0	6,751,147

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SCHEDULE OF TOTAL ANNUAL EXPENDITURES
Prairie Island Nuclear Generating Plant Unit 1

Year	Radiological	Spent Fuel	Site Restoration	ISFSI Radiological	Yearly Total
2117	0	6,732,695	0	0	6,732,695
2118	0	19,035,985	0	0	19,035,985
2119	0	15,960,165	0	0	15,960,165
2120	0	6,751,147	0	0	6,751,147
2121	0	6,732,695	0	0	6,732,695
2122	0	22,111,805	0	0	22,111,805
2123	0	6,732,695	0	0	6,732,695
2124	0	6,751,147	0	0	6,751,147
2125	0	22,111,805	0	0	22,111,805
2126	0	6,732,695	0	0	6,732,695
2127	0	6,732,695	0	0	6,732,695
2128	0	22,130,257	0	0	22,130,257
2129	0	6,732,695	0	0	6,732,695
2130	0	6,732,695	0	0	6,732,695
2131	0	6,732,695	0	0	6,732,695
2132	0	22,130,257	0	0	22,130,257
2133	0	6,732,695	0	0	6,732,695
2134	0	6,732,695	0	0	6,732,695
2135	0	6,732,695	0	0	6,732,695
2136	0	6,751,147	0	0	6,751,147
2137	0	6,732,695	0	0	6,732,695
2138	0	6,732,695	0	0	6,732,695
2139	0	99,190,825	0	0	99,190,825
2140	0	6,751,147	0	0	6,751,147
2141	0	6,732,695	0	0	6,732,695
2142	0	6,732,695	0	0	6,732,695
2143	0	6,732,695	0	0	6,732,695
2144	0	6,751,147	0	0	6,751,147
2145	0	15,960,165	0	0	15,960,165
2146	0	12,884,335	0	0	12,884,335
2147	0	12,884,335	0	0	12,884,335
2148	0	6,751,147	0	0	6,751,147
2149	0	6,732,695	0	0	6,732,695
2150	0	15,960,165	0	0	15,960,165
2151	0	15,960,165	0	0	15,960,165
2152	0	15,978,607	0	0	15,978,607
2153	0	6,732,695	0	0	6,732,695
2154	0	6,732,695	0	0	6,732,695
2155	0	17,287,455	0	0	17,287,455
2156	0	12,902,787	0	0	12,902,787
2157	0	12,884,335	0	0	12,884,335
2158	0	6,732,695	0	0	6,732,695

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SCHEDULE OF TOTAL ANNUAL EXPENDITURES
Prairie Island Nuclear Generating Plant Unit 1

Year	Radiological	Spent Fuel	Site Restoration	ISFSI Radiological	Yearly Total
2159	0	12,884,335	0	0	12,884,335
2160	0	12,902,787	0	0	12,902,787
2161	0	12,884,335	0	0	12,884,335
2162	0	6,732,695	0	0	6,732,695
2163	0	25,187,635	0	0	25,187,635
2164	0	19,054,427	0	0	19,054,427
2165	0	12,884,335	0	0	12,884,335
2166	0	6,732,695	0	0	6,732,695
2167	0	6,732,695	0	0	6,732,695
2168	0	19,054,427	0	0	19,054,427
2169	0	15,960,165	0	0	15,960,165
2170	0	6,732,695	0	0	6,732,695
2171	0	6,732,695	0	0	6,732,695
2172	0	22,130,257	0	0	22,130,257
2173	0	6,732,695	0	0	6,732,695
2174	0	6,732,695	0	0	6,732,695
2175	0	22,111,805	0	0	22,111,805
2176	0	6,751,147	0	0	6,751,147
2177	0	6,732,695	0	0	6,732,695
2178	0	22,111,805	0	0	22,111,805
2179	0	6,732,695	0	0	6,732,695
2180	0	6,751,147	0	0	6,751,147
2181	0	6,732,695	0	0	6,732,695
2182	0	22,111,805	0	0	22,111,805
2183	0	6,732,695	0	0	6,732,695
2184	0	6,751,147	0	0	6,751,147
2185	0	6,732,695	0	0	6,732,695
2186	0	6,732,695	0	0	6,732,695
2187	0	6,732,695	0	0	6,732,695
2188	0	6,751,147	0	0	6,751,147
2189	0	99,190,825	0	0	99,190,825
2190	0	6,732,695	0	0	6,732,695
2191	0	6,732,695	0	0	6,732,695
2192	0	6,751,147	0	0	6,751,147
2193	0	6,270,658	0	0	6,270,658
2194	0	6,653,408	0	0	6,653,408
2195	0	17,208,158	0	0	17,208,158
2196	0	13,012,555	0	0	13,012,555
2197	0	12,613,678	0	0	12,613,678
2198	0	7,036,158	0	0	7,036,158
2199	0	6,462,038	0	0	6,462,038
2200	0	15,498,128	0	0	15,498,128

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SCHEDULE OF TOTAL ANNUAL EXPENDITURES
Prairie Island Nuclear Generating Plant Unit 1

Year	Radiological	Spent Fuel	Site Restoration	ISFSI Radiological	Yearly Total
2201	0	15,880,878	0	0	15,880,878
2202	0	15,880,878	0	0	15,880,878
2203	0	6,462,038	0	0	6,462,038
2204	0	6,669,535	0	0	6,669,535
2205	0	15,880,878	0	0	15,880,878
2206	0	12,613,678	0	0	12,613,678
2207	0	12,805,048	0	0	12,805,048
2208	0	6,669,535	0	0	6,669,535
2209	0	12,613,678	0	0	12,613,678
2210	0	12,776,338	0	0	12,776,338
2211	0	12,747,638	0	0	12,747,638
2212	0	6,612,125	0	0	6,612,125
2213	0	25,050,928	0	0	25,050,928
2214	0	18,899,278	0	0	18,899,278
2215	0	12,747,638	0	0	12,747,638
2216	11,656,078	6,612,125	0	0	18,268,203
2217	0	6,653,408	0	0	6,653,408
2218	0	0	1,547,368	1,794,290	3,341,659
	$566,465,141	$2,358,423,972	$50,854,783	$1,794,290	$2,977,538,186

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SCHEDULE OF TOTAL ANNUAL EXPENDITURES
Prairie Island Nuclear Generating Plant Unit 1

Year	Radiological	Spent Fuel	Site Restoration	ISFSI Radiological	Yearly Total
2033	$22,183,884	$1,703,879	$0	$0	$23,887,764
2034	72,565,018	3,989,769	0	0	76,554,787
2035	25,421,983	8,484,170	0	0	33,906,153
2036	20,980,032	7,469,933	0	0	28,449,965
2037	20,922,710	7,261,286	0	0	28,183,995
2038	20,922,710	7,069,325	0	0	27,992,034
2039	18,301,770	91,623,229	0	0	109,924,999
2040	5,991,531	4,840,930	0	0	10,832,462
2041	5,975,161	5,020,645	0	0	10,995,806
2042	5,975,161	4,829,273	0	0	10,804,434
2043	5,975,161	4,637,900	0	0	10,613,061
2044	5,991,531	4,649,557	0	0	10,641,089
2045	5,975,161	4,637,900	0	0	10,613,061
2046	5,975,161	4,255,154	0	0	10,230,315
2047	5,975,161	4,255,154	0	0	10,230,315
2048	5,991,531	4,266,811	0	0	10,258,343
2049	5,975,161	4,255,154	0	0	10,230,315
2050	5,975,161	4,637,900	0	0	10,613,061
2051	5,975,161	4,637,901	0	0	10,613,062
2052	5,991,531	4,649,558	0	0	10,641,090
2053	5,975,161	4,637,900	0	0	10,613,061
2054	5,975,161	4,637,900	0	0	10,613,061
2055	5,975,161	4,637,900	0	0	10,613,061
2056	5,991,531	4,649,557	0	0	10,641,089
2057	5,975,161	4,637,900	0	0	10,613,061
2058	5,975,161	4,637,900	0	0	10,613,061
2059	5,975,161	4,637,900	0	0	10,613,061
2060	5,991,531	4,649,557	0	0	10,641,089
2061	5,975,161	4,637,900	0	0	10,613,061
2062	5,975,161	4,637,900	0	0	10,613,061
2063	5,975,161	4,637,900	0	0	10,613,061
2064	5,991,531	4,634,041	0	0	10,625,573
2065	7,667,573	0	0	0	7,667,573
2066	7,667,573	0	0	0	7,667,573
2067	7,667,573	0	0	0	7,667,573
2068	7,688,580	0	0	0	7,688,580
2069	7,667,573	0	0	0	7,667,573
2070	7,667,573	0	0	0	7,667,573
2071	7,667,573	0	0	0	7,667,573
2072	7,688,580	0	0	0	7,688,580
2073	7,667,573	0	0	0	7,667,573
2074	7,667,573	0	0	0	7,667,573

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SCHEDULE OF TOTAL ANNUAL EXPENDITURES
Prairie Island Nuclear Generating Plant Unit 1

Year	Radiological	Spent Fuel	Site Restoration	ISFSI Radiological	Yearly Total
2075	7,667,573	0	0	0	7,667,573
2076	7,688,580	0	0	0	7,688,580
2077	7,667,573	0	0	0	7,667,573
2078	7,667,573	0	0	0	7,667,573
2079	7,667,573	0	0	0	7,667,573
2080	7,688,580	0	0	0	7,688,580
2081	7,667,573	0	0	0	7,667,573
2082	7,667,573	0	0	0	7,667,573
2083	7,667,573	0	0	0	7,667,573
2084	7,688,580	0	0	0	7,688,580
2085	7,667,573	0	0	0	7,667,573
2086	7,667,573	0	0	0	7,667,573
2087	25,556,875	0	239,596	0	25,796,471
2088	56,305,869	0	1,038,690	0	57,344,559
2089	123,949,539	0	1,781,065	0	125,730,604
2090	85,816,173	0	2,393,961	1,672,615	89,882,749
2091	62,232,939	0	2,691,718	2,502,067	67,426,725
2092	14,477,672	0	302,357	281,054	15,061,084
2093	15,676,967	0	8,640,412	0	24,317,379
2094	99,305	0	21,750,002	0	21,849,307
2095	71,826	0	15,731,509	0	15,803,334
	$903,770,535	$242,849,678	$54,569,310	$4,455,737	$1,205,645,260

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SCHEDULE OF TOTAL ANNUAL EXPENDITURES
Prairie Island Nuclear Generating Plant Unit 2

Year	Radiological	Spent Fuel	Site Restoration	ISFSI Radiological	Yearly Total
2034	$10,524,583	$800,696	$0	$0	$11,325,279
2035	72,246,891	6,861,663	0	0	79,108,554
2036	38,795,945	6,185,160	0	0	44,981,105
2037	18,267,426	6,706,743	0	0	24,974,169
2038	18,267,426	6,514,781	0	0	24,782,207
2039	16,135,984	91,165,921	0	0	107,301,905
2040	6,128,292	4,840,930	0	0	10,969,223
2041	6,111,548	5,020,645	0	0	11,132,193
2042	6,111,548	4,829,273	0	0	10,940,821
2043	6,111,548	4,637,900	0	0	10,749,448
2044	6,128,292	4,649,557	0	0	10,777,850
2045	6,111,548	4,637,900	0	0	10,749,448
2046	6,111,548	4,255,154	0	0	10,366,702
2047	6,111,548	4,255,154	0	0	10,366,702
2048	6,128,292	4,266,811	0	0	10,395,104
2049	6,111,548	4,255,154	0	0	10,366,702
2050	6,111,548	4,637,900	0	0	10,749,448
2051	6,111,548	4,637,900	0	0	10,749,448
2052	6,128,292	4,649,558	0	0	10,777,851
2053	6,111,548	4,637,901	0	0	10,749,449
2054	6,111,548	4,637,900	0	0	10,749,448
2055	6,111,548	4,637,900	0	0	10,749,448
2056	6,128,292	4,649,557	0	0	10,777,850
2057	6,111,548	4,637,900	0	0	10,749,448
2058	6,111,548	4,637,900	0	0	10,749,448
2059	6,111,548	4,637,900	0	0	10,749,448
2060	6,128,292	4,649,557	0	0	10,777,850
2061	6,111,548	4,637,900	0	0	10,749,448
2062	6,111,548	4,637,900	0	0	10,749,448
2063	6,111,548	4,637,900	0	0	10,749,448
2064	6,128,292	4,634,041	0	0	10,762,334
2065	4,670,342	0	0	0	4,670,342
2066	4,670,342	0	0	0	4,670,342
2067	4,670,342	0	0	0	4,670,342
2068	4,683,138	0	0	0	4,683,138
2069	4,670,342	0	0	0	4,670,342
2070	4,670,342	0	0	0	4,670,342
2071	4,670,342	0	0	0	4,670,342
2072	4,683,138	0	0	0	4,683,138
2073	4,670,342	0	0	0	4,670,342
2074	4,670,342	0	0	0	4,670,342
2075	4,670,342	0	0	0	4,670,342
2076	4,683,138	0	0	0	4,683,138

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SCHEDULE OF TOTAL ANNUAL EXPENDITURES
Prairie Island Nuclear Generating Plant Unit 2

Year	Radiological	Spent Fuel	Site Restoration	ISFSI Radiological	Yearly Total
2077	4,670,342	0	0	0	4,670,342
2078	4,670,342	0	0	0	4,670,342
2079	4,670,342	0	0	0	4,670,342
2080	4,683,138	0	0	0	4,683,138
2081	4,670,342	0	0	0	4,670,342
2082	4,670,342	0	0	0	4,670,342
2083	4,670,342	0	0	0	4,670,342
2084	4,683,138	0	0	0	4,683,138
2085	4,670,342	0	0	0	4,670,342
2086	4,670,342	0	0	0	4,670,342
2087	4,670,342	0	0	0	4,670,342
2088	23,631,880	0	152,170	0	23,784,050
2089	45,175,615	0	608,816	0	45,784,431
2090	142,637,422	0	2,284,320	0	144,921,742
2091	91,138,868	0	2,818,773	2,310,128	96,267,770
2092	79,323,192	0	2,455,274	2,145,608	83,924,074
2093	20,097,964	0	11,363,655	0	31,461,619
2094	42,462	0	28,605,062	0	28,647,524
2095	30,712	0	20,689,688	0	20,720,401
2096	0	0	0	0	0
	$836,704,137	$233,483,052	$68,977,759	$4,455,737	$1,143,620,684

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SCHEDULE OF TOTAL ANNUAL EXPENDITURES
Prairie Island Nuclear Generating Plant Unit 1

Year	Radiological	Spent Fuel	Site Restoration	ISFSI Radiological	Yearly Total
2033	$22,183,884	$1,703,879	$0	$0	$23,887,764
2034	72,565,018	3,989,769	0	0	76,554,787
2035	25,421,983	7,718,682	0	0	33,140,665
2036	20,980,032	6,704,435	0	0	27,684,467
2037	20,922,710	6,687,168	0	0	27,609,877
2038	20,922,710	17,803,834	0	0	38,726,543
2039	18,314,517	92,148,002	0	0	110,462,519
2040	6,064,432	4,266,867	0	0	10,331,299
2041	6,047,862	4,255,208	0	0	10,303,071
2042	6,047,862	4,255,208	0	0	10,303,071
2043	6,047,862	4,255,208	0	0	10,303,071
2044	6,064,432	4,266,867	0	0	10,331,299
2045	6,047,862	4,255,208	0	0	10,303,071
2046	6,047,862	4,255,208	0	0	10,303,071
2047	6,047,862	4,255,208	0	0	10,303,071
2048	6,064,432	4,266,867	0	0	10,331,299
2049	6,047,862	4,255,208	0	0	10,303,071
2050	6,047,862	4,255,208	0	0	10,303,071
2051	6,047,862	4,255,208	0	0	10,303,071
2052	6,064,432	4,266,867	0	0	10,331,299
2053	6,047,862	4,637,954	0	0	10,685,817
2054	6,047,862	5,020,699	0	0	11,068,562
2055	6,047,862	5,020,699	0	0	11,068,562
2056	6,064,432	5,223,731	0	0	11,288,163
2057	6,047,862	4,829,327	0	0	10,877,190
2058	6,047,862	5,403,445	0	0	11,451,308
2059	6,047,862	4,829,327	0	0	10,877,190
2060	6,064,432	4,649,612	0	0	10,714,044
2061	6,047,862	5,020,699	0	0	11,068,562
2062	6,047,862	5,020,699	0	0	11,068,562
2063	6,047,862	4,829,327	0	0	10,877,190
2064	6,064,432	5,032,357	0	0	11,096,789
2065	6,047,862	5,020,699	0	0	11,068,562
2066	6,047,862	4,829,327	0	0	10,877,190
2067	6,047,862	5,020,699	0	0	11,068,562
2068	6,064,432	5,032,357	0	0	11,096,789
2069	6,047,862	4,829,327	0	0	10,877,190
2070	6,047,862	5,020,699	0	0	11,068,562
2071	6,047,862	5,020,699	0	0	11,068,562
2072	6,064,432	5,032,357	0	0	11,096,789
2073	6,047,862	5,020,699	0	0	11,068,562
2074	6,047,862	5,020,699	0	0	11,068,562

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SCHEDULE OF TOTAL ANNUAL EXPENDITURES
Prairie Island Nuclear Generating Plant Unit 1

Year	Radiological	Spent Fuel	Site Restoration	ISFSI Radiological	Yearly Total
2075	6,047,862	6,347,990	0	0	12,395,853
2076	6,064,432	5,032,357	0	0	11,096,789
2077	6,047,862	5,020,699	0	0	11,068,562
2078	7,198,929	0	0	0	7,198,929
2079	7,198,929	0	0	0	7,198,929
2080	7,218,652	0	0	0	7,218,652
2081	7,198,929	0	0	0	7,198,929
2082	7,198,929	0	0	0	7,198,929
2083	7,198,929	0	0	0	7,198,929
2084	7,218,652	0	0	0	7,218,652
2085	7,198,929	0	0	0	7,198,929
2086	7,198,929	0	0	0	7,198,929
2087	16,629,177	0	125,083	0	16,754,260
2088	56,064,486	0	851,806	0	56,916,291
2089	112,295,157	0	1,801,126	0	114,096,283
2090	97,291,550	0	2,324,556	1,326,502	100,942,608
2091	62,226,832	0	2,753,951	2,521,736	67,502,519
2092	22,631,021	0	701,692	642,525	23,975,237
2093	15,676,967	0	8,640,412	0	24,317,379
2094	99,305	0	21,750,002	0	21,849,307
2095	71,826	0	15,731,509	0	15,803,334
	$879,111,451	$317,886,609	$54,680,136	$4,490,764	$1,256,168,959

Xcel Energy **Docket No. E002/M-17-828**
Schedule of Annual Expenditures **Schedule A.14**
60-Year SAFSTOR Decommissioning Period **Page 3 of 4**

SCHEDULE OF TOTAL ANNUAL EXPENDITURES
Prairie Island Nuclear Generating Plant Unit 2

Year	Radiological	Spent Fuel	Site Restoration	ISFSI Radiological	Yearly Total
2034	$10,524,583	$800,696	$0	$0	$11,325,279
2035	72,246,891	6,096,163	0	0	78,343,054
2036	38,795,944	5,419,660	0	0	44,215,603
2037	18,267,423	6,132,624	0	0	24,400,047
2038	18,267,423	17,249,290	0	0	35,516,713
2039	16,136,004	91,690,693	0	0	107,826,698
2040	6,128,422	4,266,867	0	0	10,395,289
2041	6,111,677	4,255,208	0	0	10,366,886
2042	6,111,677	4,255,208	0	0	10,366,886
2043	6,111,677	4,255,208	0	0	10,366,886
2044	6,128,422	4,266,867	0	0	10,395,289
2045	6,111,677	4,255,208	0	0	10,366,886
2046	6,111,677	4,255,208	0	0	10,366,886
2047	6,111,677	4,255,208	0	0	10,366,886
2048	6,128,422	4,266,867	0	0	10,395,289
2049	6,111,677	4,255,208	0	0	10,366,886
2050	6,111,677	4,255,208	0	0	10,366,886
2051	6,111,677	4,255,208	0	0	10,366,886
2052	6,128,422	4,266,867	0	0	10,395,289
2053	6,111,677	4,637,955	0	0	10,749,633
2054	6,111,677	5,020,699	0	0	11,132,377
2055	6,111,677	5,020,699	0	0	11,132,377
2056	6,128,422	5,223,731	0	0	11,352,153
2057	6,111,677	4,829,327	0	0	10,941,005
2058	6,111,677	5,403,445	0	0	11,515,123
2059	6,111,677	4,829,327	0	0	10,941,005
2060	6,128,422	4,649,612	0	0	10,778,034
2061	6,111,677	5,020,699	0	0	11,132,377
2062	6,111,677	5,020,699	0	0	11,132,377
2063	6,111,677	4,829,327	0	0	10,941,005
2064	6,128,422	5,032,357	0	0	11,160,779
2065	6,111,677	5,020,699	0	0	11,132,377
2066	6,111,677	4,829,327	0	0	10,941,005
2067	6,111,677	5,020,699	0	0	11,132,377
2068	6,128,422	5,032,357	0	0	11,160,779
2069	6,111,677	4,829,327	0	0	10,941,005
2070	6,111,677	5,020,699	0	0	11,132,377
2071	6,111,677	5,020,699	0	0	11,132,377
2072	6,128,422	5,032,357	0	0	11,160,779
2073	6,111,677	5,020,699	0	0	11,132,377
2074	6,111,677	5,020,699	0	0	11,132,377
2075	6,111,677	6,347,990	0	0	12,459,668
2076	6,128,422	5,032,357	0	0	11,160,779

Xcel Energy **Docket No. E002/M-17-828**
Schedule of Annual Expenditures **Schedule A.14**
60-Year SAFSTOR Decommissioning Period **Page 4 of 4**

SCHEDULE OF TOTAL ANNUAL EXPENDITURES
Prairie Island Nuclear Generating Plant Unit 2

Year	Radiological	Spent Fuel	Site Restoration	ISFSI Radiological	Yearly Total
2077	6,111,677	5,020,699	0	0	11,132,377
2078	4,095,838	0	0	0	4,095,838
2079	4,095,838	0	0	0	4,095,838
2080	4,107,059	0	0	0	4,107,059
2081	4,095,838	0	0	0	4,095,838
2082	4,095,838	0	0	0	4,095,838
2083	4,095,838	0	0	0	4,095,838
2084	4,107,059	0	0	0	4,107,059
2085	4,095,838	0	0	0	4,095,838
2086	4,095,838	0	0	0	4,095,838
2087	4,095,838	0	0	0	4,095,838
2088	17,159,142	0	103,205	0	17,262,347
2089	39,319,995	0	443,390	0	39,763,385
2090	145,727,354	0	2,465,981	0	148,193,335
2091	92,518,134	0	2,908,964	2,328,288	97,755,386
2092	79,325,447	0	2,508,642	2,162,475	83,996,564
2093	20,097,964	0	11,363,655	0	31,461,619
2094	42,462	0	28,605,062	0	28,647,524
2095	30,712	0	20,689,688	0	20,720,401
	$841,851,473	$308,519,969	$69,088,586	$4,490,764	$1,223,950,792

Xcel Energy **Docket No. E002/M-17-828**
NRC Minimum Historical Escalation **Schedule A.15**
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January 1986 to June 2014

1. Determine Most Recent Escalation Component

	Base Conversion 1986	Value (2005 base)	4Q - 16 (Dec '05 Base)	Base Labor Adjustment Factor	Current Labor Adjustment Factor
	(1)	(2)	(3)	(4)	(5)
Labor (L)	48.1	100.00	125.7	2.08	2.61

Dept of Labor, Bureau of Labor Statistics, Employment Cost Index (NAICS), 4th Qtr 2016 (Retrieved July 2017), Private industry, Midwest region

Industrial Power (P)	114.2			211.7	1.854
Light Fuel Oil (F)	82.0			153.3	1.870

Department of Labor, Bureau of Labor Statistics, Producer Price Index Data for December 2016 (Retrieved July 2017); Industrial Power from Commodity code 0543, 500 kw demand, Midwest Region; Light Fuel Oils from Commodity code 0573

Burial (B)	
PWR - Blended	10.971
PWR - Direct	30.061
BWR - Blended	12.111
BWR - Direct	26.329

NUREG 1307, Report on Waste Burial, Revision 16 (Table 2.1 in November 2016)

2. Calculate Energy Component (E)

	Equation	Industrial Power	Light Fuel Oil	Energy Component
Energy (PWR)	= .58(P) + .42(F)	1.854	1.870	1.860
Energy (BWR)	= .54(P) + .46(F)	1.854	1.870	1.861

3. Calculate NRC Escalation Factor as of June 2017

	Labor	Energy	Burial	NRC Escalation Factor
	(L)	(E)	(B)	(6)
PWR - Blended	2.613	1.860	10.971	4.3541
PWR - Direct	2.613	1.860	30.061	8.5539
BWR - Blended	2.613	1.861	12.111	4.6050
BWR - Direct	2.613	1.861	26.329	7.7330

Notes:

(1) = Base values from NRC Proposed Guidelines
(2) = Conversion factor to convert from 1986 base to 2005 base.
(3) = The most recent published value:
(4) = (3) / (1), Labor only
(5) = (4) * (3) for Labor, Industrial Power, and Light Fuel Oil
(6) = (.65 x L) + (.13 x E) + (.22 x B)

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NRC Minimum Historical Escalation **Schedule A.16**
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January 1986 to June 2014

1. NRC Minimum Calculation in 1986 Dollars

	Equation	MWt	1986 Minimum Calculation
Monticello (BWR)	= $104 million + (0.009 * MWt)	2004	122,036,000
Prairie Island (PWR), Unit 1	= $75 million + (0.0088 * MWt)	1677	89,757,600
Prairie Island (PWR), Unit 2	= $75 million + (0.0088 * MWt)	1677	89,757,600

2. NRC Minimum Calculation in 2017 Dollars - Combination of Facilities

	1986 Minimum Calculation	Escalation Rate	2017 Minimum Calculation (Blended)
Monticello (BWR)	122,036,000	4.6050	561,975,756
Prairie Island (PWR), Unit 1	89,757,600	4.3541	390,815,175
Prairie Island (PWR), Unit 2	89,757,600	4.3541	390,815,175

3. NRC Minimum Calculation in 2017 Dollars - Compact-Affiliated Facilities Only

	1986 Minimum Calculation	Escalation Rate	2017 Minimum Calculation (Direct)
Monticello (BWR)	122,036,000	7.7330	943,699,483
Prairie Island (PWR), Unit 1	89,757,600	8.5539	767,779,143
Prairie Island (PWR), Unit 2	89,757,600	8.5539	767,779,143

Xcel Energy
Spent Fuel Management Costs
60-year Decommissioning Period
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	Monticello												
	Emergency Planning Fees	Spent Fuel Pool O&M	Spent Fuel Casks & Transfer	ISFSI Operating Costs	PIIC Payments	Security Staff Cost	Utility Staff Cost	Insurance	Property taxes	NRC ISFSI Fees	Fixed Overhead	Railroad Track Maintenance	Total
2030	1,088	288	845	37	0	0	0	0	0	0	0	0	2,258
2031	3,482	923	832	119	0	0	0	0	0	0	0	0	5,357
2032	2,957	925	831	119	0	0	0	0	0	0	0	0	4,833
2033	2,825	923	23,066	119	0	0	0	0	0	0	0	0	26,933
2034	2,825	923	66	119	0	0	0	0	0	0	0	0	3,933
2035	2,825	635	98,692	119	0	1,402	355	0	0	0	0	0	104,027
2036	1,330	0	60	118	0	4,500	1,143	0	0	0	0	0	7,151
2037	150	0	74	119	0	4,487	1,140	641	1,403	198	0	0	8,212
2038	150	0	65	119	0	4,487	1,139	793	1,659	244	21	10	8,689
2039	150	0	66	119	0	4,485	1,137	793	698	245	286	133	8,112
2040	151	0	66	119	0	4,497	1,140	796	699	245	287	133	8,134
2041	150	0	66	119	0	4,485	1,137	793	698	245	286	133	8,112
2042	150	0	66	119	0	4,485	1,137	793	698	245	286	133	8,112
2043	150	0	66	119	0	4,485	1,137	793	698	245	286	133	8,112
2044	151	0	66	119	0	4,497	1,140	796	699	245	287	133	8,134
2045	150	0	66	119	0	4,485	1,137	793	698	245	286	133	8,112
2046	150	0	66	119	0	4,485	1,137	793	698	245	286	133	8,112
2047	150	0	66	119	0	4,485	1,137	793	698	245	286	133	8,112
2048	151	0	2,721	119	0	4,497	1,140	796	699	245	287	133	10,789
2049	150	0	66	119	0	4,485	1,137	793	698	245	286	133	8,112
2050	150	0	6,039	119	0	4,485	1,137	793	698	245	286	133	14,085
2051	150	0	6,039	119	0	4,485	1,137	793	698	245	286	133	14,085
2052	151	0	9,489	119	0	4,497	1,140	796	699	245	287	133	17,557
2053	150	0	12,077	119	0	4,485	1,137	793	698	245	286	133	20,122
2054	150	0	6,902	119	0	4,485	1,137	793	698	245	286	133	14,947
2055	150	0	11,214	119	0	4,485	1,137	793	698	245	286	133	19,260
2056	151	0	12,939	119	0	4,497	1,140	796	699	245	287	133	21,007
2057	150	0	0	119	0	4,485	1,137	793	698	245	286	133	8,046
2058	150	0	0	119	0	4,485	1,137	793	698	245	286	133	8,046

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	Monticello												
	Emergency Planning Fees	Spent Fuel Pool O&M	Spent Fuel Casks & Transfer	ISFSI Operating Costs	PIIC Payments	Security Staff Cost	Utility Staff Cost	Insurance	Property taxes	NRC ISFSI Fees	Fixed Overhead	Railroad Track Maintenance	Total
2059	150	0	0	119	0	4,485	1,137	793	698	245	286	133	8,046
2060	151	0	(0)	119	0	4,497	1,140	796	699	245	287	133	8,068
2061	150	0	0	119	0	4,485	1,137	793	698	245	286	133	8,046
2062	150	0	0	119	0	4,485	1,137	793	698	245	286	133	8,046
2063	150	0	0	119	0	4,485	1,137	793	698	245	286	133	8,046
2064	151	0	(0)	119	0	4,497	1,140	796	699	245	287	133	8,068
2065	150	0	0	119	0	4,485	1,137	793	698	245	286	133	8,046
2066	150	0	0	119	0	4,485	1,137	793	698	245	286	133	8,046
2067	150	0	0	119	0	4,485	1,137	793	698	245	286	133	8,046
2068	151	0	(0)	119	0	4,497	1,140	796	699	245	287	133	8,068
2069	150	0	0	119	0	4,485	1,137	793	698	245	286	133	8,046
2070	150	0	0	119	0	4,485	1,137	793	698	245	286	133	8,046
2071	150	0	0	119	0	4,485	1,137	793	698	245	286	133	8,046
2072	151	0	(0)	119	0	4,497	1,140	796	699	245	287	133	8,068
2073	150	0	0	119	0	4,485	1,137	793	698	245	286	133	8,046
2074	150	0	0	119	0	4,485	1,137	793	698	245	286	133	8,046
2075	150	0	0	119	0	4,485	1,137	793	698	245	286	133	8,046
2076	151	0	(0)	119	0	4,497	1,140	796	699	245	287	133	8,068
2077	150	0	0	119	0	4,485	1,137	793	698	245	286	133	8,046
2078	150	0	1,912	119	0	4,486	1,138	794	567	360	286	133	9,944
2079	150	0	2,295	119	0	4,486	1,138	794	567	360	286	133	10,327
2080	151	0	1,912	119	0	4,498	1,141	796	569	361	287	133	9,966
2081	150	0	1,912	119	0	4,486	1,138	794	567	360	286	133	9,944
2082	150	0	1,912	119	0	4,486	1,138	794	567	360	286	133	9,944
2083	150	0	2,295	119	0	4,486	1,138	794	567	360	286	133	10,327
2084	151	0	1,912	119	0	4,498	1,141	796	569	361	287	133	9,966
2085	150	0	1,912	119	0	4,486	1,138	794	567	360	286	133	9,944
2086	150	0	1,912	119	0	4,486	1,138	794	567	360	286	133	9,944
2087	150	0	2,295	119	0	4,486	1,138	794	567	360	286	133	10,327
2088	151	0	4,567	119	0	4,498	1,141	796	569	361	287	133	12,621
2089	150	0	1,912	119	0	4,486	1,138	794	567	360	286	133	9,944
2090	150	0	764	119	0	4,486	1,138	794	567	360	286	133	8,796
2091	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	25,461	4,617	220,127	7,166	0	248,276	62,963	42,723	37,661	14,674	14,898	6,912	685,479

From Schedule A.02_Monticello 60-year for DECON Spent Fuel Cash Flows 685,479

Xcel Energy
Spent Fuel Management Costs
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	Prairie Island Unit 1												
	Emergency Planning Fees	Spent Fuel Pool O&M	Spent Fuel Casks & Transfer	ISFSI Operating Costs	PIIC Payments	Security Staff Cost	Utility Staff Cost	Insurance	Property taxes	NRC ISFSI Fees	Fixed Overhead	Railroad Track Maintenance	Total
2030	0	0	0	0	0	0	0	0	0	0	0	0	0
2031	0	0	0	0	0	0	0	0	0	0	0	0	0
2032	0	0	0	0	0	0	0	0	0	0	0	0	0
2033	696	182	0	23	802	0	0	0	0	0	0	0	1,704
2034	1,765	461	6	59	1,698	0	0	0	0	0	0	0	3,990
2035	1,451	462	1,709	59	1,250	0	0	0	0	0	0	0	4,930
2036	1,416	463	385	60	1,250	0	0	0	0	0	0	0	3,574
2037	1,412	307	381	60	1,250	0	0	0	0	0	0	0	3,410
2038	1,412	0	11,500	59	1,250	0	0	0	0	0	0	0	14,222
2039	1,412	0	86,205	59	1,250	0	97	0	0	0	0	0	89,024
2040	885	0	(2)	59	1,250	0	568	0	0	0	0	0	2,760
2041	75	0	13	59	1,250	1,495	569	182	1,460	79	0	0	5,183
2042	75	0	0	59	1,250	2,302	569	281	2,248	122	0	0	6,907
2043	75	0	(2)	59	1,250	2,302	569	281	1,730	153	93	35	6,546
2044	75	0	3	60	1,250	2,309	570	282	1,273	180	176	66	6,244
2045	75	0	(1)	59	1,250	2,302	569	281	1,269	180	175	66	6,227
2046	75	0	(1)	59	1,250	2,302	569	281	1,269	180	175	66	6,227
2047	75	0	(1)	59	1,250	2,302	569	281	1,269	180	175	66	6,227
2048	75	0	3	60	1,250	2,309	570	282	1,273	180	176	66	6,244
2049	75	0	(1)	59	1,250	2,302	569	281	1,269	180	175	66	6,227
2050	75	0	(1)	59	1,250	2,302	569	281	1,269	180	175	66	6,227
2051	75	0	(1)	59	1,250	2,302	569	281	1,269	180	175	66	6,227
2052	75	0	3	60	1,250	2,309	570	282	1,273	180	176	66	6,244
2053	75	0	382	59	1,250	2,302	569	281	1,269	180	175	66	6,609
2054	75	0	765	59	1,250	2,302	569	281	1,269	180	175	66	6,992
2055	75	0	765	59	1,250	2,302	569	281	1,269	180	175	66	6,992
2056	75	0	959	60	1,250	2,309	570	282	1,273	180	176	66	7,201
2057	75	0	573	59	1,250	2,302	569	281	1,269	180	175	66	6,801
2058	75	0	1,147	59	1,250	2,302	569	281	1,269	180	175	66	7,375

Xcel Energy
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	Prairie Island Unit 1												
	Emergency Planning Fees	Spent Fuel Pool O&M	Spent Fuel Casks & Transfer	ISFSI Operating Costs	PIIC Payments	Security Staff Cost	Utility Staff Cost	Insurance	Property taxes	NRC ISFSI Fees	Fixed Overhead	Railroad Track Maintenance	Total
2059	75	0	573	59	1,250	2,302	569	281	1,269	180	175	66	6,801
2060	75	0	385	60	1,250	2,309	570	282	1,273	180	176	66	6,627
2061	75	0	765	59	1,250	2,302	569	281	1,269	180	175	66	6,992
2062	75	0	765	59	1,250	2,302	569	281	1,269	180	175	66	6,992
2063	75	0	573	59	1,250	2,302	569	281	1,269	180	175	66	6,801
2064	75	0	768	60	1,250	2,309	570	282	1,273	180	176	66	7,009
2065	75	0	765	59	1,250	2,302	569	281	1,269	180	175	66	6,992
2066	75	0	573	59	1,250	2,302	569	281	1,269	180	175	66	6,801
2067	75	0	765	59	1,250	2,302	569	281	1,269	180	175	66	6,992
2068	75	0	768	60	1,250	2,309	570	282	1,273	180	176	66	7,009
2069	75	0	573	59	1,250	2,302	569	281	1,269	180	175	66	6,801
2070	75	0	765	59	1,250	2,302	569	281	1,269	180	175	66	6,992
2071	75	0	765	59	1,250	2,302	569	281	1,269	180	175	66	6,992
2072	75	0	768	60	1,250	2,309	570	282	1,273	180	176	66	7,009
2073	75	0	765	59	1,250	2,302	569	281	1,269	180	175	66	6,992
2074	75	0	765	59	1,250	2,302	569	281	1,269	180	175	66	6,992
2075	75	0	2,092	59	1,250	2,302	569	281	1,269	180	175	66	8,320
2076	75	0	768	60	1,250	2,309	570	282	1,273	180	176	66	7,009
2077	76	0	750	59	1,250	2,220	548	271	1,224	179	169	67	6,814
2078	0	0	0	0	0	0	0	0	0	0	0	0	0
2079	0	0	0	0	0	0	0	0	0	0	0	0	0
2080	0	0	0	0	0	0	0	0	0	0	0	0	0
2081	0	0	0	0	0	0	0	0	0	0	0	0	0
2082	0	0	0	0	0	0	0	0	0	0	0	0	0
2083	0	0	0	0	0	0	0	0	0	0	0	0	0
2084	0	0	0	0	0	0	0	0	0	0	0	0	0
2085	0	0	0	0	0	0	0	0	0	0	0	0	0
2086	0	0	0	0	0	0	0	0	0	0	0	0	0
2087	0	0	0	0	0	0	0	0	0	0	0	0	0
2088	0	0	0	0	0	0	0	0	0	0	0	0	0
2089	0	0	0	0	0	0	0	0	0	0	0	0	0
2090	0	0	0	0	0	0	0	0	0	0	0	0	0
2091	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	13,235	1,875	119,500	2,636	56,249	84,353	21,701	10,296	48,579	6,477	6,057	2,292	373,250

From Schedule A.09_Prairie Island 60-year for DECON Spent Fuel Cash Flows 373,250

Xcel Energy
Spent Fuel Management Costs
60-year Decommissioning Period
DECON Method

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Schedule A.17
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($s in 000's)

	Prairie Island Unit 2												
	Emergency Planning Fees	Spent Fuel Pool O&M	Spent Fuel Casks & Transfer	ISFSI Operating Costs	PIIC Payments	Security Staff Cost	Utility Staff Cost	Insurance	Property taxes	NRC ISFSI Fees	Fixed Overhead	Railroad Track Maintenance	Total
2030	0	0	0	0	0	0	0	0	0	0	0	0	0
2031	0	0	0	0	0	0	0	0	0	0	0	0	0
2032	0	0	0	0	0	0	0	0	0	0	0	0	0
2033	0	0	0	0	0	0	0	0	0	0	0	0	0
2034	305	80	0	10	406	0	0	0	0	0	0	0	801
2035	1,765	461	1,717	59	2,094	0	0	0	0	0	0	0	6,096
2036	1,533	463	383	59	1,250	0	0	0	0	0	0	0	3,689
2037	1,412	462	383	59	1,250	0	0	0	0	0	0	0	3,566
2038	1,412	241	11,499	59	1,250	0	0	0	0	0	0	0	14,462
2039	1,412	0	86,205	59	1,250	0	97	0	0	0	0	0	89,024
2040	885	0	(2)	59	1,250	0	568	0	0	0	0	0	2,760
2041	75	0	13	59	1,250	1,495	569	182	1,460	79	0	0	5,183
2042	75	0	0	59	1,250	2,302	569	281	2,248	122	0	0	6,907
2043	75	0	(2)	59	1,250	2,302	569	281	1,730	153	93	35	6,546
2044	75	0	3	60	1,250	2,309	570	282	1,273	180	176	66	6,244
2045	75	0	(1)	59	1,250	2,302	569	281	1,269	180	175	66	6,227
2046	75	0	(1)	59	1,250	2,302	569	281	1,269	180	175	66	6,227
2047	75	0	(1)	59	1,250	2,302	569	281	1,269	180	175	66	6,227
2048	75	0	3	60	1,250	2,309	570	282	1,273	180	176	66	6,244
2049	75	0	(1)	59	1,250	2,302	569	281	1,269	180	175	66	6,227
2050	75	0	(1)	59	1,250	2,302	569	281	1,269	180	175	66	6,227
2051	75	0	(1)	59	1,250	2,302	569	281	1,269	180	175	66	6,227
2052	75	0	3	60	1,250	2,309	570	282	1,273	180	176	66	6,244
2053	75	0	382	59	1,250	2,302	569	281	1,269	180	175	66	6,609
2054	75	0	765	59	1,250	2,302	569	281	1,269	180	175	66	6,992
2055	75	0	765	59	1,250	2,302	569	281	1,269	180	175	66	6,992
2056	75	0	959	60	1,250	2,309	570	282	1,273	180	176	66	7,201
2057	75	0	573	59	1,250	2,302	569	281	1,269	180	175	66	6,801
2058	75	0	1,147	59	1,250	2,302	569	281	1,269	180	175	66	7,375

Xcel Energy
Spent Fuel Management Costs
60-year Decommissioning Period
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($s in 000's)

	Prairie Island Unit 2												
	Emergency Planning Fees	Spent Fuel Pool O&M	Spent Fuel Casks & Transfer	ISFSI Operating Costs	PIIC Payments	Security Staff Cost	Utility Staff Cost	Insurance	Property taxes	NRC ISFSI Fees	Fixed Overhead	Railroad Track Maintenance	Total
2059	75	0	573	59	1,250	2,302	569	281	1,269	180	175	66	6,801
2060	75	0	385	60	1,250	2,309	570	282	1,273	180	176	66	6,627
2061	75	0	765	59	1,250	2,302	569	281	1,269	180	175	66	6,992
2062	75	0	765	59	1,250	2,302	569	281	1,269	180	175	66	6,992
2063	75	0	573	59	1,250	2,302	569	281	1,269	180	175	66	6,801
2064	75	0	768	60	1,250	2,309	570	282	1,273	180	176	66	7,009
2065	75	0	765	59	1,250	2,302	569	281	1,269	180	175	66	6,992
2066	75	0	573	59	1,250	2,302	569	281	1,269	180	175	66	6,801
2067	75	0	765	59	1,250	2,302	569	281	1,269	180	175	66	6,992
2068	75	0	768	60	1,250	2,309	570	282	1,273	180	176	66	7,009
2069	75	0	573	59	1,250	2,302	569	281	1,269	180	175	66	6,801
2070	75	0	765	59	1,250	2,302	569	281	1,269	180	175	66	6,992
2071	75	0	765	59	1,250	2,302	569	281	1,269	180	175	66	6,992
2072	75	0	768	60	1,250	2,309	570	282	1,273	180	176	66	7,009
2073	75	0	765	59	1,250	2,302	569	281	1,269	180	175	66	6,992
2074	75	0	765	59	1,250	2,302	569	281	1,269	180	175	66	6,992
2075	75	0	2,092	59	1,250	2,302	569	281	1,269	180	175	66	8,320
2076	75	0	768	60	1,250	2,309	570	282	1,273	180	176	66	7,009
2077	76	0	750	59	1,250	2,220	548	271	1,224	179	169	67	6,814
2078	0	0	0	0	0	0	0	0	0	0	0	0	0
2079	0	0	0	0	0	0	0	0	0	0	0	0	0
2080	0	0	0	0	0	0	0	0	0	0	0	0	0
2081	0	0	0	0	0	0	0	0	0	0	0	0	0
2082	0	0	0	0	0	0	0	0	0	0	0	0	0
2083	0	0	0	0	0	0	0	0	0	0	0	0	0
2084	0	0	0	0	0	0	0	0	0	0	0	0	0
2085	0	0	0	0	0	0	0	0	0	0	0	0	0
2086	0	0	0	0	0	0	0	0	0	0	0	0	0
2087	0	0	0	0	0	0	0	0	0	0	0	0	0
2088	0	0	0	0	0	0	0	0	0	0	0	0	0
2089	0	0	0	0	0	0	0	0	0	0	0	0	0
2090	0	0	0	0	0	0	0	0	0	0	0	0	0
2091	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	11,509	1,707	119,500	2,563	55,000	84,353	21,701	10,296	48,579	6,477	6,057	2,292	370,034

From Schedule A.09_Prairie Island 60-year for DECON Spent Fuel Cash Flows 370,034

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Red Wing Plan Schedule B
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The Commission's Order from the last triennial directed the Company to "develop a 60, 100 and 200-year plan for the City of Red Wing to enable Xcel to build, improve, communicate, and share an understanding of the long-term safety-related costs of spent fuel storage on host communities."

We value our relationship with our host communities and meet with a subset of the city council each quarter to keep them informed of operations as well as long term plans including eventual decommissioning. Consistent with our past practice, we have continued to have discussions with our host communities regarding potential costs and other concerns arising from the storage of used nuclear fuel following the cessation of operations at our nuclear facilities. We understand from these discussions and from the City of Red Wing's comments in our last triennial that it continues to have concerns regarding the need for public safety services in connection with the long-term storage of spent fuel after the plant's retirement. As discussed in our last triennial, we will continue to have appropriate on-site radiological emergency plans in place during the ISFSI management and decommissioning period. And while we certainly appreciate the emergency response support we receive from our local communities during plant operations, current NRC guidance indicates that off-site radiological emergency support will not be required after the plants cease operations and nuclear fuel is moved to dry storage.[1]

Additionally—with the exception of radiological issues—the Prairie Island Plant and ISFSI are no different from any other industrial facility when it comes to public and emergency services. Nearly all special costs incurred by the City for radiological emergency preparedness—such as costs for emergency planning, training, and equipment—are reimbursed by the state under the Minnesota Emergency Management Act (MEMA). Under MEMA, Xcel Energy pays quarterly assessments

[1] In late 2014, the NRC granted Kewaunee Nuclear Plant an exemption from the emergency planning requirements for an operating nuclear facility. As part of that exemption, Kewaunee will no longer be required to maintain offsite radiological emergency preparedness plans for the 10-mile emergency planning zone. The exemption package for Kewaunee was issued October 27, 2014 and is available in the NRC's ADAMS database under accession number ML14261A223. In addition, the NRC held a meeting on April 23, 2015 with members of the NEI Emergency Preparedness Decommissioning Task Force to discuss issues related to potential changes to a licensee's emergency plan, based on the requirements of Section 50.47(b) of Title 10 of the Code of Federal Regulations and Appendix E to Part 50, following a decision to permanently cease operation and permanently remove fuel from the reactor vessel in accordance with 10 CFR 50.82(a).

to the Minnesota Division of Emergency Management to cover emergency response preparedness costs in the event of a radiological incident for the Prairie Island and Monticello nuclear facilities. Thus, Red Wing receives—and will continue to receive—funding for radiological emergency preparedness, including expenses for planning, training, drills/exercises, and equipment. The ISFSI will continue to be monitored and regulated per federal and state requirements.

That said, we do want to foster a shared understanding between the Company and Red Wing regarding any long-term safety-related issues in connection with the ISFSI following closure of the plant. Under current federal rules, after permanent shut down, the plant must submit written certification of permanent cessation of operations to NRC within 30 days. Within 2 years after certification of permanent closure, Xcel Energy will submit a post shut down decommissioning activities report (PSDAR) including things that describe activities and schedules during decommissioning. That report is available for public review and comments along with public hearings. As part of that process, three years prior to plant shutdown, we propose to work with the city to develop a safety plan that would outline responsibilities and coordinated efforts for response once we get to ISFSI only.

We believe we can learn best practices and insight from the plants and host communities currently going through decommissioning. To that end, we are proposing to facilitate an ongoing dialogue between the City of Red Wing and host communities in other parts of the country to assist the City in developing a better understanding of the issues faceting communities near standalone ISFSI's after plant shutdown and decommissioning. We have discussed this plan with the City of Red Wing and provided contacts to other city officials who host shut down plants.

We look forward to continued dialogue with our host communities throughout plant operations and into decommissioning.

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Escalation Analysis Schedule C
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Introduction

The escalation rate for decommissioning costs is an important element in determining the appropriate investment strategy, funding contributions, and the computation of the annual nuclear decommissioning external sinking fund accrual. This rate is used to inflate the 2017 decommissioning cost estimate out to the time that expenditures are predicted to occur. Since the decommissioning costs were provided by TLG in 2017 dollars (i.e., they are real costs), the escalation rate considers only the projected increases in costs from 2017 out to the estimated years of the final decommissioning expenditures. To arrive at these projections, long-range inflation and escalation assumptions are independently provided by Goldman Sachs Asset Management (GSAM).

Economic Forecast

The trend projection used for escalation is a baseline scenario based on a steady long-term real Gross Domestic Product (GDP) growth of 2.0 percent. The projection assumes that the economy suffers no major long-term mishaps, but grows smoothly, in the sense that actual output follows potential output relatively closely. This projection is best described as depicting the assumed mean of all possible paths that the economy could follow in the absence of major long-term disruptions. Such disruptions include large oil price shocks, untoward and persistent swings in macroeconomic policy, or excessively rapid increases in demand. The trend projection can be considered an unbiased reflection of the future performance of the economy. The real GDP forecast of 2.0 percent is slightly below the 3.2 percent average since 1947.

For the 60-Year Scenario, the 2017 decommissioning cost for Monticello and Prairie Island generating plants depict an overall expenditure period from 2033 to 2078 for the Prairie Island plant and from 2030 to 2091 for the Monticello plant. The expenditure pattern for this scenario requires the estimation of an escalation rate to 2091.

Inflation Factors

Inflation is the decrease in the purchasing power of money or the increase in the prices of goods and services. However, decommissioning is a unique combination of functions with many operations that are not performed often in

industry, and it may be more consistent to use a decommissioning-specific inflation factor rather than a general rate of inflation.

GSAM has refined the analysis surrounding the calculation of the escalation rate and believes its methodology provides an appropriate estimate. TLG provides a detailed decommissioning cost estimate that is site specific for the units at Monticello and Prairie Island. These site-specific decommissioning cost components need only be linked with appropriate escalation.

Escalation is broken down into two components: inflation and non-inflation escalation. Non-inflation escalation reflects idiosyncratic costs for decommissioning nuclear power plants, above and beyond the escalation associated with inflation.

The long-term escalation rates used in this analysis are as follows

Escalation Component	**Trend Projection**
Inflation	1.85%
Non-inflation escalation (Non-labor costs)	1.00%
Total escalation (Non-labor costs)	**2.85%**
Non-inflation escalation (Labor costs)	2.20%
Total escalation (Labor costs)	**4.05%**

Long-term expected inflation is assumed to be 1.85 percent, which is estimated from the expected inflation implied in long-term US treasury rates. The long-term risk-free (treasury) rate is observed to be 2.84 percent and the observed long-term Treasury Inflation Protected Securities (TIPS) yield (proxy for assuming the long-term real rate of interest) is 0.99 percent. This implies expected inflation of 1.85 percent. Non-inflation escalation is assumed to be 1.00 percent for non-labor costs, but 2.20% for labor costs.

The overall escalation rates in the above table should be compared with the 4.36 percent escalation rate in the 2014 analysis, 3.63 percent escalation rate in the 2011 analysis and the escalation rate of 2.89 percent from the 2008 analysis.

Decommissioning Cost Breakdown and Escalation

GSAM related the calculation of the escalation rate to the detailed cost categories provided by TLG. The TLG cost estimates are divided into five components or categories: labor, equipment & materials, energy, LLRW

disposal, and other. GSAM began its forecast by separating labor from the other four categories of costs.

Inflation is the general increase in all prices across the economy. If all costs in every industry were analyzed, in aggregate they must increase by inflation. Therefore, an assumption of costs growing by more than inflation requires that other costs somewhere are growing less. We assume that the non-labor parts of the costs grow at one percent more than inflation. In general, this increase would constitute a conservative assumption. However, given regulatory uncertainty and the complexities of forecasting technical change, the assumption that other costs grow faster than inflation seems reasonable. Historically, the escalation of nuclear decommissioning costs based on NRC filings and on engineer reports as reported in the Callan study[1] appears to have been substantially greater than inflation, by perhaps 4% - 5%.

According to economic theory, labor costs increase by inflation plus productivity (merit). We have assumed merit increases are 1.2 percent per year, consistent with a 2.00 percent long-term real GDP growth and an assumption that labor productivity accounts for 60 percent of GDP growth. Labor productivity has varied since 1950 between 60 and 66 percent.

In the 2014 triennial filing, an average escalation rate was calculated and used to escalate all costs based on the percentage of costs coming from labor. In the 2017 triennial filing, the two different escalation rates are being applied to labor and non-labor costs separately, which should be more precise than the previous approach. The 2017 triennial filing contains an additional third category for the Prairie Island Indian Community (PIIC) payments because they are determined by a settlement agreement that does not contain a provision for escalation beyond their current nominal amounts. These Labor, Non-Labor, and PIIC groups of cash flows are shown separately on Schedule F for the 2017 filing based upon the respective escalation rate applied.

Application of the Escalation Rate

A critical aspect of the valuation procedure is to ensure that assumptions are consistent between asset and liability growth. The analysis assumes that:

Expected cost (liability) growth = inflation + non-inflation escalation

[1] Callan 2017 Nuclear Decommissioning Funding Study

Expected pre-tax asset returns = inflation + real interest rate + risk premium

Note that inflation increases both pre-tax asset returns and decommissioning costs (i.e., the liability) equally. Thus, in the absence of taxes, inflation would be neutral to the valuation, which is consistent with economic theory based on real liability cash flows. The introduction of taxes, however, changes the analysis somewhat. Taxation means that lower inflation helps improve funded status, as the reduction in liability escalation will exceed the reduction in the after-tax asset return.

The other variables, however, have major implications for the analysis, since they are not offset in the same way as inflation. In general, the most important variables are non-inflation escalation, the real rate of interest, and the risk premium associated with the growth portfolio assets.

Historical Real GDP and Labor Productivity

In order to provide some context for the escalation assumptions presented above, below we present charts of historical real GDP and labor productivity for the US economy.

Analysis indicates that the real GDP growth assumption of 2.0 percent and labor productivity assumption of 60% are reasonable long-term forecasts.

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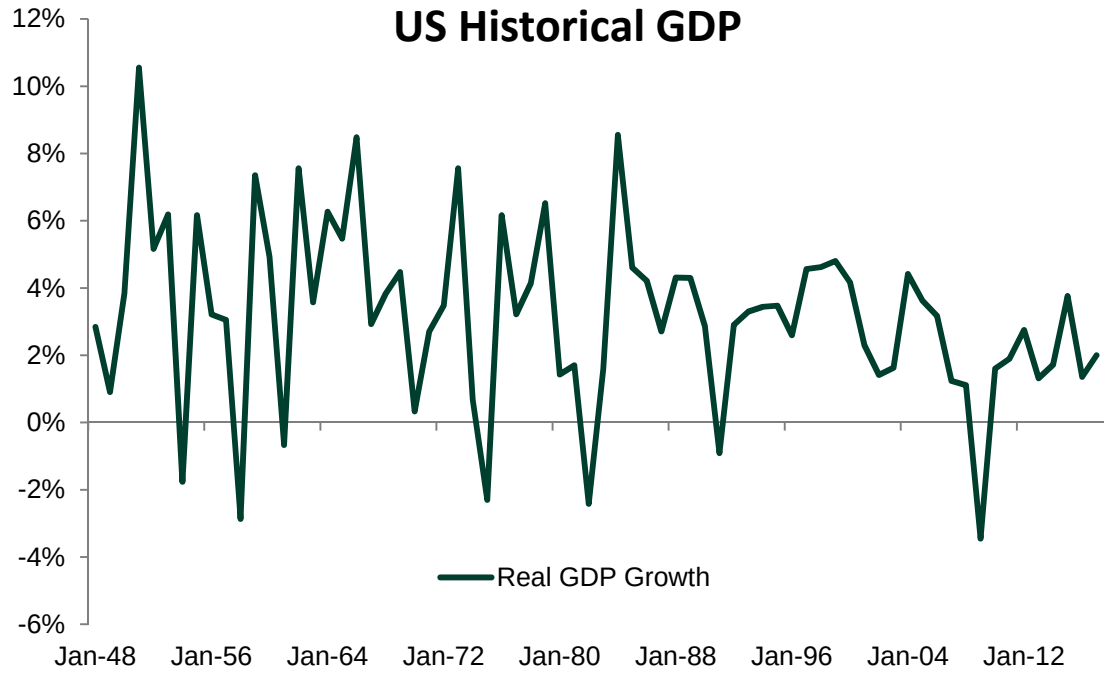
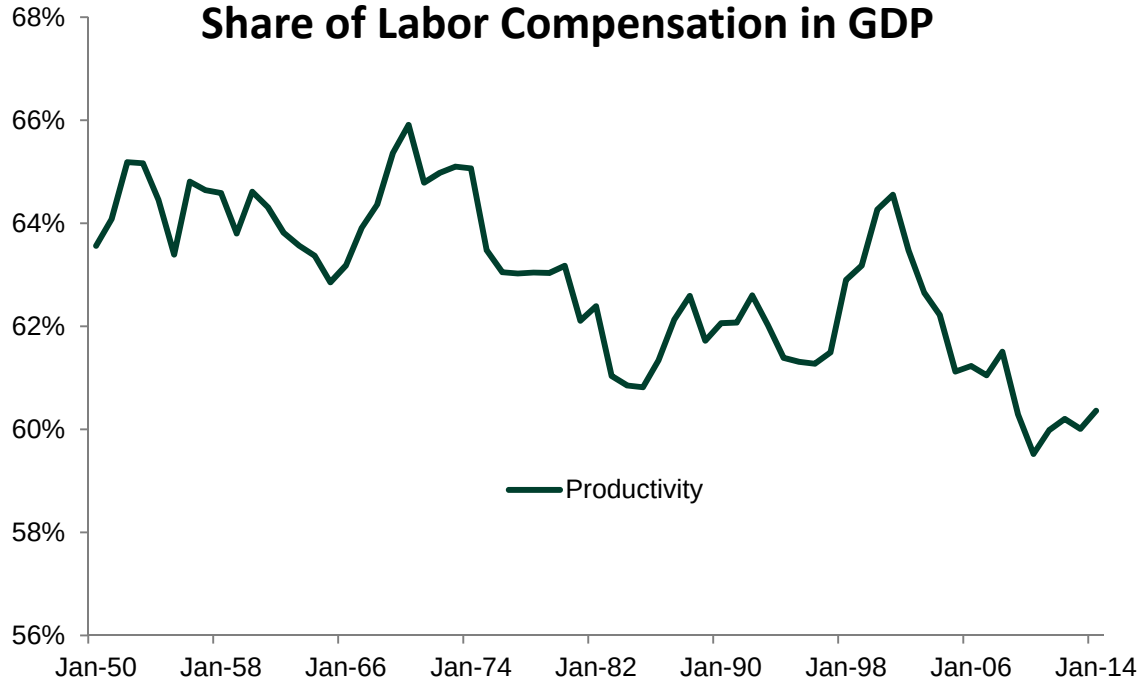


Source: St. Louis Fed



Source: St. Louis Fed

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Portfolio Analysis Schedule D
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Background

Per Commission Orders, beginning with Docket No. E002/D-86-604 and through subsequent dockets, the Company is required to review the financial parameters, the funding methodology, and cost estimate every three years. In between triennial filings, the Company submits an Informational Letter annually discussing NDT performance.

Since the nuclear power plants deliver power across state lines, each state is responsible for its share of the plants' ownership/use, and as such, its share of decommissioning cost. Based upon the demand of Minnesota Retail customers, Xcel Energy estimates that Minnesota's usage of the plants is 73.4886 percent. However, the engineering reports and asset-liability analysis, which use the engineering reports, do not distinguish between jurisdictions. Likewise, the analyses referred to in this schedule are performed on a total plant basis, and the figures (assets, liabilities, funded status, and expected contributions) are allocated to Minnesota by multiplying figures by 73.4886 percent.

There are references in this schedule to both the total across all jurisdictions (Total Company) and the MN Jurisdiction for various figures. References to the MN jurisdiction generally correspond to the Total Company multiplied by 73.4886 percent.

Recent Portfolio Updates

As discussed in previous triennial dockets, the Company's NDT Committee routinely evaluates both the NDT's performance and the overall investment strategy for the NDT (including its asset allocation), and it revises both the strategy and allocation as necessary. Following a hearing on the Company's 2016 Annual Informational Report, the Commission's issued an order in February 2017 requiring Xcel Energy to re-evaluate the investment mix for the NDT with the purpose of reducing the NDT's investment management fees and increasing the annual return on its investment portfolio.

With this Order in mind, the NDT Committee's most recent investment strategy review focused on the following objectives:

1. The desire for higher expected portfolio returns
2. The desire for lower investment manager fees
3. The desire for a simplified portfolio with fewer asset classes

As part of the investment strategy review, the company considered portfolio options that shifted NDT objectives slightly from liability matching characteristics such as inflation sensitivity to instead focus on lower cost, more traditional investments. To this end, the NDT's investment in commodities was removed from the portfolio.

The company also re-evaluated the diversifying assets included in the portfolio, such as the hedge fund investments. Consistent with the objective of reducing investment manager fees and simplifying the portfolio, hedge funds were removed.

We believe these updates to the asset mix achieve the objectives established by the Commission. The expected portfolio return increases; expected manager fees decline; and there are two fewer line items in the portfolio, all at a similar risk profile. The tradeoff is that the portfolio has a larger allocation to fixed income investments, and will likely be more closely tied to movements in interest rates. That said, we believe this tradeoff is reasonable and in the best interests of our customers.

The 2016 and updated 2017 target asset allocations are included below for comparison:

Portfolio Line Item	2016 Target	Updated 2017 Target
Total Equity	60.0%	60.0%
Private Equity	10.0%	10.0%
Public Equity	50.0%	50.0%
US All Cap Equity	26.0%	25.8%
Non-US Developed Equity	14.0%	14.1%
Emerging Markets Equity	10.0%	10.1%
Fixed Income	17.5%	30.0%
Investment Grade Fixed Income	5.0%	12.1%
High Yield Fixed Income	8.5%	10.0%
Emerging Market Debt	4.0%	7.9%
Hedge Funds	7.5%	0.0%
Private Real Estate	10.0%	10.0%
Real Assets (Commodities)	5.0%	0.0%
Cash	0.0%	0.0%
Total	**100.0%**	**100.0%**

Trustee

BNY Mellon is the trustee for Xcel Energy's three external nuclear decommissioning Qualified Trusts (in aggregate the NDT). The primary duty of the trustee is the safe custody of its assets including handling the settlement of all purchases and sales, whether placed by the trustee or by an independent investment manager. The trustee has limited investment duties other than the responsibility for keeping cash balances temporarily invested. Other duties include paying income taxes on the earnings of the Qualified Trusts, paying invoices for services for the trust and investment managers, conducting investment performance reporting, and keeping accurate records of all of its activities with respect to the Qualified Trusts.

Investment Managers

Following regulatory approval of the life extension of the Monticello and Prairie Island nuclear generating plants, the Xcel Energy's NDT portfolio was updated to reflect a longer time horizon and a more diversified, higher risk, long-term investment strategy.

Following the investment strategy review conducted ahead of the 2017 triennial filing, three investment managers were selected for removal from the portfolio by 2017 year-end, at which point the target allocation will include eight investment managers covering eight asset categories. Those asset managers and mandates include:

1. StepStone Group manages the private equity component of the portfolio.
2. Parametric Portfolio Advisors, a subsidiary of Eaton Vance Management, manages the U.S. equity component of the portfolio, a portion of the non-U.S. developed market equity component of the portfolio, and the emerging markets equity component of the portfolio (distributed through Eaton Vance Management). Parametric utilizes tax-efficient strategies with respect to the whole trust.
3. Marathon International manages a portion of the non-U.S. developed market equity component of the portfolio
4. First Principles Capital Management manages the domestic investment grade fixed income component of the portfolio.
5. Eaton Vance Management manages the high yield fixed income component of the portfolio.

6. Wellington Management Company manages a portion of the emerging markets fixed income component of the portfolio.
7. Marathon Asset Management manages a portion of the emerging markets fixed income component of the portfolio.
8. The Townsend Group manages the private real estate component of the portfolio.

Although the trusts are not subject to the Employee Retirement Income Security Act (ERISA), the company uses fiduciary standards similar to those imposed by ERISA for the management of the Trusts. A fiduciary as defined by the ERISA is any person who:

1. Exercises any discretionary control over the management of a plan or the management or disposition of its assets;
2. Renders investment advice for a fee with respect to the funds or property of a plan or has the authority to do so; or
3. Has any discretionary authority or responsibility in the administration of a plan.

Although Xcel Energy has established the general guidelines in the investment advisory contracts, the Company does not direct the purchase of individual investments. The investment managers, however, being fiduciaries to the NDT, must act in the best interests of the NDT.

Earnings Evaluation

When making comparisons between market value and book value (original cost), the current market value of the Qualified Trusts less an allowance for assumed taxes is used because it represents the value of the securities if they were sold today. For accounting purposes, Xcel Energy records the actual purchase price of the investments. Quarterly, a market value adjustment journal entry is made to book any unrealized gains or losses to special regulatory accounts per SFAS No. 115, Accounting for Certain Investments in Debt and Equity Securities (ASC 320 *Investments-Debt and Equity Securities*). The difference between market and book values represents the unrealized gains or losses. In addition it should be noted that trustee fees, investment management fees, and income taxes also are paid from the Qualified Trusts, thereby impacting overall fund performance.

The trustee statements for the Qualified Trusts are a part of Schedule E and show the current holdings for the Qualified Trusts by operating unit and investment manager.

Benchmark Portfolio Performance

It is standard practice in the investment industry to measure the performance of a diversified portfolio, like the NDT, by identifying benchmarks that are representative of each asset class comprising the portfolio, and then to benchmark the total portfolio to the weighted sum of the individual benchmarks.

The updated 2017 target asset allocation and associated benchmarks are included below:

Portfolio Line Item	Updated 2017 Target	Benchmark (BM)
Total Equity	60.0%	Weighted average of equity BMs:
Private Equity	10.0%	Cambridge PE (1Q lagged)
US All Cap Equity	25.8%	Russell 3000
Non-US Developed Equity	14.1%	MSCI EAFE ND
Emerging Markets Equity	10.1%	MSCI EM ND
Fixed Income	30.0%	Weighted average of fixed income BMs:
Investment Grade Fixed Income	12.1%	75% Barclays Investment Grade Corporate Index, 25% Barclays U.S. TIPS 10+ year Index, 50% Bloomberg 20yr ZC Inflation Swap Overlay
High Yield Fixed Income	10.0%	BofA ML US High Yield
Emerging Market Debt	7.9%	JPM EM Bond Index GD
Private Real Estate	10.0%	NCREIF - ODCE (1Q lagged)
Cash	0.0%	Fed funds effective
Overall fund benchmark:	**100.0%**	**Weighted average of all portfolio BMs**

The focus of performance evaluation for the NDT should be at the overall fund benchmark level, given the portfolio is composed of several investment managers and assets classes that are designed to work together on the whole. The overall fund benchmark is comprised of the actual weights of each individual asset class benchmark as shown in the table above.

Both the performance of Xcel Energy's NDT asset portfolio and the performance of the weighted average overall fund benchmark are calculated by the trustee - an independent third party. Since benchmarks will be changed or updated over time,

Xcel Energy will update the Commission with respect to future modifications as they become necessary.

Analytical Method

There are two principal components to determining the overall strategy for the NDT:

1. Investment strategy (*i.e.,* the composition of the investment portfolio); and
2. Contributions strategy, (*i.e.,* the annual annuity payment amount required to fund the decommissioning costs).

First, the liability is calculated based on the projected decommissioning costs and the projected escalation of these costs through time. The valuation of the liability involves the following steps:

i. obtaining the current decommissioning costs from TLG in real dollars;
ii. escalation of the real decommissioning cash flows to account for realized and expected future inflation and non-inflation escalation; and
iii. calculation of the present value of the escalated cash flows back to the valuation date, using the expected return on assets as the discount rate. For this analysis, the valuation date is June 30, 2017.

Second, the projected liability is compared to the projected value of the assets (investments) net of an allowance for taxes of the NDT.

Method – Determining Investment Strategy

In light of the benefits of the Energy Policy Act of 1992 for nuclear decommissioning trust investment management, the Company has established a nuclear decommissioning investment policy with the goal to maximize after-tax portfolio returns and minimize aggregate portfolio risk for external fund investing. This policy was approved in the 1993 filing. Accomplishing this goal requires finding the combination of assets that optimizes the after-tax risk/return characteristics of the fund which leads to full funding in the expected case without an increase in contributions.

GSAM was engaged by the Company to recommend an appropriate investment strategy for trust assets intended for the eventual decommissioning of the Prairie Island and Monticello nuclear generating plants.

This process is called asset allocation optimization. Different mixes of assets can produce hundreds, or even thousands, of alternative combinations of risk and returns. As a result, asset allocation techniques have been developed to evaluate the various possible asset mixes and determine those combinations that are likely to deliver optimal performance in terms of risk and return.

This process has been used to perform a long-term optimization of the asset allocation for the Company's investments. In any investment there is always a trade-off between risk and the expected rate of return on that investment. Typically, strategies with higher expected returns also come with higher risk and vice versa. The goal is to optimize the trade-off between risk and return over the long term. If on the one hand too little risk is taken, then there is a significant chance that the trust remains underfunded, necessitating very large contributions into the trust in later years. If on the other hand too much risk is taken, there is a risk of significant underfunding of the NDT in the future, or of overfunding of the NDT, which because of the difficulty of removing assets from the Qualified Trust is also undesirable.

Method – Determining Contributions

Contributions are calculated in terms of the annual annuity payment amounts required to fund the difference between liabilities (the present value of decommissioning cash flows) and the projected asset level at the start of decommissioning.

The projected asset level in the future is calculated by applying the expected asset returns at any point in time to the pool of assets.

In the analysis, the liabilities are calculated as the present value of all the decommissioning costs. The present value is calculated in a two-stage process by:

1. Escalating the real decommissioning cash flows by the escalation factors discussed in Schedule C.

2. Discounting the escalated cash flows using the expected after-tax return on the asset portfolio.

As a result, the present value of the liabilities will depend on the escalation of the decommissioning costs and the expected return of the chosen investment portfolio. Because inflation impacts both the escalation of cash flows and the pre-tax discount rate, it only has a small impact on the value of the liabilities from the tax effects of changed inflation assumptions.

A measure of the degree to which assets will be able to meet the decommissioning cost liabilities is the funded status which is the ratio of the value of assets net of assumed taxes to the value of liabilities, expressed as a percentage.

Assumptions – Overview

The assumption set that goes into the process involves three different types of assumptions which are developed in a consistent manner:

- *Investment assumptions.* These include long-term expected returns, volatilities (standard deviations of returns) and correlations for different types of assets.
- *Other economic assumptions.* These include assumptions for the long-term inflation rate and the long-term escalation of decommissioning costs.
- *Tax assumptions.* These include assumptions for state and federal tax rates and deductibility.

Investment and Economic Assumptions

The development of consistent investment assumptions goes hand-in-hand with the development of other economic assumptions about inflation, interest rates, GDP growth, etc.

The return assumptions for each type of asset represent expected market returns for that asset class on a forward-looking basis. The assumptions reflect a blend of rigorous analysis of historical performance and the forward looking views of the financial markets, as revealed through the yields on long term bonds, the price-earnings ratios of the major stock market indices, implied inflation expectations in TIPS, etc.

This methodology will produce more conservative expected rates of return than an analysis that looks simply at historical averages. The important distinction is that, in using this methodology, the expected asset return is tied to the inflation rate and overall risk-free rates, so at lower inflation and interest rates investors require lower rates of return. Current markets indicate much lower expected inflation over even long-term horizons than historical averages.

The inflation rate used for expected returns is matched to the inflation rate used for liability growth, enforcing the consistency of asset and liability assumptions.

Expected asset returns (on a pre-tax basis) are developed via a building-block approach that starts with the expected long-term real interest rate and expected long-term inflation. Together these two define the expected long-term nominal risk-free interest rate. Expected returns for different assets are then determined by adding appropriate risk premiums to this. In other words, we have the following relationship:

Expected net-of-fee, pre-tax asset return	=	inflation + real interest rate + risk premium - fees

The next step in the assumption setting process involves an analysis of historical risks and correlations of asset class returns to which subjective judgment is applied. The result of this analysis is incorporated into a risk matrix from which expected long-term risk premiums are estimated for each asset class.

The long-term nominal return expectations are then determined by combining the asset class risk premiums with expected inflation and real risk-free rate assumptions. As a final consideration, the nominal return assumptions are blended with current market conditions to develop long-term equilibrium expectations. The return and risk expectations for each asset class incorporate assumptions about historical return relationships, current financial market conditions and the degree of global capital market integration.

The assumptions pertaining to the volatility of investment returns are based on observed experience and calculated in terms of the standard deviation of historical asset returns.

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The following table shows the expected return and volatility assumption inputs:

Long-term Investment Assumptions for 2017

	Expected pre-tax		Expected after-tax	
Asset class	**Arithmetic return**	**Volatility**	**Arithmetic return**	**Volatility**
US Large Cap Equity (Passive)	7.23%	14.62%	5.22%	10.55%
US Small Cap Equity (Passive)	8.53%	18.64%	6.16%	13.45%
EAFE Equity (Passive)	8.06%	15.90%	5.82%	11.47%
EAFE Equity (Active)	8.24%	16.27%	5.94%	11.74%
EM Equity	11.90%	21.38%	8.59%	15.43%
IG Fixed Income (10+ yr TIPS constant maturity)	5.32%	10.62%	4.25%	8.49%
High Yield Debt	6.13%	8.85%	4.43%	6.38%
EM Debt	6.21%	9.64%	4.48%	6.96%
Private Equity	10.03%	20.99%	7.24%	15.15%
Private Real Estate	6.44%	11.71%	4.65%	8.45%

These expected return assumptions are based on an assumed long-term risk-free rate of 2.84 percent, consisting of a 0.99 percent real asset return and expected inflation of 1.85 percent, based on market bond rates.

The correlations between the investment returns of different asset classes are important characteristics, in addition to the expected returns and the volatility of returns. Recent and long-term histories are used as a guide to setting these parameters. The table below shows the correlations between asset returns used in the analysis.

Long-Term Investment Return Correlations for 2017

	Asset class	1	2	3	4	5	6	7	8	9	10
1	US Large Cap Equity (Passive)	1.00	0.89	0.85	0.83	0.73	0.42	0.65	0.44	0.65	0.06
2	US Small Cap Equity (Passive)	0.89	1.00	0.75	0.73	0.67	0.36	0.61	0.46	0.61	0.01
3	EAFE Equity (Passive)	0.85	0.75	1.00	0.98	0.82	0.48	0.67	0.43	0.56	0.13
4	EAFE Equity (Active)	0.83	0.73	0.98	1.00	0.81	0.47	0.66	0.42	0.54	0.13
5	EM Equity	0.73	0.67	0.82	0.81	1.00	0.50	0.65	0.40	0.49	0.20
6	IG Fixed Income (10+ yr TIPS constant maturity)	0.42	0.36	0.48	0.47	0.50	1.00	0.65	0.33	0.30	0.49
7	High Yield Debt	0.65	0.61	0.67	0.66	0.65	0.65	1.00	0.48	0.36	0.26
8	EM Debt	0.44	0.46	0.43	0.42	0.40	0.33	0.48	1.00	0.35	0.25
9	Private Equity	0.65	0.61	0.56	0.54	0.49	0.30	0.36	0.35	1.00	0.12
10	Private Real Estate	0.06	0.01	0.13	0.13	0.20	0.49	0.26	0.25	0.12	1.00

Taxation Assumptions

The taxation assumptions, along with the investment and other economic assumptions are important inputs for both the asset allocation portion, and the overall analysis performed. The following table shows the applicable tax rates for the Qualified Trust.

Municipal bonds are assumed to be free of federal taxes. Therefore, only state taxes are imposed. In practice, some municipal bonds will be exempt from state taxes also, specifically municipal bonds issued by Minnesota, but these are assumed to be a small percentage of the portfolio.

Treasury bonds are exempt from state taxes. Therefore, treasuries are taxed only at the federal rate and not at the state tax rate.

The Company's view is that US stocks in the Qualified Trust do not earn a dividends' received deduction, therefore stock returns are assumed to be fully taxed.

Tax Element	Tax Rate
Federal tax rate for the qualified trust	20%
State tax on both the qualified trust and escrow account *Note: State taxes are deductible from federal taxes.*	9.8%

As a result, the total tax rates are (assuming that investments are fully taxed – this is modified for municipal bonds and treasuries):

Portfolio	Composite Tax Rate
Qualified Trust	27.84%*

*Calculation: 20% + 9.8% (1-20%)

These tax assumptions are incorporated into the after-tax expected returns in the table of investment assumptions above.

Results – Investment Strategy

The investment strategy is based on the use of an efficient risk-seeking portfolio (Growth Portfolio) for the majority of the investment period before decommissioning, and an efficient low-risk portfolio for the period just before decommissioning. The mix is determined by the following rule:

Five years prior to each decommissioning cash flow, the portion of the growth assets that are required to make that payment is reallocated into bonds.

This strategy is efficient from an asset-liability management perspective in order to reduce the risk that market volatility significantly reduces the value of this portion of the assets just when they are needed to make payments.

A period of five years is needed for assets to earn their long-term rate of return with some degree of confidence. As discussed above, year to year variation can be very large for high returning assets, and five years is needed to justify long-term assumptions. Therefore, as decommissioning payments come due at less than five years, the assumption is that the funds are switched to bonds. Further details related to the selection of a five year bond conversion period are described below.

Analysis of Bond Holding Period

Our analysis assumes that the funds are invested in bonds as a cash outlay is approached. For each expected annual outflow cash flow, assets are converted to bonds ahead of time to give more certainty to the ability to make the payment. It is important to recognize that not all funds are converted to bonds – only enough to cover each annual cash outflow. For example, if the conversion is at a 5 year period, the first outflows expected in 2030 are converted to bonds in 2025; then in 2026, enough cash is converted to bonds to match the 2031 expected outflow.

In the 2014 Filing, we assumed that funds would be converted to bonds six years ahead of each annual cash outflow. This is roughly consistent with converting to bonds in time to cover the length of a business cycle, which helps to ensure the appropriateness of our long-term growth assumptions. That said, we have modified our assumption in this Triennial to convert funds to bonds five years ahead of each annual cash outflow. Since expected bond returns are lower than the expected Growth Portfolio returns, a later transition to bonds results in higher expected returns, and therefore a lower accrual. And while a later conversion can lead to additional risk, we believe any additional risk of the shorter period is mitigated by the iterative transfer to bonds each year rather than converting the entire portfolio simultaneously. That is because even if a single year conversion does not match the business cycle and growth assumptions exactly, it is reasonable to expect that—over the multi-year conversion—average returns will be achieved.

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Rates of Return

Note that the portion of the portfolio assigned to growth assets changes over time based on how large expected decommissioning payments will be over the next five years. The updated target asset allocation for the growth assets are shown in the table below:

Portfolio Line Item	Updated 2017 Target	Benchmark (BM)
Total Equity	60.0%	Weighted average of equity BMs:
Private Equity	10.0%	Cambridge PE (1Q lagged)
US All Cap Equity	25.8%	Russell 3000
Non-US Developed Equity	14.1%	MSCI EAFE ND
Emerging Markets Equity	10.1%	MSCI EM ND
Fixed Income	30.0%	Weighted average of fixed income BMs:
Investment Grade Fixed Income	12.1%	75% Barclays Investment Grade Corporate Index, 25% Barclays U.S. TIPS 10+ year Index, 50% Bloomberg 20yr ZC Inflation Swap Overlay
High Yield Fixed Income	10.0%	BofA ML US High Yield
Emerging Market Debt	7.9%	JPM EM Bond Index GD
Private Real Estate	10.0%	NCREIF - ODCE (1Q lagged)
Cash	0.0%	Fed funds effective
Overall fund benchmark:	**100.0%**	**Weighted average of all portfolio BMs**

Potential Growth Portfolios are the portfolios of assets that earn an expected rate of return with the lowest risk and the actual choice of the growth portfolio is based on setting the level of risk or return desired. Please note even the growth portion of the portfolio includes some bonds to provide diversification and efficiency. The 'growth portion' is not the same as the investment in equities.

The overall expected portfolio returns and volatilities for each plant's Qualified Trust are given in the table below:

Expected Returns for the Updated Strategy

	60-Year Scenario	
Nuclear Unit	**Operations**	**Decom.**
Monticello	5.00%	4.43%
Prairie Island Unit 1	4.99%	4.15%
Prairie Island Unit 2	5.04%	4.09%

To arrive at the rates of return listed in the table above, the analysis uses different rates of return for bonds and the NDT Growth Portfolio; and the weights assigned to these portfolios change through time. Therefore, expected combined rates of return vary through time; the expected rates included are Single Effective Rates, which are weighted average rates. This expected rate leads to the same final funding level if applied to each of these components that would be obtained by using the actual expected rates.

Conclusion

The analysis presented in this Schedule addresses the decisions relating to investment strategy, and contribution strategy.

In terms of investment strategy, GSAM's analysis has led to a recommended asset allocation for the growth portion of the assets that involves equities, fixed income and alternative assets. The portion of the assets required to meet each decommissioning payment is switched from growth assets into bonds five years prior to that payment.

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Qualified Trust Statements Schedule E
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Schedule E contains the documents required by the Commission to be filed with every submittal. Annually, the Company submits a compliance filing in April. These compliance filings include the Qualified Trust fund activity for the prior year. For example the 2017 compliance filing made under the docket number for the 2014 Filing included the Qualified Trust fund activity for 2016. Therefore, this filing only includes the activity for the Qualified Trust since the last compliance filing. The 2017 activity documents the roll forward of the Qualified Trust balances from January 1, 2017 through June 30, 2017.

The June 30, 2017 Qualified Trust balances for the two wholesale jurisdictions have been included in Schedule E.8 as these balances were used to assign 73.4886 percent to the beginning balance used in the accrual calculations. In addition, the Escrow Fund had a zero balance in 2016, thus no activity is shown for the Escrow Fund. Below is a list of the schedules included.

Qualified Trust Analysis, Statements and Balances Supporting Schedules

E.1	Analysis of Qualified Trust Balances –January - June 2017
E.2	Trustee Statements – Qualified Trust, Monticello (All Managers, MN Jurisdiction)
E.3	Trustee Statements – Qualified Trust, Monticello (By Manager, Total Company)
E.4	Trustee Statements – Qualified Trust, Prairie Island Unit 1 (All Managers, MN Jurisdiction)
E.5	Trustee Statements – Qualified Trust, Prairie Island Unit 1 (By Manager, Total Company)
E.6	Trustee Statements – Qualified Trust, Prairie Island Unit 2 (All Managers, MN Jurisdiction)
E.7	Trustee Statements – Qualified Trust, Prairie Island Unit 2 (By Manager, Total Company)
E.8	June 30, 2017 Trustee Statements – Qualified Trust, MN and WI Wholesale, All Units

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Qualified Trust Analysis, Statements and Balances
2017 Minnesota Jurisdiction Balance

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Schedule E.1
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	Beginning Balance	Accruals	Gains & Losses	Dividends & Interest	Commissions, Taxes & Fees	Transfers & Adjustments	Ending Book Balance Jun. 30, 2017	Unrealized Gain/(Loss) Jun. 30, 2017	Ending Market Balance Jun. 30, 2017
Qualified Trust									
Prairie Island Unit 1	292,599,639	24,632	4,826,268	3,188,250	(2,291,220)	-	298,347,569	89,965,695	388,313,263
Prairie Island Unit 2	331,992,382	294,670	4,911,143	3,501,861	(3,247,279)	-	337,452,778	99,354,345	436,807,122
Monticello	504,432,968	6,696,114	4,991,034	5,098,587	(6,447,278)	-	514,771,426	127,112,802	641,884,228
Total	1,129,024,989	7,015,416	14,728,445	11,788,699	(11,985,777)	-	1,150,571,773	316,432,842	1,467,004,613

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Qualified Trust Analysis, Statements and Balances
2017 FERC Jurisdiction Balance

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Schedule E.1
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	Beginning Balance	Accruals	Gains & Losses	Dividends & Interest	Commissions, Taxes & Fees	Transfers & Adjustments	Ending Balance Jun. 30, 2017	Unrealized Gain/(Loss) Jun. 30, 2017	Ending Market Balance Jun. 30, 2017
FERC MN									
Qualified Trust									
Prairie Island Unit 1	7,171,932	-	121,671	80,377	(57,760)	-	7,316,219	2,472,947	9,789,167
Prairie Island Unit 2	6,804,932	-	100,815	71,878	(66,638)	-	6,910,987	2,051,897	8,962,884
Monticello	9,416,018	-	97,248	99,167	(124,990)	-	9,487,443	2,923,474	12,410,917
Total	23,392,881	-	319,734	251,421	(249,387)	-	23,714,649	7,448,318	31,162,967
FERC WI									
Qualified Trust									
Prairie Island Unit 1	5,836,630	-	74,976	49,559	(35,604)	-	5,925,560	108,734	6,034,295
Prairie Island Unit 2	5,489,199	-	79,626	56,801	(52,646)	-	5,572,979	1,508,034	7,081,014
Monticello	10,004,575	-	97,364	99,341	(125,194)	-	10,076,087	2,355,119	12,431,206
Total	21,330,404	-	251,966	205,701	(213,444)	-	21,574,626	3,971,888	25,546,514
						Total Wholesale	45,289,275	11,420,206	56,709,481
						MN Jurisdiction %	73.4886%	73.4886%	73.4886%
						Allocated to MN Jurisdiction	33,282,434	8,392,544	41,674,978

MN Jurisdiction Qualified Trust	316,432,842
Wlse Qualified Trust Allocated to MN Jurisdiction	324,825,386

Xcel Energy
Qualified Trust Analysis, Statements and Balances
2017 MN Adjusted Jurisdiction Balance

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Schedule E.1
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	Beginning Balance	Accruals	Gains & Losses	Dividends & Interest	Commissions, Taxes & Fees	Transfers & Adjustments	Ending Balance Jun. 30, 2017	Unrealized Gain/(Loss) Jun. 30, 2017	Ending Market Balance Jun. 30, 2017
Qualified Trust									
Prairie Island Unit 1	302,159,442	24,632	4,970,780	3,283,738	(2,359,831)	-	308,078,761	91,862,935	399,941,696
Prairie Island Unit 2	341,027,161	294,670	5,043,746	3,596,425	(3,334,939)	-	346,627,064	101,970,487	448,597,551
Monticello	518,704,882	6,696,114	5,134,052	5,244,468	(6,631,135)	-	529,148,381	130,991,964	660,140,345
Total	1,161,891,485	7,015,416	15,148,579	12,124,631	(12,325,905)	-	1,183,854,206	324,825,386	1,508,679,592

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BNY MELLON

TRDNSN [redacted] MONTHLY FINAL 232113 2017-06-30 CYCLE A 23:21:19 RUN DATE: 17-JUL-17
INVESTMENT DETAIL PAGE: 1
[redacted] 30 JUNE 2017 M1101
XCEL ENERGY NDT
NSP/XCEL ENERGY NDT

SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS UNIT OF PARTICIPATION					
49,311,021.3740	MONTICELLO QUALIFIED MTU	514,771,425.73	13.0170	641,884,228.02	127,112,802.29
TOTAL INVESTMENTS UNIT OF PARTICIPATION		514,771,425.73		641,884,228.02	127,112,802.29
TOTAL INVESTMENT		514,771,425.73		641,884,228.02	127,112,802.29

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BNY MELLON

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INVESTMENT DETAIL PAGE: 1
[redacted] 30 JUNE 2017 M1101
CASH - MONTICELLO
XCEL ENERGY NDT

SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS CASH EQUIVALENTS					
594,528.8700	BLACKROCK LIQ T FUND INSTL FUND 60	594,528.87	100.0000	594,528.87	0.00
TOTAL INVESTMENTS CASH EQUIVALENTS		594,528.87		594,528.87	0.00
TOTAL INVESTMENT		594,528.87		594,528.87	0.00

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INVESTMENT DETAIL PAGE: 1
[redacted] 30 JUNE 2017 M1101
PARAMETRIC US - MONTICELLO
XCEL ENERGY NDT

SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS CASH EQUIVALENTS					
388,188.9900	BLACKROCK LIQ T FUND INSTL FUND 60	388,188.99	100.0000	388,188.99	0.00
TOTAL INVESTMENTS CASH EQUIVALENTS		388,188.99		388,188.99	0.00
INVESTMENTS EQUITY					
902.0000	ADIENT PLC	42,394.00	65.3800	58,972.76	16,578.76
461.0000	AIRCASTLE LTD	5,628.81	21.7500	10,026.75	4,397.94
881.0000	ALLEGION PLC	19,534.23	81.1200	71,466.72	51,932.49
1,278.0000	ALKERMES PLC	22,433.80	57.9700	74,085.66	51,651.86
3,042.0000	ALLERGAN PLC	756,990.69	243.0900	739,479.78	17,510.91-
1,779.0000	AMDOCS LTD	52,712.09	64.4600	114,674.34	61,962.25
2,883.0000	AON PLC	161,003.23	132.9500	383,294.85	222,291.62
288.0000	ARGO GROUP INTERNATIONAL HOLDI	6,147.32	60.6000	17,452.80	11,305.48
562.0000	ASPEN INSURANCE HOLDINGS LTD	13,965.70	49.8500	28,015.70	14,050.00
984.0000	ARRIS INTERNATIONAL PLC	10,784.64	28.0200	27,571.68	16,787.04
1,966.0000	ASSURED GUARANTY LTD	26,934.20	41.7400	82,060.84	55,126.64

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INVESTMENT DETAIL PAGE: 2
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PARAMETRIC US - MONTICELLO
XCEL ENERGY NDT

SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
1,028.0000	AXIS CAPITAL HOLDINGS LTD	32,054.41	64.6600	66,470.48	34,416.07
1,452.0000	AXALTA COATING SYSTEMS LTD	41,715.96	32.0400	46,522.08	4,806.12
5,934.0000	ACCENTURE PLC	323,644.02	123.6800	733,917.12	410,273.10
757.0000	BELMOND LTD	7,607.85	13.3000	10,068.10	2,460.25
1,134.0000	BUNGE LTD	70,153.81	74.6000	84,596.40	14,442.59
1,966.0000	DELPHI AUTOMOTIVE PLC	92,096.86	87.6500	172,319.90	80,223.04
4,344.0000	EATON CORP PLC	229,960.72	77.8300	338,093.52	108,132.80
50.0000	ENSTAR GROUP LTD	5,024.00	198.6500	9,932.50	4,908.50
189.0000	FRESH DEL MONTE PRODUCE INC	4,887.54	50.9100	9,621.99	4,734.45
3,425.0000	FRUIT OF THE LOOM INC CL A	29,060.51	8.4848	29,060.51	0.00
1,414.0000	GENPACT LTD	35,067.20	27.8300	39,351.62	4,284.42
222.0000	GREENLIGHT CAPITAL RE LTD	5,692.08	20.9000	4,639.80	1,052.28-
245.0000	HELEN OF TROY LTD	7,935.55	94.1000	23,054.50	15,118.95
866.0000	HERBALIFE LTD	20,641.11	71.3300	61,771.78	41,130.67
0.6710	JANUS HENDERSON GROUP PLC	10.61	33.1100	22.22	11.61
4,386.0000	HORIZON PHARMA PLC	10,570.26	11.8700	52,061.82	41,491.56
2,642.0000	INGERSOLL-RAND PLC	77,252.11	91.3900	241,452.38	164,200.27

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8,304.0000	WEATHERFORD INTERNATIONAL PLC	43,891.64	3.8700	32,136.48	11,755.16-
4,244.0000	INVESCO LTD	109,748.51	35.1900	149,346.36	39,597.85
7,422.0000	JOHNSON CONTROLS INTERNATIONAL	285,387.55	43.3600	321,817.92	36,430.37
1,065.0000	MALLINCKRODT PLC	52,331.98	44.8100	47,722.65	4,609.33-
3,111.0000	MARVELL TECHNOLOGY GROUP LTD	30,137.64	16.5200	51,393.72	21,256.08
13,504.0000	MEDTRONIC PLC	1,020,256.11	88.7500	1,198,480.00	178,223.89
1,989.0000	MICHAEL KORS HOLDINGS LTD	86,518.79	36.2500	72,101.25	14,417.54-
615.0000	ALPHA & OMEGA SEMICONDUCTOR LT	5,024.55	16.6700	10,252.05	5,227.50
3,269.0000	NABORS INDUSTRIES LTD	44,971.11	8.1400	26,609.66	18,361.45-
3,712.0000	NIELSEN HOLDINGS PLC	150,817.58	38.6600	143,505.92	7,311.66-
954.0000	NORWEGIAN CRUISE LINE HOLDINGS	44,694.90	54.2900	51,792.66	7,097.76
1,951.0000	ONEBEACON INSURANCE GROUP LTD	28,536.88	18.2300	35,566.73	7,029.85
1,880.0000	PENTAIR PLC	69,393.10	66.5400	125,095.20	55,702.10
883.0000	PROTHENA CORP PLC	47,019.75	54.1200	47,787.96	768.21
479.0000	RENAISSANCERE HOLDINGS LTD	27,264.68	139.0500	66,604.95	39,340.27
454.0000	SIGNET JEWELERS LTD	37,214.23	63.2400	28,710.96	8,503.27-
455.0000	THERAVANCE BIOPHARMA INC	12,875.34	39.8400	18,127.20	5,251.86

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2,967.0000	THIRD POINT REINSURANCE LTD	42,279.75	13.9000	41,241.30	1,038.45-
823.0000	VALIDUS HOLDINGS LTD	20,525.62	51.9700	42,771.31	22,245.69
54.0000	WHITE MOUNTAINS INSURANCE GROU	21,762.54	868.6300	46,906.02	25,143.48
1,295.0000	PERRIGO CO PLC	115,384.55	75.5200	97,798.40	17,586.15-
2,738.0000	XL GROUP LTD	75,376.06	43.8000	119,924.40	44,548.34
777.0000	ALLIED WORLD ASSURANCE CO HOLD	21,991.69	52.9000	41,103.30	19,111.61
4,226.0000	CHUBB LTD	329,645.17	145.3800	614,375.88	284,730.71
989.0000	GARMIN LTD	36,249.24	51.0300	50,468.67	14,219.43
2,976.0000	TRANSOCEAN LTD	44,421.80	8.2300	24,492.48	19,929.32-
444.0000	CIMPRESS NV	36,350.28	94.5300	41,971.32	5,621.04
2,996.0000	LYONDELLBASELL INDUSTRIES NV	165,331.69	84.3900	252,832.44	87,500.75
3,367.0000	MYLAN NV	154,166.80	38.8200	130,706.94	23,459.86-
2,679.0000	QIAGEN NV	49,107.62	33.5300	89,826.87	40,719.25
351.0000	WRIGHT MEDICAL GROUP NV	7,427.16	27.4900	9,648.99	2,221.83
1,227.0000	BANCO LATINOAMERICANO DE COMER	20,822.19	27.3800	33,595.26	12,773.07
273.0000	COPA HOLDINGS SA	21,153.92	117.0000	31,941.00	10,787.08
1,180.0000	ROYAL CARIBBEAN CRUISES LTD	57,416.82	109.2300	128,891.40	71,474.58

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3,901.0000	BROADCOM LTD	407,099.40	233.0500	909,128.05	502,028.65
422.0000	ABM INDUSTRIES INC	9,646.92	41.5200	17,521.44	7,874.52
4,034.0000	AFLAC INC	229,312.36	77.6800	313,361.12	84,048.76
762.0000	AGCO CORP	30,154.04	67.3900	51,351.18	21,197.14
2,489.0000	AGNC INVESTMENT CORP	45,710.07	21.2900	52,990.81	7,280.74
6,454.0000	AES CORP/VA	68,961.39	11.1100	71,703.94	2,742.55
299.0000	AMAG PHARMACEUTICALS INC	5,142.80	18.4000	5,501.60	358.80
474.0000	AMC NETWORKS INC	25,745.48	53.4100	25,316.34	429.14-
55,171.0000	AT&T INC	1,741,910.45	37.7300	2,081,601.83	339,691.38
98.0000	AZZ INC	2,131.50	55.8000	5,468.40	3,336.90
636.0000	AARON'S INC	17,178.36	38.9000	24,740.40	7,562.04
14,595.0000	ABBOTT LABORATORIES	399,436.31	48.6100	709,462.95	310,026.64
15,568.0000	ABBVIE INC	496,845.38	72.5100	1,128,835.68	631,990.30
391.0000	ABIOMED INC	15,260.54	143.3000	56,030.30	40,769.76
1,458.0000	ACADIA HEALTHCARE CO INC	45,232.10	49.3800	71,996.04	26,763.94
1,051.0000	ACADIA PHARMACEUTICALS INC	39,328.42	27.8900	29,312.39	10,016.03-
321.0000	ACADIA REALTY TRUST	6,480.99	27.8000	8,923.80	2,442.81

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1,185.0000	ACI WORLDWIDE INC	15,102.21	22.3700	26,508.45	11,406.24
407.0000	ACORDA THERAPEUTICS INC	9,995.92	19.7000	8,017.90	1,978.02-
5,057.0000	ACTIVISION BLIZZARD INC	103,646.11	57.5700	291,131.49	187,485.38
1,703.0000	ACTUANT CORP	41,502.11	24.6000	41,893.80	391.69
345.0000	ACUITY BRANDS INC	18,864.60	203.2800	70,131.60	51,267.00
645.0000	ACXIOM CORP	7,759.35	25.9800	16,757.10	8,997.75
4,652.0000	ADOBE SYSTEMS INC	214,309.58	141.4400	657,978.88	443,669.30
1,775.0000	ADTALEM GLOBAL EDUCATION INC	42,493.50	37.9500	67,361.25	24,867.75
774.0000	ADVANCE AUTO PARTS INC	53,045.04	116.5900	90,240.66	37,195.62
1,384.0000	AECOM	33,552.93	32.3300	44,744.72	11,191.79
264.0000	AEGION CORP	5,084.64	21.8800	5,776.32	691.68
290.0000	ADVANSIX INC	1,983.74	31.2400	9,059.60	7,075.86
13,652.0000	ADVANCED MICRO DEVICES INC	32,082.20	12.4800	170,376.96	138,294.76
3,246.0000	AETNA INC	133,712.56	151.8300	492,840.18	359,127.62
583.0000	AFFILIATED MANAGERS GROUP INC	76,157.81	165.8600	96,696.38	20,538.57
2,763.0000	AGILENT TECHNOLOGIES INC	61,868.11	59.3100	163,873.53	102,005.42
1,257.0000	AGREE REALTY CORP	42,536.88	45.8700	57,658.59	15,121.71

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1,691.0000	AIR LEASE CORP	53,461.02	37.3600	63,175.76	9,714.74
1,842.0000	AIR PRODUCTS & CHEMICALS INC	118,594.24	143.0600	263,516.52	144,922.28
1,986.0000	AKAMAI TECHNOLOGIES INC	83,529.14	49.8100	98,922.66	15,393.52
756.0000	AKORN INC	9,880.92	33.5400	25,356.24	15,475.32
1,288.0000	ALASKA AIR GROUP INC	21,574.00	89.7600	115,610.88	94,036.88
220.0000	ALBANY INTERNATIONAL CORP	5,442.80	53.4000	11,748.00	6,305.20
747.0000	ALBEMARLE CORP	40,082.23	105.5400	78,838.38	38,756.15
1,603.0000	ALCOA CORP	32,792.35	32.6500	52,337.95	19,545.60
761.0000	ALERE INC	36,193.48	50.1900	38,194.59	2,001.11
331.0000	ALEXANDER & BALDWIN INC	6,971.79	41.3800	13,696.78	6,724.99
47.0000	ALEXANDER'S INC	15,373.73	421.4600	19,808.62	4,434.89
585.0000	ALEXANDRIA REAL ESTATE EQUITIE	40,491.22	120.4700	70,474.95	29,983.73
2,006.0000	ALEXION PHARMACEUTICALS INC	243,711.70	121.6700	244,070.02	358.32
626.0000	ALIGN TECHNOLOGY INC	19,945.24	150.1200	93,975.12	74,029.88
95.0000	ALLEGHANY CORP	26,568.30	594.8000	56,506.00	29,937.70
243.0000	ALLETE INC	9,907.11	71.6800	17,418.24	7,511.13
483.0000	ALLIANCE DATA SYSTEMS CORP	84,507.22	256.6900	123,981.27	39,474.05

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2,636.0000	ALLIANT ENERGY CORP	70,702.73	40.1700	105,888.12	35,185.39
1,221.0000	ALLISON TRANSMISSION HOLDINGS	35,763.09	37.5100	45,799.71	10,036.62
2,546.0000	ALLSCRIPTS HEALTHCARE SOLUTION	35,898.60	12.7600	32,486.96	3,411.64-
3,932.0000	ALLSTATE CORP/THE	144,374.78	88.4400	347,746.08	203,371.30
5,739.0000	ALLY FINANCIAL INC	118,236.90	20.9000	119,945.10	1,708.20
795.0000	ALNYLAM PHARMACEUTICALS INC	68,229.54	79.7600	63,409.20	4,820.34-
1,815.0000	ALPHABET INC-CL C	384,754.87	908.7300	1,649,344.95	1,264,590.08
3,665.0000	ALPHABET INC-CL A	1,992,263.75	929.6800	3,407,277.20	1,415,013.45
3,375.0000	ALTISOURCE RESIDENTIAL CORP	38,643.75	12.9400	43,672.50	5,028.75
1,312.0000	ALTRA INDUSTRIAL MOTION CORP	36,329.28	39.8000	52,217.60	15,888.32
17,274.0000	ALTRIA GROUP INC	496,395.32	74.4700	1,286,394.78	789,999.46
3,604.0000	AMAZON.COM INC	1,125,215.20	968.0000	3,488,672.00	2,363,456.80
69.0000	AMERCO	6,606.06	366.0600	25,258.14	18,652.08
1,767.0000	AMEREN CORP	59,630.12	54.6700	96,601.89	36,971.77
4,221.0000	AMERICAN AIRLINES GROUP INC	156,667.95	50.3200	212,400.72	55,732.77
227.0000	AMERICAN ASSETS TRUST INC	5,077.99	39.3900	8,941.53	3,863.54
545.0000	AMERICAN AXLE & MANUFACTURING	6,058.20	15.6000	8,502.00	2,443.80

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540.0000	AMERICAN CAMPUS COMMUNITIES IN	18,694.80	47.3000	25,542.00	6,847.20
2,707.0000	AMERICAN EAGLE OUTFITTERS INC	42,716.46	12.0500	32,619.35	10,097.11-
4,550.0000	AMERICAN ELECTRIC POWER CO INC	181,998.44	69.4700	316,088.50	134,090.06
473.0000	AMERICAN EQUITY INVESTMENT LIF	5,832.09	26.2800	12,430.44	6,598.35
8,036.0000	AMERICAN EXPRESS CO	517,648.94	84.2400	676,952.64	159,303.70
846.0000	AMERICAN FINANCIAL GROUP INC/O	24,968.34	99.3700	84,067.02	59,098.68
4,525.0000	AMERICAN HOMES 4 RENT	71,030.84	22.5700	102,129.25	31,098.41
10,700.0000	AMERICAN INTERNATIONAL GROUP I	400,281.77	62.5200	668,964.00	268,682.23
187.0000	AMERICAN RAILCAR INDUSTRIES IN	5,864.32	38.3000	7,162.10	1,297.78
860.0000	AMERICAN STATES WATER CO	34,907.40	47.4100	40,772.60	5,865.20
3,934.0000	AMERICAN TOWER CORP	219,192.46	132.3200	520,546.88	301,354.42
1,093.0000	AMERICAN WATER WORKS CO INC	38,661.76	77.9500	85,199.35	46,537.59
19.0000	AMERISAFE INC	421.80	56.9500	1,082.05	660.25
1,847.0000	AMERISOURCEBERGEN CORP	108,873.53	94.5300	174,596.91	65,723.38
1,716.0000	AMERIPRISE FINANCIAL INC	80,214.18	127.2900	218,429.64	138,215.46
2,223.0000	AMETEK INC	65,340.74	60.5700	134,647.11	69,306.37
7,209.0000	AMGEN INC	573,076.12	172.2300	1,241,606.07	668,529.95

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3,123.0000	AMPHENOL CORP	135,257.16	73.8200	230,539.86	95,282.70
544.0000	AMTRUST FINANCIAL SERVICES INC	4,958.94	15.1400	8,236.16	3,277.22
4,922.0000	ANADARKO PETROLEUM CORP	248,721.56	45.3400	223,163.48	25,558.08-
2,150.0000	ANALOG DEVICES INC	82,451.20	77.8000	167,270.00	84,818.80
187.0000	ANDERSONS INC/THE	4,965.47	34.1500	6,386.05	1,420.58
231.0000	ANIXTER INTERNATIONAL INC	14,125.65	78.2000	18,064.20	3,938.55
5,521.0000	ANNALY CAPITAL MANAGEMENT INC	55,403.88	12.0500	66,528.05	11,124.17
730.0000	ANSYS INC	34,079.88	121.6800	88,826.40	54,746.52
1,992.0000	ANTERO RESOURCES CORP	45,647.41	21.6100	43,047.12	2,600.29-
2,449.0000	ANTHEM INC	226,910.81	188.1300	460,730.37	233,819.56
3,367.0000	APACHE CORP	187,862.35	47.9300	161,380.31	26,482.04-
1,011.0000	APARTMENT INVESTMENT & MANAGEM	25,289.01	42.9700	43,442.67	18,153.66
839.0000	APOGEE ENTERPRISES INC	42,403.06	56.8400	47,688.76	5,285.70
924.0000	APOLLO COMMERCIAL REAL ESTATE	15,073.27	18.5500	17,140.20	2,066.93
48,441.0000	APPLE INC	1,650,714.53	144.0200	6,976,472.82	5,325,758.29
1,778.0000	APPLE HOSPITALITY REIT INC	35,560.00	18.7100	33,266.38	2,293.62-
337.0000	APPLIED INDUSTRIAL TECHNOLOGIE	11,522.03	59.0500	19,899.85	8,377.82

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11,981.0000	APPLIED MATERIALS INC	181,133.38	41.3100	494,935.11	313,801.73
535.0000	APTARGROUP INC	27,081.70	86.8600	46,470.10	19,388.40
3,633.0000	AQUA AMERICA INC	53,303.37	33.3000	120,978.90	67,675.53
1,155.0000	ARAMARK	35,077.35	40.9800	47,331.90	12,254.55
519.0000	ARCBEST CORP	10,037.46	20.6000	10,691.40	653.94
5,777.0000	ARCHER-DANIELS-MIDLAND CO	180,903.91	41.3800	239,052.26	58,148.35
4,810.0000	ARCONIC INC	97,918.03	22.6500	108,946.50	11,028.47
573.0000	ARISTA NETWORKS INC	42,579.63	149.7900	85,829.67	43,250.04
3,264.0000	ARMADA HOFFLER PROPERTIES INC	35,457.81	12.9500	42,268.80	6,810.99
84.0000	ARMSTRONG FLOORING INC	947.93	17.9700	1,509.48	561.55
168.0000	ARMSTRONG WORLD INDUSTRIES INC	6,445.75	46.0000	7,728.00	1,282.25
1,053.0000	ARROW ELECTRONICS INC	35,296.56	78.4200	82,576.26	47,279.70
463.0000	ARROW FINANCIAL CORP	9,761.14	31.6500	14,653.95	4,892.81
1,317.0000	ARTESIAN RESOURCES CORP	40,051.95	37.6400	49,571.88	9,519.93
7,668.0000	ASHFORD HOSPITALITY TRUST INC	42,557.40	6.0800	46,621.44	4,064.04
683.0000	ASHLAND GLOBAL HOLDINGS INC	18,811.39	65.9100	45,016.53	26,205.14
1,040.0000	ASPEN TECHNOLOGY INC	20,317.25	55.2600	57,470.40	37,153.15

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963.0000	ASSOCIATED BANC-CORP	10,275.21	25.2000	24,267.60	13,992.39
109.0000	ASSOCIATED CAPITAL GROUP INC	2,270.59	34.0000	3,706.00	1,435.41
444.0000	ASSURANT INC	18,131.88	103.6900	46,038.36	27,906.48
142.0000	ASTEC INDUSTRIES INC	4,979.94	55.5100	7,882.42	2,902.48
299.0000	ATHENAHEALTH INC	33,858.65	140.5500	42,024.45	8,165.80
778.0000	ATMOS ENERGY CORP	24,258.04	82.9500	64,535.10	40,277.06
51.0000	ATRION CORP	10,220.40	643.3000	32,808.30	22,587.90
1,824.0000	AUTODESK INC	63,004.24	100.8200	183,895.68	120,891.44
4,478.0000	AUTOMATIC DATA PROCESSING INC	282,240.78	102.4600	458,815.88	176,575.10
292.0000	AUTOZONE INC	221,157.07	570.4600	166,574.32	54,582.75-
1,195.0000	AVALONBAY COMMUNITIES INC	212,974.92	192.1700	229,643.15	16,668.23
629.0000	AVANGRID INC	23,279.17	44.1500	27,770.35	4,491.18
545.0000	AVERY DENNISON CORP	23,535.68	88.3700	48,161.65	24,625.97
835.0000	AVIS BUDGET GROUP INC	13,201.35	27.2700	22,770.45	9,569.10
944.0000	AVNET INC	30,089.27	38.8800	36,702.72	6,613.45
7,403.0000	BB&T CORP	255,802.83	45.4100	336,170.23	80,367.40
224.0000	B&G FOODS INC	4,650.24	35.6000	7,974.40	3,324.16

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4,640.0000	BGC PARTNERS INC	43,662.40	12.6400	58,649.60	14,987.20
672.0000	BOK FINANCIAL CORP	35,207.42	84.1300	56,535.36	21,327.94
1,707.0240	B. RILEY FINANCIAL INC	40,797.87	18.5500	31,665.30	9,132.57-
1,005.0000	BWX TECHNOLOGIES INC	18,989.84	48.7500	48,993.75	30,003.91
502.0000	BABCOCK & WILCOX ENTERPRISES I	6,987.57	11.7600	5,903.52	1,084.05-
270.0000	BADGER METER INC	4,965.30	39.8500	10,759.50	5,794.20
4,110.0000	BAKER HUGHES INC	211,748.67	54.5100	224,036.10	12,287.43
123.0000	BALCHEM CORP	5,078.67	77.7100	9,558.33	4,479.66
2,852.0000	BALL CORP	87,824.99	42.2100	120,382.92	32,557.93
132.0000	BANCFIRST CORP	5,043.72	96.6000	12,751.20	7,707.48
657.0000	BANCORPSOUTH INC	6,878.79	30.5000	20,038.50	13,159.71
2,106.0000	BANC OF CALIFORNIA INC	29,273.40	21.5000	45,279.00	16,005.60
81,970.0000	BANK OF AMERICA CORP	1,103,836.47	24.2600	1,988,592.20	884,755.73
876.0000	BANK OF HAWAII CORP	40,008.36	82.9700	72,681.72	32,673.36
1,382.0000	BANK MUTUAL CORP	4,906.10	9.1500	12,645.30	7,739.20
448.0000	BANK OF THE OZARKS INC	5,622.40	46.8700	20,997.76	15,375.36
8,699.0000	BANK OF NEW YORK MELLON CORP/T	306,939.97	51.0200	443,822.98	136,883.01

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266.0000	BANKUNITED INC	7,097.57	33.7100	8,966.86	1,869.29
678.0000	CR BARD INC	50,908.17	316.1100	214,322.58	163,414.41
433.0000	BARNES GROUP INC	10,158.18	58.5300	25,343.49	15,185.31
5,636.0000	BAXTER INTERNATIONAL INC	152,124.64	60.5400	341,203.44	189,078.80
366.0000	BEACON ROOFING SUPPLY INC	8,132.52	49.0000	17,934.00	9,801.48
1,941.0000	BECTON DICKINSON AND CO	135,800.51	195.1100	378,708.51	242,908.00
1,977.0000	BED BATH & BEYOND INC	76,367.16	30.4000	60,100.80	16,266.36-
377.0000	BELDEN INC	12,226.11	75.4300	28,437.11	16,211.00
838.0000	BEMIS CO INC	27,718.44	46.2500	38,757.50	11,039.06
483.0000	BENCHMARK ELECTRONICS INC	7,515.48	32.3000	15,600.90	8,085.42
675.0000	BENEFICIAL BANCORP INC	5,001.59	15.0000	10,125.00	5,123.41
924.0000	WR BERKLEY CORP	25,017.89	69.1700	63,913.08	38,895.19
17,708.0000	BERKSHIRE HATHAWAY INC	1,805,666.76	169.3700	2,999,203.96	1,193,537.20
233.0000	BERKSHIRE HILLS BANCORP INC	5,063.09	35.1500	8,189.95	3,126.86
1,200.0000	BERRY GLOBAL GROUP INC	40,213.74	57.0100	68,412.00	28,198.26
2,712.0000	BEST BUY CO INC	61,649.26	57.3300	155,478.96	93,829.70
692.0000	BIG LOTS INC	13,930.52	48.3000	33,423.60	19,493.08

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251.0000	BIO-RAD LABORATORIES INC	35,554.15	226.3100	56,803.81	21,249.66
1,431.0000	BIOMARIN PHARMACEUTICAL INC	122,315.97	90.8200	129,963.42	7,647.45
2,112.0000	BIOGEN INC	399,448.61	271.3600	573,112.32	173,663.71
398.0000	BIO-TECHNE CORP	31,893.88	117.5000	46,765.00	14,871.12
1,056.0000	BIOVERATIV INC	33,846.61	60.1700	63,539.52	29,692.91
1,098.0000	BLACK HILLS CORP	45,137.58	67.4700	74,082.06	28,944.48
835.0000	BLACKBAUD INC	45,190.56	85.7500	71,601.25	26,410.69
194.0000	BLACKHAWK NETWORK HOLDINGS INC	4,588.10	43.6000	8,458.40	3,870.30
896.0000	BLACKROCK INC	172,961.94	422.4100	378,479.36	205,517.42
1,963.0000	H&R BLOCK INC	48,252.75	30.9100	60,676.33	12,423.58
2,435.0000	BLOOMIN' BRANDS INC	42,198.55	21.2300	51,695.05	9,496.50
984.0000	BLUEBIRD BIO INC	39,143.52	105.0500	103,369.20	64,225.68
5,209.0000	BOEING CO/THE	517,366.67	197.7500	1,030,079.75	512,713.08
1,189.0000	BOOZ ALLEN HAMILTON HOLDING CO	35,384.64	32.5400	38,690.06	3,305.42
2,039.0000	BORGWARNER INC	64,042.61	42.3600	86,372.04	22,329.43
1,249.0000	BOSTON PROPERTIES INC	128,808.21	123.0200	153,651.98	24,843.77
12,588.0000	BOSTON SCIENTIFIC CORP	123,717.70	27.7200	348,939.36	225,221.66

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216.0000	BOTTOMLINE TECHNOLOGIES DE INC	5,080.32	25.6900	5,549.04	468.72
1,945.0000	BOYD GAMING CORP	30,183.90	24.8100	48,255.45	18,071.55
1,597.0000	BRADY CORP	42,160.80	33.9000	54,138.30	11,977.50
1,639.0000	BRANDYWINE REALTY TRUST	20,192.48	17.5300	28,731.67	8,539.19
674.0000	BRINKER INTERNATIONAL INC	16,560.18	38.1000	25,679.40	9,119.22
1,310.0000	BRINK'S CO/THE	42,064.10	67.0000	87,770.00	45,705.90
15,388.0000	BRISTOL-MYERS SQUIBB CO	487,296.91	55.7200	857,419.36	370,122.45
1,678.0000	BRIXMOR PROPERTY GROUP INC	42,872.90	17.8800	30,002.64	12,870.26-
914.0000	BROADRIDGE FINANCIAL SOLUTIONS	19,651.00	75.5600	69,061.84	49,410.84
3,503.0000	BROCADE COMMUNICATIONS SYSTEMS	20,317.40	12.6100	44,172.83	23,855.43
1,676.0000	BROOKDALE SENIOR LIVING INC	35,571.57	14.7100	24,653.96	10,917.61-
925.0000	BROWN & BROWN INC	23,300.75	43.0700	39,839.75	16,539.00
2,621.0000	BROWN-FORMAN CORP	59,008.54	48.6000	127,380.60	68,372.06
1,908.0000	BRUKER CORP	35,736.84	28.8400	55,026.72	19,289.88
68.0000	BRUNOS INC NEW	680.00	10.0000	680.00	0.00
1,071.0000	BRUNSWICK CORP/DE	23,452.29	62.7300	67,183.83	43,731.54
1,204.0000	BRYN MAWR BANK CORP	35,710.64	42.5000	51,170.00	15,459.36

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337.0000	BUFFALO WILD WINGS INC	23,482.25	126.7000	42,697.90	19,215.65
736.0000	BURLINGTON STORES INC	34,793.91	91.9900	67,704.64	32,910.73
4,702.0000	CBS CORP	133,308.29	63.7800	299,893.56	166,585.27
676.0000	CBOE HOLDINGS INC	27,108.50	91.4000	61,786.40	34,677.90
2,246.0000	CBRE GROUP INC	44,178.82	36.4000	81,754.40	37,575.58
1,269.0000	CDK GLOBAL INC	38,612.21	62.0600	78,754.14	40,141.93
1,023.0000	CDW CORP/DE	45,676.95	62.5300	63,968.19	18,291.24
2,650.0000	CF INDUSTRIES HOLDINGS INC	74,583.45	27.9600	74,094.00	489.45-
923.0000	CH ROBINSON WORLDWIDE INC	58,139.77	68.6800	63,391.64	5,251.87
2,366.0000	CIGNA CORP	99,153.48	167.3900	396,044.74	296,891.26
1,557.0000	CIT GROUP INC	55,680.02	48.7000	75,825.90	20,145.88
2,981.0000	CME GROUP INC	250,255.47	125.2400	373,340.44	123,084.97
2,574.0000	CMS ENERGY CORP	91,725.52	46.2500	119,047.50	27,321.98
216.0000	CSS INDUSTRIES INC	4,965.84	26.1600	5,650.56	684.72
749.0000	CNA FINANCIAL CORP	20,432.72	48.7500	36,513.75	16,081.03
1,763.0000	CNO FINANCIAL GROUP INC	12,781.75	20.8800	36,811.44	24,029.69
278.0000	CSG SYSTEMS INTERNATIONAL INC	5,017.90	40.5800	11,281.24	6,263.34

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9,648.0000	CSX CORP	129,147.47	54.5600	526,394.88	397,247.41
1,164.0000	CSRA INC	28,569.57	31.7500	36,957.00	8,387.43
551.0000	CTS CORP	4,959.00	21.6000	11,901.60	6,942.60
710.0000	CVB FINANCIAL CORP	6,248.00	22.4300	15,925.30	9,677.30
10,492.0000	CVS HEALTH CORP	406,608.67	80.4600	844,186.32	437,577.65
8,723.0000	CYS INVESTMENTS INC	77,390.36	8.4100	73,360.43	4,029.93-
2,848.0000	CA INC	67,399.06	34.4700	98,170.56	30,771.50
587.0000	CABELA'S INC	18,853.89	59.4200	34,879.54	16,025.65
12.0000	CABLE ONE INC	1,902.67	710.9000	8,530.80	6,628.13
522.0000	CABOT CORP	20,065.68	53.4300	27,890.46	7,824.78
4,199.0000	CABOT OIL & GAS CORP	75,590.36	25.0800	105,310.92	29,720.56
361.0000	CACI INTERNATIONAL INC	36,219.13	125.0500	45,143.05	8,923.92
2,138.0000	CADENCE DESIGN SYSTEMS INC	21,828.98	33.4900	71,601.62	49,772.64
508.0000	CALATLANTIC GROUP INC	20,079.87	35.3500	17,957.80	2,122.07-
449.0000	CALGON CARBON CORP	7,835.05	15.1000	6,779.90	1,055.15-
1,871.0000	CALIFORNIA WATER SERVICE GROUP	42,284.60	36.8000	68,852.80	26,568.20
781.0000	CALLAWAY GOLF CO	4,810.96	12.7800	9,981.18	5,170.22

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4,723.0000	CALLON PETROLEUM CO	48,911.66	10.6100	50,111.03	1,199.37
4,559.0000	CALPINE CORP	57,718.95	13.5300	61,683.27	3,964.32
786.0000	CAMBREX CORP	41,642.28	59.7500	46,963.50	5,321.22
558.0000	CAMDEN PROPERTY TRUST	35,583.66	85.5100	47,714.58	12,130.92
1,434.0000	CAMPBELL SOUP CO	52,825.19	52.1500	74,783.10	21,957.91
349.9490	CANADIAN IMPERIAL BANK OF COMM	21,944.77	81.1600	28,401.86	6,457.09
591.0000	CANTEL MEDICAL CORP	35,879.61	77.9100	46,044.81	10,165.20
117.0000	CAPELLA EDUCATION CO	4,999.41	85.6000	10,015.20	5,015.79
4,824.0000	CAPITAL ONE FINANCIAL CORP	346,013.23	82.6200	398,558.88	52,545.65
550.0000	CAPITAL SENIOR LIVING CORP	10,114.50	15.2100	8,365.50	1,749.00-
3,112.0000	CARDINAL HEALTH INC	166,696.01	77.9200	242,487.04	75,791.03
1,064.0000	CARE CAPITAL PROPERTIES INC	33,941.22	26.7000	28,408.80	5,532.42-
487.0000	CARLISLE COS INC	23,103.28	95.4000	46,459.80	23,356.52
1,937.0000	CARMAX INC	50,536.33	63.0600	122,147.22	71,610.89
4,086.0000	CARNIVAL CORP	215,807.58	65.5700	267,919.02	52,111.44
1,173.0000	CARPENTER TECHNOLOGY CORP	42,920.07	37.4300	43,905.39	985.32
640.0000	CARS.COM INC	7,624.87	26.6300	17,043.20	9,418.33

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727.0000	CARTER'S INC	29,892.09	88.9500	64,666.65	34,774.56
331.0000	CASEY'S GENERAL STORES INC	14,247.60	107.1100	35,453.41	21,205.81
5,613.0000	CATERPILLAR INC	358,506.75	107.4600	603,172.98	244,666.23
160.0000	CATHAY GENERAL BANCORP	2,235.20	37.9500	6,072.00	3,836.80
211.0000	CAVCO INDUSTRIES INC	9,826.27	129.6500	27,356.15	17,529.88
1,139.0000	CAVIUM INC	63,429.59	62.1300	70,766.07	7,336.48
969.0000	CEDAR REALTY TRUST INC	4,903.14	4.8500	4,699.65	203.49-
1,375.0000	CELANESE CORP	44,646.25	94.9400	130,542.50	85,896.25
7,475.0000	CELGENE CORP	253,338.36	129.8700	970,778.25	717,439.89
1,112.0000	CELLDEX THERAPEUTICS INC	7,261.36	2.4700	2,746.64	4,514.72-
1,519.0000	CENTENE CORP	48,533.25	79.8800	121,337.72	72,804.47
5,131.0000	CENTERPOINT ENERGY INC	74,714.02	27.3800	140,486.78	65,772.76
196.0000	CENTERSTATE BANKS INC	1,250.48	24.8600	4,872.56	3,622.08
1,929.0000	CENTRAL GARDEN & PET CO	40,373.97	30.0200	57,908.58	17,534.61
371.0000	CENTRAL PACIFIC FINANCIAL CORP	4,889.59	31.4700	11,675.37	6,785.78
2,991.0000	CERNER CORP	102,696.69	66.4700	198,811.77	96,115.08
411.0000	CHARLES RIVER LABORATORIES INT	16,152.30	101.1500	41,572.65	25,420.35

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1,938.0000	CHARTER COMMUNICATIONS INC	150,416.94	336.8500	652,815.30	502,398.36
2,957.0000	CHATHAM LODGING TRUST	66,118.52	20.0900	59,406.13	6,712.39-
470.0000	CHEESECAKE FACTORY INC/THE	15,113.04	50.3000	23,641.00	8,527.96
77.0000	CHEMED CORP	4,924.15	204.5300	15,748.81	10,824.66
272.0000	CHEMICAL FINANCIAL CORP	4,972.16	48.4100	13,167.52	8,195.36
2,360.0000	CHENIERE ENERGY INC	69,389.86	48.7100	114,955.60	45,565.74
8,384.0000	CHESAPEAKE ENERGY CORP	40,997.76	4.9700	41,668.48	670.72
1,552.0000	CHESAPEAKE LODGING TRUST	42,835.20	24.4700	37,977.44	4,857.76-
17,581.0000	CHEVRON CORP	1,259,429.03	104.3300	1,834,225.73	574,796.70
832.0000	CHICAGO BRIDGE & IRON CO NV	28,427.57	19.7300	16,415.36	12,012.21-
1,879.0000	CHICO'S FAS INC	23,908.69	9.4200	17,700.18	6,208.51-
208.0000	CHILDREN'S PLACE INC/THE	9,191.52	102.1000	21,236.80	12,045.28
2,834.0000	CHIMERA INVESTMENT CORP	38,259.00	18.6300	52,797.42	14,538.42
22,248.0000	CHIMERIX INC	103,039.39	5.4500	121,251.60	18,212.21
238.0000	CHIPOTLE MEXICAN GRILL INC	52,913.86	416.1000	99,031.80	46,117.94
2,268.0000	CHURCH & DWIGHT CO INC	42,312.59	51.8800	117,663.84	75,351.25
115.0000	CHURCHILL DOWNS INC	4,940.40	183.3000	21,079.50	16,139.10

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1,857.0000	CIENA CORP	31,006.71	25.0200	46,462.14	15,455.43
1,058.0000	CIMAREX ENERGY CO	87,064.62	94.0100	99,462.58	12,397.96
270.0000	CINCINNATI BELL INC	4,468.50	19.5500	5,278.50	810.00
1,274.0000	CINCINNATI FINANCIAL CORP	71,415.10	72.4500	92,301.30	20,886.20
739.0000	CINEMARK HOLDINGS INC	14,809.56	38.8500	28,710.15	13,900.59
124.0000	CIRCOR INTERNATIONAL INC	4,977.36	59.3800	7,363.12	2,385.76
47,291.0000	CISCO SYSTEMS INC	1,230,272.04	31.3000	1,480,208.30	249,936.26
523.0000	CIRRUS LOGIC INC	8,969.45	62.7200	32,802.56	23,833.11
885.0000	CINTAS CORP	31,602.30	126.0400	111,545.40	79,943.10
26,496.0000	CITIGROUP INC	1,210,327.36	66.8800	1,772,052.48	561,725.12
1,852.0000	CITIZENS FINANCIAL GROUP INC	50,146.57	35.6800	66,079.36	15,932.79
1,793.0000	CITRIX SYSTEMS INC	69,885.01	79.5800	142,686.94	72,801.93
733.0000	CITY HOLDING CO	32,880.72	65.8700	48,282.71	15,401.99
3,415.0000	CITY OFFICE REIT INC	40,334.57	12.7000	43,370.50	3,035.93
974.0000	CLEAN HARBORS INC	42,690.42	55.8300	54,378.42	11,688.00
6,186.0000	CLEAN ENERGY FUELS CORP	26,785.38	2.5400	15,712.44	11,072.94-
160.0000	CLEARWATER PAPER CORP	5,031.20	46.7500	7,480.00	2,448.80

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939.0000	CLOROX CO/THE	76,502.46	133.2400	125,112.36	48,609.90
2,437.0000	COACH INC	78,036.50	47.3400	115,367.58	37,331.08
795.0000	COBIZ FINANCIAL INC	4,984.65	17.4000	13,833.00	8,848.35
166.0000	COCA-COLA BOTTLING CO CONSOLID	10,121.02	228.8700	37,992.42	27,871.40
32,228.0000	COCA-COLA CO/THE	902,893.83	44.8500	1,445,425.80	542,531.97
320.0000	COGENT COMMUNICATIONS HOLDINGS	5,020.80	40.1000	12,832.00	7,811.20
660.0000	COGNEX CORP	11,121.00	84.9000	56,034.00	44,913.00
5,395.0000	COGNIZANT TECHNOLOGY SOLUTIONS	163,444.52	66.4000	358,228.00	194,783.48
157.0000	COHEN & STEERS INC	4,953.35	40.5400	6,364.78	1,411.43
200.0000	COHERENT INC	10,368.00	224.9900	44,998.00	34,630.00
1,300.0000	COLFAX CORP	36,634.00	39.3700	51,181.00	14,547.00
8,411.0000	COLGATE-PALMOLIVE CO	292,935.66	74.1300	623,507.43	330,571.77
5,182.0000	COLONY NORTHSTAR INC	63,510.51	14.0900	73,014.38	9,503.87
314.0000	COLUMBIA BANKING SYSTEM INC	5,221.82	39.8500	12,512.90	7,291.08
45,958.0000	COMCAST CORP	921,168.57	38.9200	1,788,685.36	867,516.79
1,603.0000	COMERICA INC	43,855.14	73.2400	117,403.72	73,548.58
1,460.0000	COMMERCE BANCSHARES INC/MO	42,823.36	56.8300	82,971.80	40,148.44

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108.0000	COMMERCEHUB INC	405.18	17.4200	1,881.36	1,476.18
217.0000	COMMERCEHUB INC	820.45	17.4400	3,784.48	2,964.03
902.0000	COMMERCIAL METALS CO	12,934.68	19.4300	17,525.86	4,591.18
1,081.0000	COMMSCOPE HOLDING CO INC	35,467.61	38.0300	41,110.43	5,642.82
2,401.0000	COMMUNITY BANK SYSTEM INC	77,074.14	55.7700	133,903.77	56,829.63
739.0000	COMMUNITY TRUST BANCORP INC	18,132.37	43.7500	32,331.25	14,198.88
350.0000	COMMVAULT SYSTEMS INC	14,434.00	56.4500	19,757.50	5,323.50
501.0000	COMPASS MINERALS INTERNATIONAL	42,334.50	65.3000	32,715.30	9,619.20-
3,669.0000	CONAGRA BRANDS INC	69,683.38	35.7600	131,203.44	61,520.06
1,367.0000	CONCHO RESOURCES INC	106,630.83	121.5300	166,131.51	59,500.68
2,471.0000	CONDUENT INC	31,989.90	15.9400	39,387.74	7,397.84
161.0000	CONMED CORP	4,929.82	50.9400	8,201.34	3,271.52
5,764.0000	CONNECTONE BANCORP INC	103,651.71	22.5500	129,978.20	26,326.49
11,464.0000	CONOCOPHILLIPS	542,013.16	43.9600	503,957.44	38,055.72-
5,714.0000	CONSOL ENERGY INC	38,340.94	14.9400	85,367.16	47,026.22
1,218.0000	CONSOLIDATED COMMUNICATIONS HO	28,708.26	21.4700	26,150.46	2,557.80-
2,681.0000	CONSOLIDATED EDISON INC	125,152.03	80.8200	216,678.42	91,526.39

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1,547.0000	CONSTELLATION BRANDS INC	68,188.84	193.7300	299,700.31	231,511.47
1,051.0000	CONTINENTAL RESOURCES INC/OK	27,224.23	32.3300	33,978.83	6,754.60
1,515.0000	CONVERGYS CORP	19,967.70	23.7800	36,026.70	16,059.00
356.0000	COOPER COS INC/THE	26,659.02	239.4200	85,233.52	58,574.50
494.0000	COOPER TIRE & RUBBER CO	9,835.54	36.1000	17,833.40	7,997.86
1,936.0000	COPART INC	22,347.69	31.7900	61,545.44	39,197.75
988.0000	CORE-MARK HOLDING CO INC	42,187.60	33.0600	32,663.28	9,524.32-
900.0000	CORELOGIC INC/UNITED STATES	32,673.36	43.3800	39,042.00	6,368.64
1,482.0000	CORECIVIC INC	39,643.50	27.5800	40,873.56	1,230.06
815.0000	CORNERSTONE ONDEMAND INC	23,040.05	35.7500	29,136.25	6,096.20
11,899.0000	CORNING INC	224,058.17	30.0500	357,564.95	133,506.78
568.0000	CORPORATE OFFICE PROPERTIES TR	12,342.64	35.0300	19,897.04	7,554.40
3,228.0000	COSTCO WHOLESALE CORP	228,487.85	159.9300	516,254.04	287,766.19
315.0000	COSTAR GROUP INC	21,128.49	263.6000	83,034.00	61,905.51
4,350.0000	COTY INC	77,408.81	18.7600	81,606.00	4,197.19
3,841.0000	COUSINS PROPERTIES INC	25,461.02	8.7900	33,762.39	8,301.37
1,244.0000	COVANTA HOLDING CORP	20,165.24	13.2000	16,420.80	3,744.44-

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1,170.0000	COWEN INC	15,139.17	16.2500	19,012.50	3,873.33
32.0000	CRACKER BARREL OLD COUNTRY STO	1,555.52	167.2500	5,352.00	3,796.48
388.0000	CRANE CO	18,197.20	79.3800	30,799.44	12,602.24
1,251.0000	CRAY INC	25,167.27	18.4000	23,018.40	2,148.87-
210.0000	CREDIT ACCEPTANCE CORP	45,091.20	257.1400	53,999.40	8,908.20
875.0000	CREE INC	20,825.00	24.6500	21,568.75	743.75
3,055.0000	CROWN CASTLE INTERNATIONAL COR	170,125.86	100.1800	306,049.90	135,924.04
1,988.0000	CROWN HOLDINGS INC	71,685.29	59.6600	118,604.08	46,918.79
1,115.0000	CUBESMART	15,017.41	24.0400	26,804.60	11,787.19
358.0000	CULLEN/FROST BANKERS INC	20,037.26	93.9100	33,619.78	13,582.52
1,804.0000	CUMMINS INC	187,042.38	162.2200	292,644.88	105,602.50
434.0000	CURTISS-WRIGHT CORP	14,975.69	91.7800	39,832.52	24,856.83
5,784.0000	CYPRESS SEMICONDUCTOR CORP	67,792.23	13.6500	78,951.60	11,159.37
1,166.0000	CYRUSONE INC	42,663.94	55.7500	65,004.50	22,340.56
1,304.0000	DCT INDUSTRIAL TRUST INC	36,919.11	53.4400	69,685.76	32,766.65
2,602.0000	DDR CORP	33,588.36	9.0700	23,600.14	9,988.22-
2,742.0000	DR HORTON INC	48,784.05	34.5700	94,790.94	46,006.89

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560.0000	DST SYSTEMS INC	14,316.40	61.7000	34,552.00	20,235.60
1,244.0000	DTE ENERGY CO	51,903.91	105.7900	131,602.76	79,698.85
344.0000	DSW INC	8,514.00	17.7000	6,088.80	2,425.20-
2,444.0000	DXC TECHNOLOGY CO	78,606.50	76.7200	187,503.68	108,897.18
4,707.0000	DANAHER CORP	130,394.65	84.3900	397,223.73	266,829.08
1,359.0000	DARDEN RESTAURANTS INC	76,337.63	90.4400	122,907.96	46,570.33
3,850.0000	DARLING INGREDIENTS INC	42,350.00	15.7400	60,599.00	18,249.00
1,324.0000	DAVITA INC	62,018.56	64.7600	85,742.24	23,723.68
2,046.0000	DEAN FOODS CO	34,758.44	17.0000	34,782.00	23.56
108.0000	DECKERS OUTDOOR CORP	5,114.88	68.2600	7,372.08	2,257.20
3,265.0000	DEERE & CO	190,351.72	123.5900	403,521.35	213,169.63
7,112.0000	DELTA AIR LINES INC	90,228.93	53.7400	382,198.88	291,969.95
409.0000	DELUXE CORP	9,627.86	69.2200	28,310.98	18,683.12
2,074.0000	DENTSPLY SIRONA INC	59,528.63	64.8400	134,478.16	74,949.53
3,862.0000	DEVON ENERGY CORP	162,761.59	31.9700	123,468.14	39,293.45-
769.0000	DEXCOM INC	57,947.92	73.1500	56,252.35	1,695.57-
1,044.0000	DIAMONDBACK ENERGY INC	84,601.60	88.8100	92,717.64	8,116.04

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2,441.0000	DIAMONDROCK HOSPITALITY CO	23,699.60	10.9500	26,728.95	3,029.35
787.0000	DICK'S SPORTING GOODS INC	35,045.11	39.8300	31,346.21	3,698.90-
519.0000	DIEBOLD NIXDORF INC	15,564.81	28.0000	14,532.00	1,032.81-
1,338.0000	DIGITAL REALTY TRUST INC	80,581.95	112.9500	151,127.10	70,545.15
357.0000	DIME COMMUNITY BANCSHARES INC	5,083.68	19.6000	6,997.20	1,913.52
327.0000	DILLARD'S INC	18,357.87	57.6900	18,864.63	506.76
123.0000	DINEEQUITY INC	6,157.38	44.0500	5,418.15	739.23-
12,794.0000	WALT DISNEY CO/THE	400,490.97	106.2500	1,359,362.50	958,871.53
2,681.0000	DISCOVERY COMMUNICATIONS INC	69,770.67	25.8300	69,250.23	520.44-
919.0000	DISCOVERY COMMUNICATIONS INC	18,239.40	25.2100	23,167.99	4,928.59
1,723.0000	DISH NETWORK CORP	50,429.77	62.7600	108,135.48	57,705.71
4,200.0000	DISCOVER FINANCIAL SERVICES	101,117.46	62.1900	261,198.00	160,080.54
1,219.0000	DOLBY LABORATORIES INC	42,713.76	48.9600	59,682.24	16,968.48
2,824.0000	DOLLAR GENERAL CORP	151,528.16	72.0900	203,582.16	52,054.00
2,060.0000	DOLLAR TREE INC	60,408.58	69.9200	144,035.20	83,626.62
5,750.0000	DOMINION ENERGY INC	263,993.35	76.6300	440,622.50	176,629.15
658.0000	DOMINO'S PIZZA INC	28,175.56	211.5300	139,186.74	111,011.18

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530.0000	DOMTAR CORP	19,629.76	38.4200	20,362.60	732.84
875.0000	DONALDSON CO INC	19,936.87	45.5400	39,847.50	19,910.63
35.0000	DONEGAL GROUP INC	442.05	15.9000	556.50	114.45
351.6670	RR DONNELLEY & SONS CO	5,285.72	12.5400	4,409.90	875.82-
531.8750	DONNELLEY FINANCIAL SOLUTIONS	11,907.84	22.9600	12,211.85	304.01
753.0000	DORMAN PRODUCTS INC	36,708.75	82.7700	62,325.81	25,617.06
1,302.0000	DOUGLAS EMMETT INC	20,154.96	38.2100	49,749.42	29,594.46
1,480.0000	DOVER CORP	58,873.43	80.2200	118,725.60	59,852.17
10,403.0000	DOW CHEMICAL CO/THE	463,635.84	63.0700	656,117.21	192,481.37
1,437.0000	DR PEPPER SNAPPLE GROUP INC	129,098.70	91.1100	130,925.07	1,826.37
409.0000	DRIL-QUIP INC	27,298.09	48.8000	19,959.20	7,338.89-
8,418.0000	EI DU PONT DE NEMOURS & CO	379,810.74	80.7100	679,416.78	299,606.04
6,617.0000	DUKE ENERGY CORP	372,281.57	83.5900	553,115.03	180,833.46
2,180.0000	DUKE REALTY CORP	25,549.60	27.9500	60,931.00	35,381.40
429.0000	DUN & BRADSTREET CORP/THE	32,948.78	108.1500	46,396.35	13,447.57
1,071.0000	DUNKIN' BRANDS GROUP INC	34,657.56	55.1200	59,033.52	24,375.96
1,273.0000	CONTRA DYAX CORPORATION	0.00	0.0000	0.00	0.00

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321.0000	DYCOM INDUSTRIES INC	4,798.95	89.5200	28,735.92	23,936.97
5,287.0000	DYNEX CAPITAL INC	35,792.99	7.1000	37,537.70	1,744.71
3,210.0000	DYNEGY INC	39,322.50	8.2700	26,546.70	12,775.80-
397.0000	EMC INSURANCE GROUP INC	4,999.55	27.7800	11,028.66	6,029.11
5,558.0000	EOG RESOURCES INC	313,134.65	90.5200	503,110.16	189,975.51
1,525.0000	EQT CORP	90,400.72	58.5900	89,349.75	1,050.97-
371.0000	EPR PROPERTIES	17,058.58	71.8700	26,663.77	9,605.19
3,295.0000	E*TRADE FINANCIAL CORP	29,391.40	38.0300	125,308.85	95,917.45
531.0000	EAGLE MATERIALS INC	36,464.92	92.4200	49,075.02	12,610.10
2,079.0000	EAST WEST BANCORP INC	36,100.19	58.5800	121,787.82	85,687.63
2,005.0000	EASTERLY GOVERNMENT PROPERTIES	35,106.55	20.9500	42,004.75	6,898.20
172.0000	EASTGROUP PROPERTIES INC	9,958.80	83.8000	14,413.60	4,454.80
1,153.0000	EASTMAN CHEMICAL CO	80,088.47	83.9900	96,840.47	16,752.00
9,423.0000	EBAY INC	130,932.29	34.9200	329,051.16	198,118.87
133.0000	ECHOSTAR CORP	4,983.51	60.7000	8,073.10	3,089.59
1,891.0000	ECOLAB INC	82,287.55	132.7500	251,030.25	168,742.70
514.0000	EDGEWELL PERSONAL CARE CO	39,703.11	76.0200	39,074.28	628.83-

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3,175.0000	EDISON INTERNATIONAL	134,590.47	78.1900	248,253.25	113,662.78
2,160.0000	EDWARDS LIFESCIENCES CORP	142,293.24	118.2400	255,398.40	113,105.16
906.0000	EL PASO ELECTRIC CO	35,207.16	51.7000	46,840.20	11,633.04
3,258.0000	ELECTRONIC ARTS INC	82,502.94	105.7200	344,435.76	261,932.82
309.0000	ELECTRONICS FOR IMAGING INC	5,101.59	47.3800	14,640.42	9,538.83
660.0000	ELLIE MAE INC	42,893.40	109.9100	72,540.60	29,647.20
532.0000	EMCOR GROUP INC	15,119.44	65.3800	34,782.16	19,662.72
1,119.0000	EMERGENT BIOSOLUTIONS INC	40,214.76	33.9100	37,945.29	2,269.47-
6,214.0000	EMERSON ELECTRIC CO	277,696.51	59.6200	370,478.68	92,782.17
2,292.0000	EMPIRE STATE REALTY TRUST INC	42,493.68	20.7700	47,604.84	5,111.16
220.0000	ENCORE WIRE CORP	5,108.40	42.7000	9,394.00	4,285.60
573.0000	ENERGEN CORP	31,497.81	49.3700	28,289.01	3,208.80-
256.0000	ENERGIZER HOLDINGS INC	5,111.01	48.0200	12,293.12	7,182.11
329.0000	ENERSYS	12,202.61	72.4500	23,836.05	11,633.44
1,772.0000	ENSIGN GROUP INC/THE	42,510.28	21.7700	38,576.44	3,933.84-
1,068.0000	ENTEGRIS INC	10,455.72	21.9500	23,442.60	12,986.88
1,693.0000	ENTERCOM COMMUNICATIONS CORP	10,346.09	10.3500	17,522.55	7,176.46

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1,421.0000	ENTERGY CORP	96,158.89	76.7700	109,090.17	12,931.28
390.0000	ENTERPRISE FINANCIAL SERVICES	5,190.90	40.8000	15,912.00	10,721.10
930.0000	ENVISION HEALTHCARE CORP	66,743.63	62.6700	58,283.10	8,460.53-
830.0000	EPLUS INC	34,930.55	74.1000	61,503.00	26,572.45
1,208.0000	EQUIFAX INC	46,012.32	137.4200	166,003.36	119,991.04
517.0000	EQUINIX INC	108,335.80	429.1600	221,875.72	113,539.92
1,496.0000	EQUITY COMMONWEALTH	29,873.99	31.6000	47,273.60	17,399.61
572.0000	EQUITY LIFESTYLE PROPERTIES IN	30,069.60	86.3400	49,386.48	19,316.88
2,621.0000	EQUITY RESIDENTIAL	133,778.88	65.8300	172,540.43	38,761.55
8,386.0000	ESPERION THERAPEUTICS INC	90,312.19	46.2800	388,104.08	297,791.89
5,159.0000	ESSENDANT INC	104,160.21	14.8300	76,507.97	27,652.24-
651.0000	ESSEX PROPERTY TRUST INC	114,173.46	257.2700	167,482.77	53,309.31
243.0000	ESTERLINE TECHNOLOGIES CORP	17,802.18	94.8000	23,036.40	5,234.22
242.0000	ETHAN ALLEN INTERIORS INC	5,055.38	32.3000	7,816.60	2,761.22
437.0000	EURONET WORLDWIDE INC	22,510.60	87.3700	38,180.69	15,670.09
427.0000	EVERCORE PARTNERS INC	15,145.56	70.5000	30,103.50	14,957.94
3,249.0000	EVERSOURCE ENERGY	147,365.80	60.7100	197,246.79	49,880.99

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625.0000	EXACT SCIENCES CORP	5,131.25	35.3700	22,106.25	16,975.00
8,459.0000	EXELON CORP	242,880.19	36.0700	305,116.13	62,235.94
5,342.0000	EXELIXIS INC	40,652.62	24.6300	131,573.46	90,920.84
902.0000	EXLSERVICE HOLDINGS INC	42,078.30	55.5800	50,133.16	8,054.86
1,106.0000	EXPEDIA INC	61,869.57	148.9500	164,738.70	102,869.13
1,484.0000	EXPEDITORS INTERNATIONAL OF WA	75,402.04	56.4800	83,816.32	8,414.28
5,061.0000	EXPRESS SCRIPTS HOLDING CO	192,985.73	63.8400	323,094.24	130,108.51
1,086.0000	EXTRA SPACE STORAGE INC	86,722.98	78.0000	84,708.00	2,014.98-
39,122.0000	EXXON MOBIL CORP	2,858,207.76	80.7300	3,158,319.06	300,111.30
1,314.0000	FLIR SYSTEMS INC	36,174.42	34.6600	45,543.24	9,368.82
1,036.0000	FMC CORP	42,672.84	73.0500	75,679.80	33,006.96
3,316.0000	FNB CORP/PA	33,524.76	14.1600	46,954.56	13,429.80
165.0000	FTD COS INC	3,787.68	20.0000	3,300.00	487.68-
20,940.0000	FACEBOOK INC	1,338,125.17	150.9800	3,161,521.20	1,823,396.03
333.0000	FACTSET RESEARCH SYSTEMS INC	56,664.90	166.1800	55,337.94	1,326.96-
317.0000	FAIR ISAAC CORP	9,189.83	139.4100	44,192.97	35,003.14
1,000.0000	FAIRPOINT COMMUNICATIONS INC	13,671.10	15.6500	15,650.00	1,978.90

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3,647.0000	FARMLAND PARTNERS INC	40,708.54	8.9400	32,604.18	8,104.36-
123.0000	FARO TECHNOLOGIES INC	5,098.35	37.8000	4,649.40	448.95-
3,266.0000	FASTENAL CO	132,149.78	43.5300	142,168.98	10,019.20
497.0000	FEDERAL REALTY INVESTMENT TRUS	45,818.79	126.3900	62,815.83	16,997.04
208.0000	FEDERATED INVESTORS INC	4,915.04	28.2500	5,876.00	960.96
2,504.0000	FEDEX CORP	263,570.17	217.3300	544,194.32	280,624.15
3,702.0000	FELCOR LODGING TRUST INC	21,175.44	7.2100	26,691.42	5,515.98
1,561.0000	FERRO CORP	8,366.96	18.2900	28,550.69	20,183.73
558.0000	F5 NETWORKS INC	45,982.53	127.0600	70,899.48	24,916.95
2,715.0000	FIDELITY NATIONAL INFORMATION	89,829.67	85.4000	231,861.00	142,031.33
2,176.0000	FNF GROUP	60,692.04	44.8300	97,550.08	36,858.04
376.0000	FNFV GROUP	3,243.61	15.8000	5,940.80	2,697.19
5,969.0000	FIFTH THIRD BANCORP	90,167.87	25.9600	154,955.24	64,787.37
305.0000	FINANCIAL ENGINES INC	7,667.70	36.6000	11,163.00	3,495.30
311.0000	FINANCIAL INSTITUTIONS INC	5,010.21	29.8000	9,267.80	4,257.59
713.0000	FINISAR CORP	11,457.91	25.9800	18,523.74	7,065.83
2,409.0000	FIREEYE INC	40,615.74	15.2100	36,640.89	3,974.85-

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627.0000	FIRST AMERICAN FINANCIAL CORP	9,630.72	44.6900	28,020.63	18,389.91
12,836.0000	FIRST BANCORP/PUERTO RICO	54,821.05	5.7900	74,320.44	19,499.39
37.0000	FIRST CITIZENS BANCSHARES INC/	6,464.27	372.7000	13,789.90	7,325.63
404.0000	FIRST CONNECTICUT BANCORP INC/	5,684.28	25.6500	10,362.60	4,678.32
915.0000	FIRST DEFIANCE FINANCIAL CORP	31,520.22	52.6800	48,202.20	16,681.98
2,850.0000	FIRST DATA CORP	45,134.75	18.2000	51,870.00	6,735.25
1,017.0000	FIRST FINANCIAL BANKSHARES INC	31,004.77	44.2000	44,951.40	13,946.63
3,601.0000	FIRST HAWAIIAN INC	114,102.68	30.6200	110,262.62	3,840.06-
598.0000	FIRST HORIZON NATIONAL CORP	6,003.10	17.4200	10,417.16	4,414.06
1,295.0000	FIRST INDUSTRIAL REALTY TRUST	16,776.50	28.6200	37,062.90	20,286.40
1,236.0000	FIRST INTERSTATE BANCSYSTEM IN	35,473.20	37.2000	45,979.20	10,506.00
593.0000	FIRST MIDWEST BANCORP INC/IL	6,955.89	23.3100	13,822.83	6,866.94
2,750.0000	FIRST POTOMAC REALTY TRUST	29,425.00	11.1100	30,552.50	1,127.50
1,322.0000	FIRST REPUBLIC BANK/CA	75,812.03	100.1000	132,332.20	56,520.17
614.0000	FIRST SOLAR INC	25,486.98	39.8800	24,486.32	1,000.66-
269.0000	1ST SOURCE CORP	4,912.90	47.9400	12,895.86	7,982.96
249.0000	FIRSTCASH INC	9,691.08	58.3000	14,516.70	4,825.62

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2,281.0000	FISERV INC	53,828.75	122.3400	279,057.54	225,228.79
735.0000	FLAGSTAR BANCORP INC	9,929.85	30.8200	22,652.70	12,722.85
3,274.0000	FIRSTENERGY CORP	104,798.10	29.1600	95,469.84	9,328.26-
972.0000	FLEETCOR TECHNOLOGIES INC	112,503.74	144.2100	140,172.12	27,668.38
646.0000	FLOTEK INDUSTRIES INC	4,921.03	8.9400	5,775.24	854.21
1,550.0000	FLUOR CORP	60,413.88	45.7800	70,959.00	10,545.12
1,299.0000	FLOWERS FOODS INC	24,732.81	17.3100	22,485.69	2,247.12-
1,725.0000	FLOWSERVE CORP	80,422.98	46.4300	80,091.75	331.23-
1,691.0000	FOOT LOCKER INC	45,710.75	49.2800	83,332.48	37,621.73
25,737.0000	FORD MOTOR CO	220,936.33	11.1900	287,997.03	67,060.70
1,695.0000	FOREST CITY REALTY TRUST INC	27,545.07	24.1700	40,968.15	13,423.08
305.0000	FORESTAR GROUP INC	4,901.35	17.1500	5,230.75	329.40
1,107.0000	FORTINET INC	29,065.74	37.4400	41,446.08	12,380.34
1,814.0000	FORTUNE BRANDS HOME & SECURITY	47,578.11	65.2400	118,345.36	70,767.25
234.0000	FORWARD AIR CORP	7,607.34	53.2800	12,467.52	4,860.18
230.0000	FRANKLIN ELECTRIC CO INC	5,146.25	41.4000	9,522.00	4,375.75
4,025.0000	FRANKLIN RESOURCES INC	149,581.39	44.7900	180,279.75	30,698.36

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12,097.0000	FREEPORT-MCMORAN INC	63,436.14	12.0100	145,284.97	81,848.83
4,360.0000	FRESHPET INC	40,460.80	16.6000	72,376.00	31,915.20
393.0000	HB FULLER CO	9,211.92	51.1100	20,086.23	10,874.31
3,539.0000	FULTON FINANCIAL CORP	35,391.42	19.0000	67,241.00	31,849.58
902.0000	GAMCO INVESTORS INC	25,237.99	29.6000	26,699.20	1,461.21
369.0000	GATX CORP	13,379.94	64.2700	23,715.63	10,335.69
891.0000	GEO GROUP INC/THE	13,927.34	29.5700	26,346.87	12,419.53
764.0000	GCP APPLIED TECHNOLOGIES INC	7,318.90	30.5000	23,302.00	15,983.10
5,394.0000	GGP INC	99,434.80	23.5600	127,082.64	27,647.84
592.0000	G-III APPAREL GROUP LTD	9,732.48	24.9500	14,770.40	5,037.92
1,470.0000	GTT COMMUNICATIONS INC	47,566.85	31.6500	46,525.50	1,041.35-
1,830.0000	ARTHUR J GALLAGHER & CO	77,958.38	57.2500	104,767.50	26,809.12
2,247.0000	GAMING AND LEISURE PROPERTIES	68,046.49	37.6700	84,644.49	16,598.00
987.0000	GAMESTOP CORP	19,923.30	21.6100	21,329.07	1,405.77
960.0000	GANNETT CO INC	4,849.29	8.7200	8,371.20	3,521.91
2,761.0000	GAP INC/THE	59,432.51	21.9900	60,714.39	1,281.88
1,130.0000	GARTNER INC	50,277.98	123.5100	139,566.30	89,288.32

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1,313.0000	GENERAC HOLDINGS INC	42,725.02	36.1300	47,438.69	4,713.67
1,926.0000	GENERAL COMMUNICATION INC	28,716.66	36.6400	70,568.64	41,851.98
2,111.0000	GENERAL DYNAMICS CORP	151,989.04	198.1000	418,189.10	266,200.06
82,356.0000	GENERAL ELECTRIC CO	2,161,629.94	27.0100	2,224,435.56	62,805.62
5,613.0000	GENERAL MILLS INC	180,432.56	55.4000	310,960.20	130,527.64
14,256.0000	GENERAL MOTORS CO	466,178.97	34.9300	497,962.08	31,783.11
189.0000	GENESCO INC	9,642.78	33.9000	6,407.10	3,235.68-
331.0000	GENESEE & WYOMING INC	23,197.51	68.3900	22,637.09	560.42-
2,362.0000	GENTEX CORP	25,436.59	18.9700	44,807.14	19,370.55
1,248.0000	GENUINE PARTS CO	54,398.94	92.7600	115,764.48	61,365.54
327.0000	GENTHERM INC	5,310.48	38.8000	12,687.60	7,377.12
454.0000	GERBER SCIENTIFIC INC COM ESCROW	0.00	0.0000	0.00	0.00
2,087.0000	GETTY REALTY CORP	35,963.76	25.1000	52,383.70	16,419.94
457.0000	GIBRALTAR INDUSTRIES INC	4,958.45	35.6500	16,292.05	11,333.60
2,499.0000	GIGAMON INC	48,255.69	39.3500	98,335.65	50,079.96
13,238.0000	GILEAD SCIENCES INC	448,317.68	70.7800	936,985.64	488,667.96

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572.0000	GLACIER BANCORP INC	7,424.56	36.6100	20,940.92	13,516.36
2,235.0000	GLADSTONE COMMERCIAL CORP	33,068.33	21.7900	48,700.65	15,632.32
331.0000	PH GLATFELTER CO	4,981.55	19.5400	6,467.74	1,486.19
1,303.0000	GLOBAL PAYMENTS INC	31,314.75	90.3200	117,686.96	86,372.21
1,554.0000	GLOBUS MEDICAL INC	43,107.96	33.1500	51,515.10	8,407.14
8,248.0000	GOLD RESOURCE CORP	30,021.90	4.0800	33,651.84	3,629.94
3,310.0000	GOLDMAN SACHS GROUP INC/THE	562,941.96	221.9000	734,489.00	171,547.04
2,015.0000	GOODYEAR TIRE & RUBBER CO/THE	29,500.61	34.9600	70,444.40	40,943.79
2,490.0000	GOVERNMENT PROPERTIES INCOME T	42,180.60	18.3100	45,591.90	3,411.30
764.0000	WR GRACE & CO	29,746.94	72.0100	55,015.64	25,268.70
450.0000	GRACO INC	22,596.88	109.2800	49,176.00	26,579.12
12.0000	GRAHAM HOLDINGS CO	2,966.21	599.6500	7,195.80	4,229.59
584.0000	WW GRAINGER INC	120,407.38	180.5300	105,429.52	14,977.86-
2,878.0000	GRAMERCY PROPERTY TRUST	52,126.06	29.7100	85,505.38	33,379.32
209.0000	GRAND CANYON EDUCATION INC	4,817.45	78.4100	16,387.69	11,570.24
308.0000	GRANITE CONSTRUCTION INC	7,527.52	48.2400	14,857.92	7,330.40
2,476.0000	GRAPHIC PACKAGING HOLDING CO	23,992.56	13.7800	34,119.28	10,126.72

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1,175.0000	GREAT PLAINS ENERGY INC	22,865.50	29.2800	34,404.00	11,538.50
715.0000	GREEN DOT CORP	9,066.20	38.5300	27,548.95	18,482.75
485.0000	GREEN PLAINS INC	4,951.85	20.5500	9,966.75	5,014.90
249.0000	GREENBRIER COS INC/THE	4,932.69	46.2500	11,516.25	6,583.56
511.0000	GRIFFON CORP	4,997.58	21.9500	11,216.45	6,218.87
111.0000	GROUP 1 AUTOMOTIVE INC	4,362.30	63.3200	7,028.52	2,666.22
4,346.0000	GROUPON INC	23,081.50	3.8400	16,688.64	6,392.86-
1,396.0000	GRUBHUB INC	41,991.68	43.6000	60,865.60	18,873.92
522.0000	GUIDEWIRE SOFTWARE INC	29,613.06	68.7100	35,866.62	6,253.56
1,151.0000	GULFPORT ENERGY CORP	35,172.42	14.7500	16,977.25	18,195.17-
379.0000	H&E EQUIPMENT SERVICES INC	4,839.83	20.4100	7,735.39	2,895.56
3,075.0000	HCA HEALTHCARE INC	215,341.08	87.2000	268,140.00	52,798.92
3,935.0000	HCP INC	129,068.27	31.9600	125,762.60	3,305.67-
1,339.0000	HD SUPPLY HOLDINGS INC	40,677.96	30.6300	41,013.57	335.61
700.0000	HFF INC	9,604.00	34.7700	24,339.00	14,735.00
356.0000	HNI CORP	8,590.28	39.8700	14,193.72	5,603.44
2,171.0000	HRG GROUP INC	29,569.02	17.7100	38,448.41	8,879.39

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15,604.0000	HP INC	183,850.45	17.4800	272,757.92	88,907.47
1,307.0000	HAEMONETICS CORP	42,582.06	39.4900	51,613.43	9,031.37
680.0000	HAIN CELESTIAL GROUP INC/THE	14,843.02	38.8200	26,397.60	11,554.58
8,273.0000	HALLIBURTON CO	249,766.83	42.7100	353,339.83	103,573.00
758.0000	HALOZYME THERAPEUTICS INC	4,972.48	12.8200	9,717.56	4,745.08
352.0000	HALYARD HEALTH INC	7,654.28	39.2800	13,826.56	6,172.28
4,512.0000	HANESBRANDS INC	34,039.20	23.1600	104,497.92	70,458.72
595.0000	HANOVER INSURANCE GROUP INC/TH	24,926.93	88.6300	52,734.85	27,807.92
2,431.0000	HARLEY-DAVIDSON INC	122,339.29	54.0200	131,322.62	8,983.33
1,158.0000	HARRIS CORP	51,076.66	109.0800	126,314.64	75,237.98
4,007.0000	HARTFORD FINANCIAL SERVICES GR	102,705.16	52.5700	210,647.99	107,942.83
1,337.0000	HASBRO INC	57,750.59	111.5100	149,088.87	91,338.28
1,197.0000	HAWAIIAN ELECTRIC INDUSTRIES I	34,868.61	32.3800	38,758.86	3,890.25
879.0000	HAWAIIAN HOLDINGS INC	5,054.25	46.9500	41,269.05	36,214.80
251.0000	HAWAIIAN TELCOM HOLDCO INC	5,022.51	24.9900	6,272.49	1,249.98
941.0000	HEALTHCARE SERVICES GROUP INC	35,014.61	46.8300	44,067.03	9,052.42
756.0000	HEALTHSOUTH CORP	18,711.00	48.4000	36,590.40	17,879.40

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579.0000	HEALTHCARE REALTY TRUST INC	11,857.92	34.1500	19,772.85	7,914.93
435.0000	HEALTHSTREAM INC	9,922.35	26.3200	11,449.20	1,526.85
456.0000	HEALTHCARE TRUST OF AMERICA IN	10,177.92	31.1100	14,186.16	4,008.24
647.0000	HEICO CORP	17,639.81	71.8400	46,480.48	28,840.67
366.0000	HEIDRICK & STRUGGLES INTERNATI	4,933.68	21.7500	7,960.50	3,026.82
1,531.0000	HELMERICH & PAYNE INC	91,013.85	54.3400	83,194.54	7,819.31-
687.0000	JACK HENRY & ASSOCIATES INC	20,129.10	103.8700	71,358.69	51,229.59
209.0000	HERC HOLDINGS INC	8,467.47	39.3200	8,217.88	249.59-
905.0000	HERITAGE FINANCIAL CORP/WA	12,758.94	26.5000	23,982.50	11,223.56
741.0000	HERSHA HOSPITALITY TRUST	16,197.96	18.5100	13,715.91	2,482.05-
1,130.0000	HERSHEY CO/THE	88,700.10	107.3700	121,328.10	32,628.00
2,090.0000	HESS CORP	95,692.49	43.8700	91,688.30	4,004.19-
15,648.0000	HEWLETT PACKARD ENTERPRISE CO	156,720.59	16.5900	259,600.32	102,879.73
779.0000	HEXCEL CORP	16,335.63	52.7900	41,123.41	24,787.78
574.0000	HIGHWOODS PROPERTIES INC	18,620.56	50.7100	29,107.54	10,486.98
939.0000	HILL-ROM HOLDINGS INC	45,222.43	79.6100	74,753.79	29,531.36
268.0000	HILLENBRAND INC	6,362.32	36.1000	9,674.80	3,312.48

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215.0000	HILLTOP HOLDINGS INC	4,321.50	26.2100	5,635.15	1,313.65
1,945.0000	HILTON WORLDWIDE HOLDINGS INC	100,343.88	61.8500	120,298.25	19,954.37
1,499.0000	HOLLYFRONTIER CORP	45,866.90	27.4700	41,177.53	4,689.37-
2,246.0000	HOLOGIC INC	41,710.86	45.3800	101,923.48	60,212.62
1,387.0000	HOME BANCSHARES INC/AR	31,088.89	24.9000	34,536.30	3,447.41
10,016.0000	HOME DEPOT INC/THE	376,014.15	153.4000	1,536,454.40	1,160,440.25
351.0000	HOMESTREET INC	5,101.71	27.6750	9,713.93	4,612.22
1,850.0000	HOMETRUST BANCSHARES INC	34,632.00	24.4000	45,140.00	10,508.00
7,269.0000	HONEYWELL INTERNATIONAL INC	367,483.52	133.2900	968,885.01	601,401.49
331.0000	HORACE MANN EDUCATORS CORP	4,951.76	37.8000	12,511.80	7,560.04
2,267.0000	HORMEL FOODS CORP	65,745.10	34.1100	77,327.37	11,582.27
1,070.0000	HOSPITALITY PROPERTIES TRUST	23,775.40	29.1500	31,190.50	7,415.10
7,920.0000	HOST HOTELS & RESORTS INC	129,359.09	18.2700	144,698.40	15,339.31
308.0000	HOWARD HUGHES CORP/THE	36,144.32	122.8400	37,834.72	1,690.40
293.0000	HUB GROUP INC	10,600.74	38.3500	11,236.55	635.81
659.0000	HUBBELL INC	46,009.66	113.1700	74,579.03	28,569.37
1,470.0000	HUDSON PACIFIC PROPERTIES INC	42,262.50	34.1900	50,259.30	7,996.80

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1,441.0000	HUMANA INC	113,343.03	240.6200	346,733.42	233,390.39
727.0000	JB HUNT TRANSPORT SERVICES INC	33,238.44	91.3800	66,433.26	33,194.82
10,103.0000	HUNTINGTON BANCSHARES INC/OH	67,097.95	13.5200	136,592.56	69,494.61
434.0000	HUNTINGTON INGALLS INDUSTRIES	16,354.58	186.1600	80,793.44	64,438.86
1,660.0000	HUNTSMAN CORP	20,517.60	25.8400	42,894.40	22,376.80
165.0000	HURON CONSULTING GROUP INC	4,851.00	43.2000	7,128.00	2,277.00
352.0000	HYATT HOTELS CORP	13,819.52	56.2100	19,785.92	5,966.40
492.0000	IDT CORP	2,775.15	14.3700	7,070.04	4,294.89
523.0000	IAC/INTERACTIVECORP	31,664.49	103.2400	53,994.52	22,330.03
198.0000	ICF INTERNATIONAL INC	4,950.00	47.1000	9,325.80	4,375.80
1,066.0000	ILG INC	11,830.72	27.4900	29,304.34	17,473.62
202.0000	IPG PHOTONICS CORP	8,580.96	145.1000	29,310.20	20,729.24
2,669.0000	ISTAR INC	20,312.66	12.0400	32,134.76	11,822.10
732.0000	ITT INC	14,239.70	40.1800	29,411.76	15,172.06
174.0000	IBERIABANK CORP	9,824.04	81.5000	14,181.00	4,356.96
388.0000	IDACORP INC	18,620.12	85.3500	33,115.80	14,495.68
659.0000	IDEX CORP	28,666.50	113.0100	74,473.59	45,807.09

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778.0000	IDEXX LABORATORIES INC	30,505.88	161.4200	125,584.76	95,078.88
3,474.0000	ILLINOIS TOOL WORKS INC	156,597.15	143.2500	497,650.50	341,053.35
1,217.0000	ILLUMINA INC	194,451.86	173.5200	211,173.84	16,721.98
1,470.0000	INCYTE CORP	43,020.29	125.9100	185,087.70	142,067.41
2,271.0000	INDEPENDENCE HOLDING CO	36,795.88	20.4500	46,441.95	9,646.07
4,470.0000	INDEPENDENCE REALTY TRUST INC	35,985.74	9.8700	44,118.90	8,133.16
386.0000	INDEPENDENT BANK CORP/ROCKLAND	12,619.40	66.6500	25,726.90	13,107.50
831.0000	INFINERA CORP	5,476.29	10.6700	8,866.77	3,390.48
408.0000	INGEVITY CORP	7,393.99	57.4000	23,419.20	16,025.21
301.0000	INGLES MARKETS INC	4,809.98	33.3000	10,023.30	5,213.32
608.0000	INGREDION INC	29,897.31	119.2100	72,479.68	42,582.37
305.0000	INSIGHT ENTERPRISES INC	5,072.15	39.9900	12,196.95	7,124.80
1,258.0000	INPHI CORP	46,972.43	34.3000	43,149.40	3,823.03-
176.0000	INSPERITY INC	5,026.56	71.0000	12,496.00	7,469.44
245.0000	INSULET CORP	5,049.45	51.3100	12,570.95	7,521.50
1,344.0000	INTEGRA LIFESCIENCES HOLDINGS	42,994.56	54.5100	73,261.44	30,266.88
1,178.0000	INTEGRATED DEVICE TECHNOLOGY I	8,852.67	25.7900	30,380.62	21,527.95

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42,413.0000	INTEL CORP	950,753.06	33.7400	1,431,014.62	480,261.56
883.0000	INTER PARFUMS INC	29,156.66	36.6500	32,361.95	3,205.29
1,471.0000	INTERACTIVE BROKERS GROUP INC	24,094.98	37.4200	55,044.82	30,949.84
5,117.0000	INTERCONTINENTAL EXCHANGE INC	191,459.10	65.9200	337,312.64	145,853.54
800.0000	INTERDIGITAL INC/PA	42,344.00	77.3000	61,840.00	19,496.00
752.0000	INTERNATIONAL BANCSHARES CORP	16,765.34	35.0500	26,357.60	9,592.26
8,444.0000	INTERNATIONAL BUSINESS MACHINE	882,013.16	153.8300	1,298,940.52	416,927.36
555.0000	INTERNATIONAL FLAVORS & FRAGRA	22,017.41	135.0000	74,925.00	52,907.59
3,830.0000	INTERNATIONAL PAPER CO	133,043.07	56.6100	216,816.30	83,773.23
1,185.0000	INTERNATIONAL SPEEDWAY CORP	42,825.90	37.5500	44,496.75	1,670.85
4,603.0000	INTERPUBLIC GROUP OF COS INC/T	46,710.78	24.6000	113,233.80	66,523.02
363.0000	INTUITIVE SURGICAL INC	132,675.17	935.3700	339,539.31	206,864.14
2,564.0000	INTUIT INC	153,339.36	132.8100	340,524.84	187,185.48
4,058.0000	INVESTORS BANCORP INC	45,364.70	13.3600	54,214.88	8,850.18
1,326.0000	IONIS PHARMACEUTICALS INC	29,303.28	50.8700	67,453.62	38,150.34
7,929.0000	IRIDIUM COMMUNICATIONS INC	65,731.41	11.0500	87,615.45	21,884.04
1,274.0000	IROBOT CORP	42,284.06	84.1400	107,194.36	64,910.30

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1,851.0000	IRON MOUNTAIN INC	50,149.99	34.3600	63,600.36	13,450.37
3,455.0000	IRONWOOD PHARMACEUTICALS INC	42,807.45	18.8800	65,230.40	22,422.95
324.0000	ITRON INC	11,877.84	67.7500	21,951.00	10,073.16
64.0000	J ALEXANDER'S HOLDINGS INC	470.68	12.2500	784.00	313.32
34,507.0000	JPMORGAN CHASE & CO	1,593,905.53	91.4000	3,153,939.80	1,560,034.27
1,525.0000	JABIL INC	28,983.55	29.1900	44,514.75	15,531.20
350.0000	JACK IN THE BOX INC	10,024.00	98.5000	34,475.00	24,451.00
872.0000	JACOBS ENGINEERING GROUP INC	35,819.28	54.3900	47,428.08	11,608.80
4,035.0000	JETBLUE AIRWAYS CORP	24,492.45	22.8300	92,119.05	67,626.60
24,840.0000	JOHNSON & JOHNSON	1,965,930.38	132.2900	3,286,083.60	1,320,153.22
414.0000	JONES LANG LASALLE INC	35,541.97	125.0000	51,750.00	16,208.03
507.0000	J2 GLOBAL INC	14,786.94	85.0900	43,140.63	28,353.69
4,430.0000	JUNIPER NETWORKS INC	76,619.79	27.8800	123,508.40	46,888.61
940.0000	JUNO THERAPEUTICS INC	39,865.40	29.8900	28,096.60	11,768.80-
1,967.0000	KAR AUCTION SERVICES INC	75,848.79	41.9700	82,554.99	6,706.20
1,089.0000	KCG HOLDINGS INC	14,107.02	19.9400	21,714.66	7,607.64
1,471.0000	KLA-TENCOR CORP	67,343.46	91.5100	134,611.21	67,267.75

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277.0000	KLX INC	4,587.24	50.0000	13,850.00	9,262.76
130.0000	KAISER ALUMINUM CORP	6,880.90	88.5200	11,507.60	4,626.70
1,050.0000	KAMAN CORP	42,388.50	49.8700	52,363.50	9,975.00
1,350.0000	KANSAS CITY SOUTHERN	87,581.27	104.6500	141,277.50	53,696.23
646.0000	KAPSTONE PAPER AND PACKAGING C	5,151.85	20.6300	13,326.98	8,175.13
1,388.0000	KATE SPADE & CO	29,619.92	18.4900	25,664.12	3,955.80-
2,322.0000	KELLOGG CO	152,981.16	69.4600	161,286.12	8,304.96
302.0000	KELLY SERVICES INC	4,925.62	22.4500	6,779.90	1,854.28
713.0000	KEMPER CORP	20,151.16	38.6000	27,521.80	7,370.64
1,310.0000	KENNAMETAL INC	37,649.40	37.4200	49,020.20	11,370.80
1,430.0000	KENNEDY-WILSON HOLDINGS INC	35,306.70	19.0500	27,241.50	8,065.20-
7,736.0000	KEYCORP	79,449.96	18.7400	144,972.64	65,522.68
1,996.0000	KEYSIGHT TECHNOLOGIES INC	43,300.23	38.9300	77,704.28	34,404.05
465.0000	KILROY REALTY CORP	17,693.25	75.1500	34,944.75	17,251.50
2,901.0000	KIMBERLY-CLARK CORP	238,366.87	129.1100	374,548.11	136,181.24
3,838.0000	KIMCO REALTY CORP	90,020.66	18.3500	70,427.30	19,593.36-
15,420.0000	KINDER MORGAN INC/DE	342,115.30	19.1600	295,447.20	46,668.10-

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274.0000	KIRBY CORP	17,909.37	66.8500	18,316.90	407.53
515.0000	KITE PHARMA INC	37,255.10	103.6700	53,390.05	16,134.95
267.0000	KITE REALTY GROUP TRUST	4,891.44	18.9300	5,054.31	162.87
485.0000	KNIGHT TRANSPORTATION INC	7,827.90	37.0500	17,969.25	10,141.35
741.0000	KNOWLES CORP	11,611.84	16.9200	12,537.72	925.88
1,632.0000	KOHL'S CORP	75,407.50	38.6700	63,109.44	12,298.06-
374.0000	KORN/FERRY INTERNATIONAL	7,954.98	34.5300	12,914.22	4,959.24
5,618.0000	KRAFT HEINZ CO/THE	222,532.21	85.6400	481,125.52	258,593.31
1,748.0000	KRATOS DEFENSE & SECURITY SOLU	10,068.48	11.8700	20,748.76	10,680.28
489.0000	KRATON CORP	9,579.51	34.4400	16,841.16	7,261.65
9,608.0000	KROGER CO/THE	109,909.11	23.3200	224,058.56	114,149.45
2,201.0000	L BRANDS INC	64,442.37	53.8900	118,611.89	54,169.52
2,360.0000	LKQ CORP	70,493.20	32.9500	77,762.00	7,268.80
214.0000	LCI INDUSTRIES	4,981.92	102.4000	21,913.60	16,931.68
634.8750	LSC COMMUNICATIONS INC	15,218.25	21.4000	13,586.33	1,631.92-
777.0000	L3 TECHNOLOGIES INC	56,302.58	167.0800	129,821.16	73,518.58
515.0000	LA-Z-BOY INC	4,830.70	32.5000	16,737.50	11,906.80

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494.0000	LABORATORY CORP OF AMERICA HOL	47,962.80	154.1400	76,145.16	28,182.36
13,723.0000	LADENBURG THALMANN FINANCIAL S	26,465.45	2.4400	33,484.12	7,018.67
968.0000	LAKELAND BANCORP INC	8,630.79	18.8500	18,246.80	9,616.01
1,170.0000	LAKELAND FINANCIAL CORP	30,263.12	45.8800	53,679.60	23,416.48
1,269.0000	LAM RESEARCH CORP	31,132.80	141.4300	179,474.67	148,341.87
837.0000	LAMAR ADVERTISING CO	29,927.49	73.5700	61,578.09	31,650.60
1,223.0000	LAMB WESTON HOLDINGS INC	20,243.81	44.0400	53,860.92	33,617.11
151.0000	LANCASTER COLONY CORP	9,917.68	122.6200	18,515.62	8,597.94
381.0000	LANDSTAR SYSTEM INC	17,145.00	85.6000	32,613.60	15,468.60
3,744.0000	LAS VEGAS SANDS CORP	140,896.31	63.8900	239,204.16	98,307.85
677.0000	LASALLE HOTEL PROPERTIES	17,101.02	29.8000	20,174.60	3,073.58
2,103.0000	ESTEE LAUDER COS INC/THE	181,995.50	95.9800	201,845.94	19,850.44
900.0000	LEAR CORP	44,976.99	142.0800	127,872.00	82,895.01
1,136.0000	LEGGETT & PLATT INC	26,003.04	52.5300	59,674.08	33,671.04
472.0000	LEGACYTEXAS FINANCIAL GROUP IN	9,907.28	38.1300	17,997.36	8,090.08
783.0000	LEGG MASON INC	23,191.49	38.1600	29,879.28	6,687.79
2,055.0000	LEIDOS HOLDINGS INC	71,313.65	51.6900	106,222.95	34,909.30

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8,132.0000	LENDINGCLUB CORP	39,684.16	5.5100	44,807.32	5,123.16
1,519.0000	LENNAR CORP	57,752.38	53.3200	80,993.08	23,240.70
514.0000	LENNOX INTERNATIONAL INC	23,730.67	183.6400	94,390.96	70,660.29
2,549.0000	LEUCADIA NATIONAL CORP	51,969.04	26.1600	66,681.84	14,712.80
2,542.0000	LEVEL 3 COMMUNICATIONS INC	94,674.83	59.3000	150,740.60	56,065.77
2,338.0000	LEXINGTON REALTY TRUST	18,796.68	9.9100	23,169.58	4,372.90
336.0000	LIBBEY INC	4,952.64	8.0600	2,708.16	2,244.48-
744.0000	LIBERTY BROADBAND CORP	40,222.04	86.7500	64,542.00	24,319.96
434.0000	LIBERTY EXPEDIA HOLDINGS INC	5,286.79	54.0200	23,444.68	18,157.89
5,023.0000	LIBERTY INTERACTIVE CORP QVC G	59,266.05	24.5400	123,264.42	63,998.37
651.0000	LIBERTY VENTURES	6,798.82	52.2900	34,040.79	27,241.97
981.0000	LIBERTY PROPERTY TRUST	30,411.00	40.7100	39,936.51	9,525.51
2,305.0000	LIBERTY MEDIA CORP-LIBERTY SIR	68,974.69	41.9800	96,763.90	27,789.21
372.0000	LIBERTY TRIPADVISOR HOLDINGS I	3,403.72	11.6000	4,315.20	911.48
544.0000	LIFEPOINT HEALTH INC	20,410.88	67.1500	36,529.60	16,118.72
393.0000	LIGAND PHARMACEUTICALS INC	42,648.36	121.4000	47,710.20	5,061.84
44.0000	LIFE STORAGE INC	1,738.88	74.1000	3,260.40	1,521.52

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8,496.0000	ELI LILLY & CO	604,033.71	82.3000	699,220.80	95,187.09
622.0000	LINCOLN ELECTRIC HOLDINGS INC	32,375.10	92.0900	57,279.98	24,904.88
1,641.0000	LINCOLN NATIONAL CORP	47,432.78	67.5800	110,898.78	63,466.00
100.0000	LINDSAY CORP	6,217.00	89.2500	8,925.00	2,708.00
750.0000	LIONS GATE ENTERTAINMENT CORP	12,012.71	28.2200	21,165.00	9,152.29
750.0000	LIONS GATE ENTERTAINMENT CORP	11,612.29	26.2800	19,710.00	8,097.71
181.0000	LITTELFUSE INC	9,973.10	165.0000	29,865.00	19,891.90
1,122.0000	LIVE NATION ENTERTAINMENT INC	12,285.90	34.8500	39,101.70	26,815.80
1,936.0000	LOCKHEED MARTIN CORP	414,797.61	277.6100	537,452.96	122,655.35
2,415.0000	LOEWS CORP	90,779.85	46.8100	113,046.15	22,266.30
308.0000	LOGMEIN INC	17,598.68	104.5000	32,186.00	14,587.32
2,122.0000	LOUISIANA-PACIFIC CORP	36,880.36	24.1100	51,161.42	14,281.06
8,935.0000	LOWE'S COS INC	255,551.34	77.5300	692,730.55	437,179.21
1,049.0000	LULULEMON ATHLETICA INC	61,778.15	59.6700	62,593.83	815.68
1,959.0000	LUMINEX CORP	42,960.87	21.1200	41,374.08	1,586.79-
1,103.0000	M&T BANK CORP	98,970.42	161.9500	178,630.85	79,660.43
433.0000	MB FINANCIAL INC	8,227.00	44.0400	19,069.32	10,842.32

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313.0000	MDC HOLDINGS INC	7,607.39	35.3300	11,058.29	3,450.90
1,859.0000	MDU RESOURCES GROUP INC	38,865.53	26.2000	48,705.80	9,840.27
882.0000	MGE ENERGY INC	25,174.38	64.3500	56,756.70	31,582.32
2,020.0000	MGIC INVESTMENT CORP	10,140.40	11.2000	22,624.00	12,483.60
4,995.0000	MGM RESORTS INTERNATIONAL	82,648.50	31.2900	156,293.55	73,645.05
416.0000	MKS INSTRUMENTS INC	10,437.44	67.3000	27,996.80	17,559.36
2,850.0000	MRC GLOBAL INC	43,804.50	16.5200	47,082.00	3,277.50
138.0000	MSA SAFETY INC	4,854.84	81.1700	11,201.46	6,346.62
683.0000	MSC INDUSTRIAL DIRECT CO INC	42,352.83	85.9600	58,710.68	16,357.85
954.0000	MSCI INC	34,965.92	102.9900	98,252.46	63,286.54
215.0000	MYR GROUP INC	5,061.10	31.0200	6,669.30	1,608.20
1,121.0000	MACERICH CO/THE	47,622.50	58.0600	65,085.26	17,462.76
579.0000	MACQUARIE INFRASTRUCTURE CORP	46,209.99	78.4000	45,393.60	816.39-
3,242.0000	MACY'S INC	131,955.45	23.2400	75,344.08	56,611.37-
801.0000	STEVEN MADDEN LTD	20,138.70	39.9500	31,999.95	11,861.25
197.0000	MADISON SQUARE GARDEN CO/THE	35,010.84	196.9000	38,789.30	3,778.46
853.0000	MAGELLAN HEALTH INC	45,699.18	72.9000	62,183.70	16,484.52

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672.0000	MANHATTAN ASSOCIATES INC	9,881.76	48.0600	32,296.32	22,414.56
1,781.0000	MANITOWOC CO INC/THE	5,410.74	6.0100	10,703.81	5,293.07
656.0000	MANPOWERGROUP INC	31,605.26	111.6500	73,242.40	41,637.14
6,124.0000	MARATHON OIL CORP	77,242.88	11.8500	72,569.40	4,673.48-
4,394.0000	MARATHON PETROLEUM CORP	98,020.71	52.3300	229,938.02	131,917.31
513.0000	MARCUS CORP/THE	4,945.32	30.2000	15,492.60	10,547.28
88.0000	MARKEL CORP	41,099.80	975.8600	85,875.68	44,775.88
346.0000	MARKETAXESS HOLDINGS INC	27,960.82	201.1000	69,580.60	41,619.78
603.0000	MARRIOTT VACATIONS WORLDWIDE C	23,263.74	117.7500	71,003.25	47,739.51
4,993.0000	MARSH & MCLENNAN COS INC	169,404.52	77.9600	389,254.28	219,849.76
3,578.0000	MARRIOTT INTERNATIONAL INC/MD	169,300.00	100.3100	358,909.18	189,609.18
357.0000	MARTEN TRANSPORT LTD	4,971.82	27.4000	9,781.80	4,809.98
534.0000	MARTIN MARIETTA MATERIALS INC	56,225.19	222.5800	118,857.72	62,632.53
2,444.0000	MASCO CORP	29,183.68	38.2100	93,385.24	64,201.56
875.0000	MASIMO CORP	36,303.75	91.1800	79,782.50	43,478.75
639.0000	MASONITE INTERNATIONAL CORP	42,908.85	75.5000	48,244.50	5,335.65
450.0000	MASTEC INC	8,212.50	45.1500	20,317.50	12,105.00

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9,295.0000	MASTERCARD INC	384,005.68	121.4500	1,128,877.75	744,872.07
1,388.0000	MATADOR RESOURCES CO	27,801.64	21.3700	29,661.56	1,859.92
4,233.0000	MATTEL INC	97,883.43	21.5300	91,136.49	6,746.94-
2,344.0000	MAXIM INTEGRATED PRODUCTS INC	55,786.19	44.9000	105,245.60	49,459.41
1,228.0000	MAXLINEAR INC	10,794.12	27.8900	34,248.92	23,454.80
866.0000	MAXIMUS INC	20,860.81	62.6300	54,237.58	33,376.77
991.0000	MCCORMICK & CO INC/MD	66,800.36	97.5100	96,632.41	29,832.05
8,058.0000	MCDONALD'S CORP	523,100.41	153.1600	1,234,163.28	711,062.87
507.0000	MCGRATH RENTCORP	14,893.26	34.6300	17,557.41	2,664.15
1,823.0000	MCKESSON CORP	120,219.98	164.5400	299,956.42	179,736.44
1,533.0000	MEDICAL PROPERTIES TRUST INC	16,478.18	12.8700	19,729.71	3,251.53
741.0000	MEDICINES CO/THE	21,335.54	38.0100	28,165.41	6,829.87
340.0000	MEDIFAST INC	8,673.40	41.4700	14,099.80	5,426.40
498.0000	MEDIDATA SOLUTIONS INC	9,800.64	78.2000	38,943.60	29,142.96
1,246.0000	MEDNAX INC	60,891.60	60.3700	75,221.02	14,329.42
26,461.0000	MERCK & CO INC	1,179,784.64	64.0900	1,695,885.49	516,100.85
984.0000	MERIDIAN BANCORP INC	5,120.14	16.9000	16,629.60	11,509.46

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222.0000	MERITAGE HOMES CORP	5,072.70	42.2000	9,368.40	4,295.70
1,923.0000	MERITOR INC	9,634.23	16.6100	31,941.03	22,306.80
8,710.0000	METLIFE INC	422,514.02	54.9400	478,527.40	56,013.38
324.0000	METTLER-TOLEDO INTERNATIONAL I	59,209.59	588.5400	190,686.96	131,477.37
66,345.0000	MICROSOFT CORP	2,371,900.97	68.9300	4,573,160.85	2,201,259.88
1,592.0000	MICROCHIP TECHNOLOGY INC	57,217.17	77.1800	122,870.56	65,653.39
8,354.0000	MICRON TECHNOLOGY INC	90,927.98	29.8600	249,450.44	158,522.46
799.0000	MICROSEMI CORP	16,941.74	46.8000	37,393.20	20,451.46
910.0000	MID-AMERICA APARTMENT COMMUNIT	57,792.80	105.3800	95,895.80	38,103.00
444.0000	MIDDLEBY CORP/THE	13,485.76	121.5100	53,950.44	40,464.68
255.0000	MIDDLESEX WATER CO	4,924.05	39.6000	10,098.00	5,173.95
1,105.0000	HERMAN MILLER INC	35,415.25	30.4000	33,592.00	1,823.25-
152.0000	MINERALS TECHNOLOGIES INC	4,883.76	73.2000	11,126.40	6,242.64
250.0000	MOBILE MINI INC	5,067.50	29.8500	7,462.50	2,395.00
453.0000	MOHAWK INDUSTRIES INC	25,830.06	241.6900	109,485.57	83,655.51
191.0000	MOLINA HEALTHCARE INC	4,935.44	69.1800	13,213.38	8,277.94
1,485.0000	MOLSON COORS BREWING CO	106,881.89	86.3400	128,214.90	21,333.01

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12,740.0000	MONDELEZ INTERNATIONAL INC	234,767.37	43.1900	550,240.60	315,473.23
3,367.0000	MONMOUTH REAL ESTATE INVESTMEN	35,589.19	15.0500	50,673.35	15,084.16
3,170.0000	MONOGRAM RESIDENTIAL TRUST INC	29,924.80	9.7100	30,780.70	855.90
345.0000	MONOLITHIC POWER SYSTEMS INC	5,226.75	96.4000	33,258.00	28,031.25
366.0000	MONOTYPE IMAGING HOLDINGS INC	5,025.18	18.3000	6,697.80	1,672.62
242.0000	MONRO MUFFLER BRAKE INC	8,252.20	41.7500	10,103.50	1,851.30
4,427.0000	MONSANTO CO	265,626.58	118.3600	523,979.72	258,353.14
4,545.0000	MONSTER BEVERAGE CORP	161,909.39	49.6800	225,795.60	63,886.21
1,919.0000	MOODY'S CORP	139,499.69	121.6800	233,503.92	94,004.23
360.0000	MOOG INC	14,846.40	71.7200	25,819.20	10,972.80
11,891.0000	MORGAN STANLEY	295,631.20	44.5600	529,862.96	234,231.76
3,122.0000	MOSAIC CO/THE	103,043.64	22.8300	71,275.26	31,768.38-
1,371.0000	MOTOROLA SOLUTIONS INC	96,984.54	86.7400	118,920.54	21,936.00
600.0000	MUELLER INDUSTRIES INC	10,908.00	30.4500	18,270.00	7,362.00
1,824.0000	MUELLER WATER PRODUCTS INC	10,086.72	11.6800	21,304.32	11,217.60
2,183.0000	MURPHY OIL CORP	39,839.75	25.6300	55,950.29	16,110.54
399.0000	MURPHY USA INC	11,529.40	74.1100	29,569.89	18,040.49

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273.0000	NBT BANCORP INC	5,978.70	36.9500	10,087.35	4,108.65
449.0000	NCI BUILDING SYSTEMS INC	4,992.88	16.7000	7,498.30	2,505.42
1,929.0000	NCR CORP	40,041.90	40.8400	78,780.36	38,738.46
441.0000	NIC INC	5,538.96	18.9500	8,356.95	2,817.99
3,910.0000	NRG ENERGY INC	38,748.10	17.2200	67,330.20	28,582.10
2,738.0000	NRG YIELD INC	41,042.62	17.6000	48,188.80	7,146.18
43.0000	NVR INC	33,133.78	2,410.6100	103,656.23	70,522.45
849.0000	NASDAQ INC	28,080.68	71.4900	60,695.01	32,614.33
1,204.0000	NATIONAL BANKSHARES INC	41,056.40	40.8000	49,123.20	8,066.80
806.0000	NATIONAL FUEL GAS CO	41,194.66	55.8400	45,007.04	3,812.38
698.0000	NATIONAL HEALTH INVESTORS INC	42,591.96	79.2000	55,281.60	12,689.64
1,150.0000	NATIONAL INSTRUMENTS CORP	35,339.50	40.2200	46,253.00	10,913.50
4,080.0000	NATIONAL OILWELL VARCO INC	144,629.66	32.9400	134,395.20	10,234.46-
675.0000	NATIONAL RETAIL PROPERTIES INC	16,395.75	39.1000	26,392.50	9,996.75
1,979.0000	NATIONAL STORAGE AFFILIATES TR	40,549.71	23.1100	45,734.69	5,184.98
84.0000	NATIONAL WESTERN LIFE GROUP IN	13,623.84	319.6200	26,848.08	13,224.24
398.0000	NAVIGATORS GROUP INC/THE	9,843.61	54.9000	21,850.20	12,006.59

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507.0000	NAVIGANT CONSULTING INC	5,070.00	19.7600	10,018.32	4,948.32
3,438.0000	NAVIENT CORP	35,481.33	16.6500	57,242.70	21,761.37
710.0000	NEENAH PAPER INC	46,746.40	80.2500	56,977.50	10,231.10
1,887.0000	NEKTAR THERAPEUTICS	10,001.10	19.5500	36,890.85	26,889.75
233.0000	NELNET INC	5,039.79	47.0100	10,953.33	5,913.54
325.0000	NEOGEN CORP	9,949.33	69.1100	22,460.75	12,511.42
2,435.0000	NETAPP INC	83,713.01	40.0500	97,521.75	13,808.74
3,692.0000	NETFLIX INC	352,029.76	149.4100	551,621.72	199,591.96
846.0000	NETGEAR INC	35,811.18	43.1000	36,462.60	651.42
1,022.0000	NETSCOUT SYSTEMS INC	30,807.92	34.4000	35,156.80	4,348.88
692.0000	NEUROCRINE BIOSCIENCES INC	5,217.68	46.0000	31,832.00	26,614.32
230.0000	NEW JERSEY RESOURCES CORP	4,991.00	39.7000	9,131.00	4,140.00
3,314.0000	NEW RESIDENTIAL INVESTMENT COR	41,425.00	15.5600	51,565.84	10,140.84
4,462.0000	NEW YORK COMMUNITY BANCORP INC	58,425.80	13.1300	58,586.06	160.26
4,138.0000	NEWELL BRANDS INC	100,476.79	53.6200	221,879.56	121,402.77
1,765.0000	NEWFIELD EXPLORATION CO	65,704.29	28.4600	50,231.90	15,472.39-
89.0000	NEWMARKET CORP	35,158.56	460.4800	40,982.72	5,824.16

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4,311.0000	NEWMONT MINING CORP	87,263.90	32.3900	139,633.29	52,369.39
3,768.0000	NEWS CORP	33,421.54	13.7000	51,621.60	18,200.06
4,096.0000	NEXTERA ENERGY INC	228,858.38	140.1300	573,972.48	345,114.10
3,089.0000	NEXPOINT RESIDENTIAL TRUST INC	38,581.61	24.8900	76,885.21	38,303.60
11,672.0000	NIKE INC	452,324.52	59.0000	688,648.00	236,323.48
2,218.0000	NISOURCE INC	17,902.28	25.3600	56,248.48	38,346.20
4,552.0000	NOBLE ENERGY INC	165,882.50	28.3000	128,821.60	37,060.90-
492.0000	NORDSON CORP	33,197.16	121.3200	59,689.44	26,492.28
1,487.0000	NORDSTROM INC	66,306.19	47.8300	71,123.21	4,817.02
2,804.0000	NORFOLK SOUTHERN CORP	121,256.74	121.7000	341,246.80	219,990.06
1,810.0000	NORTHERN TRUST CORP	122,412.80	97.2100	175,950.10	53,537.30
2,288.0000	NORTHFIELD BANCORP INC	32,710.21	17.1500	39,239.20	6,528.99
2,180.0000	NORTHROP GRUMMAN CORP	134,983.14	256.7100	559,627.80	424,644.66
4,286.0000	NORTHSTAR REALTY EUROPE CORP	43,419.21	12.6800	54,346.48	10,927.27
843.0000	NORTHWEST BANCSHARES INC	10,242.45	15.6100	13,159.23	2,916.78
773.0000	NORTHWESTERN CORP	42,344.94	61.0200	47,168.46	4,823.52
644.0000	NOW INC	11,913.40	16.0800	10,355.52	1,557.88-

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435.0000	NU SKIN ENTERPRISES INC	15,712.20	62.8400	27,335.40	11,623.20
2,066.0000	NUANCE COMMUNICATIONS INC	34,900.60	17.4100	35,969.06	1,068.46
3,441.0000	NUCOR CORP	147,743.77	57.8700	199,130.67	51,386.90
5,434.0000	NVIDIA CORP	161,117.19	144.5600	785,539.04	624,421.85
743.0000	NUVASIVE INC	36,726.49	76.9200	57,151.56	20,425.07
1,725.0000	OGE ENERGY CORP	46,773.84	34.7900	60,012.75	13,238.91
756.0000	O'REILLY AUTOMOTIVE INC	203,904.91	218.7400	165,367.44	38,537.47-
3,668.0000	OASIS PETROLEUM INC	41,668.48	8.0500	29,527.40	12,141.08-
7,142.0000	OCCIDENTAL PETROLEUM CORP	377,118.88	59.8700	427,591.54	50,472.66
652.0000	OCEANFIRST FINANCIAL CORP	8,482.52	27.1200	17,682.24	9,199.72
3,779.0000	OFFICE DEPOT INC	9,919.13	5.6400	21,313.56	11,394.43
585.0000	OIL STATES INTERNATIONAL INC	17,144.57	27.1500	15,882.75	1,261.82-
565.0000	OLD DOMINION FREIGHT LINE INC	13,612.73	95.2400	53,810.60	40,197.87
752.0000	OLD NATIONAL BANCORP/IN	7,753.12	17.2500	12,972.00	5,218.88
2,060.0000	OLD REPUBLIC INTERNATIONAL COR	25,865.97	19.5300	40,231.80	14,365.83
2,470.0000	OLIN CORP	53,287.95	30.2800	74,791.60	21,503.65
2,430.0000	OMNICOM GROUP INC	113,723.75	82.9000	201,447.00	87,723.25

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1,187.0000	OMEGA HEALTHCARE INVESTORS INC	29,493.00	33.0200	39,194.74	9,701.74
974.0000	OMEGA PROTEIN CORP	6,447.88	17.9000	17,434.60	10,986.72
504.0000	ON ASSIGNMENT INC	9,843.12	54.1500	27,291.60	17,448.48
3,187.0000	ON SEMICONDUCTOR CORP	27,862.53	14.0400	44,745.48	16,882.95
488.0000	ONE GAS INC	7,459.70	69.8100	34,067.28	26,607.58
316.0000	ONE LIBERTY PROPERTIES INC	4,964.36	23.4300	7,403.88	2,439.52
1,949.0000	ONEOK INC	52,783.11	52.1600	101,659.84	48,876.73
5,126.0000	OPKO HEALTH INC	45,667.80	6.5800	33,729.08	11,938.72-
29,461.0000	ORACLE CORP	597,146.59	50.1400	1,477,174.54	880,027.95
696.0000	ORBITAL ATK INC	48,344.59	98.3600	68,458.56	20,113.97
446.0000	ORITANI FINANCIAL CORP	5,646.36	17.0500	7,604.30	1,957.94
220.0000	ORMAT TECHNOLOGIES INC	4,802.60	58.6800	12,909.60	8,107.00
1,107.0000	OSHKOSH CORP	23,667.66	68.8800	76,250.16	52,582.50
1,277.0000	OTTER TAIL CORP	35,347.36	39.6000	50,569.20	15,221.84
1,845.0000	OUTFRONT MEDIA INC	42,693.30	23.1200	42,656.40	36.90-
1,446.0000	OWENS CORNING	40,919.94	66.9200	96,766.32	55,846.38
155.0000	OXFORD INDUSTRIES INC	5,068.50	62.4900	9,685.95	4,617.45

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1,031.0000	PBF ENERGY INC	35,538.57	22.2600	22,950.06	12,588.51-
1,272.0000	PDC ENERGY INC	60,614.14	43.1100	54,835.92	5,778.22-
4,482.0000	PG&E CORP	239,585.96	66.3700	297,470.34	57,884.38
3,542.0000	PNC FINANCIAL SERVICES GROUP I	264,818.82	124.8700	442,289.54	177,470.72
1,656.0000	PNM RESOURCES INC	40,561.08	38.2500	63,342.00	22,780.92
2,527.0000	PPG INDUSTRIES INC	168,328.57	109.9600	277,868.92	109,540.35
6,357.0000	PPL CORP	199,381.35	38.6600	245,761.62	46,380.27
1,133.0000	PRA GROUP INC	34,779.63	37.9000	42,940.70	8,161.07
193.0000	PS BUSINESS PARKS INC	9,588.24	132.3900	25,551.27	15,963.03
676.0000	PVH CORP	52,279.52	114.5000	77,402.00	25,122.48
946.0000	PTC INC	21,587.72	55.1200	52,143.52	30,555.80
3,671.0000	PACCAR INC	149,774.67	66.0400	242,432.84	92,658.17
3,921.0000	PACIFIC BIOSCIENCES OF CALIFOR	10,508.28	3.5600	13,958.76	3,450.48
752.0000	PACIRA PHARMACEUTICALS INC/DE	12,791.52	47.7000	35,870.40	23,078.88
863.0000	PACKAGING CORP OF AMERICA	22,248.14	111.3900	96,129.57	73,881.43
981.0000	PACWEST BANCORP	21,041.46	46.7000	45,812.70	24,771.24
885.0000	PALO ALTO NETWORKS INC	112,588.15	133.8100	118,421.85	5,833.70

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3,261.0000	PANDORA MEDIA INC	43,099.11	8.9200	29,088.12	14,010.99-
197.0000	PANERA BREAD CO	31,222.20	314.6400	61,984.08	30,761.88
1,972.0000	PARAMOUNT GROUP INC	36,087.60	16.0000	31,552.00	4,535.60-
801.0000	PAREXEL INTERNATIONAL CORP	20,278.45	86.9100	69,614.91	49,336.46
1,262.0000	PARK HOTELS & RESORTS INC	33,620.25	26.9600	34,023.52	403.27
340.0000	PARK NATIONAL CORP	21,654.60	103.7200	35,264.80	13,610.20
253.0000	PARK-OHIO HOLDINGS CORP	5,039.76	38.1000	9,639.30	4,599.54
3,185.0000	PARK STERLING CORP	14,844.16	11.8800	37,837.80	22,993.64
1,413.0000	PARKER-HANNIFIN CORP	93,345.65	159.8200	225,825.66	132,480.01
480.2110	PARKWAY INC	10,924.80	22.8900	10,992.03	67.23
3,550.0000	PARSLEY ENERGY INC	79,693.32	27.7500	98,512.50	18,819.18
820.0000	PATTERSON COS INC	25,953.00	46.9500	38,499.00	12,546.00
2,199.0000	PATTERSON-UTI ENERGY INC	39,559.41	20.1900	44,397.81	4,838.40
3,206.0000	PAYCHEX INC	111,863.41	56.9400	182,549.64	70,686.23
11,296.0000	PAYPAL HOLDINGS INC	254,660.58	53.6700	606,256.32	351,595.74
432.0000	PEBBLEBROOK HOTEL TRUST	9,789.12	32.2400	13,927.68	4,138.56
539.0000	PENN NATIONAL GAMING INC	4,585.97	21.4000	11,534.60	6,948.63

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5,734.0000	JC PENNEY CO INC	51,026.68	4.6500	26,663.10	24,363.58-
677.0000	PENNSYLVANIA REAL ESTATE INVES	11,923.01	11.3200	7,663.64	4,259.37-
354.0000	PENSKE AUTOMOTIVE GROUP INC	7,625.16	43.9100	15,544.14	7,918.98
1,675.0000	PEOPLE'S UNITED FINANCIAL INC	21,369.72	17.6600	29,580.50	8,210.78
12,635.0000	PEPSICO INC	996,457.91	115.4900	1,459,216.15	462,758.24
773.0000	PERKINELMER INC	26,065.00	68.1400	52,672.22	26,607.22
51,011.0000	PFIZER INC	1,536,417.44	33.5900	1,713,459.49	177,042.05
395.0000	PHARMERICA CORP	5,186.35	26.2500	10,368.75	5,182.40
14,342.0000	PHILIP MORRIS INTERNATIONAL IN	746,386.62	117.4500	1,684,467.90	938,081.28
4,742.0000	PHILLIPS 66	178,349.72	82.6900	392,115.98	213,766.26
2,251.0000	PHYSICIANS REALTY TRUST	47,940.04	20.1400	45,335.14	2,604.90-
2,163.0000	PIEDMONT OFFICE REALTY TRUST I	42,675.99	21.0800	45,596.04	2,920.05
322.0000	PINNACLE FINANCIAL PARTNERS IN	4,842.88	62.8000	20,221.60	15,378.72
795.0000	PINNACLE FOODS INC	34,685.85	59.4000	47,223.00	12,537.15
1,289.0000	PINNACLE ENTERTAINMENT INC	15,486.97	19.7600	25,470.64	9,983.67
1,117.0000	PINNACLE WEST CAPITAL CORP	60,274.75	85.1600	95,123.72	34,848.97
1,435.0000	PIONEER NATURAL RESOURCES CO	189,798.38	159.5800	228,997.30	39,198.92

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172.0000	PIPER JAFFRAY COS	4,819.44	59.9500	10,311.40	5,491.96
1,697.0000	PITNEY BOWES INC	26,804.99	15.1000	25,624.70	1,180.29-
382.0000	PLANTRONICS INC	13,331.80	52.3100	19,982.42	6,650.62
9,708.0000	PLATFORM SPECIALTY PRODUCTS CO	97,113.00	12.6800	123,097.44	25,984.44
298.0000	PLEXUS CORP	9,506.20	52.5700	15,665.86	6,159.66
695.0000	POLARIS INDUSTRIES INC	42,382.78	92.2300	64,099.85	21,717.07
1,242.0000	POLYONE CORP	20,837.56	38.7400	48,115.08	27,277.52
382.0000	POOL CORP	10,948.12	117.5700	44,911.74	33,963.62
645.0000	POPULAR INC	10,042.65	41.7100	26,902.95	16,860.30
1,280.0000	PORTLAND GENERAL ELECTRIC CO	45,493.20	45.6900	58,483.20	12,990.00
545.0000	POST HOLDINGS INC	33,672.94	77.6500	42,319.25	8,646.31
1,123.0000	POTLATCH CORP	36,973.38	45.7000	51,321.10	14,347.72
229.0000	POWER INTEGRATIONS INC	8,408.88	72.9000	16,694.10	8,285.22
2,785.0000	PRAXAIR INC	221,565.89	132.5500	369,151.75	147,585.86
878.0000	PREFERRED BANK/LOS ANGELES CA	26,866.80	53.4700	46,946.66	20,079.86
2,916.0000	PREFERRED APARTMENT COMMUNITIE	32,693.61	15.7500	45,927.00	13,233.39
1,227.0000	PREMIER INC	42,503.28	36.0000	44,172.00	1,668.72

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411.0000	PRESTIGE BRANDS HOLDINGS INC	4,960.77	52.8100	21,704.91	16,744.14
2,501.0000	T ROWE PRICE GROUP INC	119,183.16	74.2100	185,599.21	66,416.05
448.0000	PRICELINE GROUP INC/THE	246,639.12	1,870.5200	837,992.96	591,353.84
107.0000	PRICESMART INC	5,056.82	87.6000	9,373.20	4,316.38
1,826.0000	PRIMORIS SERVICES CORP	43,466.47	24.9400	45,540.44	2,073.97
865.0000	PRIMERICA INC	44,720.50	75.7500	65,523.75	20,803.25
3,766.0000	PRIMO WATER CORP	40,074.01	12.7000	47,828.20	7,754.19
1,646.0000	PRINCIPAL FINANCIAL GROUP INC	51,710.74	64.0700	105,459.22	53,748.48
484.0000	PROASSURANCE CORP	16,845.62	60.8000	29,427.20	12,581.58
24,843.0000	PROCTER & GAMBLE CO/THE	1,718,956.97	87.1500	2,165,067.45	446,110.48
5,850.0000	PROGRESSIVE CORP/THE	173,247.87	44.0900	257,926.50	84,678.63
5,085.0000	PROLOGIS INC	184,797.37	58.6400	298,184.40	113,387.03
544.0000	PROOFPOINT INC	46,560.96	86.8300	47,235.52	674.56
613.0000	PROS HOLDINGS INC	9,814.13	27.3900	16,790.07	6,975.94
372.0000	PROSPERITY BANCSHARES INC	15,791.40	64.2400	23,897.28	8,105.88
480.0000	PROVIDENT FINANCIAL SERVICES I	6,628.80	25.3800	12,182.40	5,553.60
4,212.0000	PRUDENTIAL FINANCIAL INC	333,967.77	108.1400	455,485.68	121,517.91

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4,296.0000	PUBLIC SERVICE ENTERPRISE GROU	132,634.02	43.0100	184,770.96	52,136.94
1,286.0000	PUBLIC STORAGE	155,707.75	208.5300	268,169.58	112,461.83
2,828.0000	PULTEGROUP INC	52,675.64	24.5300	69,370.84	16,695.20
932.0000	PZENA INVESTMENT MANAGEMENT IN	5,070.08	10.1600	9,469.12	4,399.04
122.0000	QUAKER CHEMICAL CORP	4,941.00	145.2300	17,718.06	12,777.06
2,267.0000	QEP RESOURCES INC	36,974.77	10.1000	22,896.70	14,078.07-
912.0000	QTS REALTY TRUST INC	47,889.12	52.3300	47,724.96	164.16-
1,464.0000	QORVO INC	50,842.25	63.3200	92,700.48	41,858.23
3,086.0000	Q2 HOLDINGS INC	110,962.13	36.9500	114,027.70	3,065.57
14,769.0000	QUALCOMM INC	583,618.60	55.2200	815,544.18	231,925.58
787.0000	QUALITY CARE PROPERTIES INC	24,278.95	18.3100	14,409.97	9,868.98-
781.0000	QUALYS INC	28,037.90	40.8000	31,864.80	3,826.90
7,522.0000	QUALITY SYSTEMS INC	114,828.33	17.2100	129,453.62	14,625.29
1,822.0000	QUANTA SERVICES INC	42,147.42	32.9200	59,980.24	17,832.82
1,257.0000	QUEST DIAGNOSTICS INC	87,181.07	111.1600	139,728.12	52,547.05
1,044.2080	QUINTILES IMS HOLDINGS INC	71,802.72	89.5000	93,456.62	21,653.90
576.0000	RLI CORP	35,164.80	54.6200	31,461.12	3,703.68-

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735.0000	RLJ LODGING TRUST	14,928.20	19.8700	14,604.45	323.75-
322.0000	RPC INC	4,840.73	20.2100	6,507.62	1,666.89
77.0000	RMR GROUP INC/THE	1,001.00	48.6500	3,746.05	2,745.05
1,036.0000	RPM INTERNATIONAL INC	23,133.88	54.5500	56,513.80	33,379.92
1,813.0000	RSP PERMIAN INC	51,989.05	32.2700	58,505.51	6,516.46
2,609.0000	RADIAN GROUP INC	38,600.11	16.3500	42,657.15	4,057.04
971.0000	RAMBUS INC	7,360.18	11.4300	11,098.53	3,738.35
465.0000	RALPH LAUREN CORP	38,908.88	73.8000	34,317.00	4,591.88-
1,081.0000	RAMCO-GERSHENSON PROPERTIES TR	14,977.65	12.9000	13,944.90	1,032.75-
2,115.0000	RANGE RESOURCES CORP	76,456.73	23.1700	49,004.55	27,452.18-
1,428.0000	RAYMOND JAMES FINANCIAL INC	60,409.74	80.2200	114,554.16	54,144.42
1,548.0000	RAYONIER INC	36,703.08	28.7700	44,535.96	7,832.88
2,827.0000	RAYTHEON CO	135,852.04	161.4800	456,503.96	320,651.92
130.0000	RBC BEARINGS INC	4,838.60	101.7600	13,228.80	8,390.20
2,167.0000	REALTY INCOME CORP	87,676.21	55.1800	119,575.06	31,898.85
1,914.0000	RED HAT INC	137,284.25	95.7500	183,265.50	45,981.25
307.0000	REGAL BELOIT CORP	19,519.06	81.5500	25,035.85	5,516.79

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643.0000	REGAL ENTERTAINMENT GROUP	7,580.97	20.4600	13,155.78	5,574.81
708.0000	REGENCY CENTERS CORP	29,098.80	62.6400	44,349.12	15,250.32
669.0000	REGENERON PHARMACEUTICALS INC	109,482.60	491.1400	328,572.66	219,090.06
12,655.0000	REGIONS FINANCIAL CORP	96,409.40	14.6400	185,269.20	88,859.80
547.0000	REINSURANCE GROUP OF AMERICA I	29,417.66	128.3900	70,229.33	40,811.67
594.0000	RELIANCE STEEL & ALUMINUM CO	29,736.92	72.8100	43,249.14	13,512.22
415.0000	RENASANT CORP	6,102.92	43.7400	18,152.10	12,049.18
2,681.0000	REPUBLIC SERVICES INC	66,865.64	63.7300	170,860.13	103,994.49
1,215.0000	RESMED INC	37,659.58	77.8700	94,612.05	56,952.47
418.0000	RESOURCES CONNECTION INC	5,082.88	13.7000	5,726.60	643.72
393.0000	RETAIL OPPORTUNITY INVESTMENTS	5,144.37	19.1900	7,541.67	2,397.30
2,342.0000	RETAIL PROPERTIES OF AMERICA I	35,856.02	12.2100	28,595.82	7,260.20-
471.0000	REXNORD CORP	9,989.91	23.2500	10,950.75	960.84
7,088.0000	REYNOLDS AMERICAN INC	223,657.18	65.0400	461,003.52	237,346.34
1,947.0000	RICE ENERGY INC	46,995.84	26.6300	51,848.61	4,852.77
3,861.0000	RIGEL PHARMACEUTICALS INC	9,999.99	2.7300	10,540.53	540.54
2,219.0000	RINGCENTRAL INC	33,418.14	36.5500	81,104.45	47,686.31

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3,977.0000	RING ENERGY INC	47,206.42	13.0000	51,701.00	4,494.58
1,166.0000	ROBERT HALF INTERNATIONAL INC	34,465.11	47.9300	55,886.38	21,421.27
1,153.0000	ROCKWELL AUTOMATION INC	66,115.55	161.9600	186,739.88	120,624.33
1,106.0000	ROCKWELL COLLINS INC	61,106.38	105.0800	116,218.48	55,112.10
110.0000	ROGERS CORP	4,951.10	108.6200	11,948.20	6,997.10
931.0000	ROLLINS INC	22,853.82	40.7100	37,901.01	15,047.19
3,978.0000	ROSS STORES INC	194,450.14	57.7300	229,649.94	35,199.80
631.0000	ROYAL GOLD INC	33,368.94	78.1700	49,325.27	15,956.33
275.0000	RUSH ENTERPRISES INC	5,049.00	37.1800	10,224.50	5,175.50
2,444.0000	RUTH'S HOSPITALITY GROUP INC	41,841.28	21.7500	53,157.00	11,315.72
408.0000	RYDER SYSTEM INC	21,356.64	71.9800	29,367.84	8,011.20
602.0000	RYMAN HOSPITALITY PROPERTIES I	19,685.50	64.0100	38,534.02	18,848.52
281.0000	S&T BANCORP INC	4,979.32	35.8600	10,076.66	5,097.34
2,545.0000	S&P GLOBAL INC	201,216.05	145.9900	371,544.55	170,328.50
1,131.0000	SBA COMMUNICATIONS CORP	50,146.35	134.9000	152,571.90	102,425.55
1,672.0000	SEI INVESTMENTS CO	50,149.42	53.7800	89,920.16	39,770.74
172.0000	SEACOR MARINE HOLDINGS INC	4,355.06	20.3600	3,501.92	853.14-

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987.0000	SL GREEN REALTY CORP	59,076.86	105.8000	104,424.60	45,347.74
3,438.0000	SLM CORP	19,830.04	11.5000	39,537.00	19,706.96
279.0000	SPS COMMERCE INC	10,041.21	63.7600	17,789.04	7,747.83
1,082.0000	SS&C TECHNOLOGIES HOLDINGS INC	25,371.84	38.4100	41,559.62	16,187.78
244.0000	SP PLUS CORP	4,953.20	30.5500	7,454.20	2,501.00
340.0000	SVB FINANCIAL GROUP	19,485.40	175.7900	59,768.60	40,283.20
615.0000	SABRA HEALTH CARE REIT INC	10,239.75	24.1000	14,821.50	4,581.75
1,186.0000	SAFEWAY CASA LEY CVR	1,203.67	1.0100	1,197.86	5.81-
1,186.0000	SAFEWAY PDC LLC CVR	37.72	0.0300	35.58	2.14-
264.0000	SAFEGUARD SCIENTIFICS INC	4,823.28	11.9000	3,141.60	1,681.68-
495.0000	SAFETY INSURANCE GROUP INC	29,328.75	68.3000	33,808.50	4,479.75
571.0000	SAGE THERAPEUTICS INC	46,256.71	79.6400	45,474.44	782.27-
168.0000	SAIA INC	1,733.76	51.3000	8,618.40	6,884.64
6,100.0000	SALESFORCE.COM INC	316,447.64	86.6000	528,260.00	211,812.36
1,779.0000	SALLY BEAUTY HOLDINGS INC	37,236.72	20.2500	36,024.75	1,211.97-
175.0000	SANDERSON FARMS INC	8,447.25	115.6500	20,238.75	11,791.50
276.0000	SANDY SPRING BANCORP INC	4,832.76	40.6600	11,222.16	6,389.40

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639.0000	SANMINA CORP	5,923.53	38.1000	24,345.90	18,422.37
130.0000	SAUL CENTERS INC	4,982.90	57.9800	7,537.40	2,554.50
1,148.0000	SCANA CORP	39,069.76	67.0100	76,927.48	37,857.72
1,016.0000	SCANSOURCE INC	37,662.20	40.3000	40,944.80	3,282.60
730.0000	HENRY SCHEIN INC	48,438.50	183.0200	133,604.60	85,166.10
13,199.0000	SCHLUMBERGER LTD	845,761.50	65.8400	869,022.16	23,260.66
202.0000	A SCHULMAN INC	4,951.02	32.0000	6,464.00	1,512.98
10,451.0000	CHARLES SCHWAB CORP/THE	204,285.43	42.9600	448,974.96	244,689.53
190.0000	SCHWEITZER-MAUDUIT INTERNATION	5,102.45	37.2300	7,073.70	1,971.25
165.0000	SCIENCE APPLICATIONS INTERNATI	4,839.30	69.4200	11,454.30	6,615.00
604.0000	SCOTTS MIRACLE-GRO CO/THE	42,563.88	89.4600	54,033.84	11,469.96
746.0000	SCRIPPS NETWORKS INTERACTIVE I	33,792.98	68.3100	50,959.26	17,166.28
621.0000	SEACOAST BANKING CORP OF FLORI	4,685.76	24.1000	14,966.10	10,280.34
172.0000	SEACOR HOLDINGS INC	6,606.93	34.3000	5,899.60	707.33-
2,328.0000	SEALED AIR CORP	78,723.64	44.7600	104,201.28	25,477.64
1,177.0000	SEATTLE GENETICS INC	25,325.08	51.7400	60,897.98	35,572.90
530.0000	SELECT MEDICAL HOLDINGS CORP	4,754.10	15.3500	8,135.50	3,381.40

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429.0000	SELECTIVE INSURANCE GROUP INC	6,803.94	50.0500	21,471.45	14,667.51
2,097.0000	SEMTECH CORP	42,254.55	35.7500	74,967.75	32,713.20
2,317.0000	SEMPRA ENERGY	117,038.62	112.7500	261,241.75	144,203.13
2,917.0000	SENIOR HOUSING PROPERTIES TRUS	42,559.03	20.4400	59,623.48	17,064.45
397.0000	SENSIENT TECHNOLOGIES CORP	14,434.92	80.5300	31,970.41	17,535.49
1,485.0000	SERVICE CORP INTERNATIONAL/US	13,780.80	33.4500	49,673.25	35,892.45
983.0000	SERVICEMASTER GLOBAL HOLDINGS	35,230.72	39.1900	38,523.77	3,293.05
1,652.0000	SERVICENOW INC	120,310.86	106.0000	175,112.00	54,801.14
1,362.0000	SHENANDOAH TELECOMMUNICATIONS	27,076.56	30.7000	41,813.40	14,736.84
732.0000	SHERWIN-WILLIAMS CO/THE	79,084.32	350.9600	256,902.72	177,818.40
2,217.0000	SHORETEL INC	9,865.65	5.8000	12,858.60	2,992.95
340.0000	SHUTTERFLY INC	10,091.20	47.5000	16,150.00	6,058.80
397.0000	SIGNATURE BANK/NEW YORK NY	28,350.53	143.5300	56,981.41	28,630.88
353.0000	SILICON LABORATORIES INC	13,791.71	68.3500	24,127.55	10,335.84
284.0000	SILGAN HOLDINGS INC	5,689.94	31.7800	9,025.52	3,335.58
633.0000	SIMMONS FIRST NATIONAL CORP	15,451.53	52.9000	33,485.70	18,034.17
3,105.0000	SIMON PROPERTY GROUP INC	354,000.76	161.7600	502,264.80	148,264.04

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487.0000	SINCLAIR BROADCAST GROUP INC	5,084.28	32.9000	16,022.30	10,938.02
20,595.0000	SIRIUS XM HOLDINGS INC	40,984.05	5.4700	112,654.65	71,670.60
812.0000	SIX FLAGS ENTERTAINMENT CORP	42,122.98	59.6100	48,403.32	6,280.34
1,053.0000	SKECHERS U.S.A. INC	4,794.66	29.5000	31,063.50	26,268.84
1,680.0000	SKYWORKS SOLUTIONS INC	40,168.56	95.9500	161,196.00	121,027.44
2,452.0000	AO SMITH CORP	31,556.68	56.3300	138,121.16	106,564.48
928.0000	JM SMUCKER CO/THE	108,975.04	118.3300	109,810.24	835.20
352.0000	SNAP-ON INC	21,144.64	158.0000	55,616.00	34,471.36
229.0000	SNYDER'S-LANCE INC	4,813.58	34.6200	7,927.98	3,114.40
375.0000	SONIC AUTOMOTIVE INC	5,231.25	19.4500	7,293.75	2,062.50
588.0000	SONOCO PRODUCTS CO	19,862.64	51.4200	30,234.96	10,372.32
1,489.0000	SOTHEBY'S	42,570.51	53.6700	79,914.63	37,344.12
1,836.0000	SOUTH JERSEY INDUSTRIES INC	42,962.40	34.1700	62,736.12	19,773.72
8,186.0000	SOUTHERN CO/THE	348,799.49	47.8800	391,945.68	43,146.19
1,263.0000	SOUTHERN COPPER CORP	35,427.15	34.6300	43,737.69	8,310.54
1,107.0000	SOUTHSIDE BANCSHARES INC	16,283.15	34.9400	38,678.58	22,395.43
6,214.0000	SOUTHWEST AIRLINES CO	126,402.78	62.1400	386,137.96	259,735.18

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133.0000	SOUTHWEST GAS HOLDINGS INC	4,984.84	73.0600	9,716.98	4,732.14
6,117.0000	SOUTHWESTERN ENERGY CO	36,396.15	6.0800	37,191.36	795.21
903.0000	SPARTANNASH CO	14,948.21	25.9600	23,441.88	8,493.67
153.0000	SPECTRUM BRANDS HOLDINGS INC	4,984.74	125.0400	19,131.12	14,146.38
363.0000	SPEEDWAY MOTORSPORTS INC	5,027.55	18.2700	6,632.01	1,604.46
246.0000	SPIRE INC	9,972.84	69.7500	17,158.50	7,185.66
982.0000	SPIRIT AEROSYSTEMS HOLDINGS IN	19,698.92	57.9400	56,897.08	37,198.16
945.0000	SPIRIT AIRLINES INC	30,794.08	51.6500	48,809.25	18,015.17
6,368.0000	SPIRIT REALTY CAPITAL INC	55,176.40	7.4100	47,186.88	7,989.52-
437.0000	SPOK HOLDINGS INC	4,959.95	17.7000	7,734.90	2,774.95
1,059.0000	SPLUNK INC	53,613.27	56.8900	60,246.51	6,633.24
11,904.0000	SPRINT CORP	40,235.52	8.2100	97,731.84	57,496.32
1,720.0000	SPROUTS FARMERS MARKET INC	36,016.80	22.6700	38,992.40	2,975.60
1,586.0000	STANLEY BLACK & DECKER INC	99,451.77	140.7300	223,197.78	123,746.01
5,057.0000	STAPLES INC	60,677.50	10.0700	50,923.99	9,753.51-
11,240.0000	STARBUCKS CORP	192,374.29	58.3100	655,404.40	463,030.11
308.0000	STATE AUTO FINANCIAL CORP	4,989.60	25.7300	7,924.84	2,935.24

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2,707.0000	STARWOOD PROPERTY TRUST INC	55,546.50	22.3900	60,609.73	5,063.23
1,638.0000	STATE BANK FINANCIAL CORP	35,266.14	27.1000	44,389.80	9,123.66
3,744.0000	STATE STREET CORP	258,339.97	89.7300	335,949.12	77,609.15
1,897.0000	STEEL DYNAMICS INC	34,526.35	35.8100	67,931.57	33,405.22
632.0000	STEELCASE INC	7,059.44	14.0000	8,848.00	1,788.56
693.0000	STERICYCLE INC	50,538.12	76.3200	52,889.76	2,351.64
2,056.0000	STERLING BANCORP/DE	15,031.20	23.2500	47,802.00	32,770.80
368.0000	STIFEL FINANCIAL CORP	13,141.28	45.9800	16,920.64	3,779.36
1,395.0000	STOCK YARDS BANCORP INC	27,532.50	38.9000	54,265.50	26,733.00
1,775.0000	STRAIGHT PATH COMMUNICATIONS I	35,771.55	179.6500	318,878.75	283,107.20
102.0000	STRAYER EDUCATION INC	4,783.80	93.2200	9,508.44	4,724.64
3,113.0000	STRYKER CORP	175,521.75	138.7800	432,022.14	256,500.39
225.0000	STURM RUGER & CO INC	9,650.25	62.1500	13,983.75	4,333.50
168.0000	SUN COMMUNITIES INC	6,177.36	87.6900	14,731.92	8,554.56
168.0000	SUN HYDRAULICS CORP	4,962.72	42.6700	7,168.56	2,205.84
802.0000	SUNPOWER CORP	5,333.30	9.3400	7,490.68	2,157.38
2,377.0000	SUNSTONE HOTEL INVESTORS INC	19,479.71	16.1200	38,317.24	18,837.53

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4,409.0000	SUNTRUST BANKS INC	123,824.33	56.7200	250,078.48	126,254.15
1,550.0000	SUPERIOR ENERGY SERVICES INC	29,093.50	10.4300	16,166.50	12,927.00-
3,787.0000	SUPERVALU INC	10,111.29	3.2900	12,459.23	2,347.94
629.0000	SWIFT TRANSPORTATION CO	8,060.64	26.5000	16,668.50	8,607.86
6,068.0000	SYMANTEC CORP	123,707.00	28.2500	171,421.00	47,714.00
272.0000	SYNAPTICS INC	6,808.16	51.7100	14,065.12	7,256.96
1,479.0000	SYNOPSYS INC	39,454.24	72.9300	107,863.47	68,409.23
1,269.0000	SYNOVUS FINANCIAL CORP	19,797.96	44.2400	56,140.56	36,342.60
886.0000	SYNTEL INC	19,965.53	16.9600	15,026.56	4,938.97-
199.0000	SYNNEX CORP	6,095.37	119.9600	23,872.04	17,776.67
7,752.0000	SYNCHRONY FINANCIAL	250,089.72	29.8200	231,164.64	18,925.08-
5,579.0000	SYSCO CORP	224,023.10	50.3300	280,791.07	56,767.97
1,270.0000	TCF FINANCIAL CORP	12,954.00	15.9400	20,243.80	7,289.80
2,116.0000	TD AMERITRADE HOLDING CORP	40,079.34	42.9900	90,966.84	50,887.50
6,327.0000	TJX COS INC/THE	377,188.10	72.1700	456,619.59	79,431.49
2,425.0000	T-MOBILE US INC	74,002.99	60.6200	147,003.50	73,000.51
4,723.0000	TAHOE RESOURCES INC	43,338.52	8.6200	40,712.26	2,626.26-

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584.0000	TAKE-TWO INTERACTIVE SOFTWARE	8,649.04	73.3800	42,853.92	34,204.88
646.0000	TANGER FACTORY OUTLET CENTERS	17,241.74	25.9800	16,783.08	458.66-
3,354.0000	TARGET CORP	210,713.43	52.2900	175,380.66	35,332.77-
1,383.0000	TARGA RESOURCES CORP	40,466.58	45.2000	62,511.60	22,045.02
586.0000	TAUBMAN CENTERS INC	43,041.70	59.5500	34,896.30	8,145.40-
183.0000	TEAM INC	5,038.88	23.4500	4,291.35	747.53-
477.0000	TECH DATA CORP	20,119.86	101.0000	48,177.00	28,057.14
1,921.0000	TEGNA INC	13,164.69	14.4100	27,681.61	14,516.92
535.0000	TELEDYNE TECHNOLOGIES INC	45,249.54	127.6500	68,292.75	23,043.21
359.0000	TELEFLEX INC	19,863.47	207.7600	74,585.84	54,722.37
433.0000	TELEPHONE & DATA SYSTEMS INC	10,235.20	27.7500	12,015.75	1,780.55
497.0000	TEMPUR SEALY INTERNATIONAL INC	19,671.26	53.3900	26,534.83	6,863.57
1,090.0000	TENET HEALTHCARE CORP	25,189.03	19.3400	21,080.60	4,108.43-
205.0000	TENNANT CO	9,667.80	73.8000	15,129.00	5,461.20
524.0000	TENNECO INC	20,231.14	57.8300	30,302.92	10,071.78
1,247.0000	TERADATA CORP	36,300.17	29.4900	36,774.03	473.86
1,473.0000	TERADYNE INC	19,592.08	30.0300	44,234.19	24,642.11

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808.0000	TEREX CORP	14,197.98	37.5000	30,300.00	16,102.02
567.0000	TERRENO REALTY CORP	9,769.41	33.6600	19,085.22	9,315.81
334.0000	TESARO INC	46,085.32	139.8600	46,713.24	627.92
1,141.0000	TESLA INC	271,393.62	361.6100	412,597.01	141,203.39
1,488.0000	TESORO CORP	99,053.92	93.6000	139,276.80	40,222.88
224.0000	TETRA TECH INC	5,071.36	45.7500	10,248.00	5,176.64
13,207.0000	TETRAPHASE PHARMACEUTICALS INC	49,987.17	7.1300	94,165.91	44,178.74
9,674.0000	TEXAS INSTRUMENTS INC	353,318.43	76.9300	744,220.82	390,902.39
1,020.0000	TEXAS ROADHOUSE INC	35,720.40	50.9500	51,969.00	16,248.60
2,162.0000	TEXTRON INC	57,065.37	47.1000	101,830.20	44,764.83
3,701.0000	THERMO FISHER SCIENTIFIC INC	249,648.05	174.4700	645,713.47	396,065.42
728.0000	THOR INDUSTRIES INC	44,007.60	104.5200	76,090.56	32,082.96
5,781.0000	3M CO	490,052.68	208.1900	1,203,546.39	713,493.71
876.0000	TIFFANY & CO	72,453.96	93.8700	82,230.12	9,776.16
864.0000	TIME INC	10,402.07	14.3500	12,398.40	1,996.33
7,667.0000	TIME WARNER INC	305,783.09	100.4100	769,843.47	464,060.38
666.0000	TIMKEN CO/THE	14,324.46	46.2500	30,802.50	16,478.04

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188.0000	TIVO CORP	4,192.40	18.6500	3,506.20	686.20-
1,391.0000	TOLL BROTHERS INC	30,679.35	39.5100	54,958.41	24,279.06
354.0000	TOMPKINS FINANCIAL CORP	13,784.76	78.7200	27,866.88	14,082.12
271.0000	TOPBUILD CORP	3,771.58	53.0700	14,381.97	10,610.39
945.0000	TORCHMARK CORP	26,371.81	76.5000	72,292.50	45,920.69
984.0000	TORO CO/THE	14,696.04	69.2900	68,181.36	53,485.32
1,308.0000	TOTAL SYSTEM SERVICES INC	19,999.32	58.2500	76,191.00	56,191.68
1,087.0000	TOWNE BANK/PORTSMOUTH VA	14,036.02	30.8000	33,479.60	19,443.58
1,371.0000	TRACTOR SUPPLY CO	46,974.62	54.2100	74,321.91	27,347.29
436.0000	TRANSDIGM GROUP INC	70,896.04	268.8700	117,227.32	46,331.28
2,898.0000	TRAVELERS COS INC/THE	313,417.52	126.5300	366,683.94	53,266.42
897.0000	TRECORA RESOURCES	11,795.55	11.2500	10,091.25	1,704.30-
282.0000	TREEHOUSE FOODS INC	15,281.58	81.6900	23,036.58	7,755.00
380.0000	TREX CO INC	4,913.40	67.6600	25,710.80	20,797.40
869.0000	TRIBUNE MEDIA CO	35,281.40	40.7700	35,429.13	147.73
422.0000	TRICO BANCSHARES	6,055.70	35.1500	14,833.30	8,777.60
2,230.0000	TRIMBLE INC	52,048.06	35.6700	79,544.10	27,496.04

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1,076.0000	TRIPADVISOR INC	42,489.62	38.2000	41,103.20	1,386.42-
345.0000	TRUEBLUE INC	5,023.20	26.5000	9,142.50	4,119.30
5,626.0000	TRUSTCO BANK CORP NY	34,266.22	7.7500	43,601.50	9,335.28
508.0000	TRUSTMARK CORP	11,536.68	32.1600	16,337.28	4,800.60
547.0000	TUPPERWARE BRANDS CORP	26,086.43	70.2300	38,415.81	12,329.38
262.0000	TUTOR PERINI CORP	4,904.64	28.7500	7,532.50	2,627.86
15,574.0000	TWENTY-FIRST CENTURY FOX INC	307,550.52	28.3400	441,367.16	133,816.64
6,421.0000	TWITTER INC	104,488.37	17.8700	114,743.27	10,254.90
605.0000	TYLER TECHNOLOGIES INC	24,641.80	175.6700	106,280.35	81,638.55
3,168.0000	TYSON FOODS INC	51,073.23	62.6300	198,411.84	147,338.61
1,807.0000	UDR INC	45,305.15	38.9700	70,418.79	25,113.64
1,330.0000	UGI CORP	27,717.20	48.4100	64,385.30	36,668.10
254.0000	UMB FINANCIAL CORP	10,170.16	74.8600	19,014.44	8,844.28
12,967.0000	US BANCORP	489,844.24	51.9200	673,246.64	183,402.40
680.0000	USG CORP	15,660.61	29.0200	19,733.60	4,072.99
504.0000	US SILICA HOLDINGS INC	10,241.28	35.4900	17,886.96	7,645.68
587.0000	UBIQUITI NETWORKS INC	10,114.01	51.9700	30,506.39	20,392.38

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629.0000	ULTA BEAUTY INC	67,430.73	287.3400	180,736.86	113,306.13
369.0000	ULTIMATE SOFTWARE GROUP INC/TH	26,098.55	210.0600	77,512.14	51,413.59
675.0000	ULTRAGENYX PHARMACEUTICAL INC	37,125.00	62.1100	41,924.25	4,799.25
1,390.0000	UMPQUA HOLDINGS CORP	14,640.26	18.3600	25,520.40	10,880.14
1,935.0000	UNDER ARMOUR INC	20,360.69	21.7600	42,105.60	21,744.91
1,948.0000	UNDER ARMOUR INC	19,690.16	20.1600	39,271.68	19,581.52
97.0000	UNIFIRST CORP/MA	4,938.27	140.7000	13,647.90	8,709.63
817.0000	UNION BANKSHARES CORP	9,722.80	33.9000	27,696.30	17,973.50
8,036.0000	UNION PACIFIC CORP	490,431.61	108.9100	875,200.76	384,769.15
1,441.0000	UNITED BANKSHARES INC/WV	43,873.52	39.2000	56,487.20	12,613.68
2,360.0000	UNITED CONTINENTAL HOLDINGS IN	55,272.74	75.2500	177,590.00	122,317.26
2,701.0000	UNITED FINANCIAL BANCORP INC	34,421.13	16.6900	45,079.69	10,658.56
384.0000	UNITED NATURAL FOODS INC	15,970.56	36.7000	14,092.80	1,877.76-
6,333.0000	UNITED PARCEL SERVICE INC	571,184.62	110.5900	700,366.47	129,181.85
783.0000	UNITED RENTALS INC	26,289.74	112.7100	88,251.93	61,962.19
137.0000	UNITED STATES CELLULAR CORP	4,985.43	38.3200	5,249.84	264.41
3,898.0000	UNITED STATES STEEL CORP	26,896.20	22.1400	86,301.72	59,405.52

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7,979.0000	UNITED TECHNOLOGIES CORP	568,731.19	122.1100	974,315.69	405,584.50
453.0000	UNITED THERAPEUTICS CORP	24,890.81	129.7300	58,767.69	33,876.88
8,687.0000	UNITEDHEALTH GROUP INC	526,844.89	185.4200	1,610,743.54	1,083,898.65
434.0000	UNITIL CORP	12,143.23	48.3100	20,966.54	8,823.31
802.0000	UNIVERSAL DISPLAY CORP	42,778.68	109.2500	87,618.50	44,839.82
184.0000	UNIVERSAL FOREST PRODUCTS INC	4,852.08	87.3100	16,065.04	11,212.96
706.0000	UNIVERSAL HEALTH REALTY INCOME	35,504.74	79.5400	56,155.24	20,650.50
993.0000	UNIVERSAL HEALTH SERVICES INC	77,420.65	122.0800	121,225.44	43,804.79
567.0000	UNIVEST CORP OF PENNSYLVANIA	8,686.44	29.9500	16,981.65	8,295.21
2,926.0000	UNUM GROUP	57,333.98	46.6300	136,439.38	79,105.40
577.0000	URBAN EDGE PROPERTIES	8,849.71	23.7300	13,692.21	4,842.50
896.0000	URBAN OUTFITTERS INC	27,625.92	18.5400	16,611.84	11,014.08-
1,744.0000	URSTADT BIDDLE PROPERTIES INC	35,717.12	19.8000	34,531.20	1,185.92-
653.0000	VCA INC	14,947.32	92.3100	60,278.43	45,331.11
3,294.0000	VF CORP	156,951.73	57.6000	189,734.40	32,782.67
442.0000	VSE CORP	4,906.20	44.9800	19,881.16	14,974.96
286.0000	VAIL RESORTS INC	12,644.06	202.8300	58,009.38	45,365.32

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4,730.0000	VALERO ENERGY CORP	273,372.26	67.4600	319,085.80	45,713.54
733.0000	VALLEY NATIONAL BANCORP	5,180.42	11.8100	8,656.73	3,476.31
242.0000	VALMONT INDUSTRIES INC	20,410.28	149.6000	36,203.20	15,792.92
1,875.0000	VALVOLINE INC	18,800.76	23.7200	44,475.00	25,674.24
1,113.0000	VANTIV INC	40,995.58	63.3400	70,497.42	29,501.84
371.0000	VAREX IMAGING CORP	5,354.41	33.8000	12,539.80	7,185.39
928.0000	VARIAN MEDICAL SYSTEMS INC	39,655.34	103.1900	95,760.32	56,104.98
770.0000	VECTREN CORP	31,567.48	58.4400	44,998.80	13,431.32
81.0000	VECTRUS INC	1,152.03	32.3200	2,617.92	1,465.89
1,382.0000	VEEVA SYSTEMS INC	35,627.96	61.3100	84,730.42	49,102.46
2,766.0000	VENTAS INC	142,374.90	69.4800	192,181.68	49,806.78
8,414.0000	VEREIT INC	70,926.73	8.1400	68,489.96	2,436.77-
1,338.0000	VERISIGN INC	31,500.80	92.9600	124,380.48	92,879.68
34,427.0000	VERIZON COMMUNICATIONS INC	1,325,758.58	44.6600	1,537,509.82	211,751.24
1,475.0000	VERISK ANALYTICS INC	74,381.41	84.3700	124,445.75	50,064.34
67.0000	VERITIV CORP	1,699.79	45.0000	3,015.00	1,315.21
2,211.0000	VERTEX PHARMACEUTICALS INC	140,018.70	128.8700	284,931.57	144,912.87

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921.0000	VERSUM MATERIALS INC	9,504.63	32.5000	29,932.50	20,427.87
288.0000	VIASAT INC	12,041.28	66.2000	19,065.60	7,024.32
4,308.0000	VIACOM INC	160,890.88	33.5700	144,619.56	16,271.32-
6,628.0000	VIAVI SOLUTIONS INC	42,419.20	10.5300	69,792.84	27,373.64
18,149.0000	VISA INC	641,077.12	93.7800	1,702,013.22	1,060,936.10
1,153.0000	VISHAY INTERTECHNOLOGY INC	10,884.32	16.6000	19,139.80	8,255.48
460.0000	VISTA OUTDOOR INC	10,301.07	22.5100	10,354.60	53.53
275.0000	VISTEON CORP	18,138.37	102.0600	28,066.50	9,928.13
424.0000	VLASIC FOODS INTL INC COM	4,492.60	10.5957	4,492.60	0.00
840.0000	VMWARE INC	37,371.60	87.4300	73,441.20	36,069.60
14,238.0000	VONAGE HOLDINGS CORP	44,085.50	6.5400	93,116.52	49,031.02
1,748.0000	VORNADO REALTY TRUST	144,155.05	93.9000	164,137.20	19,982.15
1,109.0000	VOYA FINANCIAL INC	44,547.98	36.8900	40,911.01	3,636.97-
1,472.0000	VULCAN MATERIALS CO	107,165.41	126.6800	186,472.96	79,307.55
328.0000	WD-40 CO	23,211.58	110.3500	36,194.80	12,983.22
684.0000	WGL HOLDINGS INC	42,305.40	83.4300	57,066.12	14,760.72
423.0000	WABCO HOLDINGS INC	38,620.86	127.5100	53,936.73	15,315.87

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384.0000	WSFS FINANCIAL CORP	4,825.60	45.3500	17,414.40	12,588.80
2,934.0000	WEC ENERGY GROUP INC	134,307.25	61.3800	180,088.92	45,781.67
1,602.0000	WABASH NATIONAL CORP	14,823.13	21.9800	35,211.96	20,388.83
1,062.0000	WABTEC CORP/DE	44,032.50	91.5000	97,173.00	53,140.50
14,687.0000	WAL-MART STORES INC	781,826.15	75.6800	1,111,512.16	329,686.01
7,994.0000	WALGREENS BOOTS ALLIANCE INC	460,780.49	78.3100	626,010.14	165,229.65
1,272.0000	WASHINGTON FEDERAL INC	19,728.72	33.2000	42,230.40	22,501.68
1,264.0000	WASHINGTON PRIME GROUP INC	14,566.31	8.3700	10,579.68	3,986.63-
526.0000	WASHINGTON TRUST BANCORP INC	11,698.24	51.5500	27,115.30	15,417.06
1,887.0000	WASTE MANAGEMENT INC	74,346.72	73.3500	138,411.45	64,064.73
330.0000	WATERS CORP	39,539.61	183.8400	60,667.20	21,127.59
223.0000	WATSCO INC	14,637.72	154.2000	34,386.60	19,748.88
239.0000	WATTS WATER TECHNOLOGIES INC	7,918.07	63.2000	15,104.80	7,186.73
652.0000	WAYFAIR INC	48,580.52	76.8800	50,125.76	1,545.24
675.0000	WEB.COM GROUP INC	10,071.00	25.3000	17,077.50	7,006.50
722.0000	WEBMD HEALTH CORP	11,169.34	58.6500	42,345.30	31,175.96
572.0000	WEBSTER FINANCIAL CORP	11,422.84	52.2200	29,869.84	18,447.00

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1,041.0000	WEINGARTEN REALTY INVESTORS	24,244.89	30.1000	31,334.10	7,089.21
256.0000	WEIS MARKETS INC	9,799.68	48.7200	12,472.32	2,672.64
1,781.0000	WELBILT INC	17,076.47	18.8500	33,571.85	16,495.38
338.0000	WELLCARE HEALTH PLANS INC	16,592.42	179.5600	60,691.28	44,098.86
41,996.0000	WELLS FARGO & CO	1,653,154.38	55.4100	2,326,998.36	673,843.98
3,277.0000	WELLTOWER INC	170,038.76	74.8500	245,283.45	75,244.69
4,237.0000	WENDY'S CO/THE	19,744.42	15.5100	65,715.87	45,971.45
261.0000	WESBANCO INC	4,909.41	39.5400	10,319.94	5,410.53
716.0000	WESCO INTERNATIONAL INC	36,265.40	57.3000	41,026.80	4,761.40
584.0000	WEST PHARMACEUTICAL SERVICES I	26,357.32	94.5200	55,199.68	28,842.36
1,827.0000	WESTAR ENERGY INC	70,552.37	53.0200	96,867.54	26,315.17
229.0000	WESTAMERICA BANCORPORATION	11,021.77	56.0400	12,833.16	1,811.39
2,369.0000	WESTERN DIGITAL CORP	67,475.04	88.6000	209,893.40	142,418.36
2,781.0000	WESTERN UNION CO/THE	55,805.92	19.0500	52,978.05	2,827.87-
592.0000	WESTLAKE CHEMICAL CORP	19,081.10	66.2100	39,196.32	20,115.22
2,449.0000	WESTROCK CO	69,088.97	56.6600	138,760.34	69,671.37
203.0000	WESTWOOD HOLDINGS GROUP INC	7,346.57	56.6900	11,508.07	4,161.50

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381.0000	WEX INC	20,544.63	104.2700	39,726.87	19,182.24
6,909.0000	WEYERHAEUSER CO	163,992.96	33.5000	231,451.50	67,458.54
822.0000	WHIRLPOOL CORP	91,350.04	191.6200	157,511.64	66,161.60
2,836.0000	WHITESTONE REIT	35,649.36	12.2500	34,741.00	908.36-
3,123.0000	WHOLE FOODS MARKET INC	94,440.02	42.1100	131,509.53	37,069.51
6,829.0000	WILLIAMS COS INC/THE	155,868.78	30.2800	206,782.12	50,913.34
834.0000	WILLIAMS-SONOMA INC	30,118.26	48.5000	40,449.00	10,330.74
277.0000	WINTRUST FINANCIAL CORP	8,670.10	76.4400	21,173.88	12,503.78
788.0000	WOLVERINE WORLD WIDE INC	15,960.94	28.0100	22,071.88	6,110.94
488.0000	WOODWARD INC	15,796.56	67.5800	32,979.04	17,182.48
1,328.0000	WORKDAY INC	95,661.13	97.0000	128,816.00	33,154.87
779.0000	WORLD FUEL SERVICES CORP	29,225.55	38.4500	29,952.55	727.00
456.0000	WORTHINGTON INDUSTRIES INC	8,974.08	50.2200	22,900.32	13,926.24
4,437.0000	WPX ENERGY INC	42,107.13	9.6600	42,861.42	754.29
862.0000	WYNDHAM WORLDWIDE CORP	30,945.19	100.4100	86,553.42	55,608.23
698.0000	WYNN RESORTS LTD	50,449.32	134.1200	93,615.76	43,166.44
2,753.0000	XPO LOGISTICS INC	78,460.50	64.6300	177,926.39	99,465.89

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2,717.0000	XILINX INC	63,931.01	64.3200	174,757.44	110,826.43
2,517.0000	XENIA HOTELS & RESORTS INC	42,839.34	19.3700	48,754.29	5,914.95
3,088.7500	XEROX CORP	75,740.38	28.7300	88,739.79	12,999.41
1,269.0000	XYLEM INC/NY	33,996.51	55.4300	70,340.67	36,344.16
406.0000	XPERI CORP	6,565.02	29.8000	12,098.80	5,533.78
1,507.0000	YELP INC	40,583.51	30.0200	45,240.14	4,656.63
545.0000	YORK WATER CO/THE	10,224.20	34.8500	18,993.25	8,769.05
3,986.0000	YUM! BRANDS INC	145,021.36	73.7600	294,007.36	148,986.00
2,978.0000	YUM CHINA HOLDINGS INC	37,625.57	39.4300	117,422.54	79,796.97
1,321.0000	ZAYO GROUP HOLDINGS INC	35,363.17	30.9000	40,818.90	5,455.73
789.0000	ZEBRA TECHNOLOGIES CORP	30,531.76	100.5200	79,310.28	48,778.52
394.0000	ZILLOW GROUP INC	10,791.43	48.8400	19,242.96	8,451.53
1,067.0000	ZILLOW GROUP INC	31,804.26	49.0100	52,293.67	20,489.41
1,673.0000	ZIMMER BIOMET HOLDINGS INC	113,126.08	128.4000	214,813.20	101,687.12
2,461.0000	ZIONS BANCORPORATION	65,129.76	43.9100	108,062.51	42,932.75
4,735.0000	ZOETIS INC	218,636.72	62.3800	295,369.30	76,732.58
15,998.0000	ZYNGA INC	47,054.75	3.6400	58,232.72	11,177.97

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
TOTAL INVESTMENTS EQUITY		133,974,642.63		230,678,772.25	96,704,129.62
TOTAL INVESTMENT		134,362,831.62		231,066,961.24	96,704,129.62

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INVESTMENTS CASH EQUIVALENTS					
1,047,721.5400	BLACKROCK LIQ T FUND INSTL FUND 60	1,047,721.54	100.0000	1,047,721.54	0.00
TOTAL INVESTMENTS CASH EQUIVALENTS		1,047,721.54		1,047,721.54	0.00
INVESTMENTS FIXED INCOME SECURITIES					
133,182.4600	ADVANCED DISPOSAL 10/16 COV-LITE TLB	133,182.46	100.3040	133,587.33	404.87
175,000.0000	AES CORP/VA 4.875% 05/15/2023 DD 04/30/13	177,232.85	101.8750	178,281.25	1,048.40
100,000.0000	AES CORP/VA 5.500% 04/15/2025 DD 04/06/15	99,180.21	104.6250	104,625.00	5,444.79
25,000.0000	AK STEEL CORP 7.000% 03/15/2027 DD 03/23/17	25,000.00	103.2500	25,812.50	812.50
150,000.0000	AMC NETWORKS INC 5.000% 04/01/2024 DD 03/30/16	150,000.00	102.3750	153,562.50	3,562.50
50,000.0000	AMN HEALTHCARE INC 144A 5.125% 10/01/2024 DD 10/03/16	50,000.00	101.2500	50,625.00	625.00
25,000.0000	AMERICAN TIRE DISTRIBUTOR 144A 10.250% 03/01/2022 DD 02/25/15	22,931.60	103.5000	25,875.00	2,943.40
150,000.0000	ACADIA HEALTHCARE CO INC 6.500% 03/01/2024 DD 02/16/16	150,253.44	106.7500	160,125.00	9,871.56

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50,000.0000	AECOM 5.750% 10/15/2022 DD 10/15/15	49,947.41	104.6250	52,312.50	2,365.09
75,000.0000	AECOM 5.875% 10/15/2024 DD 10/15/15	74,015.97	108.7500	81,562.50	7,546.53
50,000.0000	AECOM 5.125% 03/15/2027 DD 02/21/17	50,000.00	100.3750	50,187.50	187.50
75,000.0000	ADVANCED DISPOSAL SERVICE 144A 5.625% 11/15/2024 DD 11/10/16	75,000.00	103.0000	77,250.00	2,250.00
150,000.0000	ALBERTSONS COS LLC / SAFE 144A 6.625% 06/15/2024 DD 05/31/16	150,000.00	99.2500	148,875.00	1,125.00-
200,000.0000	ALBERTSONS COS LLC / SAFE 144A 5.750% 03/15/2025 DD 08/09/16	200,000.00	93.0000	186,000.00	14,000.00-
150,000.0000	ALLIANCE DATA SYSTEMS COR 144A 5.250% 12/01/2017 DD 11/20/12	150,682.43	100.7500	151,125.00	442.57
75,000.0000	ALLIANCE DATA SYSTEMS COR 144A 5.875% 11/01/2021 DD 10/27/16	75,000.00	103.5000	77,625.00	2,625.00
100,000.0000	ALLY FINANCIAL INC 4.750% 09/10/2018 DD 09/09/13	102,727.39	102.7500	102,750.00	22.61
100,000.0000	ALLY FINANCIAL INC 4.625% 05/19/2022 DD 05/19/15	99,567.96	104.0000	104,000.00	4,432.04
50,000.0000	ALPHA 3 BV / ALPHA US BID 144A 6.250% 02/01/2025 DD 01/31/17	50,000.00	102.8750	51,437.50	1,437.50

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50,000.0000	ALPINE FINANCE MERGER SUB 144A 6.875% 08/01/2025 DD 07/12/17	50,000.00	101.7500	50,875.00	875.00
250,000.0000	ALTICE FINANCING SA 144A 7.500% 05/15/2026 DD 05/03/16	268,558.46	111.0000	277,500.00	8,941.54
200,000.0000	ALTICE LUXEMBOURG SA 144A 7.750% 05/15/2022 DD 05/08/14	212,324.89	106.1250	212,250.00	74.89-
55,000.0000	AMERICAN AXLE & MANUFACTURING 7.750% 11/15/2019 DD 11/03/11	60,704.69	109.7500	60,362.50	342.19-
50,000.0000	AMERICAN AXLE & MANUFACTU 144A 6.250% 04/01/2025 DD 03/23/17	50,000.00	97.5000	48,750.00	1,250.00-
50,000.0000	AMERICAN AXLE & MANUFACTU 144A 6.500% 04/01/2027 DD 03/23/17	50,000.00	97.2500	48,625.00	1,375.00-
56,000.0000	AMERICAN BUILDERS & CONTR 144A 5.625% 04/15/2021 DD 04/16/13	56,308.63	102.8750	57,610.00	1,301.37
50,000.0000	AMERIGAS PARTNERS LP / AMERIGA 5.750% 05/20/2027 DD 02/13/17	50,000.00	101.2500	50,625.00	625.00
22,500.0000	ANCESTRY.COM 10/16 2ND LIEN COV-LITE TL	22,287.37	102.0830	22,968.68	681.31
29,700.0000	ANCESTRY.COM 2/17 TL	29,565.81	100.3330	29,798.90	233.09
100,000.0000	ANGLO AMERICAN CAPITAL PL 144A 9.375% 04/08/2019 DD 04/08/09	112,520.56	111.8750	111,875.00	645.56-
50,000.0000	ANTERO MIDSTREAM PARTNERS 144A 5.375% 09/15/2024 DD 09/13/16	50,000.00	102.2500	51,125.00	1,125.00

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200,000.0000	ARAMARK SERVICES INC 5.125% 01/15/2024 DD 12/17/15	200,000.00	105.1250	210,250.00	10,250.00
250,000.0000	ARDAGH PACKAGING FINANCE 144A 4.625% 05/15/2023 DD 05/16/16	250,000.00	102.4590	256,147.50	6,147.50
200,000.0000	ARDAGH PACKAGING FINANCE 144A 6.000% 02/15/2025 DD 01/30/17	200,000.00	105.0000	210,000.00	10,000.00
250,000.0000	PETSMART INC 144A 7.125% 03/15/2023 DD 03/04/15	252,350.19	89.0000	222,500.00	29,850.19-
50,000.0000	ASCENT RESOURCES UTICA HO 144A 10.000% 04/01/2022 DD 04/05/17	50,000.00	100.0000	50,000.00	0.00
150,000.0000	BASS PRO SHOPS 11/16 COV-LITE TLB	148,674.07	97.0500	145,575.00	3,099.07-
50,000.0000	BLOCK COMMUNICATIONS INC 144A 6.875% 02/15/2025 DD 02/16/17	50,000.00	107.2500	53,625.00	3,625.00
150,000.0000	BLUE RACER MIDSTREAM LLC 144A 6.125% 11/15/2022 DD 11/13/14	151,728.98	100.7500	151,125.00	603.98-
200,000.0000	BLUESCOPE STEEL FINANCE L 144A 6.500% 05/15/2021 DD 05/05/16	212,007.77	105.5000	211,000.00	1,007.77-
75,000.0000	BOMBARDIER INC 144A 6.125% 01/15/2023 DD 01/14/13	75,000.00	100.2500	75,187.50	187.50
100,000.0000	BOMBARDIER INC 144A 6.000% 10/15/2022 DD 04/03/14	100,242.96	100.0000	100,000.00	242.96-

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
150,000.0000	BOYD GAMING CORP 6.875% 05/15/2023 DD 05/21/15	152,807.90	107.0000	160,500.00	7,692.10
60,000.0000	BRAND ENERGY & INFRASTRUC 144A 8.500% 07/15/2025 DD 06/21/17	60,000.00	103.5000	62,100.00	2,100.00
175,000.0000	BWAY HOLDING CO 144A 5.500% 04/15/2024 DD 04/03/17	175,000.00	102.1250	178,718.75	3,718.75
195,000.0000	BWAY HOLDING CO 144A 7.250% 04/15/2025 DD 04/03/17	195,000.00	101.5000	197,925.00	2,925.00
150,000.0000	CCO HOLDINGS LLC / CCO HO 144A 5.875% 04/01/2024 DD 02/19/16	150,000.00	106.7500	160,125.00	10,125.00
210,000.0000	CCO HOLDINGS LLC / CCO HO 144A 5.125% 05/01/2027 DD 02/06/17	210,541.55	102.2500	214,725.00	4,183.45
100,000.0000	CBS RADIO INC 144A 7.250% 11/01/2024 DD 10/17/16	102,998.20	103.0000	103,000.00	1.80
50,000.0000	OUTFRONT MEDIA CAPITAL LLC / O 5.625% 02/15/2024 DD 11/15/14	52,069.46	104.3750	52,187.50	118.04
25,000.0000	CDK GLOBAL INC VAR RT 10/15/2019 DD 04/15/15	25,807.67	103.0000	25,750.00	57.67-
100,000.0000	CDW LLC / CDW FINANCE CORP 5.000% 09/01/2023 DD 03/03/15	100,562.60	104.1250	104,125.00	3,562.40
150,000.0000	CHS/COMMUNITY HEALTH SYSTEMS I 6.250% 03/31/2023 DD 03/16/17	150,859.13	103.2350	154,852.50	3,993.37

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
50,000.0000	CNH INDUSTRIAL CAPITAL LLC 4.375% 04/05/2022 DD 04/10/17	50,000.00	104.6500	52,325.00	2,325.00
100,000.0000	CSC HOLDINGS LLC 6.750% 11/15/2021 DD 11/15/11	101,821.44	110.7500	110,750.00	8,928.56
70,000.0000	CTR PARTNERSHIP LP / CARETRUST 5.250% 06/01/2025 DD 05/24/17	70,000.00	103.0000	72,100.00	2,100.00
250,000.0000	CST BRANDS INC 5.000% 05/01/2023 DD 11/01/13	250,510.50	105.0200	262,550.00	12,039.50
200,000.0000	CABLEVISION SYSTEMS CORP 7.750% 04/15/2018 DD 04/15/10	200,058.15	103.7500	207,500.00	7,441.85
100,000.0000	CABLEVISION SYSTEMS CORP 8.000% 04/15/2020 DD 04/15/10	110,965.35	111.3750	111,375.00	409.65
150,000.0000	CABLEVISION SYSTEMS CORP 5.875% 09/15/2022 DD 09/27/12	128,785.97	105.1250	157,687.50	28,901.53
25,000.0000	CALATLANTIC GROUP INC 5.000% 06/15/2027 DD 06/09/17	25,000.00	100.2500	25,062.50	62.50
200,000.0000	CALPINE CORP 5.375% 01/15/2023 DD 07/22/14	200,000.00	97.5000	195,000.00	5,000.00-
125,000.0000	CALPINE CORP 5.750% 01/15/2025 DD 07/22/14	120,486.23	93.7500	117,187.50	3,298.73-
105,000.0000	CAMELOT FINANCE SA 144A 7.875% 10/15/2024 DD 10/03/16	105,000.00	107.7500	113,137.50	8,137.50

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
150,000.0000	CENTENE CORP 6.125% 02/15/2024 DD 02/11/16	150,000.00	108.1180	162,177.00	12,177.00
150,000.0000	CENTENE CORP 4.750% 01/15/2025 DD 11/09/16	150,000.00	102.7500	154,125.00	4,125.00
175,000.0000	CENTURYLINK INC 5.625% 04/01/2025 DD 10/01/15	175,000.00	99.8330	174,707.75	292.25-
50,000.0000	CENTURYLINK INC 7.500% 04/01/2024 DD 04/06/16	50,000.00	109.5000	54,750.00	4,750.00
110,000.0000	CEQUEL COMMUNICATIONS HOL 144A 6.375% 09/15/2020 DD 10/25/12	106,661.30	102.0000	112,200.00	5,538.70
75,000.0000	CHANGE HEALTHCARE HOLDING 144A 5.750% 03/01/2025 DD 02/15/17	75,000.00	102.0000	76,500.00	1,500.00
75,000.0000	CHENIERE CORPUS CHRISTI HOLDIN 5.875% 03/31/2025 DD 12/09/16	75,000.00	106.6250	79,968.75	4,968.75
100,000.0000	CHENIERE CORPUS CHRISTI H 144A 5.125% 06/30/2027 DD 05/19/17	100,000.00	102.5000	102,500.00	2,500.00
61,000.0000	CHESAPEAKE ENERGY CORP 144A 8.000% 12/15/2022 DD 12/23/15	62,521.85	105.7500	64,507.50	1,985.65
200,000.0000	CHURCHILL DOWNS INC 5.375% 12/15/2021 DD 12/16/13	201,538.16	103.7500	207,500.00	5,961.84
150,000.0000	FRONTIER COMMUNICATIONS CORP 7.125% 03/15/2019 DD 03/23/07	154,752.84	104.2500	156,375.00	1,622.16

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
100,000.0000	CLEAR CHANNEL WORLDWIDE HOLDIN 7.625% 03/15/2020 DD 03/15/12	103,398.74	99.5000	99,500.00	3,898.74-
100,000.0000	CLEAR CHANNEL WORLDWIDE HOLDIN 6.500% 11/15/2022 DD 05/15/13	103,349.64	102.7700	102,770.00	579.64-
50,000.0000	COGENT COMMUNICATIONS GRO 144A 5.375% 03/01/2022 DD 02/20/15	50,168.50	105.0000	52,500.00	2,331.50
25,000.0000	COMMERCIAL METALS CO 5.375% 07/15/2027 DD 07/11/17	25,000.00	101.8750	25,468.75	468.75
200,000.0000	COMMSCOPE TECHNOLOGIES LL 144A 6.000% 06/15/2025 DD 06/11/15	200,000.00	106.7500	213,500.00	13,500.00
50,000.0000	UNITI GROUP INC / CSL CAP 144A 7.125% 12/15/2024 DD 12/15/16	50,000.00	99.2820	49,641.00	359.00-
150,000.0000	CONSOLIDATED ENERGY FINAN 144A 6.875% 06/15/2025 DD 06/12/17	149,253.74	103.0000	154,500.00	5,246.26
25,000.0000	COVANTA HOLDING CORP 5.875% 07/01/2025 DD 03/16/17	25,000.00	97.0000	24,250.00	750.00-
75,000.0000	CRESTWOOD MIDSTREAM PARTN 144A 5.750% 04/01/2025 DD 03/14/17	75,000.00	99.7500	74,812.50	187.50-
150,000.0000	CROWNROCK LP / CROWNROCK 144A 7.125% 04/15/2021 DD 04/15/13	140,035.47	102.7500	154,125.00	14,089.53
50,000.0000	CROWNROCK LP / CROWNROCK 144A 7.750% 02/15/2023 DD 02/06/15	47,228.20	105.5000	52,750.00	5,521.80

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
35,000.0000	CYRUSONE LP / CYRUSONE FI 144A 5.000% 03/15/2024 DD 03/17/17	35,000.00	103.0000	36,050.00	1,050.00
25,000.0000	CYRUSONE LP / CYRUSONE FI 144A 5.375% 03/15/2027 DD 03/17/17	25,000.00	104.1250	26,031.25	1,031.25
150,000.0000	DANA INC 5.375% 09/15/2021 DD 08/02/13	153,617.44	102.8750	154,312.50	695.06
245,000.0000	DAVITA INC 5.750% 08/15/2022 DD 08/28/12	250,168.50	102.7500	251,737.50	1,569.00
100,000.0000	DENBURY RESOURCES INC 144A 9.000% 05/15/2021 DD 05/10/16	104,412.59	95.2500	95,250.00	9,162.59-
250,000.0000	DISH DBS CORP 7.875% 09/01/2019 DD 08/17/09	251,002.13	110.2500	275,625.00	24,622.87
200,000.0000	DISH DBS CORP 5.875% 07/15/2022 DD 05/16/12	203,846.97	107.5000	215,000.00	11,153.03
50,000.0000	DOLE FOOD CO INC 144A 7.250% 06/15/2025 DD 04/06/17	50,000.00	104.0000	52,000.00	2,000.00
200,000.0000	RR DONNELLEY & SONS CO 6.000% 04/01/2024 DD 03/20/14	204,750.15	97.3750	194,750.00	10,000.15-
100,000.0000	DYNEGY INC 5.875% 06/01/2023 DD 12/01/13	98,887.86	93.5000	93,500.00	5,387.86-
100,000.0000	DYNEGY INC 7.375% 11/01/2022 DD 05/01/15	99,442.13	98.7500	98,750.00	692.13-

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
100,000.0000	EMC CORP 2.650% 06/01/2020 DD 06/06/13	97,161.35	98.1230	98,123.00	961.65
25,000.0000	ELDORADO RESORTS INC 144A 6.000% 04/01/2025 DD 03/29/17	25,000.00	106.0000	26,500.00	1,500.00
200,000.0000	ENDO FINANCE LLC / ENDO F 144A VAR RT 01/15/2022 DD 05/06/14	202,621.49	95.7500	191,500.00	11,121.49-
50,000.0000	ENPRO INDUSTRIES INC 144A 5.875% 09/15/2022 DD 03/15/17	50,478.35	104.2500	52,125.00	1,646.65
200,000.0000	ENTEGRIS INC 144A 6.000% 04/01/2022 DD 04/01/14	200,000.00	104.6250	209,250.00	9,250.00
75,000.0000	EQUINIX INC 5.375% 05/15/2027 DD 03/22/17	75,000.00	106.6250	79,968.75	4,968.75
200,000.0000	TRONOX FINANCE LLC 144A 7.500% 03/15/2022 DD 03/19/15	177,310.76	103.0000	206,000.00	28,689.24
50,000.0000	EXTRACTION OIL & GAS INC 144A 7.875% 07/15/2021 DD 07/18/16	50,000.00	102.7500	51,375.00	1,375.00
50,000.0000	FMG RESOURCES AUGUST 2006 144A 4.750% 05/15/2022 DD 05/12/17	50,000.00	100.3750	50,187.50	187.50
75,000.0000	FMG RESOURCES AUGUST 2006 144A 5.125% 05/15/2024 DD 05/12/17	75,000.00	100.0000	75,000.00	0.00
200,000.0000	FTI CONSULTING INC 6.000% 11/15/2022 DD 05/15/13	200,000.00	103.7500	207,500.00	7,500.00

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
125,000.0000	FELCOR LODGING LP 5.625% 03/01/2023 DD 03/01/13	125,000.00	103.7500	129,687.50	4,687.50
125,000.0000	FERRELLGAS LP / FERRELLGAS FIN VAR RT 06/15/2023 DD 06/15/16	125,000.00	93.2500	116,562.50	8,437.50-
175,000.0000	FIRST DATA CORP 144A 5.375% 08/15/2023 DD 08/11/15	175,000.00	104.5000	182,875.00	7,875.00
25,000.0000	FIRST DATA CORP 144A 5.750% 01/15/2024 DD 11/25/15	24,894.18	103.8750	25,968.75	1,074.57
175,000.0000	FIRST QUALITY FINANCE CO 144A 4.625% 05/15/2021 DD 05/14/13	175,000.00	100.8750	176,531.25	1,531.25
10,000.0000	FIRSTCASH INC 144A 5.375% 06/01/2024 DD 05/30/17	10,000.00	104.3750	10,437.50	437.50
75,000.0000	FLEX ACQUISITION CO INC 144A 6.875% 01/15/2025 DD 01/17/17	75,000.00	104.0000	78,000.00	3,000.00
25,000.0000	FRESENIUS MEDICAL CARE US 144A 5.625% 07/31/2019 DD 01/26/12	26,635.13	105.7500	26,437.50	197.63-
200,000.0000	FRESENIUS US FINANCE II I 144A 4.500% 01/15/2023 DD 09/25/15	200,000.00	105.0000	210,000.00	10,000.00
100,000.0000	FRONTIER COMMUNICATIONS CORP 7.125% 01/15/2023 DD 08/15/12	93,796.60	83.2500	83,250.00	10,546.60-
10,000.0000	FRONTIER COMMUNICATIONS CORP 11.000% 09/15/2025 DD 03/15/16	9,226.22	92.7500	9,275.00	48.78

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
125,000.0000	GFL ENVIRONMENTAL INC 144A 5.625% 05/01/2022 DD 05/12/17	125,487.88	102.2500	127,812.50	2,324.62
100,000.0000	TEGNA INC 5.125% 07/15/2020 DD 07/29/13	102,888.85	102.5000	102,500.00	388.85-
300,000.0000	GARDA WORLD SECURITY CORP 144A 7.250% 11/15/2021 DD 11/08/13	307,011.82	101.1250	303,375.00	3,636.82-
200,000.0000	GENESIS ENERGY LP / GENESIS EN 6.000% 05/15/2023 DD 05/21/15	200,000.00	98.0000	196,000.00	4,000.00-
225,000.0000	GIBSON ENERGY INC 144A 6.750% 07/15/2021 DD 06/28/13	223,075.97	103.2500	232,312.50	9,236.53
200,000.0000	GOODYEAR TIRE & RUBBER CO/THE 5.000% 05/31/2026 DD 05/13/16	200,000.00	103.5000	207,000.00	7,000.00
75,000.0000	GOODYEAR TIRE & RUBBER CO/THE 4.875% 03/15/2027 DD 03/07/17	75,000.00	101.5000	76,125.00	1,125.00
93,720.9200	WHEELABRATOR TECHNOLOGIES 10/14 TLB	92,289.68	100.3750	94,072.37	1,782.69
1,372.5800	WHEELABRATOR TECHNOLOGIES 10/14 TLC	1,351.61	100.3750	1,377.73	26.12
50,000.0000	GENESYS TELECOMMUNICATION 144A 10.000% 11/30/2024 DD 12/01/16	50,000.00	112.3750	56,187.50	6,187.50
99,500.0000	GENESYS 1/17 (USD) COV-LT TLB 0.000% 12/01/2023 DD 01/09/17	98,310.48	100.2250	99,723.88	1,413.40

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
100,000.0000	GRINDING MEDIA INC / MOLY 144A 7.375% 12/15/2023 DD 12/16/16	100,445.45	108.7500	108,750.00	8,304.55
300,000.0000	GROUP 1 AUTOMOTIVE INC VAR RT 06/01/2022 DD 06/01/15	300,693.59	101.5000	304,500.00	3,806.41
50,000.0000	GULFPORT ENERGY CORP 144A 6.000% 10/15/2024 DD 10/14/16	50,000.00	97.2500	48,625.00	1,375.00-
50,000.0000	GULFPORT ENERGY CORP 144A 6.375% 05/15/2025 DD 12/21/16	50,000.00	98.5000	49,250.00	750.00-
100,000.0000	HCA INC 5.250% 04/15/2025 DD 10/17/14	101,771.86	107.5000	107,500.00	5,728.14
250,000.0000	HCA INC 5.250% 06/15/2026 DD 03/15/16	262,432.44	107.8500	269,625.00	7,192.56
100,000.0000	HCA INC 4.500% 02/15/2027 DD 08/15/16	100,116.62	102.8750	102,875.00	2,758.38
150,000.0000	HCA INC 5.500% 06/15/2047 DD 06/22/17	150,000.00	103.5000	155,250.00	5,250.00
50,000.0000	HCA HEALTHCARE INC 6.250% 02/15/2021 DD 12/06/12	52,011.46	109.2500	54,625.00	2,613.54
175,000.0000	HCA INC 6.500% 02/15/2020 DD 08/01/11	191,253.08	109.1250	190,968.75	284.33-
200,000.0000	HALYARD HEALTH INC 6.250% 10/15/2022 DD 04/15/15	200,000.00	104.2500	208,500.00	8,500.00

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150,000.0000	HERTZ CORP/THE 5.875% 10/15/2020 DD 10/16/12	151,493.51	96.7500	145,125.00	6,368.51-
75,000.0000	HERTZ CORP/THE 144A 7.625% 06/01/2022 DD 06/06/17	75,000.00	99.7600	74,820.00	180.00-
182,000.0000	HERC RENTALS INC 144A 7.500% 06/01/2022 DD 06/09/16	182,000.00	105.5000	192,010.00	10,010.00
50,000.0000	HILL-ROM HOLDINGS INC 144A 5.000% 02/15/2025 DD 02/14/17	50,000.00	102.0000	51,000.00	1,000.00
100,000.0000	HOLLY ENERGY PARTNERS LP 144A 6.000% 08/01/2024 DD 07/19/16	100,000.00	104.0000	104,000.00	4,000.00
180,000.0000	HOLOGIC INC 144A 5.250% 07/15/2022 DD 07/02/15	180,000.00	105.0000	189,000.00	9,000.00
25,000.0000	HUDBAY MINERALS INC 144A 7.625% 01/15/2025 DD 12/12/16	25,000.00	104.7500	26,187.50	1,187.50
250,000.0000	HUGHES SATELLITE SYSTEMS CORP 7.625% 06/15/2021 DD 12/15/11	257,746.92	113.6250	284,062.50	26,315.58
225,000.0000	HUNTSMAN INTERNATIONAL LLC 4.875% 11/15/2020 DD 11/19/12	235,300.08	105.2500	236,812.50	1,512.42
300,000.0000	INFOR US INC 6.500% 05/15/2022 DD 11/15/15	304,010.18	103.5000	310,500.00	6,489.82
400,000.0000	INMARSAT FINANCE PLC 144A 4.875% 05/15/2022 DD 06/04/14	389,115.47	101.5000	406,000.00	16,884.53

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100,000.0000	INTELSAT JACKSON HOLDINGS SA 7.250% 04/01/2019 DD 10/01/11	86,314.23	100.0250	100,025.00	13,710.77
100,000.0000	INTELSAT JACKSON HOLDINGS SA 5.500% 08/01/2023 DD 06/05/13	84,709.74	82.7500	82,750.00	1,959.74-
125,000.0000	INVENTIV GROUP HOLDINGS I 144A 7.500% 10/01/2024 DD 10/14/16	125,000.00	108.5000	135,625.00	10,625.00
200,000.0000	IRON MOUNTAIN INC 6.000% 08/15/2023 DD 08/13/13	204,357.00	106.2500	212,500.00	8,143.00
100,000.0000	PATHEON HOLDINGS I BV 144A 7.500% 02/01/2022 DD 02/05/14	105,822.32	106.2500	106,250.00	427.68
38,000.0000	J2 CLOUD SERVICES LLC / J 144A 6.000% 07/15/2025 DD 06/27/17	38,000.00	103.0000	39,140.00	1,140.00
50,000.0000	RP CROWN PARENT LLC 144A 7.375% 10/15/2024 DD 10/06/16	50,000.00	104.0000	52,000.00	2,000.00
15,000.0000	JONAH ENERGY 5/14 COV-LITE 2ND LIEN TL	14,550.00	95.1670	14,275.05	274.95-
150,000.0000	JUPITER RESOURCES INC 144A 8.500% 10/01/2022 DD 09/18/14	145,435.29	75.0000	112,500.00	32,935.29-
150,000.0000	KFC HOLDING CO/PIZZA HUT 144A 5.000% 06/01/2024 DD 06/16/16	150,000.00	104.2500	156,375.00	6,375.00
25,000.0000	KFC HOLDING CO/PIZZA HUT 144A 4.750% 06/01/2027 DD 06/15/17	25,000.00	102.1250	25,531.25	531.25

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
200,000.0000	KLX INC 144A 5.875% 12/01/2022 DD 12/08/14	205,370.08	105.0000	210,000.00	4,629.92
25,000.0000	KINROSS GOLD CORP 144A 4.500% 07/15/2027 DD 07/06/17	25,000.00	99.7500	24,937.50	62.50-
25,000.0000	KOPPERS INC 144A 6.000% 02/15/2025 DD 01/25/17	25,000.00	106.2500	26,562.50	1,562.50
175,000.0000	KRONOS ACQUISITION HOLDIN 144A 9.000% 08/15/2023 DD 08/26/15	178,462.06	99.7500	174,562.50	3,899.56-
150,000.0000	LENNAR CORP VAR RT 12/01/2018 DD 02/04/13	153,331.89	102.2500	153,375.00	43.11
75,000.0000	LENNAR CORP 4.500% 04/30/2024 DD 04/28/17	75,000.00	103.3600	77,520.00	2,520.00
150,000.0000	LIONS GATE ENTERTAINMENT 144A 5.875% 11/01/2024 DD 10/27/16	151,431.47	105.2500	157,875.00	6,443.53
135,000.0000	MDC PARTNERS INC 144A 6.500% 05/01/2024 DD 03/23/16	135,000.00	99.7500	134,662.50	337.50-
100,000.0000	MGM RESORTS INTERNATIONAL 6.625% 12/15/2021 DD 12/20/12	101,952.12	112.2500	112,250.00	10,297.88
300,000.0000	MPH ACQUISITION HOLDINGS 144A 7.125% 06/01/2024 DD 06/07/16	303,269.65	106.6250	319,875.00	16,605.35
175,000.0000	MSCI INC 144A 5.750% 08/15/2025 DD 08/13/15	175,000.00	108.3120	189,546.00	14,546.00

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
50,000.0000	MALLINCKRODT INTERNATIONA 144A 5.500% 04/15/2025 DD 04/15/15	50,000.00	87.5000	43,750.00	6,250.00-
150,000.0000	MEDIACOM BROADBAND LLC / MEDIA 5.500% 04/15/2021 DD 03/17/14	150,000.00	102.2500	153,375.00	3,375.00
100,000.0000	MICRON TECHNOLOGY INC 144A 5.250% 01/15/2024 DD 04/30/15	100,000.00	103.5000	103,500.00	3,500.00
150,000.0000	MIDAS INTERMEDIATE HOLDCO 144A 7.875% 10/01/2022 DD 09/24/14	151,323.11	103.0000	154,500.00	3,176.89
225,000.0000	MIDCONTINENT COMMUNICATIO 144A 6.875% 08/15/2023 DD 08/14/15	226,262.84	107.7500	242,437.50	16,174.66
90,000.0000	MOLINA HEALTHCARE INC VAR RT 11/15/2022 DD 05/15/16	90,000.00	105.8750	95,287.50	5,287.50
50,000.0000	MOLINA HEALTHCARE INC 144A 4.875% 06/15/2025 DD 06/06/17	50,000.00	100.7500	50,375.00	375.00
200,000.0000	NATURE'S BOUNTY CO/THE 144A 7.625% 05/15/2021 DD 05/05/16	200,000.00	106.2500	212,500.00	12,500.00
150,000.0000	NCR CORP 4.625% 02/15/2021 DD 02/15/13	150,189.59	102.0000	153,000.00	2,810.41
100,000.0000	NCR CORP 5.875% 12/15/2021 DD 06/15/14	99,447.08	104.0000	104,000.00	4,552.92
125,000.0000	NGL ENERGY PARTNERS LP / 144A 7.500% 11/01/2023 DD 10/24/16	125,000.00	98.6250	123,281.25	1,718.75-

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
100,000.0000	NGL ENERGY PARTNERS LP / 144A 6.125% 03/01/2025 DD 02/22/17	100,000.00	91.5000	91,500.00	8,500.00-
300,000.0000	NRG ENERGY INC 6.625% 03/15/2023 DD 03/15/13	304,562.84	102.7500	308,250.00	3,687.16
100,000.0000	NRG ENERGY INC 6.250% 07/15/2022 DD 07/15/14	102,193.21	102.6250	102,625.00	431.79
300,000.0000	NAVISTAR INTERNATIONAL CORP 8.250% 11/01/2021 DD 10/28/09	302,897.07	101.0000	303,000.00	102.93
35,000.0000	NAVIENT CORP 6.500% 06/15/2022 DD 03/07/17	35,000.00	106.0000	37,100.00	2,100.00
170,000.0000	NFP CORP 144A 6.875% 07/15/2025 DD 07/12/17	170,000.00	101.0000	171,700.00	1,700.00
100,000.0000	NIELSEN FINANCE LLC / NIELSEN 4.500% 10/01/2020 DD 04/01/13	102,140.71	101.5280	101,528.00	612.71-
150,000.0000	NIELSEN FINANCE LLC / NIE 144A 5.000% 04/15/2022 DD 04/11/14	149,710.53	103.7500	155,625.00	5,914.47
200,000.0000	NOVA CHEMICALS CORP 144A 5.000% 05/01/2025 DD 10/28/14	195,642.61	99.5000	199,000.00	3,357.39
75,000.0000	NOVA CHEMICALS CORP 144A 4.875% 06/01/2024 DD 06/09/17	75,000.00	99.6250	74,718.75	281.25-
25,000.0000	NOVA CHEMICALS CORP 144A 5.250% 06/01/2027 DD 06/09/17	25,000.00	99.5000	24,875.00	125.00-

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
200,000.0000	NOVELIS CORP 144A 6.250% 08/15/2024 DD 08/29/16	200,000.00	105.0000	210,000.00	10,000.00
10,000.0000	NOVELIS CORP 144A 5.875% 09/30/2026 DD 09/14/16	10,000.00	103.0000	10,300.00	300.00
12,000.0000	NUANCE COMMUNICATIONS INC 144A 5.375% 08/15/2020 DD 08/14/12	11,978.64	101.6250	12,195.00	216.36
50,000.0000	NUANCE COMMUNICATIONS INC 144A 5.625% 12/15/2026 DD 12/22/16	49,549.83	106.7500	53,375.00	3,825.17
200,000.0000	SFR GROUP SA 144A 6.000% 05/15/2022 DD 05/08/14	203,679.25	104.6250	209,250.00	5,570.75
300,000.0000	OASIS PETROLEUM INC 6.500% 11/01/2021 DD 11/10/11	292,164.05	97.0000	291,000.00	1,164.05-
50,000.0000	1011778 BC ULC / NEW RED 144A 4.250% 05/15/2024 DD 05/17/17	50,000.00	99.3690	49,684.50	315.50-
50,000.0000	ORBITAL ATK INC 5.250% 10/01/2021 DD 04/01/15	51,718.39	103.2500	51,625.00	93.39-
150,000.0000	ORBITAL ATK INC 5.500% 10/01/2023 DD 04/01/16	150,000.00	105.2500	157,875.00	7,875.00
50,000.0000	ORCHESTRA BORROWER LLC / 144A 6.750% 06/15/2022 DD 06/16/17	50,000.00	103.0400	51,520.00	1,520.00
50,000.0000	PARK AEROSPACE HOLDINGS L 144A 5.250% 08/15/2022 DD 02/03/17	50,000.00	104.5320	52,266.00	2,266.00

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
50,000.0000	PARK AEROSPACE HOLDINGS L 144A 5.500% 02/15/2024 DD 02/03/17	50,000.00	104.4500	52,225.00	2,225.00
25,000.0000	PEABODY ENERGY CORP 144A 6.375% 03/31/2025 DD 02/15/17	25,000.00	98.5000	24,625.00	375.00-
200,000.0000	PENSKE AUTOMOTIVE GROUP INC 5.750% 10/01/2022 DD 04/01/13	200,641.84	103.2500	206,500.00	5,858.16
75,000.0000	PETSMART INC 144A 5.875% 06/01/2025 DD 05/31/17	75,000.00	96.3750	72,281.25	2,718.75-
200,000.0000	PLATFORM SPECIALTY PRODUC 144A 6.500% 02/01/2022 DD 02/02/15	191,595.92	103.2500	206,500.00	14,904.08
200,000.0000	POLYONE CORP 5.250% 03/15/2023 DD 09/15/13	198,795.49	105.0000	210,000.00	11,204.51
25,000.0000	POST HOLDINGS INC 144A 5.500% 03/01/2025 DD 02/14/17	25,000.00	103.1250	25,781.25	781.25
50,000.0000	POST HOLDINGS INC 144A 5.750% 03/01/2027 DD 02/14/17	50,000.00	102.7500	51,375.00	1,375.00
100,000.0000	PRESTIGE BRANDS INC 144A 5.375% 12/15/2021 DD 12/17/13	97,849.62	103.1250	103,125.00	5,275.38
300,000.0000	QEP RESOURCES INC 5.375% 10/01/2022 DD 03/01/12	303,362.05	96.2500	288,750.00	14,612.05-
125,000.0000	QUEBECOR MEDIA INC 5.750% 01/15/2023 DD 12/15/12	125,000.00	105.5000	131,875.00	6,875.00

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175,000.0000	QUICKEN LOANS INC 144A 5.750% 05/01/2025 DD 05/06/15	175,000.00	103.2500	180,687.50	5,687.50
300,000.0000	RHP HOTEL PROPERTIES LP / RHP 5.000% 04/15/2023 DD 04/14/15	300,611.30	102.2500	306,750.00	6,138.70
300,000.0000	RSI HOME PRODUCTS INC 144A 6.500% 03/15/2023 DD 03/16/15	300,000.00	105.2500	315,750.00	15,750.00
100,000.0000	RADIATE HOLDCO LLC / RADI 144A 6.625% 02/15/2025 DD 02/01/17	100,188.50	100.0000	100,000.00	188.50-
150,000.0000	RANGE RESOURCES CORP 4.875% 05/15/2025 DD 11/15/15	135,642.46	95.0000	142,500.00	6,857.54
100,000.0000	RANGE RESOURCES CORP 144A 5.000% 03/15/2023 DD 09/16/16	89,548.13	97.7500	97,750.00	8,201.87
250,000.0000	REALOGY GROUP LLC / REALO 144A 4.500% 04/15/2019 DD 04/07/14	254,361.26	103.2500	258,125.00	3,763.74
150,000.0000	REGIONALCARE HOSPITAL PAR 144A 8.250% 05/01/2023 DD 04/29/16	154,791.06	107.2500	160,875.00	6,083.94
64,813.5500	REYNOLDS GROUP ISSUER INC / RE VAR RT 02/15/2021 DD 02/15/12	66,417.71	102.7500	66,595.92	178.21
100,000.0000	REYNOLDS GROUP ISSUER INC / RE 5.750% 10/15/2020 DD 09/28/12	102,807.25	102.3340	102,334.00	473.25-
175,000.0000	RITE AID CORP 144A 6.125% 04/01/2023 DD 04/02/15	179,751.89	98.1880	171,829.00	7,922.89-

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
25,000.0000	ROCKIES EXPRESS PIPELINE 144A 6.000% 01/15/2019 DD 01/17/13	26,232.69	104.2500	26,062.50	170.19-
10,000.0000	SBA COMMUNICATIONS CORP 4.875% 09/01/2024 DD 03/01/17	9,925.36	101.7500	10,175.00	249.64
200,000.0000	SESI LLC 6.375% 05/01/2019 DD 11/01/11	186,512.41	98.7500	197,500.00	10,987.59
250,000.0000	NAVIENT CORP 7.250% 01/25/2022 DD 01/27/12	255,444.79	109.2500	273,125.00	17,680.21
200,000.0000	SM ENERGY CO 6.500% 01/01/2023 DD 06/29/12	194,403.98	95.2500	190,500.00	3,903.98-
50,000.0000	SPX FLOW INC 144A 5.625% 08/15/2024 DD 08/10/16	51,158.97	103.0000	51,500.00	341.03
75,000.0000	SEAGATE HDD CAYMAN 144A 4.875% 03/01/2024 DD 02/03/17	74,520.83	101.9210	76,440.75	1,919.92
75,000.0000	SEMGROUP CORP 144A 6.375% 03/15/2025 DD 03/15/17	73,883.42	96.7500	72,562.50	1,320.92-
150,000.0000	SENSATA TECHNOLOGIES BV 144A 5.000% 10/01/2025 DD 03/26/15	150,000.00	104.5800	156,870.00	6,870.00
125,000.0000	SERVICE CORP INTERNATIONAL/US 7.625% 10/01/2018 DD 10/03/06	125,411.61	106.7500	133,437.50	8,025.89
200,000.0000	SHEA HOMES LP / SHEA HOME 144A 5.875% 04/01/2023 DD 03/23/15	200,000.00	102.9500	205,900.00	5,900.00

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
250,000.0000	SIGNODE INDUSTRIAL GROUP 144A 6.375% 05/01/2022 DD 04/29/14	249,271.37	104.5000	261,250.00	11,978.63
300,000.0000	SIRIUS XM RADIO INC 144A 6.000% 07/15/2024 DD 05/06/14	302,489.89	106.2500	318,750.00	16,260.11
50,000.0000	SIRIUS XM RADIO INC 144A 5.000% 08/01/2027 DD 07/05/17	50,000.00	100.7500	50,375.00	375.00
100,000.0000	SIX FLAGS ENTERTAINMENT C 144A 4.875% 07/31/2024 DD 06/16/16	99,024.74	100.6120	100,612.00	1,587.26
50,000.0000	SONIC AUTOMOTIVE INC 144A 6.125% 03/15/2027 DD 03/10/17	50,000.00	99.5000	49,750.00	250.00-
50,000.0000	SPECTRUM BRANDS INC 6.125% 12/15/2024 DD 12/15/15	50,000.00	107.1250	53,562.50	3,562.50
300,000.0000	SPRINGLEAF FINANCE CORP 6.000% 06/01/2020 DD 12/01/13	293,676.56	105.5000	316,500.00	22,823.44
100,000.0000	SPRINT CAPITAL CORP 6.900% 05/01/2019 DD 05/06/99	107,066.88	106.7450	106,745.00	321.88-
100,000.0000	SPRINT COMMUNICATIONS INC 7.000% 08/15/2020 DD 08/14/12	98,258.05	110.0000	110,000.00	11,741.95
200,000.0000	SPRINT COMMUNICATIONS INC 6.000% 11/15/2022 DD 11/14/12	175,323.13	106.0000	212,000.00	36,676.87
100,000.0000	SPRINT CORP 7.250% 09/15/2021 DD 09/15/14	83,503.66	111.1250	111,125.00	27,621.34

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
100,000.0000	SPRINT CORP 7.875% 09/15/2023 DD 09/15/14	99,433.30	115.0000	115,000.00	15,566.70
250,000.0000	SPRINT CORP 7.125% 06/15/2024 DD 06/15/14	245,406.25	111.2500	278,125.00	32,718.75
55,000.0000	CALATLANTIC GROUP INC 8.375% 05/15/2018 DD 05/03/10	57,990.84	105.1250	57,818.75	172.09-
25,000.0000	STARWOOD PROPERTY TRUST I 144A 5.000% 12/15/2021 DD 12/16/16	25,000.00	104.0000	26,000.00	1,000.00
75,000.0000	STERIGENICS-NORDION TOPCO 144A 8.125% 11/01/2021 DD 11/01/16	75,000.00	102.5000	76,875.00	1,875.00
150,000.0000	SUBURBAN PROPANE PARTNERS LP/S 5.500% 06/01/2024 DD 05/27/14	151,116.25	99.5000	149,250.00	1,866.25-
100,000.0000	SUMMIT MATERIALS LLC / SUMMIT 6.125% 07/15/2023 DD 07/08/15	99,512.86	104.7500	104,750.00	5,237.14
50,000.0000	SUMMIT MIDSTREAM HOLDINGS LLC 5.750% 04/15/2025 DD 02/15/17	50,000.00	100.5000	50,250.00	250.00
75,000.0000	SUNCOKE ENERGY PARTNERS L 144A 7.500% 06/15/2025 DD 05/24/17	73,895.50	98.7500	74,062.50	167.00
25,000.0000	SYMANTEC CORP 144A 5.000% 04/15/2025 DD 02/09/17	25,000.00	104.6560	26,164.00	1,164.00
80,000.0000	THC ESCROW CORP III 144A 4.625% 07/15/2024 DD 06/14/17	80,000.00	100.2700	80,216.00	216.00

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
125,000.0000	THC ESCROW CORP III 144A 5.125% 05/01/2025 DD 06/14/17	125,000.00	100.3750	125,468.75	468.75
75,000.0000	THC ESCROW CORP III 144A 7.000% 08/01/2025 DD 06/14/17	75,000.00	99.6250	74,718.75	281.25-
150,000.0000	T-MOBILE USA INC 6.125% 01/15/2022 DD 11/21/13	158,508.78	105.0940	157,641.00	867.78-
200,000.0000	T-MOBILE USA INC 6.500% 01/15/2026 DD 11/05/15	200,000.00	110.3750	220,750.00	20,750.00
25,000.0000	T-MOBILE USA INC 5.375% 04/15/2027 DD 03/16/17	25,000.00	107.2500	26,812.50	1,812.50
50,000.0000	TRI POINTE GROUP INC 5.250% 06/01/2027 DD 06/08/17	50,000.00	100.2500	50,125.00	125.00
96,250.0000	ALLFLEX 7/13 TL	96,250.00	100.2500	96,490.63	240.63
75,000.0000	TALLGRASS ENERGY PARTNERS 144A 5.500% 09/15/2024 DD 09/01/16	75,000.00	101.2500	75,937.50	937.50
241,000.0000	TECK RESOURCES LTD 4.750% 01/15/2022 DD 07/05/11	220,641.58	103.5000	249,435.00	28,793.42
200,000.0000	TELECOM ITALIA SPA/MILANO 144A 5.303% 05/30/2024 DD 05/30/14	198,502.64	107.2500	214,500.00	15,997.36
100,000.0000	TELESAT CANADA / TELESAT 144A 8.875% 11/15/2024 DD 11/17/16	100,000.00	112.2500	112,250.00	12,250.00
50,000.0000	TEMPO ACQUISITION LLC / T 144A 6.750% 06/01/2025 DD 05/01/17	50,000.00	102.2500	51,125.00	1,125.00

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125,000.0000	TENET HEALTHCARE CORP 8.125% 04/01/2022 DD 09/27/13	129,874.94	106.1250	132,656.25	2,781.31
25,000.0000	TENET HEALTHCARE CORP 144A 7.500% 01/01/2022 DD 12/01/16	25,000.00	108.4800	27,120.00	2,120.00
64,000.0000	TENET HEALTHCARE CORP 144A 4.625% 07/15/2024 DD 06/14/17	64,000.00	100.1250	64,080.00	80.00
175,000.0000	TEAM HEALTH HOLDINGS INC 144A 6.375% 02/01/2025 DD 02/01/17	169,828.09	97.0000	169,750.00	78.09-
50,000.0000	TEREX CORP 144A 5.625% 02/01/2025 DD 01/31/17	50,000.00	102.8750	51,437.50	1,437.50
200,000.0000	TESORO LOGISTICS LP / TESORO L 5.500% 10/15/2019 DD 10/15/15	163,315.11	105.5000	211,000.00	47,684.89
300,000.0000	TOWNSQUARE MEDIA INC 144A 6.500% 04/01/2023 DD 04/01/15	300,000.00	100.5000	301,500.00	1,500.00
200,000.0000	TRANSDIGM INC 6.000% 07/15/2022 DD 06/04/14	207,745.34	103.0000	206,000.00	1,745.34-
75,000.0000	TRANSDIGM INC 6.500% 05/15/2025 DD 11/15/15	76,088.48	101.7500	76,312.50	224.02
50,000.0000	TRINIDAD DRILLING LTD 144A 6.625% 02/15/2025 DD 02/08/17	50,000.00	95.0000	47,500.00	2,500.00-
200,000.0000	UPCB FINANCE IV LTD 144A 5.375% 01/15/2025 DD 04/15/15	203,286.99	104.6250	209,250.00	5,963.01

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
50,000.0000	USG CORP 144A 4.875% 06/01/2027 DD 05/15/17	50,000.00	102.8750	51,437.50	1,437.50
25,000.0000	ULTRA RESOURCES INC 144A 6.875% 04/15/2022 DD 04/12/17	25,000.00	99.2500	24,812.50	187.50-
25,000.0000	ULTRA RESOURCES INC 144A 7.125% 04/15/2025 DD 04/12/17	24,634.48	98.6250	24,656.25	21.77
150,000.0000	UNITED RENTALS NORTH AMERICA I 6.125% 06/15/2023 DD 10/30/12	145,275.89	104.1250	156,187.50	10,911.61
25,000.0000	UNITED RENTALS NORTH AMERICA I 5.875% 09/15/2026 DD 05/13/16	26,123.79	106.5000	26,625.00	501.21
50,000.0000	UNITI GROUP INC / UNITI F 144A 7.125% 12/15/2024 DD 12/15/16	50,246.10	99.1250	49,562.50	683.60-
180,000.0000	UNITYMEDIA HESSEN GMBH & 144A 5.500% 01/15/2023 DD 12/14/12	181,087.15	103.7500	186,750.00	5,662.85
200,000.0000	UNIVERSAL HEALTH SERVICES 144A 4.750% 08/01/2022 DD 08/07/14	202,526.73	103.3750	206,750.00	4,223.27
200,000.0000	UNIVISION COMMUNICATIONS 144A 5.125% 05/15/2023 DD 05/21/13	204,486.33	100.9680	201,936.00	2,550.33-
100,000.0000	USIS MERGER SUB INC 144A 6.875% 05/01/2025 DD 04/18/17	100,000.00	101.7500	101,750.00	1,750.00
255,000.0000	VALEANT PHARMACEUTICALS I 144A 5.375% 03/15/2020 DD 03/27/15	241,921.05	96.6250	246,393.75	4,472.70

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
50,000.0000	VALEANT PHARMACEUTICALS I 144A 6.500% 03/15/2022 DD 03/21/17	50,000.00	104.8750	52,437.50	2,437.50
55,000.0000	VENATOR FINANCE SARL / VE 144A 5.750% 07/15/2025 DD 07/14/17	55,000.00	101.0000	55,550.00	550.00
40,000.0000	VERISIGN INC 144A 4.750% 07/15/2027 DD 07/05/17	40,000.00	101.1250	40,450.00	450.00
250,000.0000	VIASAT INC 6.875% 06/15/2020 DD 06/15/12	250,954.14	101.9680	254,920.00	3,965.86
50,000.0000	VIDEOTRON LTD 5.000% 07/15/2022 DD 07/15/12	50,506.52	105.7500	52,875.00	2,368.48
200,000.0000	VIKING CRUISES LTD 144A 8.500% 10/15/2022 DD 10/19/12	190,015.08	105.0000	210,000.00	19,984.92
200,000.0000	VISTA OUTDOOR INC 5.875% 10/01/2023 DD 10/01/16	200,000.00	102.7500	205,500.00	5,500.00
225,000.0000	VALEANT PHARMACEUTICALS I 144A 7.500% 07/15/2021 DD 07/12/13	222,843.75	96.8750	217,968.75	4,875.00-
8,000.0000	VALEANT PHARMACEUTICALS I 144A 6.750% 08/15/2018 DD 07/12/13	7,850.91	100.2500	8,020.00	169.09
146,000.0000	WMG ACQUISITION CORP 144A 5.625% 04/15/2022 DD 04/09/14	146,241.39	103.5000	151,110.00	4,868.61
100,000.0000	WAVEDIVISION ESCROW LLC / 144A 8.125% 09/01/2020 DD 08/21/12	103,288.45	103.5800	103,580.00	291.55

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
200,000.0000	WEATHERFORD INTERNATIONAL LTD 7.750% 06/15/2021 DD 06/17/16	205,911.84	100.5000	201,000.00	4,911.84-
40,000.0000	WEATHERFORD INTERNATIONAL 144A 9.875% 02/15/2024 DD 11/18/16	40,399.75	104.5000	41,800.00	1,400.25
100,000.0000	WELLCARE HEALTH PLANS INC 5.250% 04/01/2025 DD 03/22/17	100,000.00	104.7500	104,750.00	4,750.00
200,000.0000	WESCO DISTRIBUTION INC 5.375% 06/15/2024 DD 12/15/16	200,000.00	104.3750	208,750.00	8,750.00
150,000.0000	WHITING PETROLEUM CORP 5.750% 03/15/2021 DD 09/12/13	137,382.79	94.0000	141,000.00	3,617.21
175,000.0000	WHITING PETROLEUM CORP 6.250% 04/01/2023 DD 03/27/15	168,407.32	91.7500	160,562.50	7,844.82-
182,000.0000	WIDEOPENWEST FINANCE LLC / WID 10.250% 07/15/2019 DD 01/15/13	189,173.02	103.0000	187,460.00	1,713.02-
50,000.0000	WILDHORSE RESOURCE DEVELO 144A 6.875% 02/01/2025 DD 02/01/17	49,636.99	94.0000	47,000.00	2,636.99-
200,000.0000	WIND ACQUISITION FINANCE 144A 4.750% 07/15/2020 DD 07/10/14	202,778.62	101.0500	202,100.00	678.62-
200,000.0000	WPX ENERGY INC 6.000% 01/15/2022 DD 11/14/11	181,295.02	99.0000	198,000.00	16,704.98
100,000.0000	WPX ENERGY INC 5.250% 09/15/2024 DD 09/08/14	89,417.68	95.0000	95,000.00	5,582.32

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
75,000.0000	ZAYO GROUP LLC / ZAYO CAP 144A 5.750% 01/15/2027 DD 01/27/17	75,000.00	104.6250	78,468.75	3,468.75
150,000.0000	ZIGGO SECURED FINANCE BV 144A 5.500% 01/15/2027 DD 09/23/16	150,000.00	102.1250	153,187.50	3,187.50
195,000.0000	BRAND ENERGY 6/17 TL 0.000% 06/21/2024 DD 06/01/17	193,052.29	99.7810	194,572.95	1,520.66
TOTAL INVESTMENTS FIXED INCOME SECURITIES		39,381,029.94		40,484,666.94	1,103,637.00
TOTAL INVESTMENT		40,428,751.48		41,532,388.48	1,103,637.00

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS CASH EQUIVALENTS					
0.0700	BLACKROCK LIQ T FUND INSTL FUND 60	0.07	100.0000	0.07	0.00
TOTAL INVESTMENTS CASH EQUIVALENTS		0.07		0.07	0.00
INVESTMENTS EQUITY					
1,848,335.4470	PARAMETRIC TX-MGD EM MK-INST	83,091,437.05	47.7400	88,239,534.24	5,148,097.19
TOTAL INVESTMENTS EQUITY		83,091,437.05		88,239,534.24	5,148,097.19
TOTAL INVESTMENT		83,091,437.12		88,239,534.31	5,148,097.19

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PARAMETRIC EAFE - MONTICELLO
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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS CASH EQUIVALENTS					
71.0600	AUD (AUSTRALIAN DOLLARS)	54.01	0.0000	54.51	0.50 C
460.7000	NZD (NEW ZEALAND DOLLAR)	333.50	0.0000	337.32	3.82 C
57.7500	CHF (SWISS FRANC)	59.30	0.0000	60.30	1.00 C
36,219.1500	GBP (GREAT BRITISH POUNDS)	46,266.44	0.0000	47,046.86	780.42 C
35,972.6800	HKD (HONG KONG DOLLARS)	4,611.88	0.0000	4,608.07	3.81-C
13,102,918.0000	JPY (JAPANESE YEN)	116,941.46	0.0000	116,615.50	325.96-C
851.0400	SGD (SINGAPORE DOLLARS)	613.58	0.0000	618.11	4.53 C
2,584.3300	ILS (ISRAELI SHEKEL)	730.31	0.0000	740.56	10.25 C
336.2700	DKK (DANISH KRONE)	50.50	0.0000	51.58	1.08 C
17,829.3100	NOK (NORWEGIAN KRONE)	2,109.78	0.0000	2,128.45	18.67 C
438.2400	SEK (SWEDISH KRONA)	50.20	0.0000	51.96	1.76 C
38,499.7200	EUR (EURO)	43,379.95	0.0000	43,910.86	530.91 C
343,366.5500	BLACKROCK LIQ T FUND INSTL FUND 60	343,366.55	100.0000	343,366.55	0.00
TOTAL INVESTMENTS CASH EQUIVALENTS		558,567.46		559,590.63	1,023.17 1,023.17 C 0.00 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS PREFERRED SECURITIES					
1,347.0000	HENKEL AG & CO KGAA	99,338.08	137.4362	185,126.66	85,788.58 14,173.41- C 99,961.99 I
1,488.0000	VOLKSWAGEN AG	168,707.81	152.0923	226,313.41	57,605.60 12,892.70- C 70,498.30 I
540.0000	BAYERISCHE MOTOREN WERKE AG	36,574.67	82.3248	44,455.45	7,880.78 9,089.04- C 16,969.82 I
435.0000	PORSCHE AUTOMOBIL HOLDING SE	23,493.66	56.1036	24,405.09	911.43 4,561.99- C 5,473.42 I
TOTAL INVESTMENTS PREFERRED SECURITIES		328,114.22		480,300.61	152,186.39 40,717.14- C 192,903.53 I
INVESTMENTS EQUITY					
38,054.0000	SCENTRE GROUP	112,700.27	3.1065	118,216.75	5,516.48 18,299.91- C 23,816.39 I
4,433.0000	WESTFIELD CORP	29,595.88	6.1594	27,304.67	2,291.21- 281.22 C 2,572.43- I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
14,024.0000	HEALTHSCOPE LTD	30,715.81	1.6951	23,773.21	6,942.60- 898.80- C 6,043.80- I
27,729.0000	MEDIBANK PVT LTD	52,377.28	2.1477	59,554.68	7,177.40 4,177.10- C 11,354.50 I
5,245.0000	AGL ENERGY LTD	71,374.89	19.5597	102,591.02	31,216.13 14,118.37- C 45,334.50 I
52,534.0000	SOUTH32 LTD	104,287.50	2.0556	107,993.83	3,706.33 123.16 C 3,583.17 I
1,229.0000	CIMIC GROUP LTD	32,017.74	29.7922	36,614.64	4,596.90 377.10 C 4,219.80 I
28,330.0000	VICINITY CENTRES	61,453.93	1.9713	55,847.45	5,606.48- 2,154.51- C 3,451.97- I
8,849.0000	TATTS GROUP LTD	19,974.05	3.2062	28,372.27	8,398.22 5,688.87- C 14,087.09 I
12,897.0000	GOODMAN GROUP	49,717.90	6.0366	77,855.11	28,137.21 16,662.53- C 44,799.74 I
8,403.0000	DEXUS	39,754.57	7.2716	61,103.54	21,348.97 2,503.83- C 23,852.80 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
7,022.0000	BRAMBLES LTD	47,550.40	7.4633	52,407.97	4,857.57 10,508.24- C 15,365.81 I
2,182.0000	MACQUARIE GROUP LTD	102,230.73	67.8839	148,122.72	45,891.99 21,768.63- C 67,660.62 I
2,648.0000	CROWN RESORTS LTD	19,761.00	9.4193	24,942.50	5,181.50 5,001.19- C 10,182.69 I
3,045.0000	JAMES HARDIE INDUSTRIES PLC	20,086.60	15.7245	47,881.18	27,794.58 9,600.60- C 37,395.18 I
3,968.0000	TREASURY WINE ESTATES LTD	17,875.39	10.0943	40,054.49	22,179.10 8,727.33- C 30,906.43 I
9,676.0000	SYDNEY AIRPORT	40,518.28	5.4383	52,621.81	12,103.53 4,445.46 C 7,658.07 I
15,943.0000	AURIZON HOLDINGS LTD	49,791.33	4.1113	65,547.86	15,756.53 21,021.93- C 36,778.46 I
1,434.0000	RAMSAY HEALTH CARE LTD	29,788.66	56.4548	80,956.30	51,167.64 21,857.83- C 73,025.47 I
17,424.0000	AUSTRALIA & NEW ZEALAND BANKIN	389,966.74	22.0296	383,845.07	6,121.67- 54,446.11- C 48,324.44 I

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8,747.0000	AMCOR LTD/AUSTRALIA	67,266.72	12.4338	108,759.15	41,492.43	
					17,894.91-	C
					59,387.34	I
18,973.0000	WESTPAC BANKING CORP	471,330.16	23.4026	444,019.34	27,310.82-	
					61,498.14-	C
					34,187.32	I
3,052.0000	BANK OF QUEENSLAND LTD	29,376.02	8.7827	26,804.87	2,571.15-	
					1,880.06-	C
					691.09-	I
18,370.0000	FORTESCUE METALS GROUP LTD	65,171.52	4.0040	73,553.50	8,381.98	
					394.09	C
					7,987.89	I
21,657.0000	TELSTRA CORP LTD	59,858.47	3.2983	71,431.61	11,573.14	
					14,322.65-	C
					25,895.79	I
2,202.0000	BENDIGO & ADELAIDE BANK LTD	20,388.69	8.4989	18,714.61	1,674.08-	
					3,752.43-	C
					2,078.35	I
1,636.0000	ASX LTD	47,491.01	41.1215	67,274.86	19,783.85	
					3,826.82-	C
					23,610.67	I
14,955.0000	BHP BILLITON LTD	343,815.79	17.8569	267,050.30	76,765.49-	
					11,981.58-	C
					64,783.91-	I
2,007.0000	CALTEX AUSTRALIA LTD	49,804.82	24.2464	48,662.63	1,142.19-	
					669.32	C
					1,811.51-	I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS	
34,475.0000	MIRVAC GROUP	50,852.66	1.6338	56,325.82	5,473.16	
					3,959.76-	C
					9,432.92	I
5,949.0000	HARVEY NORMAN HOLDINGS LTD	20,005.20	2.9301	17,431.35	2,573.85-	
					3,495.13-	C
					921.28	I
3,288.0000	CSL LTD	123,938.65	105.8759	348,120.00	224,181.35	
					40,045.24-	C
					264,226.59	I
990.0000	REA GROUP LTD	39,521.66	50.9321	50,422.80	10,901.14	
					519.33	C
					10,381.81	I
14,169.0000	TRANSURBAN GROUP	87,753.82	9.0895	128,789.73	41,035.91	
					19,653.38-	C
					60,689.29	I
299.0000	COCHLEAR LTD	19,960.68	119.2379	35,652.14	15,691.46	
					7,148.54-	C
					22,840.00	I
5,411.0000	ORIGIN ENERGY LTD	29,138.58	5.2619	28,472.48	666.10-	
					293.25	C
					959.35-	I
10,673.0000	COMMONWEALTH BANK OF AUSTRALIA	560,320.92	63.5194	677,942.67	117,621.75	
					95,857.93-	C
					213,479.68	I
13,967.0000	BORAL LTD	51,582.55	5.3309	74,458.04	22,875.49	
					1,698.51	C
					21,176.98	I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS	
1,920.0000	RIO TINTO LTD	85,001.94	48.5312	93,180.01	8,178.07	
					1,910.11-	C
					10,088.18	I
8,399.0000	APA GROUP	50,133.99	7.0338	59,077.29	8,943.30	
					8,394.05-	C
					17,337.35	I
6,916.0000	ARISTOCRAT LEISURE LTD	41,837.62	17.3046	119,678.95	77,841.33	
					10,110.42	C
					67,730.91	I
10,929.0000	INSURANCE AUSTRALIA GROUP LTD	40,290.68	5.2005	56,837.35	16,546.67	
					10,621.77-	C
					27,168.44	I
7,952.0000	TPG TELECOM LTD	43,115.40	4.3721	34,767.62	8,347.78-	
					793.22	C
					9,141.00-	I
9,227.0000	GPT GROUP/THE	24,866.84	3.6741	33,901.56	9,034.72	
					6,797.54-	C
					15,832.26	I
4,895.0000	LENDLEASE GROUP	40,969.55	12.7713	62,515.92	21,546.37	
					2,806.37-	C
					24,352.74	I
6,688.0000	SUNCORP GROUP LTD	54,644.97	11.3676	76,027.05	21,382.08	
					14,152.13-	C
					35,534.21	I
13,348.0000	NATIONAL AUSTRALIA BANK LTD	324,060.56	22.6970	302,959.68	21,100.88-	
					35,917.86-	C
					14,816.98	I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
5,443.0000	NEWCREST MINING LTD	55,168.96	15.4637	84,169.07	29,000.11
					868.70 C
					28,131.41 I
15,811.0000	OIL SEARCH LTD	81,687.13	5.2312	82,711.78	1,024.65
					3,554.58 C
					2,529.93- I
24,670.0000	INCITEC PIVOT LTD	65,747.75	2.6156	64,527.85	1,219.90-
					1,219.77 C
					2,439.67- I
7,122.0000	QANTAS AIRWAYS LTD	19,845.44	4.3875	31,247.96	11,402.52
					6,265.48- C
					17,668.00 I
5,861.0000	QBE INSURANCE GROUP LTD	49,293.89	9.0588	53,093.98	3,800.09
					2,007.33- C
					5,807.42 I
4,753.0000	CHALLENGER LTD/AUSTRALIA	30,233.99	10.2324	48,634.82	18,400.83
					1,990.92 C
					16,409.91 I
13,593.0000	SANTOS LTD	41,297.14	2.3241	31,592.33	9,704.81-
					325.38 C
					10,030.19- I
1,834.0000	SONIC HEALTHCARE LTD	24,331.44	18.5779	34,071.96	9,740.52
					6,831.73- C
					16,572.25 I
19,184.0000	STOCKLAND	62,853.64	3.3596	64,452.08	1,598.44
					6,001.08- C
					7,599.52 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS	
8,592.0000	WESFARMERS LTD	261,042.76	30.7740	264,410.60	3,367.84	
					29,563.43-	C
					32,931.27	I
12,620.0000	ALUMINA LTD	20,521.55	1.4727	18,585.93	1,935.62-	
					3,726.64-	C
					1,791.02	I
1,712.0000	WOODSIDE PETROLEUM LTD	41,037.93	22.9117	39,224.97	1,812.96-	
					403.99	C
					2,216.95-	I
3,608.0000	WOOLWORTHS LTD	82,931.76	19.5904	70,682.37	12,249.39-	
					4,270.77-	C
					7,978.62-	I
7,651.0000	AUCKLAND INTERNATIONAL AIRPORT	21,039.75	5.2205	39,942.70	18,902.95	
					3,133.99-	C
					22,036.94	I
4,988.0000	FLETCHER BUILDING LTD	29,421.68	5.8502	29,181.19	240.49-	
					1,008.32	C
					1,248.81-	I
13,044.0000	SPARK NEW ZEALAND LTD	15,274.71	2.7677	36,102.09	20,827.38	
					1,247.43	C
					19,579.95	I
1,617.0000	RAIFFEISEN BANK INTERNATIONAL	31,391.73	25.2061	40,758.35	9,366.62	
					2,732.00	C
					6,634.62	I
746.0000	OMV AG	28,806.57	51.8208	38,658.38	9,851.81	
					7,226.32-	C
					17,078.13	I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
1,254.0000	VOESTALPINE AG	43,652.24	46.5344	58,354.19	14,701.95
					9,488.69- C
					24,190.64 I
1,365.0000	ERSTE GROUP BANK AG	39,598.69	38.2369	52,193.43	12,594.74
					2,302.98- C
					14,897.72 I
4,849.0000	ANHEUSER-BUSCH INBEV SA/NV	282,423.60	110.3025	534,857.26	252,433.66
					86,557.49- C
					338,991.15 I
809.0000	TELENET GROUP HOLDING NV	43,365.63	62.9013	50,887.18	7,521.55
					10,556.23- C
					18,077.78 I
1,378.0000	PROXIMUS SADP	39,280.61	34.9350	48,140.49	8,859.88
					3,226.81 C
					5,633.07 I
1,518.0000	AGEAS	54,255.95	40.2157	61,047.57	6,791.62
					5,951.39- C
					12,743.01 I
579.0000	UMICORE SA	21,060.05	69.4594	40,217.05	19,157.00
					7,517.68- C
					26,674.68 I
1,756.0000	KBC GROUP NV	94,569.83	75.7439	133,006.33	38,436.50
					17,341.23- C
					55,777.73 I
892.0000	SOLVAY SA	99,511.16	134.0146	119,541.05	20,029.89
					1,851.67- C
					21,881.56 I

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502.0000	UCB SA	21,798.31	68.6953	34,485.05	12,686.74
					6,446.20- C
					19,132.94 I
441.0000	COLRUYT SA	19,851.03	52.6078	23,200.08	3,349.05
					1,702.55- C
					5,051.60 I
2,969.0000	VONOVIA SE	100,691.38	39.6512	117,724.48	17,033.10
					2,339.42- C
					19,372.52 I
1,274.0000	PROSIEBENSAT.1 MEDIA SE	58,833.45	41.7897	53,240.14	5,593.31-
					4,883.00- C
					710.31- I
1,034.0000	ZALANDO SE	33,928.83	45.6334	47,184.94	13,256.11
					479.90 C
					12,776.21 I
518.0000	COVESTRO AG	38,920.13	72.0941	37,344.78	1,575.35-
					1,959.66 C
					3,535.01- I
1,107.0000	QIAGEN NV	26,788.50	33.2185	36,772.91	9,984.41
					6,873.87- C
					16,858.28 I
2,062.0000	DEUTSCHE WOHNEN AG	40,751.08	38.1970	78,762.25	38,011.17
					16,338.74- C
					54,349.91 I
799.0000	LANXESS AG	59,725.81	75.6070	60,410.04	684.23
					10,844.48- C
					11,528.71 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS	
598.0000	SYMRISE AG	37,456.45	70.7369	42,300.67	4,844.22	
					604.93	C
					4,239.29	I
1,036.0000	BRENNTAG AG	41,028.96	57.8030	59,883.98	18,855.02	
					2,612.03-	C
					21,467.05	I
1,021.0000	K+S AG	28,310.75	25.5711	26,108.12	2,202.63-	
					2,328.00-	C
					125.37	I
12,878.0000	TELEFONICA DEUTSCHLAND HOLDING	58,060.62	4.9876	64,230.63	6,170.01	
					3,442.93	C
					2,727.08	I
8,676.0000	COMMERZBANK AG	71,543.13	11.8959	103,209.15	31,666.02	
					1,378.19	C
					30,287.83	I
1,324.0000	OSRAM LICHT AG	47,456.66	79.5533	105,328.65	57,871.99	
					11,845.08-	C
					69,717.07	I
1,476.0000	ADIDAS AG	88,150.45	191.3272	282,399.04	194,248.59	
					32,236.88-	C
					226,485.47	I
2,628.0000	FRESENIUS SE & CO KGAA	89,569.77	85.6096	224,982.25	135,412.48	
					20,272.18-	C
					155,684.66	I
1,307.0000	UNITED INTERNET AG	20,278.07	54.9117	71,769.70	51,491.63	
					13,415.74-	C
					64,907.37	I

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402.0000	HANNOVER RUECK SE	20,341.76	119.7007	48,119.69	27,777.93	
					8,994.89-	C
					36,772.82	I
1,440.0000	GEA GROUP AG	42,360.16	40.8659	58,846.91	16,486.75	
					4,188.49-	C
					20,675.24	I
572.0000	CONTINENTAL AG	58,728.03	215.5069	123,269.96	64,541.93	
					17,647.25-	C
					82,189.18	I
6,103.0000	DEUTSCHE POST AG	131,292.81	37.4328	228,452.69	97,159.88	
					20,766.05-	C
					117,925.93	I
876.0000	MERCK KGAA	46,659.71	120.6131	105,657.13	58,997.42	
					9,033.19-	C
					68,030.61	I
2,231.0000	RWE AG	29,562.09	19.8968	44,389.98	14,827.89	
					2,329.36	C
					12,498.53	I
6,531.0000	SAP SE	360,042.82	104.3032	681,204.84	321,162.02	
					72,211.21-	C
					393,373.23	I
8,641.0000	E.ON SE	66,363.32	9.4072	81,288.10	14,924.78	
					4,265.55	C
					10,659.23	I
646.0000	HENKEL AG & CO KGAA	30,417.97	120.7842	78,026.62	47,608.65	
					14,585.29-	C
					62,193.94	I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
1,202.0000	METRO AG	34,883.29	33.7089	40,518.16	5,634.87 3,612.91- C 9,247.78 I
4,540.0000	BAYER AG	335,925.96	129.1102	586,160.58	250,234.62 111,580.62- C 361,815.24 I
5,984.0000	BASF SE	406,775.65	92.4872	553,443.40	146,667.75 68,218.85- C 214,886.60 I
439.0000	BEIERSDORF AG	26,432.66	104.9762	46,084.56	19,651.90 8,614.47- C 28,266.37 I
239.0000	HOCHTIEF AG	20,642.86	182.9442	43,723.67	23,080.81 8,173.15- C 31,253.96 I
995.0000	HEIDELBERGCEMENT AG	60,097.59	96.5475	96,064.82	35,967.23 10,353.21- C 46,320.44 I
1,402.0000	FRESENIUS MEDICAL CARE AG & CO	84,184.93	96.0000	134,592.13	50,407.20 26,202.50- C 76,609.70 I
3,202.0000	ALLIANZ SE	437,709.64	196.6308	629,611.89	191,902.25 77,731.83- C 269,634.08 I
1,196.0000	DEUTSCHE LUFTHANSA AG	20,491.66	22.7254	27,179.65	6,687.99 5,080.62- C 11,768.61 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
1,224.0000	MUENCHENER RUECKVERSICHERUNGS-	206,933.86	201.3641	246,469.66	39,535.80 33,116.66- C 72,652.46 I
460.0000	VOLKSWAGEN AG	56,612.24	154.8296	71,221.64	14,609.40 824.13- C 15,433.53 I
5,468.0000	DAIMLER AG	287,308.70	72.2766	395,208.74	107,900.04 53,260.26- C 161,160.30 I
395.0000	MAN SE	33,357.16	107.0634	42,290.05	8,932.89 7,905.15- C 16,838.04 I
1,154.0000	THYSSENKRUPP AG	28,785.87	28.3711	32,740.34	3,954.47 2,919.39- C 6,873.86 I
5,178.0000	SIEMENS AG	509,237.54	137.2651	710,759.17	201,521.63 94,272.26- C 295,793.89 I
1,151.0000	LINDE AG	151,260.43	189.1031	217,657.77	66,397.34 26,737.24- C 93,134.58 I
8,027.0000	DEUTSCHE BANK AG	170,915.06	17.7070	142,134.41	28,780.65- 5,015.56 C 33,796.21- I
2,308.0000	BAYERISCHE MOTOREN WERKE AG	139,538.27	92.7039	213,960.61	74,422.34 14,745.12- C 89,167.46 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
15,974.0000	DEUTSCHE TELEKOM AG	221,304.64	17.9294	286,404.97	65,100.33 54,367.30- C 119,467.63 I
7,670.0000	INFINEON TECHNOLOGIES AG	63,209.52	21.0830	161,707.12	98,497.60 15,090.94- C 113,588.54 I
673.0000	DEUTSCHE BOERSE AG	56,866.89	105.4096	70,940.68	14,073.79 1,326.20 C 12,747.59 I
378.0000	FRAPORT AG FRANKFURT AIRPORT S	20,141.04	88.1645	33,326.19	13,185.15 6,229.58- C 19,414.73 I
4,865.0000	RED ELECTRICA CORP SA	80,083.78	20.8663	101,514.86	21,431.08 1,454.64- C 22,885.72 I
1,165.0000	ACS ACTIVIDADES DE CONSTRUCCIO	962.49	0.7983	930.12	32.37- 9.71 C 42.08- I
7,136.0000	INDUSTRIA DE DISENO TEXTIL SA	123,083.19	38.3338	273,550.61	150,467.42 34,829.74- C 185,297.16 I
428.0000	AENA SA	36,615.36	194.8629	83,401.35	46,785.99 5,857.23 C 40,928.76 I
3,878.0000	GRIFOLS SA	40,158.90	27.8123	107,856.14	67,697.24 3,314.39- C 71,011.63 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
1,165.0000	ACS ACTIVIDADES DE CONSTRUCCIO	38,356.06	38.5791	44,944.66	6,588.60 4,007.61- C 10,596.21 I
5,264.0000	FERROVIAL SA	78,034.51	22.1665	116,684.93	38,650.42 905.15 C 37,745.27 I
13,417.0000	BANCO DE SABADELL SA	26,348.62	2.0290	27,223.61	874.99 3,672.21- C 4,547.20 I
8,703.0000	CAIXABANK SA	38,897.53	4.7674	41,491.54	2,594.01 156.44- C 2,750.45 I
27,037.0000	IBERDROLA SA	176,206.10	7.9074	213,793.27	37,587.17 2,549.67- C 40,136.84 I
3,878.0000	AMADEUS IT GROUP SA	136,775.09	59.7077	231,546.82	94,771.73 17,103.57- C 111,875.30 I
10,470.0000	INTERNATIONAL CONSOLIDATED AIR	58,061.17	7.9256	82,981.89	24,920.72 5,805.70- C 30,726.42 I
10,771.0000	DISTRIBUIDORA INTERNACIONAL DE	52,095.27	6.2171	66,964.79	14,869.52 4,488.59 C 10,380.93 I
6,893.0000	ABERTIS INFRAESTRUCTURAS SA	101,358.77	18.4997	127,518.58	26,159.81 1,950.71 C 24,209.10 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS	
3,813.0000	ENDESA SA	76,275.13	23.0048	87,717.66	11,442.53	
					6,031.56	C
					5,410.97	I
9,611.0000	BANKINTER SA	64,061.62	9.1985	88,407.13	24,345.51	
					641.25-	C
					24,986.76	I
34,247.0000	BANCO BILBAO VIZCAYA ARGENTARI	258,678.98	8.2860	283,773.93	25,094.95	
					6,163.33	C
					18,931.62	I
4,301.0000	GAS NATURAL SDG SA	78,860.49	23.3698	100,513.81	21,653.32	
					864.23-	C
					22,517.55	I
5,146.0000	REPSOL SA	70,402.91	15.2833	78,648.22	8,245.31	
					3,422.03	C
					4,823.28	I
77,572.0000	BANCO SANTANDER SA	472,669.96	6.6060	512,445.72	39,775.76	
					4,939.77	C
					34,835.99	I
19,883.0000	TELEFONICA SA	195,583.88	10.3082	204,959.74	9,375.86	
					9,676.38	C
					300.52-	I
2,850.0000	ENAGAS SA	71,345.68	28.0005	79,801.43	8,455.75	
					244.52	C
					8,211.23	I
1,683.0000	VALEO SA	70,951.59	67.2810	113,234.00	42,282.41	
					10,229.01-	C
					52,511.42	I

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7,671.0000	ENGIE SA	96,752.88	15.0723	115,620.14	18,867.26	
					5,745.08	C
					13,122.18	I
639.0000	ARKEMA SA	48,272.48	106.5615	68,092.85	19,820.37	
					10,338.85-	C
					30,159.22	I
2,285.0000	SES SA	55,425.87	23.4097	53,491.37	1,934.50-	
					5,039.98-	C
					3,105.48	I
317.0000	GEMALTO NV	20,537.17	59.9359	18,999.68	1,537.49-	
					404.80	C
					1,942.29-	I
1,809.0000	SAFRAN SA	85,804.05	91.5177	165,555.58	79,751.53	
					17,944.01-	C
					97,695.54	I
12,218.0000	NATIXIS SA	66,857.66	6.7030	81,897.41	15,039.75	
					1,568.93-	C
					16,608.68	I
824.0000	SCOR SE	21,137.94	39.5884	32,620.92	11,482.98	
					6,097.74-	C
					17,580.72	I
3,191.0000	REXEL SA	49,245.57	16.3383	52,135.77	2,890.20	
					2,977.82	C
					87.62-	I
3,505.0000	VINCI SA	210,615.68	85.2333	298,742.72	88,127.04	
					40,892.95-	C
					129,019.99	I

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2,304.0000	AIR LIQUIDE SA	226,988.71	123.4075	284,330.90	57,342.19	
					38,694.75-	C
					96,036.94	I
3,898.0000	DANONE SA	244,019.05	75.0595	292,582.30	48,563.25	
					33,916.98-	C
					82,480.23	I
1,824.0000	LEGRAND SA	77,747.96	69.8586	127,422.25	49,674.29	
					12,744.73-	C
					62,419.02	I
436.0000	EIFFAGE SA	31,555.28	90.7421	39,563.58	8,008.30	
					237.61	C
					7,770.69	I
14,466.0000	TOTAL SA	792,030.62	49.3687	714,167.71	77,862.91-	
					71,057.01-	C
					6,805.90-	I
249.0000	AEROPORTS DE PARIS	20,801.73	161.1597	40,128.77	19,327.04	
					7,501.18-	C
					26,828.22	I
1,524.0000	BUREAU VERITAS SA	20,716.30	22.0981	33,677.59	12,961.29	
					6,295.26-	C
					19,256.55	I
2,370.0000	GROUPE EUROTUNNEL SE	24,524.33	10.6504	25,241.58	717.25	
					4,718.34-	C
					5,435.59	I
1,264.0000	SUEZ	23,338.77	18.4940	23,376.44	37.67	
					16.32-	C
					53.99	I

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729.0000	EDENRED	14,565.66	26.0387	18,982.25	4,416.59
					3,548.31- C
					7,964.90 I
808.0000	BOUYGUES SA	29,490.59	42.1091	34,024.16	4,533.57
					1,785.42 C
					2,748.15 I
4,222.0000	AIRBUS SE	168,783.41	82.1196	346,708.95	177,925.54
					38,662.81- C
					216,588.35 I
2,184.0000	VEOLIA ENVIRONNEMENT SA	37,343.63	21.1001	46,082.78	8,739.15
					4,109.10- C
					12,848.25 I
1,191.0000	L'OREAL SA	127,388.28	208.0363	247,771.26	120,382.98
					46,315.22- C
					166,698.20 I
1,967.0000	LVMH MOET HENNESSY LOUIS VUITT	277,748.75	248.9820	489,747.72	211,998.97
					62,784.02- C
					274,782.99 I
791.0000	THALES SA	40,323.43	107.4854	85,020.98	44,697.55
					6,213.78- C
					50,911.33 I
1,534.0000	CAPGEMINI SE	99,143.08	103.1969	158,304.14	59,161.06
					5,928.14- C
					65,089.20 I
1,298.0000	PUBLICIS GROUPE SA	80,106.45	74.4893	96,687.14	16,580.69
					12,891.08- C
					29,471.77 I

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740.0000	LAGARDERE SCA	19,995.77	31.5362	23,336.79	3,341.02	
					3,145.88-	C
					6,486.90	I
8,140.0000	BOLLORE SA	29,742.64	4.5405	36,959.91	7,217.27	
					688.62	C
					6,528.65	I
1,286.0000	CIE GENERALE DES ETABLISSEMENT	109,976.94	132.7600	170,729.39	60,752.45	
					23,690.75-	C
					84,443.20	I
1,227.0000	PERNOD RICARD SA	109,818.76	133.7294	164,086.08	54,267.32	
					21,838.82-	C
					76,106.14	I
1,760.0000	RENAULT SA	114,407.62	90.3885	159,083.91	44,676.29	
					5,716.90-	C
					50,393.19	I
209.0000	REMY COINTREAU SA	20,128.29	116.6212	24,373.84	4,245.55	
					2,262.04-	C
					6,507.59	I
3,519.0000	SCHNEIDER ELECTRIC SE	204,298.62	76.7247	269,994.57	65,695.95	
					34,763.68-	C
					100,459.63	I
3,151.0000	VIVENDI SA	77,891.77	22.2293	70,044.59	7,847.18-	
					3,450.95-	C
					4,396.23-	I
11,500.0000	ORANGE SA	180,459.31	15.8422	182,185.75	1,726.44	
					2,001.51	C
					275.07-	I

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202.0000	HERMES INTERNATIONAL	59,762.21	493.4589	99,678.71	39,916.50	
					5,645.00-	C
					45,561.50	I
684.0000	DASSAULT SYSTEMES SE	20,640.82	89.5217	61,232.89	40,592.07	
					11,446.12-	C
					52,038.19	I
528.0000	KERING	81,988.54	340.1120	179,579.14	97,590.60	
					19,205.50-	C
					116,796.10	I
1,212.0000	CARREFOUR SA	29,777.57	25.2631	30,618.98	841.41	
					1,606.72	C
					765.31-	I
745.0000	ATOS SE	51,206.59	140.1735	104,429.33	53,222.74	
					19,374.31-	C
					72,597.05	I
6,939.0000	SANOFI	530,360.61	95.5324	662,899.80	132,539.19	
					95,962.23-	C
					228,501.42	I
729.0000	ACCOR SA	27,338.63	46.8138	34,127.32	6,788.69	
					6,379.33-	C
					13,168.02	I
10,953.0000	NOKIA OYJ	79,218.78	6.1213	67,046.95	12,171.83-	
					2,627.68	C
					14,799.51-	I
6,891.0000	STMICROELECTRONICS NV	54,202.77	14.3367	98,794.29	44,591.52	
					16,541.40-	C
					61,132.92	I

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6,223.0000	SOCIETE GENERALE SA	347,198.29	53.7313	334,369.95	12,828.34- 40,189.11- C 27,360.77 I
922.0000	EURAZEO SA	49,964.73	74.9227	69,078.76	19,114.03 1,783.30- C 20,897.33 I
717.0000	SODEXO SA	49,175.35	129.1102	92,572.06	43,396.71 8,304.65- C 51,701.36 I
799.0000	UNIBAIL-RODAMCO SE	158,704.73	251.6623	201,078.22	42,373.49 9,855.87- C 52,229.36 I
14,786.0000	AXA SA	346,824.93	27.3161	403,896.93	57,072.00 39,390.36- C 96,462.36 I
2,050.0000	PEUGEOT SA	30,597.05	19.9197	40,835.40	10,238.35 7,844.49- C 18,082.84 I
724.0000	JCDECAUX SA	20,563.28	32.7565	23,715.78	3,152.50 4,433.11- C 7,585.61 I
1,436.0000	ESSILOR INTERNATIONAL SA	115,134.40	127.0572	182,454.24	67,319.84 16,504.93- C 83,824.77 I
7,269.0000	CREDIT AGRICOLE SA	85,240.57	16.0646	116,773.92	31,533.35 4,770.67 C 26,762.68 I

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1,375.0000	ZODIAC AEROSPACE	25,719.85	27.0880	37,246.09	11,526.24 3,456.66- C 14,982.90 I
5,768.0000	BNP PARIBAS SA	391,940.50	71.9230	414,852.34	22,911.84 40,306.53- C 63,218.37 I
2,629.0000	CIE DE SAINT-GOBAIN	124,623.62	53.3549	140,270.11	15,646.49 17,836.53- C 33,483.02 I
266.0000	WENDEL SA	29,973.32	147.8152	39,318.86	9,345.54 222.35 C 9,123.19 I
1,165.0000	KLEPIERRE	48,917.72	40.9286	47,681.87	1,235.85- 4,524.06- C 3,288.21 I
197.0000	GECINA SA	20,883.18	156.6545	30,860.94	9,977.76 5,185.66- C 15,163.42 I
507.0000	FONCIERE DES REGIONS	44,037.24	92.6354	46,966.18	2,928.94 2,723.13 C 205.81 I
173.0000	ILIAD SA	31,243.44	236.2079	40,863.97	9,620.53 5,856.12- C 15,476.65 I
247.0000	BANCA MONTE DEI PASCHI DI SIEN	44,030.66	0.0000	0.00	44,030.66-I

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5,222.0000	CNH INDUSTRIAL NV	40,404.34	11.3085	59,053.27	18,648.93 222.64- C 18,871.57 I
593.0000	FERRARI NV	27,381.77	85.7123	50,827.41	23,445.64 1,450.78 C 21,994.86 I
10,229.0000	FIAT CHRYSLER AUTOMOBILES NV	89,724.68	10.5272	107,683.51	17,958.83 5,261.09 C 12,697.74 I
12,682.0000	UNICREDIT SPA	204,941.37	18.6479	236,493.84	31,552.47 10,754.03 C 20,798.44 I
726.0000	EXOR NV	29,414.19	54.0506	39,240.78	9,826.59 8,188.43- C 18,015.02 I
2,012.0000	LEONARDO SPA	27,251.07	16.5950	33,389.15	6,138.08 6,241.34- C 12,379.42 I
10,704.0000	TERNA RETE ELETTRICA NAZIONALE	48,680.20	5.3902	57,697.12	9,016.92 5,132.25- C 14,149.17 I
1,022.0000	PRYSMIAN SPA	20,694.15	29.3691	30,015.28	9,321.13 5,610.68- C 14,931.81 I
3,267.0000	ASSICURAZIONI GENERALI SPA	52,797.19	16.4353	53,694.21	897.02 2,654.29 C 1,757.27- I

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72,334.0000	INTESA SANPAOLO SPA	195,075.67	3.1661	229,021.50	33,945.83 6,087.17- C 40,033.00 I
20,219.0000	INTESA SANPAOLO SPA	48,105.86	2.9608	59,865.78	11,759.92 3,378.68 C 8,381.24 I
6,153.0000	MEDIOBANCA SPA	56,038.85	9.8543	60,633.83	4,594.98 7,997.75- C 12,592.73 I
1,260.0000	LUXOTTICA GROUP SPA	50,396.99	57.7688	72,788.76	22,391.77 4,626.70- C 27,018.47 I
62,803.0000	ENEL SPA	314,425.77	5.3537	336,231.04	21,805.27 30,819.43- C 52,624.70 I
10,195.0000	ENI SPA	211,463.35	15.0096	153,023.26	58,440.09- 17,205.46- C 41,234.63- I
18,260.0000	SNAM SPA	97,885.76	4.3523	79,473.71	18,412.05- 9,774.23- C 8,637.82- I
5,926.0000	TENARIS SA	112,096.85	15.5685	92,258.98	19,837.87- 4,939.35- C 14,898.52- I
35,031.0000	TELECOM ITALIA SPA/MILANO	30,142.26	0.9215	32,283.32	2,141.06 1,694.05 C 447.01 I

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2,674.0000	ATLANTIA SPA	60,462.36	28.1031	75,147.83	14,685.47	
					14,826.34-	C
					29,511.81	I
9,870.0000	KONINKLIJKE AHOLD DELHAIZE NV	170,749.86	19.0928	188,446.01	17,696.15	
					22,574.54-	C
					40,270.69	I
3,522.0000	NN GROUP NV	113,060.33	35.4939	125,009.57	11,949.24	
					3,561.88	C
					8,387.36	I
5,697.0000	ARCELORMITTAL	117,219.17	22.6513	129,044.59	11,825.42	
					3,464.26	C
					8,361.16	I
1,586.0000	ABN AMRO GROUP NV	31,458.01	26.4721	41,984.85	10,526.84	
					252.15	C
					10,274.69	I
417.0000	ALTICE NV	7,451.91	23.0448	9,609.69	2,157.78	
					1,846.02-	C
					4,003.80	I
2,106.0000	ALTICE NV	39,078.14	23.0391	48,520.37	9,442.23	
					4,073.59-	C
					13,515.82	I
28,849.0000	ING GROEP NV	322,919.74	17.2223	496,846.28	173,926.54	
					57,947.02-	C
					231,873.56	I
552.0000	HEINEKEN HOLDING NV	27,254.91	91.5291	50,524.08	23,269.17	
					6,322.32-	C
					29,591.49	I

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1,330.0000	KONINKLIJKE DSM NV	65,384.84	72.5846	96,537.52	31,152.68 9,107.20- C 40,259.88 I
10,117.0000	UNILEVER NV	334,210.93	55.1113	557,561.79	223,350.86 88,334.88- C 311,685.74 I
33.0000	GEMALTO NV	2,062.53	59.9359	1,977.88	84.65- 183.56- C 98.91 I
2,392.0000	ASML HOLDING NV	121,815.61	130.1367	311,287.12	189,471.51 43,291.14- C 232,762.65 I
5,536.0000	RELX NV	44,121.76	20.5299	113,653.53	69,531.77 21,238.04- C 90,769.81 I
506.0000	RANDSTAD HOLDING NV	24,857.29	58.3049	29,502.29	4,645.00 5,514.79- C 10,159.79 I
1,567.0000	AKZO NOBEL NV	97,071.42	86.7844	135,991.23	38,919.81 16,305.09- C 55,224.90 I
2,380.0000	WOLTERS KLUWER NV	60,143.75	42.2744	100,613.28	40,469.53 8,397.38- C 48,866.91 I
957.0000	KONINKLIJKE VOPAK NV	50,023.31	46.3063	44,315.16	5,708.15- 881.60- C 4,826.55- I

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10,494.0000	AEGON NV	58,832.23	5.0993	53,513.09	5,319.14-
					2,879.03 C
					8,198.17- I
25,877.0000	KONINKLIJKE KPN NV	76,900.16	3.1946	82,668.75	5,768.59
					3,535.00 C
					2,233.59 I
3,763.0000	KONINKLIJKE PHILIPS NV	115,442.35	35.4654	133,456.31	18,013.96
					19,270.32- C
					37,284.28 I
1,218.0000	HEINEKEN NV	62,647.05	97.0950	118,261.74	55,614.69
					22,106.34- C
					77,721.03 I
2,333.0000	GALP ENERGIA SGPS SA	22,925.91	15.1179	35,270.28	12,344.37
					751.46 C
					11,592.91 I
997.0000	JERONIMO MARTINS SGPS SA	10,177.69	19.4920	19,433.52	9,255.83
					3,632.68- C
					12,888.51 I
5,152.0000	BANCO ESPIRITO SANTO SA	13,545.89	0.0000	0.00	13,545.89-I
15,796.0000	EDP - ENERGIAS DE PORTUGAL SA	48,348.68	3.2653	51,580.18	3,231.50
					3,457.37 C
					225.87- I
3,429.0000	CIE FINANCIERE RICHEMONT SA	169,817.18	82.4936	282,870.57	113,053.39
					14,017.03 C
					99,036.36 I

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701.0000	IDORSIA LTD	5,621.64	18.9004	13,249.20	7,627.56	
					119.95	C
					7,507.61	I
26,592.0000	UBS GROUP AG	453,946.60	16.9581	450,951.89	2,994.71-	
					27,858.28	C
					30,852.99-	I
480.0000	VIFOR PHARMA AG	58,595.39	110.3743	52,979.69	5,615.70-	
					1,155.18	C
					6,770.88-	I
523.0000	PARGESA HOLDING SA	34,277.03	76.1760	39,840.08	5,563.05	
					2,115.41	C
					3,447.64	I
254.0000	DUFRY AG	36,213.98	164.0474	41,668.04	5,454.06	
					493.09-	C
					5,947.15	I
273.0000	SWISS PRIME SITE AG	19,979.10	90.9518	24,829.84	4,850.74	
					236.88-	C
					5,087.62	I
260.0000	GEBERIT AG	55,746.66	466.9764	121,413.88	65,667.22	
					7,566.39	C
					58,100.83	I
230.0000	SCHINDLER HOLDING AG	20,772.67	211.8728	48,730.75	27,958.08	
					4,152.25	C
					23,805.83	I
88.0000	PARTNERS GROUP HOLDING AG	22,346.93	620.7904	54,629.56	32,282.63	
					503.76-	C
					32,786.39	I

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425.0000	KUEHNE + NAGEL INTERNATIONAL A	49,405.66	167.0756	71,007.15	21,601.49	
					3,433.44	C
					18,168.05	I
636.0000	ARYZTA AG	27,407.08	32.9243	20,939.88	6,467.20-	
					1,649.10	C
					8,116.30-	I
1,501.0000	JULIUS BAER GROUP LTD	59,575.02	52.6810	79,074.24	19,499.22	
					4,958.73	C
					14,540.49	I
2,623.0000	SWISS RE AG	144,734.03	91.5261	240,073.04	95,339.01	
					8,545.80	C
					86,793.21	I
17.0000	SIKA AG	42,699.35	6,432.4126	109,351.02	66,651.67	
					1,510.34	C
					65,141.33	I
40.0000	SGS SA	60,493.76	2,424.6854	96,987.42	36,493.66	
					6,174.80	C
					30,318.86	I
178.0000	SWISSCOM AG	70,418.73	483.1619	86,002.82	15,584.09	
					6,267.38	C
					9,316.71	I
6.0000	CHOCOLADEFABRIKEN LINDT & SPRU	31,373.06	5,805.8789	34,835.27	3,462.21	
					2,024.57-	C
					5,486.78	I
1.0000	CHOCOLADEFABRIKEN LINDT & SPRU	27,285.93	69,806.2966	69,806.30	42,520.37	
					5,948.07	C
					36,572.30	I

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68.0000	GIVAUDAN SA	84,927.24	2,002.8194	136,191.72	51,264.48	
					3,209.76	C
					48,054.72	I
897.0000	ZURICH INSURANCE GROUP AG	220,902.52	291.4425	261,424.01	40,521.49	
					19,270.04	C
					21,251.45	I
12,809.0000	NOVARTIS AG	730,803.62	83.3289	1,067,360.94	336,557.32	
					47,688.48	C
					288,868.84	I
8,919.0000	ABB LTD	183,134.83	24.7271	220,541.87	37,407.04	
					11,711.13	C
					25,695.91	I
4,012.0000	ROCHE HOLDING AG	707,434.30	254.9992	1,023,056.86	315,622.56	
					74,977.24	C
					240,645.32	I
1,187.0000	ADECCO GROUP AG	74,225.88	76.1238	90,359.00	16,133.12	
					2,459.14	C
					13,673.98	I
1,676.0000	LAFARGEHOLCIM LTD	88,470.71	57.3278	96,081.45	7,610.74	
					3,679.86	C
					3,930.88	I
20,167.0000	NESTLE SA	1,125,384.45	87.1403	1,757,360.36	631,975.91	
					105,382.66	C
					526,593.25	I
425.0000	BALOISE HOLDING AG	42,690.13	154.7538	65,770.38	23,080.25	
					3,641.13	C
					19,439.12	I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS	
388.0000	SONOVA HOLDING AG	49,090.07	162.5854	63,083.17	13,993.10	
					3,719.88	C
					10,273.22	I
8,587.0000	CREDIT SUISSE GROUP AG	137,462.66	14.4729	124,279.04	13,183.62-	
					2,226.37	C
					15,409.99-	I
228.0000	SWATCH GROUP AG/THE	80,006.14	369.7593	84,305.12	4,298.98	
					3,563.09	C
					735.89	I
400.0000	LONZA GROUP AG	40,262.65	216.4673	86,586.96	46,324.31	
					4,681.90	C
					41,642.41	I
252.0000	SWISS LIFE HOLDING AG	41,974.42	337.9105	85,153.45	43,179.03	
					4,495.51	C
					38,683.52	I
22,520.0000	NATIONAL GRID PLC	249,721.62	12.3634	278,423.91	28,702.29	
					35,639.53-	C
					64,341.82	I
4,912.0000	MERLIN ENTERTAINMENTS PLC	30,200.16	6.2414	30,658.03	457.87	
					5,168.87-	C
					5,626.74	I
11,273.0000	COMPASS GROUP PLC	126,630.09	21.0429	237,217.63	110,587.54	
					41,013.73-	C
					151,601.27	I
1,350.0000	INTERCONTINENTAL HOTELS GROUP	41,079.10	55.4261	74,825.37	33,746.27	
					12,819.06-	C
					46,565.33	I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS	
1,561.0000	WOLSELEY PLC	49,693.77	61.2195	95,563.66	45,869.89	
					16,638.09-	C
					62,507.98	I
1,348.0000	IMI PLC	21,021.35	15.5224	20,924.27	97.08-	
					3,978.82-	C
					3,881.74	I
134,469.0000	VODAFONE GROUP PLC	442,672.10	2.8284	380,340.68	62,331.42-	
					40,571.19-	C
					21,760.23-	I
9,098.0000	STANDARD LIFE PLC	34,688.68	5.1841	47,165.03	12,476.35	
					8,325.89-	C
					20,802.24	I
9,514.0000	AUTO TRADER GROUP PLC	48,075.86	4.9360	46,961.20	1,114.66-	
					1,104.48	C
					2,219.14-	I
7.0000	LONMIN PLC	181.85	0.8540	5.98	175.87-	
					1.27-	C
					174.60-	I
12,602.0000	WORLDPAY GROUP PLC	44,631.81	4.0890	51,530.78	6,898.97	
					2,963.43	C
					3,935.54	I
1,110.0000	CRODA INTERNATIONAL PLC	43,316.83	50.4642	56,015.27	12,698.44	
					10,014.09-	C
					22,712.53	I
7,697.0000	DIRECT LINE INSURANCE GROUP PL	30,468.89	4.6164	35,532.96	5,064.07	
					8,593.63-	C
					13,657.70	I

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1,479.0000	JOHNSON MATTHEY PLC	49,746.14	37.2928	55,156.13	5,409.99 9,499.85- C 14,909.84 I
2,147.0000	LONDON STOCK EXCHANGE GROUP PL	52,721.34	47.3597	101,681.31	48,959.97 17,926.85- C 66,886.82 I
885.0000	RANDGOLD RESOURCES LTD	63,536.95	88.3935	78,228.29	14,691.34 14,703.24- C 29,394.58 I
12,404.0000	G4S PLC	51,306.55	4.2397	52,590.15	1,283.60 11,287.34- C 12,570.94 I
8,446.0000	J SAINSBURY PLC	29,897.66	3.2694	27,613.83	2,283.83- 4,620.59- C 2,336.76 I
1,006.0000	ADMIRAL GROUP PLC	20,592.59	26.0179	26,174.08	5,581.49 4,620.44- C 10,201.93 I
723.0000	BERKELEY GROUP HOLDINGS PLC	34,187.98	41.9171	30,306.08	3,881.90- 3,980.30- C 98.40 I
30,505.0000	ROYAL DUTCH SHELL PLC A SHS	892,312.79	26.4336	806,357.96	85,954.83- 111,010.07- C 25,055.24 I

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26,227.0000	ROYAL DUTCH SHELL PLC B SHS	636,296.14	26.7908	702,643.47	66,347.33	
					98,146.14-	C
					164,493.47	I
17,061.0000	CENTRICA PLC	48,410.79	2.6004	44,367.09	4,043.70-	
					1,395.28	C
					5,438.98-	I
2,561.0000	BUNZL PLC	40,737.32	29.7199	76,112.86	35,375.54	
					13,044.18-	C
					48,419.72	I
6,712.0000	INMARSAT PLC	69,167.94	9.9954	67,089.26	2,078.68-	
					2,828.53-	C
					749.85	I
2,414.0000	MONDI PLC	51,268.92	26.1608	63,152.30	11,883.38	
					11,806.44-	C
					23,689.82	I
2,156.0000	SEVERN TRENT PLC	52,106.54	28.3430	61,107.70	9,001.16	
					11,730.04-	C
					20,731.20	I
899.0000	WHITBREAD PLC	20,681.88	51.5293	46,324.88	25,643.00	
					8,177.59-	C
					33,820.59	I
1,665.0000	HARGREAVES LANSDOWN PLC	24,657.67	16.9123	28,159.03	3,501.36	
					4,994.69-	C
					8,496.05	I

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3,280.0000	SMITHS GROUP PLC	54,673.30	20.7442	68,041.08	13,367.78 11,743.91- C 25,111.69 I
6,981.0000	ANGLO AMERICAN PLC	98,170.14	13.3012	92,856.01	5,314.13- 15,608.46- C 10,294.33 I
7,641.0000	3I GROUP PLC	41,758.98	11.7230	89,575.63	47,816.65 15,364.41- C 63,181.06 I
9,196.0000	UNILEVER PLC	311,064.43	53.9713	496,320.74	185,256.31 89,392.97- C 274,649.28 I
1,735.0000	TUI AG	20,542.85	14.5352	25,218.66	4,675.81 4,451.79- C 9,127.60 I
9,335.0000	INVESTEC PLC	62,321.87	7.4494	69,540.89	7,219.02 538.12 C 6,680.90 I
6,790.0000	EXPERIAN PLC	81,210.55	20.4584	138,912.96	57,702.41 24,108.69- C 81,811.10 I
7,795.0000	RELX PLC	79,173.23	21.5625	168,080.23	88,907.00 28,995.61- C 117,902.61 I
4,849.0000	SHIRE PLC	174,948.63	55.0495	266,935.03	91,986.40 30,704.70- C 122,691.10 I

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3,373.0000	FRESNILLO PLC	55,408.09	19.3023	65,106.99	9,698.90
					2,109.38- C
					11,808.28 I
4,069.0000	RECKITT BENCKISER GROUP PLC	242,410.22	101.1102	411,417.68	169,007.46
					76,380.11- C
					245,387.57 I
7,743.0000	UNITED UTILITIES GROUP PLC	80,087.08	11.2683	87,251.16	7,164.08
					4,323.09- C
					11,487.17 I
72,451.0000	GLENCORE PLC	287,808.32	3.7305	270,284.57	17,523.75-
					54,174.83- C
					36,651.08 I
11,281.0000	DIXONS CARPHONE PLC	52,760.43	3.6838	41,557.20	11,203.23-
					977.38 C
					12,180.61- I
11,421.0000	SEGRO PLC	61,608.72	6.3544	72,574.32	10,965.60
					2,361.10- C
					13,326.70 I
11,710.0000	ROLLS-ROYCE HOLDINGS PLC	112,244.34	11.5736	135,527.38	23,283.04
					23,599.84- C
					46,882.88 I
10,313.0000	ROYAL BANK OF SCOTLAND GROUP P	28,937.61	3.2110	33,115.09	4,177.48
					1,041.41 C
					3,136.07 I
41,132.0000	OLD MUTUAL PLC	94,963.63	2.5121	103,330.55	8,366.92
					7,458.48- C
					15,825.40 I

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8,782.0000	SAGE GROUP PLC/THE	43,798.19	8.9367	78,482.77	34,684.58	
					13,487.88-	C
					48,172.46	I
6,018.0000	MEDICLINIC INTERNATIONAL PLC	57,104.75	9.6317	57,963.66	858.91	
					1,363.25	C
					504.34-	I
9,132.0000	WPP PLC	123,356.82	20.9650	191,452.86	68,096.04	
					35,717.47-	C
					103,813.51	I
1,734.0000	COCA-COLA HBC AG	41,822.89	29.3302	50,858.72	9,035.83	
					8,623.94	C
					411.89	I
15,878.0000	ABERDEEN ASSET MANAGEMENT PLC	52,152.65	3.9228	62,286.68	10,134.03	
					945.59	C
					9,188.44	I
4,037.0000	ASHTEAD GROUP PLC	65,929.49	20.6403	83,324.95	17,395.46	
					15,909.17-	C
					33,304.63	I
11,805.0000	BHP BILLITON PLC	212,868.13	15.2756	180,329.07	32,539.06-	
					2,435.07-	C
					30,103.99-	I
7,181.0000	BARRATT DEVELOPMENTS PLC	42,203.64	7.3195	52,561.93	10,358.29	
					1,236.20	C
					9,122.09	I
4,296.0000	BRITISH LAND CO PLC/THE	32,163.90	7.8651	33,788.65	1,624.75	
					5,964.62-	C
					7,589.37	I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
5,666.0000	SKY PLC	53,330.00	12.9115	73,156.92	19,826.92
					12,914.19- C
					32,741.11 I
20,975.0000	AVIVA PLC	125,265.76	6.8324	143,311.21	18,045.45
					14,046.45- C
					32,091.90 I
14,408.0000	DIAGEO PLC	267,696.49	29.4666	424,555.94	156,859.45
					74,066.89- C
					230,926.34 I
1,818.0000	SCHRODERS PLC	53,618.61	40.3194	73,300.68	19,682.07
					3,280.07- C
					22,962.14 I
22,052.0000	BAE SYSTEMS PLC	131,449.83	8.2288	181,462.56	50,012.73
					31,595.02- C
					81,607.75 I
12,737.0000	BRITISH AMERICAN TOBACCO PLC	503,781.29	67.9870	865,950.97	362,169.68
					155,957.50- C
					518,127.18 I
10,133.0000	HAMMERSON PLC	70,311.30	7.4624	75,617.19	5,305.89
					3,352.31- C
					8,658.20 I
17,020.0000	STANDARD CHARTERED PLC	159,926.07	10.0954	171,824.38	11,898.31
					4,789.99- C
					16,688.30 I
5,856.0000	IMPERIAL BRANDS PLC	186,122.96	44.7942	262,315.37	76,192.41
					48,985.14- C
					125,177.55 I

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113,066.0000	HSBC HOLDINGS PLC	1,071,973.23	9.2446	1,045,253.01	26,720.22-	
					177,711.69-	C
					150,991.47	I
29,150.0000	LEGAL & GENERAL GROUP PLC	39,755.78	3.3551	97,803.73	58,047.95	
					17,265.03-	C
					75,312.98	I
10,757.0000	MEGGITT PLC	65,124.94	6.1946	66,636.30	1,511.36	
					3,580.41-	C
					5,091.77	I
10,041.0000	WM MORRISON SUPERMARKETS PLC	29,990.82	3.1330	31,459.13	1,468.31	
					989.34	C
					478.97	I
3,278.0000	ASSOCIATED BRITISH FOODS PLC	78,851.38	38.1371	125,013.65	46,162.27	
					4,529.64-	C
					50,691.91	I
3,929.0000	PEARSON PLC	35,549.68	8.9822	35,291.22	258.46-	
					192.90	C
					451.36-	I
2,308.0000	PERSIMMON PLC	59,505.38	29.1224	67,214.64	7,709.26	
					16,660.44-	C
					24,369.70	I
15,511.0000	PRUDENTIAL PLC	168,873.90	22.8745	354,806.52	185,932.62	
					41,246.69-	C
					227,179.31	I
5,996.0000	RIO TINTO PLC	284,048.12	42.1119	252,503.31	31,544.81-	
					34,243.83-	C
					2,699.02	I

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8,430.0000	SSE PLC	155,920.35	18.8737	159,105.66	3,185.31	
					15,322.43-	C
					18,507.74	I
106,347.0000	BP PLC	826,422.54	5.7517	611,681.43	214,741.11-	
					91,669.44-	C
					123,071.67-	I
342,650.0000	LLOYDS BANKING GROUP PLC	330,461.25	0.8592	294,423.88	36,037.37-	
					38,107.19-	C
					2,069.82	I
33,040.0000	TESCO PLC	96,122.89	2.1926	72,444.42	23,678.47-	
					7,282.61-	C
					16,395.86-	I
4,247.0000	SMITH & NEPHEW PLC	42,552.13	17.2110	73,095.49	30,543.36	
					12,903.33-	C
					43,446.69	I
33,132.0000	GLAXOSMITHKLINE PLC	650,893.54	21.2443	703,867.05	52,973.51	
					116,507.12-	C
					169,480.63	I
1,358.0000	WEIR GROUP PLC/THE	31,696.25	22.4848	30,534.39	1,161.86-	
					718.13	C
					1,879.99-	I
4,533.0000	BABCOCK INTERNATIONAL GROUP PL	56,060.33	11.4372	51,845.08	4,215.25-	
					3,487.14-	C
					728.11-	I
8,873.0000	ASTRAZENECA PLC	435,501.00	66.7010	591,838.71	156,337.71	
					103,014.11-	C
					259,351.82	I

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7,196.0000	GKN PLC	19,812.66	4.2345	30,472.02	10,659.36 6,446.51- C 17,105.87 I
43,867.0000	BT GROUP PLC	98,306.26	3.8286	167,951.61	69,645.35 20,095.74- C 89,741.09 I
1,233.0000	CARNIVAL PLC	55,656.35	65.9866	81,361.55	25,705.20 14,042.31- C 39,747.51 I
72,489.0000	BARCLAYS PLC	229,718.44	2.6336	190,908.56	38,809.88- 12,648.53- C 26,161.35- I
1,582.0000	INTERTEK GROUP PLC	53,999.85	54.7767	86,656.77	32,656.92 22,799.15- C 55,456.07 I
2,749.0000	BURBERRY GROUP PLC	40,583.00	21.5755	59,311.21	18,728.21 10,494.86- C 29,223.07 I
7,717.0000	LAND SECURITIES GROUP PLC	90,551.62	13.1583	101,543.09	10,991.47 5,484.83- C 16,476.30 I
981.0000	NEXT PLC	32,909.37	50.0875	49,135.85	16,226.48 8,673.82- C 24,900.30 I
11,741.0000	KINGFISHER PLC	39,134.34	3.9059	45,859.68	6,725.34 8,095.48- C 14,820.82 I

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19,948.0000	ITV PLC	50,800.75	2.3562	47,003.38	3,797.37-	
					10,538.04-	C
					6,740.67	I
177.0000	PADDY POWER BETFAIR PLC	20,259.38	106.6072	18,869.48	1,389.90-	
					354.87	C
					1,744.77-	I
2,731.0000	RYANAIR HOLDINGS PLC	15,228.34	20.4842	55,942.56	40,714.22	
					10,457.17-	C
					51,171.39	I
6,118.0000	CRH PLC	153,050.40	35.3285	216,139.98	63,089.58	
					30,655.37-	C
					93,744.95	I
1,480.0000	KERRY GROUP PLC	82,522.67	85.9176	127,158.09	44,635.42	
					3,709.65-	C
					48,345.07	I
18,576.0000	CHEUNG KONG PROPERTY HOLDINGS	89,245.73	7.8332	145,510.75	56,265.02	
					808.39-	C
					57,073.41	I
18,576.0000	CK HUTCHISON HOLDINGS LTD	153,519.32	12.5537	233,197.93	79,678.61	
					1,295.85-	C
					80,974.46	I
3,000.0000	CK INFRASTRUCTURE HOLDINGS LTD	20,432.34	8.4033	25,209.92	4,777.58	
					159.57-	C
					4,937.15	I
15,000.0000	LINK REIT	60,465.90	7.6090	114,136.39	53,670.49	
					481.97-	C
					54,152.46	I

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10,000.0000	TECHTRONIC INDUSTRIES CO LTD	31,371.90	4.5987	45,987.61	14,615.71 334.67- C 14,950.38 I
8,800.0000	WYNN MACAU LTD	19,851.95	2.3365	20,561.46	709.51 73.61- C 783.12 I
22,400.0000	MGM CHINA HOLDINGS LTD	43,813.89	2.2238	49,813.17	5,999.28 302.37- C 6,301.65 I
79,000.0000	AIA GROUP LTD	289,000.28	7.3080	577,336.69	288,336.41 3,190.86- C 291,527.27 I
18,800.0000	SANDS CHINA LTD	39,147.67	4.5795	86,095.47	46,947.80 523.16- C 47,470.96 I
10,250.0000	SWIRE PROPERTIES LTD	26,097.18	3.2985	33,810.18	7,713.00 232.64- C 7,945.64 I
9,000.0000	HANG LUNG PROPERTIES LTD	20,207.22	2.4979	22,481.41	2,274.19 163.61- C 2,437.80 I
7,400.0000	BANK OF EAST ASIA LTD/THE	27,544.66	4.2977	31,803.19	4,258.53 160.51- C 4,419.04 I
14,000.0000	CLP HOLDINGS LTD	106,086.65	10.5809	148,133.91	42,047.26 840.65- C 42,887.91 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
7,300.0000	HONG KONG EXCHANGES & CLEARING	134,822.13	25.8504	188,708.06	53,885.93 1,036.99- C 54,922.92 I
13,500.0000	MTR CORP LTD	55,240.98	5.6299	76,004.46	20,763.48 464.09- C 21,227.57 I
5,600.0000	HANG SENG BANK LTD	82,409.65	20.9185	117,144.16	34,734.51 671.00- C 35,405.51 I
9,803.0000	HENDERSON LAND DEVELOPMENT CO	43,007.80	5.5787	54,688.19	11,680.39 276.51- C 11,956.90 I
7,000.0000	POWER ASSETS HOLDINGS LTD	41,929.50	8.8324	61,827.08	19,897.58 312.02- C 20,209.60 I
11,000.0000	WHARF HOLDINGS LTD/THE	72,813.14	8.2880	91,168.20	18,355.06 537.64- C 18,892.70 I
43,505.0000	HONG KONG & CHINA GAS CO LTD	52,134.94	1.8804	81,810.99	29,676.05 416.18- C 30,092.23 I
7,000.0000	HYSAN DEVELOPMENT CO LTD	20,761.01	4.7716	33,401.87	12,640.86 168.56- C 12,809.42 I
15,000.0000	GALAXY ENTERTAINMENT GROUP LTD	27,663.21	6.0719	91,078.53	63,415.32 343.71- C 63,759.03 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
18,500.0000	BOC HONG KONG HOLDINGS LTD	44,646.76	4.7845	88,513.34	43,866.58 446.73- C 44,313.31 I
6,000.0000	YUE YUEN INDUSTRIAL HOLDINGS L	19,389.76	4.1504	24,902.48	5,512.72 125.68- C 5,638.40 I
25,000.0000	NEW WORLD DEVELOPMENT CO LTD	29,107.61	1.2694	31,736.58	2,628.97 192.64- C 2,821.61 I
15,000.0000	SINO LAND CO LTD	22,763.12	1.6396	24,595.05	1,831.93 178.98- C 2,010.91 I
4,000.0000	SUN HUNG KAI PROPERTIES LTD	52,067.99	14.6929	58,771.91	6,703.92 415.06- C 7,118.98 I
2,000.0000	SWIRE PACIFIC LTD	22,344.72	9.7675	19,535.13	2,809.59- 142.15- C 2,667.44- I
6,000.0000	WHEELOCK & CO LTD	18,362.59	7.5450	45,270.26	26,907.67 228.47- C 27,136.14 I
800.0000	SUNTORY BEVERAGE & FOOD LTD	27,237.03	46.4578	37,166.25	9,929.22 5,572.47- C 15,501.69 I
9,000.0000	CONCORDIA FINANCIAL GROUP LTD	47,532.86	5.0427	45,384.48	2,148.38- 3,734.17- C 1,585.79 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
5,850.0000	MEBUKI FINANCIAL GROUP INC	21,665.59	3.7201	21,763.08	97.49 2,516.32- C 2,613.81 I
2,600.0000	SEIBU HOLDINGS INC	44,094.91	18.4852	48,061.59	3,966.68 3,860.92- C 7,827.60 I
7,500.0000	RECRUIT HOLDINGS CO LTD	85,326.59	17.1858	128,893.73	43,567.14 2,293.17- C 45,860.31 I
23.0000	NOMURA REAL ESTATE MASTER FUND	31,475.06	1,367.9244	31,462.26	12.80- 644.54 C 657.34- I
2,400.0000	JAPAN POST HOLDINGS CO LTD	28,531.38	12.4065	29,775.72	1,244.34 610.00 C 634.34 I
6,400.0000	JAPAN POST BANK CO LTD	82,247.66	12.7981	81,908.15	339.51- 268.42 C 607.93- I
5,500.0000	SEVEN & I HOLDINGS CO LTD	164,392.35	41.1890	226,539.68	62,147.33 16,623.15- C 78,770.48 I
1,600.0000	BANDAI NAMCO HOLDINGS INC	30,521.85	34.0868	54,538.98	24,017.13 8,177.22- C 32,194.35 I
9,400.0000	MITSUBISHI CHEMICAL HOLDINGS C	48,701.45	8.2778	77,811.85	29,110.40 5,699.79- C 34,810.19 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
4,400.0000	DAIICHI SANKYO CO LTD	80,402.83	23.5582	103,656.10	23,253.27
					12,727.41- C
					35,980.68 I
1,600.0000	M3 INC	32,221.29	27.5453	44,072.62	11,851.33
					2,015.64 C
					9,835.69 I
2,800.0000	ELECTRIC POWER DEVELOPMENT CO	77,925.54	24.7241	69,227.48	8,698.06-
					589.08- C
					8,108.98- I
1,600.0000	SEGA SAMMY HOLDINGS INC	19,317.94	13.4567	21,530.79	2,212.85
					4,213.59- C
					6,426.44 I
600.0000	DENA CO LTD	14,841.94	22.3923	13,435.39	1,406.55-
					2,629.31- C
					1,222.76 I
1,800.0000	NOMURA REAL ESTATE HOLDINGS IN	31,479.62	19.6155	35,307.94	3,828.32
					892.84 C
					2,935.48 I
1,000.0000	YAMAGUCHI FINANCIAL GROUP INC	10,806.72	12.0772	12,077.25	1,270.53
					2,363.54- C
					3,634.07 I
10,000.0000	AOZORA BANK LTD	29,284.93	3.8091	38,091.85	8,806.92
					5,711.25- C
					14,518.17 I
14,000.0000	FUKUOKA FINANCIAL GROUP INC	65,074.04	4.7525	66,536.13	1,462.09
					1,623.44- C
					3,085.53 I

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4,000.0000	INPEX CORP	46,271.42	9.6208	38,483.44	7,787.98- C 2,458.67- C 5,329.31- I
1,800.0000	ISETAN MITSUKOSHI HOLDINGS LTD	19,720.40	10.0213	18,038.45	1,681.95- C 3,530.14- C 1,848.19 I
3,800.0000	MS&AD INSURANCE GROUP HOLDINGS	102,736.75	33.5884	127,636.16	24,899.41 C 12,954.61- C 37,854.02 I
1,500.0000	J FRONT RETAILING CO LTD	18,142.52	15.3435	23,015.31	4,872.79 C 4,504.12- C 9,376.91 I
1,200.0000	SONY FINANCIAL HOLDINGS INC	19,452.09	17.0345	20,441.44	989.35 C 4,000.40- C 4,989.75 I
300.0000	TAISHO PHARMACEUTICAL HOLDINGS	18,227.69	76.0946	22,828.41	4,600.72 C 4,467.54- C 9,068.26 I
2,900.0000	OTSUKA HOLDINGS CO LTD	83,165.52	42.6308	123,629.40	40,463.88 C 19,815.62- C 60,279.50 I
1,000.0000	MEIJI HOLDINGS CO LTD	19,510.65	81.0786	81,078.67	61,568.02 C 15,867.15- C 77,435.17 I
7,200.0000	DAI-ICHI LIFE HOLDINGS INC	102,700.68	18.0357	129,857.59	27,156.91 C 19,157.55- C 46,314.46 I

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2,100.0000	SOMPO HOLDINGS INC	56,680.99	38.6169	81,095.58	24,414.59 20,168.42- C 44,583.01 I
25,315.0000	JXTG HOLDINGS INC	113,901.00	4.3672	110,555.98	3,345.02- 20,072.61- C 16,727.59 I
1,000.0000	JAPAN AIRLINES CO LTD	24,419.12	30.9184	30,918.47	6,499.35 5,628.78- C 12,128.13 I
10.0000	NIPPON PROLOGIS REIT INC	20,028.43	2,130.6513	21,306.51	1,278.08 3,194.56- C 4,472.64 I
1,600.0000	AISIN SEIKI CO LTD	49,701.19	51.1747	81,879.67	32,178.48 6,263.52- C 38,442.00 I
4,000.0000	AJINOMOTO CO INC	39,692.08	21.5957	86,383.05	46,690.97 16,905.25- C 63,596.22 I
6,000.0000	ANA HOLDINGS INC	17,420.30	3.4745	20,847.28	3,426.98 552.32- C 3,979.30 I
1,500.0000	ALPS ELECTRIC CO LTD	42,040.80	28.8358	43,253.83	1,213.03 2,674.36 C 1,461.33- I
3,000.0000	AMADA HOLDINGS CO LTD	25,712.53	11.5521	34,656.46	8,943.93 6,782.29- C 15,726.22 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
2,000.0000	ASAHI GROUP HOLDINGS LTD	37,200.67	37.6290	75,258.10	38,057.43 14,728.06- C 52,785.49 I
10,000.0000	ASAHI KASEI CORP	59,359.69	10.7467	107,467.07	48,107.38 9,631.67- C 57,739.05 I
1,400.0000	ASAHI GLASS CO LTD	37,056.19	42.0968	58,935.56	21,879.37 2,695.38 C 19,183.99 I
5,000.0000	HIROSHIMA BANK LTD/THE	21,187.56	4.4321	22,160.91	973.35 4,336.91- C 5,310.26 I
6,000.0000	BANK OF KYOTO LTD/THE	48,821.38	9.4339	56,603.77	7,782.39 540.19- C 8,322.58 I
12,600.0000	YAHOO JAPAN CORP	47,343.03	4.3520	54,836.24	7,493.21 3,887.31- C 11,380.52 I
500.0000	TREND MICRO INC/JAPAN	17,780.51	51.5307	25,765.40	7,984.89 5,042.30- C 13,027.19 I
5,500.0000	NTT DATA CORP	43,186.71	11.1249	61,187.25	18,000.54 3,692.56- C 21,693.10 I
10,000.0000	NTT DOCOMO INC	153,788.85	23.6027	236,027.05	82,238.20 40,520.04- C 122,758.24 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS	
4,600.0000	BRIDGESTONE CORP	103,812.72	43.0758	198,148.80	94,336.08	
					23,960.03-	C
					118,296.11	I
1,700.0000	BROTHER INDUSTRIES LTD	20,615.81	23.0776	39,231.93	18,616.12	
					7,677.71-	C
					26,293.83	I
2,100.0000	USS CO LTD	31,071.72	19.8736	41,734.60	10,662.88	
					6,257.43-	C
					16,920.31	I
4,100.0000	CANON INC	144,929.94	33.9622	139,245.28	5,684.66-	
					10,479.42-	C
					4,794.76	I
2,600.0000	CASIO COMPUTER CO LTD	19,654.39	15.3702	39,962.62	20,308.23	
					7,820.71-	C
					28,128.94	I
800.0000	CENTRAL JAPAN RAILWAY CO	60,730.57	162.9583	130,366.67	69,636.10	
					25,512.86-	C
					95,148.96	I
4,000.0000	CHIBA BANK LTD/THE	23,891.90	7.2445	28,978.28	5,086.38	
					5,671.07-	C
					10,757.45	I
3,600.0000	CHUBU ELECTRIC POWER CO INC	49,847.37	13.2831	47,819.51	2,027.86-	
					1,232.88	C
					3,260.74-	I
2,000.0000	CHUGOKU BANK LTD/THE	27,000.83	14.9519	29,903.88	2,903.05	
					5,852.21-	C
					8,755.26	I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
1,800.0000	CHUGAI PHARMACEUTICAL CO LTD	41,239.93	37.4243	67,363.83	26,123.90 4,407.29- C 30,531.19 I
3,600.0000	RAKUTEN INC	26,063.90	11.7657	42,356.71	16,292.81 8,289.25- C 24,582.06 I
11,400.0000	KDDI CORP	127,037.42	26.4773	301,842.28	174,804.86 38,812.66- C 213,617.52 I
500.0000	DAITO TRUST CONSTRUCTION CO LT	24,248.57	155.7048	77,852.44	53,603.87 15,235.79- C 68,839.66 I
3,000.0000	DAICEL CORP	36,937.23	12.4332	37,299.75	362.52 1,705.88 C 1,343.36- I
1,700.0000	DAIKIN INDUSTRIES LTD	85,589.93	102.0825	173,540.40	87,950.47 14,444.49- C 102,394.96 I
4,000.0000	DAIWA HOUSE INDUSTRY CO LTD	56,652.12	34.1580	136,632.25	79,980.13 10,480.42- C 90,460.55 I
12,000.0000	DAIWA SECURITIES GROUP INC	66,530.70	5.9255	71,107.15	4,576.45 7,647.70- C 12,224.15 I
200.0000	LAWSON INC	8,549.55	69.9537	13,990.74	5,441.19 2,738.01- C 8,179.20 I

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5,600.0000	MITSUBISHI UFJ LEASE & FINANCE	20,212.29	5.4645	30,601.64	10,389.35 5,988.76- C 16,378.11 I
1,000.0000	DON QUIJOTE HOLDINGS CO LTD	33,841.50	37.9138	37,913.85	4,072.35 5,684.55- C 9,756.90 I
1,700.0000	EAST JAPAN RAILWAY CO	117,649.52	95.6301	162,571.19	44,921.67 31,815.33- C 76,737.00 I
1,400.0000	EISAI CO LTD	53,313.18	55.2242	77,313.99	24,000.81 12,047.27- C 36,048.08 I
500.0000	FAMILYMART UNY HOLDINGS CO LTD	35,481.13	57.2267	28,613.38	6,867.75- 2,538.21- C 4,329.54- I
300.0000	FAST RETAILING CO LTD	53,309.60	333.0366	99,911.00	46,601.40 19,552.66- C 66,154.06 I
87,100.0000	MITSUBISHI UFJ FINANCIAL GROUP	464,437.37	6.7176	585,111.05	120,673.68 69,816.45- C 190,490.13 I
4,500.0000	SUBARU CORP	39,665.24	33.6952	151,628.69	111,963.45 23,605.20- C 135,568.65 I
3,300.0000	FUJIFILM HOLDINGS CORP	113,599.80	35.9558	118,654.32	5,054.52 14,506.22- C 19,560.74 I

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700.0000	MIRACA HOLDINGS INC	31,250.91	44.9448	31,461.37	210.46 4,717.12- C 4,927.58 I
1,200.0000	FANUC CORP	139,306.22	192.7287	231,274.46	91,968.24 29,534.47- C 121,502.71 I
4,000.0000	FUJITSU LTD	17,325.91	7.3673	29,469.56	12,143.65 1,822.08 C 10,321.57 I
800.0000	MCDONALD'S HOLDINGS CO JAPAN L	19,916.46	38.3588	30,687.08	10,770.62 11,172.82- C 21,943.44 I
1,089.0000	NOMURA RESEARCH INSTITUTE LTD	20,506.15	39.3823	42,887.37	22,381.22 8,393.09- C 30,774.31 I
6.0000	NIPPON BUILDING FUND INC	25,552.84	5,108.5793	30,651.48	5,098.64 5,998.52- C 11,097.16 I
11.0000	JAPAN REAL ESTATE INVESTMENT C	48,152.48	4,975.0798	54,725.88	6,573.40 3,120.43- C 9,693.83 I
4,000.0000	HACHIJUNI BANK LTD/THE	22,614.26	6.3456	25,382.70	2,768.44 4,967.41- C 7,735.85 I
1,200.0000	HAMAMATSU PHOTONICS KK	22,620.21	30.7048	36,845.85	14,225.64 14,981.87- C 29,207.51 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
800.0000	HANKYU HANSHIN HOLDINGS INC	18,483.22	35.9558	28,764.68	10,281.46 5,629.28- C 15,910.74 I
1,500.0000	DENTSU INC	49,670.98	47.7928	71,689.21	22,018.23 5,325.68- C 27,343.91 I
17,600.0000	RESONA HOLDINGS INC	88,534.06	5.5046	96,881.45	8,347.39 3,688.37- C 12,035.76 I
2,000.0000	HINO MOTORS LTD	19,911.51	11.0982	22,196.51	2,285.00 4,488.70- C 6,773.70 I
220.0000	HIROSE ELECTRIC CO LTD	24,806.69	142.5774	31,367.03	6,560.34 5,960.28- C 12,520.62 I
600.0000	HISAMITSU PHARMACEUTICAL CO IN	22,518.43	47.8818	28,729.08	6,210.65 5,622.31- C 11,832.96 I
27,000.0000	HITACHI LTD	110,195.67	6.1356	165,662.15	55,466.48 22,984.39- C 78,450.87 I
1,000.0000	HITACHI CHEMICAL CO LTD	21,624.08	29.8148	29,814.88	8,190.80 5,834.79- C 14,025.59 I
2,000.0000	HITACHI METALS LTD	21,102.39	13.9017	27,803.49	6,701.10 5,441.17- C 12,142.27 I

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3,143.0000	SUMITOMO MITSUI TRUST HOLDINGS	119,124.25	35.7689	112,421.83	6,702.42- 3,798.54- C 2,903.88- I
7,600.0000	HONDA MOTOR CO LTD	255,633.98	27.2694	207,248.12	48,385.86- 24,611.54- C 23,774.32- I
3,000.0000	HOYA CORP	91,696.64	51.9134	155,740.47	64,043.83 14,329.90- C 78,373.73 I
11,000.0000	IHI CORP	20,027.03	3.3997	37,397.65	17,370.62 7,318.75- C 24,689.37 I
4,000.0000	ISUZU MOTORS LTD	21,805.09	12.3353	49,341.40	27,536.31 9,656.16- C 37,192.47 I
11,000.0000	ITOCHU CORP	101,586.04	14.8540	163,394.44	61,808.40 18,246.11- C 80,054.51 I
4,000.0000	JGC CORP	70,559.46	16.2157	64,862.94	5,696.52- 5,777.57- C 81.05 I
5,900.0000	JAPAN TOBACCO INC	122,295.85	35.1281	207,256.13	84,960.28 22,565.81- C 107,526.09 I
4,500.0000	AEON CO LTD	57,282.12	15.1922	68,365.07	11,082.95 6,182.40- C 17,265.35 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS	
9,000.0000	KAJIMA CORP	22,230.97	8.4371	75,934.49	53,703.52	
					14,860.45-	C
					68,563.97	I
5,100.0000	KANSAI ELECTRIC POWER CO INC/T	51,597.94	13.7682	70,218.05	18,620.11	
					3,653.00	C
					14,967.11	I
1,000.0000	KANSAI PAINT CO LTD	17,155.81	23.0064	23,006.41	5,850.60	
					1,052.18	C
					4,798.42	I
3,200.0000	KAO CORP	86,324.51	59.3805	190,017.79	103,693.28	
					30,846.63-	C
					134,539.91	I
8,000.0000	KAWASAKI HEAVY INDUSTRIES LTD	21,975.44	2.9547	23,638.30	1,662.86	
					4,626.04-	C
					6,288.90	I
3,000.0000	KEIKYU CORP	24,562.66	12.0416	36,124.95	11,562.29	
					7,069.69-	C
					18,631.98	I
3,000.0000	KEIO CORP	19,995.09	8.3659	25,097.90	5,102.81	
					4,911.67-	C
					10,014.48	I
2,000.0000	KIKKOMAN CORP	23,529.90	31.9508	63,901.74	40,371.84	
					12,505.62-	C
					52,877.46	I
640.0000	KEYENCE CORP	97,249.38	439.1242	281,039.50	183,790.12	
					17,391.93-	C
					201,182.05	I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
14,000.0000	KINTETSU GROUP HOLDINGS CO LTD	45,803.55	3.8536	53,951.58	8,148.03 4,302.49- C 12,450.52 I
6,500.0000	KIRIN HOLDINGS CO LTD	93,773.40	20.3720	132,418.11	38,644.71 17,315.92- C 55,960.63 I
1,000.0000	KOITO MANUFACTURING CO LTD	31,821.93	51.4417	51,441.79	19,619.86 2,352.65 C 17,267.21 I
6,200.0000	KOMATSU LTD	131,657.66	25.4049	157,510.67	25,853.01 20,308.66- C 46,161.67 I
1,100.0000	KONAMI HOLDINGS CORP	21,350.45	55.5357	61,089.35	39,738.90 11,955.23- C 51,694.13 I
1,700.0000	JTEKT CORP	20,760.61	14.6137	24,843.36	4,082.75 4,861.87- C 8,944.62 I
8,000.0000	KUBOTA CORP	82,583.48	16.7986	134,389.46	51,805.98 12,920.25- C 64,726.23 I
2,000.0000	KURARAY CO LTD	26,894.36	18.1381	36,276.25	9,381.89 7,099.29- C 16,481.18 I
2,200.0000	KYOCERA CORP	108,222.75	57.9031	127,386.96	19,164.21 18,192.71- C 37,356.92 I

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2,000.0000	KYOWA HAKKO KIRIN CO LTD	21,017.20	18.5742	37,148.45	16,131.25 7,269.96- C 23,401.21 I
4,800.0000	TOKIO MARINE HOLDINGS INC	134,399.97	41.3937	198,689.92	64,289.95 34,600.87- C 98,890.82 I
12.0000	JAPAN RETAIL FUND INVESTMENT C	19,887.19	1,846.7425	22,160.91	2,273.72 8,711.31- C 10,985.03 I
1,500.0000	JFE HOLDINGS INC	19,579.35	17.3593	26,039.07	6,459.72 1,609.98 C 4,849.74 I
2,000.0000	MAKITA CORP	41,530.35	36.9793	73,958.70	32,428.35 3,626.71- C 36,055.06 I
10,200.0000	SUMITOMO MITSUI FINANCIAL GROU	350,007.16	38.9729	397,524.01	47,516.85 38,465.52- C 85,982.37 I
10,300.0000	MARUBENI CORP	59,223.36	6.4595	66,533.82	7,310.46 6,575.44- C 13,885.90 I
2,200.0000	MARUI GROUP CO LTD	31,250.19	14.7383	32,424.35	1,174.16 297.36 C 876.80 I
7,500.0000	PANASONIC CORP	79,431.90	13.5635	101,726.59	22,294.69 5,896.74- C 28,191.43 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS	
192,880.0000	MIZUHO FINANCIAL GROUP INC	364,271.14	1.8280	352,594.79	11,676.35-	
					44,979.86-	C
					33,303.51	I
1,400.0000	CREDIT SAISON CO LTD	21,181.17	19.5265	27,337.13	6,155.96	
					5,349.91-	C
					11,505.87	I
7,000.0000	MITSUBISHI ESTATE CO LTD	117,830.60	18.6320	130,424.52	12,593.92	
					19,210.09-	C
					31,804.01	I
5,300.0000	MITSUBISHI CORP	102,767.37	20.9683	111,132.07	8,364.70	
					8,721.99-	C
					17,086.69	I
2,000.0000	MITSUBISHI GAS CHEMICAL CO INC	24,360.37	21.1374	42,274.83	17,914.46	
					8,273.22-	C
					26,187.68	I
13,000.0000	MITSUBISHI ELECTRIC CORP	126,474.97	14.3778	186,912.59	60,437.62	
					21,989.86-	C
					82,427.48	I
21,000.0000	MITSUBISHI HEAVY INDUSTRIES LT	89,527.11	4.0922	85,936.27	3,590.84-	
					10,258.77-	C
					6,667.93	I
1,700.0000	MITSUBISHI MATERIALS CORP	53,395.49	30.2598	51,441.79	1,953.70-	
					2,467.99-	C
					514.29	I
8,300.0000	MITSUI & CO LTD	122,261.69	14.2888	118,597.81	3,663.88-	
					9,750.69-	C
					6,086.81	I

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7,000.0000	MITSUI CHEMICALS INC	21,538.91	5.2954	37,068.35	15,529.44 7,254.31- C 22,783.75 I
18,000.0000	MITSUI OSK LINES LTD	54,849.58	2.9369	52,865.79	1,983.79- 1,680.05 C 3,663.84- I
5,000.0000	MITSUI FUDOSAN CO LTD	85,868.17	23.8563	119,281.77	33,413.60 23,343.53- C 56,757.13 I
1,500.0000	MURATA MANUFACTURING CO LTD	109,693.41	151.9223	227,883.58	118,190.17 16,462.86- C 134,653.03 I
2,600.0000	SEIKO EPSON CORP	20,581.74	22.2410	57,826.63	37,244.89 11,316.72- C 48,561.61 I
1,000.0000	NGK INSULATORS LTD	20,133.50	19.9270	19,927.02	206.48- 3,899.73- C 3,693.25 I
1,000.0000	NGK SPARK PLUG CO LTD	13,596.23	21.2620	21,262.01	7,665.78 4,160.99- C 11,826.77 I
8,000.0000	NAGOYA RAILROAD CO LTD	31,311.00	4.6635	37,308.65	5,997.65 2,343.27 C 3,654.38 I
800.0000	NINTENDO CO LTD	106,755.36	335.3506	268,280.51	161,525.15 8,139.67- C 169,664.82 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
2,900.0000	DENSO CORP	92,199.66	42.2036	122,390.52	30,190.86 15,327.11- C 45,517.97 I
1,400.0000	NIDEC CORP	80,642.50	102.4385	143,414.02	62,771.52 14,367.26- C 77,138.78 I
1,000.0000	NH FOODS LTD	12,882.89	30.3933	30,393.38	17,510.49 5,948.01- C 23,458.50 I
1,815.0000	NISSHIN SEIFUN GROUP INC	19,611.80	16.4204	29,803.09	10,191.29 5,832.48- C 16,023.77 I
5,600.0000	NIPPON TELEGRAPH & TELEPHONE C	126,213.80	47.2588	264,649.33	138,435.53 38,007.40- C 176,442.93 I
4,100.0000	NSK LTD	36,133.83	12.4866	51,195.26	15,061.43 1,865.50- C 16,926.93 I
1,000.0000	NISSAN CHEMICAL INDUSTRIES LTD	14,192.47	33.0188	33,018.87	18,826.40 6,461.83- C 25,288.23 I
500.0000	NISSIN FOODS HOLDINGS CO LTD	16,662.57	62.4777	31,238.87	14,576.30 6,113.47- C 20,689.77 I
1,200.0000	NITTO DENKO CORP	48,912.48	82.2356	98,682.80	49,770.32 26,275.83- C 76,046.15 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
4,000.0000	NIPPON EXPRESS CO LTD	17,503.69	6.2566	25,026.70	7,523.01 4,897.74- C 12,420.75 I
1,500.0000	YAMAHA CORP	19,691.64	34.5318	51,797.79	32,106.15 10,136.85- C 42,243.00 I
3,000.0000	MINEBEA MITSUMI INC	18,493.86	16.0644	48,193.31	29,699.45 9,431.46- C 39,130.91 I
4,576.0000	NIPPON STEEL & SUMITOMO METAL	103,212.08	22.5881	103,363.19	151.11 8,575.86- C 8,726.97 I
17,500.0000	NISSAN MOTOR CO LTD	157,570.06	9.9501	174,127.80	16,557.74 25,520.88- C 42,078.62 I
8,400.0000	NOMURA HOLDINGS INC	48,825.26	5.9932	50,343.18	1,517.92 2,786.44 C 1,268.52- I
500.0000	NITORI HOLDINGS CO LTD	18,898.45	133.8554	66,927.73	48,029.28 13,097.82- C 61,127.10 I
800.0000	ORIENTAL LAND CO LTD/JAPAN	13,841.12	67.7109	54,168.74	40,327.62 10,600.87- C 50,928.49 I
3,500.0000	ODAKYU ELECTRIC RAILWAY CO LTD	58,892.57	20.1673	70,585.61	11,693.04 2,771.33- C 14,464.37 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
4,000.0000	OBAYASHI CORP	17,674.04	11.7568	47,027.41	29,353.37 9,203.29- C 38,556.66 I
1,800.0000	OLYMPUS CORP	60,191.99	36.4898	65,681.73	5,489.74 4,726.59- C 10,216.33 I
1,600.0000	OMRON CORP	41,041.22	43.3873	69,419.72	28,378.50 4,679.77- C 33,058.27 I
3,000.0000	ONO PHARMACEUTICAL CO LTD	41,111.70	21.8138	65,441.44	24,329.74 2,152.13- C 26,481.87 I
9,000.0000	TAIHEIYO CEMENT CORP	20,268.47	3.6400	32,760.77	12,492.30 14,316.85- C 26,809.15 I
7,600.0000	ORIX CORP	76,455.54	15.4859	117,693.12	41,237.58 9,810.51- C 51,048.09 I
14,000.0000	OSAKA GAS CO LTD	50,830.59	4.0895	57,253.47	6,422.88 4,857.87- C 11,280.75 I
20.0000	UNITED URBAN INVESTMENT CORP	30,554.62	1,428.4442	28,568.88	1,985.74- 4,283.44- C 2,297.70 I
300.0000	RINNAI CORP	21,724.06	93.1826	27,954.79	6,230.73 3,532.36- C 9,763.09 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS	
4,400.0000	JAPAN EXCHANGE GROUP INC	54,988.18	18.1114	79,690.28	24,702.10	
					3,977.68-	C
					28,679.78	I
4,600.0000	T&D HOLDINGS INC	54,210.31	15.2144	69,986.65	15,776.34	
					5,611.82-	C
					21,388.16	I
400.0000	ROHM CO LTD	17,676.76	76.8066	30,722.68	13,045.92	
					1,899.58	C
					11,146.34	I
200.0000	RYOHIN KEIKAKU CO LTD	40,633.18	249.8219	49,964.40	9,331.22	
					3,089.26	C
					6,241.96	I
400.0000	SMC CORP/JAPAN	73,267.72	303.9337	121,573.51	48,305.79	
					20,237.78-	C
					68,543.57	I
6,100.0000	SOFTBANK GROUP CORP	199,860.96	80.9629	493,874.13	294,013.17	
					55,398.09-	C
					349,411.26	I
2,500.0000	SANTEN PHARMACEUTICAL CO LTD	21,057.94	13.5635	33,908.86	12,850.92	
					13,262.11-	C
					26,113.03	I
1,000.0000	SECOM CO LTD	44,078.64	75.8721	75,872.19	31,793.55	
					14,848.25-	C
					46,641.80	I
4,700.0000	SEKISUI CHEMICAL CO LTD	44,478.87	17.8978	84,119.79	39,640.92	
					204.13	C
					39,436.79	I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
4,000.0000	SEKISUI HOUSE LTD	47,944.81	17.6174	70,469.91	22,525.10 11,873.25- C 34,398.35 I
15,000.0000	SHARP CORP/JAPAN	30,080.00	3.7112	55,669.27	25,589.27 2,546.00 C 23,043.27 I
200.0000	SHIMAMURA CO LTD	21,468.14	122.4635	24,492.70	3,024.56 3,282.84- C 6,307.40 I
3,000.0000	SHIMADZU CORP	42,980.61	19.0281	57,084.37	14,103.76 3,529.48 C 10,574.28 I
4,000.0000	SHIMIZU CORP	16,694.52	10.5998	42,399.43	25,704.91 8,297.60- C 34,002.51 I
2,900.0000	SHIN-ETSU CHEMICAL CO LTD	166,450.50	90.6461	262,873.79	96,423.29 39,223.11- C 135,646.40 I
2,000.0000	SHIONOGI & CO LTD	48,670.81	55.7048	111,409.75	62,738.94 4,032.27- C 66,771.21 I
500.0000	SHIMANO INC	31,786.17	158.2413	79,120.68	47,334.51 5,289.91- C 52,624.42 I
2,700.0000	SHISEIDO CO LTD	51,809.04	35.5464	95,975.43	44,166.39 16,186.21- C 60,352.60 I

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5,000.0000	SHIZUOKA BANK LTD/THE	45,897.76	9.0334	45,167.32	730.44-	
					11,727.77-	C
					10,997.33	I
5,600.0000	SONY CORP	153,799.68	38.1452	213,613.38	59,813.70	
					2,334.20-	C
					62,147.90	I
1,000.0000	STANLEY ELECTRIC CO LTD	19,239.15	30.1708	30,170.88	10,931.73	
					5,904.46-	C
					16,836.19	I
11,000.0000	SUMITOMO CHEMICAL CO LTD	54,399.47	5.7493	63,243.14	8,843.67	
					5,408.15-	C
					14,251.82	I
5,300.0000	SUMITOMO ELECTRIC INDUSTRIES L	66,533.07	15.3969	81,603.77	15,070.70	
					8,407.59-	C
					23,478.29	I
3,000.0000	SUMITOMO HEAVY INDUSTRIES LTD	18,142.52	6.5948	19,784.62	1,642.10	
					3,871.87-	C
					5,513.97	I
5,000.0000	SUMITOMO METAL MINING CO LTD	73,892.69	13.3543	66,771.98	7,120.71-	
					2,799.60-	C
					4,321.11-	I
2,000.0000	SUMITOMO REALTY & DEVELOPMENT	42,810.47	30.8383	61,676.75	18,866.28	
					18,923.50-	C
					37,789.78	I
8,600.0000	SUMITOMO CORP	95,340.33	13.0117	111,901.03	16,560.70	
					11,458.97-	C
					28,019.67	I

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1,900.0000	SUMITOMO RUBBER INDUSTRIES LTD	29,114.74	16.8743	32,061.23	2,946.49	
					1,409.03	C
					1,537.46	I
2,000.0000	SURUGA BANK LTD	17,950.87	24.2257	48,451.40	30,500.53	
					9,481.99-	C
					39,982.52	I
2,600.0000	SUZUKI MOTOR CORP	66,879.50	47.4368	123,335.70	56,456.20	
					9,550.98-	C
					66,007.18	I
550.0000	SUZUKEN CO LTD/AICHI JAPAN	17,514.34	33.1968	18,258.28	743.94	
					3,573.16-	C
					4,317.10	I
900.0000	THK CO LTD	19,643.74	28.3018	25,471.70	5,827.96	
					4,984.83-	C
					10,812.79	I
900.0000	TDK CORP	58,791.71	65.7707	59,193.66	401.95	
					4,646.30-	C
					5,048.25	I
9,000.0000	TAISEI CORP	19,835.39	9.1313	82,182.27	62,346.88	
					16,083.17-	C
					78,430.05	I
2,000.0000	TAKASHIMAYA CO LTD	16,843.58	9.5140	19,028.12	2,184.54	
					3,723.83-	C
					5,908.37	I
4,700.0000	TAKEDA PHARMACEUTICAL CO LTD	207,234.07	50.8098	238,806.50	31,572.43	
					31,093.86-	C
					62,666.29	I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS	
1,000.0000	MITSUBISHI TANABE PHARMA CORP	14,181.83	23.1043	23,104.31	8,922.48	
					4,521.54-	C
					13,444.02	I
1,000.0000	TEIJIN LTD	16,875.51	19.2328	19,232.82	2,357.31	
					3,763.88-	C
					6,121.19	I
800.0000	SYSMEX CORP	26,540.74	59.7187	47,775.01	21,234.27	
					7,163.07-	C
					28,397.34	I
2,300.0000	TERUMO CORP	63,146.57	39.3823	90,579.38	27,432.81	
					9,180.38-	C
					36,613.19	I
5,000.0000	TOBU RAILWAY CO LTD	21,427.64	5.4556	27,278.39	5,850.75	
					1,686.61	C
					4,164.14	I
1,200.0000	TOHO CO LTD/TOKYO	19,177.40	30.7938	36,952.65	17,775.25	
					7,231.67-	C
					25,006.92	I
5,000.0000	TOHO GAS CO LTD	30,434.93	7.2801	36,400.85	5,965.92	
					14,236.77-	C
					20,202.69	I
16,500.0000	TOKYO ELECTRIC POWER CO HOLDIN	73,783.90	4.1206	67,991.27	5,792.63-	
					2,341.05	C
					8,133.68-	I
15,000.0000	TOKYO GAS CO LTD	67,793.93	5.2002	78,003.73	10,209.80	
					8,502.56-	C
					18,712.36	I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
1,200.0000	TOKYO ELECTRON LTD	83,334.53	134.9234	161,908.15	78,573.62 15,981.50- C 94,555.12 I
8,000.0000	TOKYU CORP	42,690.55	7.6272	61,018.15	18,327.60 2,925.05- C 21,252.65 I
4,000.0000	TOPPAN PRINTING CO LTD	33,879.22	10.9647	43,859.02	9,979.80 2,546.25- C 12,526.05 I
10,000.0000	TORAY INDUSTRIES INC	60,383.28	8.3686	83,686.36	23,303.08 14,735.46- C 38,038.54 I
1,000.0000	TOTO LTD	28,117.62	38.1808	38,180.85	10,063.23 5,724.58- C 15,787.81 I
2,200.0000	LIXIL GROUP CORP	44,798.16	24.9999	55,000.00	10,201.84 3,514.92- C 13,716.76 I
2,300.0000	MAZDA MOTOR CORP	33,884.93	13.9551	32,096.83	1,788.10- 2,338.34- C 550.24 I
1,200.0000	TOYOTA INDUSTRIES CORP	41,638.12	52.5987	63,118.54	21,480.42 3,985.40- C 25,465.82 I
1,200.0000	TOYOTA TSUSHO CORP	19,049.63	29.9483	35,938.05	16,888.42 7,033.11- C 23,921.53 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
14,520.0000	TOYOTA MOTOR CORP	581,181.12	52.4474	761,537.52	180,356.40 148,492.98- C 328,849.38 I
3,000.0000	UNICHARM CORP	40,677.61	25.1156	75,347.10	34,669.49 20,638.55- C 55,308.04 I
1,100.0000	WEST JAPAN RAILWAY CO	46,388.22	70.6301	77,693.13	31,304.91 5,927.36- C 37,232.27 I
8,400.0000	YAMADA DENKI CO LTD	32,761.71	4.9661	41,715.91	8,954.20 1,907.85 C 7,046.35 I
700.0000	YAKULT HONSHA CO LTD	18,520.48	68.0847	47,659.31	29,138.83 9,326.98- C 38,465.81 I
1,300.0000	YAMAHA MOTOR CO LTD	19,169.95	25.7920	33,529.72	14,359.77 6,561.80- C 20,921.57 I
12,800.0000	ASTELLAS PHARMA INC	103,223.10	12.2330	156,582.41	53,359.31 19,749.29- C 73,108.60 I
1,000.0000	YAMATO HOLDINGS CO LTD	14,096.64	20.2785	20,278.57	6,181.93 3,968.52- C 10,150.45 I
2,000.0000	YASKAWA ELECTRIC CORP	18,589.69	21.1908	42,381.63	23,791.94 8,294.12- C 32,086.06 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS	
2,300.0000	YOKOGAWA ELECTRIC CORP	32,622.92	16.0288	36,866.32	4,243.40	
					3,886.29-	C
					8,129.69	I
18,800.0000	OVERSEA-CHINESE BANKING CORP L	118,312.27	7.8367	147,330.50	29,018.23	
					3,059.38	C
					25,958.85	I
14,500.0000	SINGAPORE PRESS HOLDINGS LTD	39,423.92	2.3459	34,016.05	5,407.87-	
					798.51	C
					6,206.38-	I
46,000.0000	SINGAPORE TELECOMMUNICATIONS L	106,852.19	2.8252	129,963.32	23,111.13	
					2,275.20	C
					20,835.93	I
8,600.0000	KEPPEL CORP LTD	42,034.51	4.5683	39,288.23	2,746.28-	
					510.43	C
					3,256.71-	I
33,742.0000	GLOBAL LOGISTIC PROPERTIES LTD	64,151.00	2.0772	70,089.06	5,938.06	
					2,790.82-	C
					8,728.88	I
24,900.0000	SINGAPORE TECHNOLOGIES ENGINEE	57,892.85	2.6727	66,551.91	8,659.06	
					1,054.29	C
					7,604.77	I
11,200.0000	DBS GROUP HOLDINGS LTD	120,327.96	15.0633	168,709.74	48,381.78	
					2,704.88	C
					45,676.90	I
3,000.0000	CITY DEVELOPMENTS LTD	23,337.39	7.7931	23,379.45	42.06	
					342.15	C
					300.09-	I

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1,000.0000	JARDINE CYCLE & CARRIAGE LTD	22,406.17	32.2112	32,211.21	9,805.04	
					471.43	C
					9,333.61	I
27,800.0000	CAPITALAND LTD	62,562.22	2.5420	70,668.56	8,106.34	
					1,739.07	C
					6,367.27	I
26,300.0000	GENTING SINGAPORE PLC	16,766.67	0.7880	20,725.21	3,958.54	
					303.33	C
					3,655.21	I
16,000.0000	CAPITALAND MALL TRUST	20,607.34	1.4344	22,950.94	2,343.60	
					337.85	C
					2,005.75	I
8,900.0000	HONGKONG LAND HOLDINGS LTD	57,062.52	7.3600	65,504.00	8,441.48	I
1,800.0000	JARDINE MATHESON HOLDINGS LTD	103,265.54	64.2000	115,560.00	12,294.46	I
15,000.0000	ASCENDAS REAL ESTATE INVESTMEN	20,779.81	1.8956	28,434.47	7,654.66	
					425.37	C
					7,229.29	I
18,000.0000	COMFORTDELGRO CORP LTD	20,113.99	1.6704	30,068.63	9,954.64	
					440.05	C
					9,514.59	I
8,400.0000	UNITED OVERSEAS BANK LTD	115,726.93	16.7919	141,052.40	25,325.47	
					2,751.07	C
					22,574.40	I
11,682.0000	BANK HAPOALIM BM	50,920.75	6.7455	78,801.70	27,880.95	
					8,590.80	C
					19,290.15	I

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5,653.0000	BANK LEUMI LE-ISRAEL BM	24,566.69	4.8628	27,489.87	2,923.18	
					1,982.99	C
					940.19	I
22,660.0000	BEZEQ THE ISRAELI TELECOMMUNIC	48,729.37	1.6606	37,629.22	11,100.15-	
					3,409.02	C
					14,509.17-	I
503.0000	NICE LTD	31,072.99	80.1788	40,329.94	9,256.95	
					3,838.71	C
					5,418.24	I
425.0000	CHECK POINT SOFTWARE TECHNOLOG	32,284.30	109.0800	46,359.00	14,074.70	I
2,031.0000	AERCAP HOLDINGS NV	81,767.82	46.4300	94,299.33	12,531.51	I
1,944.0000	MOBILEYE NV	73,434.39	62.8000	122,083.20	48,648.81	I
2,142.0000	NXP SEMICONDUCTORS NV	183,663.43	109.4500	234,441.90	50,778.47	I
11,862.0000	NOVO NORDISK A/S	213,914.58	42.7686	507,321.23	293,406.65	
					83,424.59-	C
					376,831.24	I
1,015.0000	ISS A/S	30,230.76	39.2250	39,813.39	9,582.63	
					273.26	C
					9,309.37	I
1,523.0000	TRYG A/S	30,307.61	21.8445	33,269.19	2,961.58	
					1,615.74	C
					1,345.84	I
1,172.0000	DSV A/S	27,012.65	61.3609	71,915.08	44,902.43	
					6,340.04-	C
					51,242.47	I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS	
831.0000	PANDORA A/S	73,370.00	93.1919	77,442.55	4,072.55	
					6,534.54-	C
					10,607.09	I
488.0000	CHR HANSEN HOLDING A/S	28,403.65	72.6360	35,446.40	7,042.75	
					430.53	C
					6,612.22	I
1,000.0000	NOVOZYMES A/S	26,215.68	43.7043	43,704.36	17,488.68	
					6,940.92-	C
					24,429.60	I
750.0000	COLOPLAST A/S	17,381.99	83.4509	62,588.21	45,206.22	
					8,801.01-	C
					54,007.23	I
831.0000	CARLSBERG A/S	70,566.71	106.6914	88,660.57	18,093.86	
					8,498.70-	C
					26,592.56	I
62.0000	AP MOLLER - MAERSK A/S	104,553.88	2,008.0382	124,498.37	19,944.49	
					6,574.41-	C
					26,518.90	I
25.0000	AP MOLLER - MAERSK A/S	38,402.55	1,906.7926	47,669.82	9,267.27	
					1,617.90-	C
					10,885.17	I
5,337.0000	DANSKE BANK A/S	129,558.57	38.4119	205,004.73	75,446.16	
					18,308.79-	C
					93,754.95	I
379.0000	GENMAB A/S	50,866.60	213.0760	80,755.81	29,889.21	
					1,459.60	C
					28,429.61	I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS	
10,157.0000	TDC A/S	52,580.75	5.8078	58,990.00	6,409.25	
					3,872.14	C
					2,537.11	I
1,417.0000	VESTAS WIND SYSTEMS A/S	78,835.69	92.1948	130,640.15	51,804.46	
					22,296.02-	C
					74,100.48	I
1,150.0000	NESTE OYJ	20,342.14	39.3375	45,238.20	24,896.06	
					8,456.27-	C
					33,352.33	I
771.0000	NOKIAN RENKAAT OYJ	20,049.85	41.3335	31,868.15	11,818.30	
					5,957.03-	C
					17,775.33	I
1,638.0000	KONE OYJ	40,535.67	50.8000	83,210.56	42,674.89	
					13,373.00-	C
					56,047.89	I
1,109.0000	ORION OYJ	29,103.66	63.7567	70,706.23	41,602.57	
					12,051.46-	C
					53,654.03	I
790.0000	WARTSILA OYJ ABP	20,559.99	59.0234	46,628.54	26,068.55	
					8,716.13-	C
					34,784.68	I
3,929.0000	UPM-KYMMENE OYJ	55,053.73	28.4681	111,851.27	56,797.54	
					11,339.38-	C
					68,136.92	I
7,104.0000	STORA ENSO OYJ	65,051.68	12.8996	91,638.90	26,587.22	
					344.29-	C
					26,931.51	I

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1,907.0000	SAMPO OYJ	51,838.65	51.1764	97,593.54	45,754.89 18,242.91- C 63,997.80 I
1,341.0000	FORTUM OYJ	19,813.77	15.6597	20,999.73	1,185.96 447.42 C 738.54 I
2,001.0000	ELISA OYJ	53,795.27	38.6988	77,436.42	23,641.15 1,089.92- C 24,731.07 I
600.0000	METSO OYJ	15,887.30	34.6270	20,776.26	4,888.96 3,883.65- C 8,772.61 I
16,708.0000	NOKIA OYJ	83,266.21	6.1076	102,046.54	18,780.33 4,009.58 C 14,770.75 I
2,663.0000	MARINE HARVEST ASA	45,149.02	17.0593	45,428.98	279.96 681.48- C 961.44 I
4,128.0000	ORKLA ASA	30,212.79	10.1293	41,813.95	11,601.16 3,256.83- C 14,857.99 I
16,241.0000	NORSK HYDRO ASA	87,172.69	5.5248	89,729.60	2,556.91 11,500.32- C 14,057.23 I
1,834.0000	GJENSIDIGE FORSIKRING ASA	25,861.87	17.0115	31,199.23	5,337.36 14,658.82- C 19,996.18 I

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7,525.0000	DNB ASA	100,902.20	16.9518	127,562.93	26,660.73	
					42,123.27-	C
					68,784.00	I
5,765.0000	TELENOR ASA	92,621.30	16.5340	95,318.83	2,697.53	
					20,604.39-	C
					23,301.92	I
4,002.0000	STATOIL ASA	67,255.37	16.5221	66,121.52	1,133.85-	
					627.62	C
					1,761.47-	I
400.0000	INTERNATIONAL PETROLEUM CORP/S	1,029.21	2.9639	1,185.60	156.39	
					71.74	C
					84.65	I
2,957.0000	KINNEVIK AB	67,330.37	30.5766	90,415.06	23,084.69	
					41.62-	C
					23,126.31	I
4,160.0000	ESSITY AB	55,495.14	27.3280	113,684.78	58,189.64	
					11,904.41-	C
					70,094.05	I
5,090.0000	ATLAS COPCO AB	97,381.12	38.2948	194,920.89	97,539.77	
					33,274.36-	C
					130,814.13	I
2,898.0000	ATLAS COPCO AB	53,461.56	34.5128	100,018.12	46,556.56	
					8,795.12-	C
					55,351.68	I
8,981.0000	SVENSKA HANDELSBANKEN AB	95,687.06	14.2983	128,413.32	32,726.26	
					17,097.61-	C
					49,823.87	I

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4,800.0000	ASSA ABLOY AB	31,611.54	21.9454	105,338.16	73,726.62
					18,480.58- C
					92,207.20 I
781.0000	ICA GRUPPEN AB	30,255.45	37.1804	29,037.90	1,217.55-
					699.85- C
					517.70- I
1,863.0000	ELECTROLUX AB	49,647.95	32.7344	60,984.20	11,336.25
					8,208.20- C
					19,544.45 I
10,756.0000	VOLVO AB	118,706.07	17.0252	183,123.18	64,417.11
					34,744.33- C
					99,161.44 I
1,800.0000	SKF AB	32,501.10	20.2381	36,428.74	3,927.64
					6,391.07- C
					10,318.71 I
1,591.0000	SANDVIK AB	20,907.75	15.7091	24,993.33	4,085.58
					4,384.84- C
					8,470.42 I
4,160.0000	SVENSKA CELLULOSA AB SCA	14,214.14	7.5581	31,442.10	17,227.96
					3,292.44- C
					20,520.40 I
3,000.0000	BOLIDEN AB	52,918.99	27.2569	81,770.81	28,851.82
					20,178.43- C
					49,030.25 I
1,966.0000	HEXAGON AB	49,816.34	47.4832	93,352.11	43,535.77
					14,306.56- C
					57,842.33 I

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2,800.0000	HUSQVARNA AB	20,398.59	9.9234	27,785.71	7,387.12 4,874.74- C 12,261.86 I
502.0000	ETRION CORP	279.38	0.2228	111.89	167.49- 29.11- C 138.38- I
6,614.0000	TELE2 AB	52,811.71	10.4569	69,162.53	16,350.82 5,386.30 C 10,964.52 I
7,600.0000	SKANDINAVISKA ENSKILDA BANKEN	49,380.49	12.0812	91,817.58	42,437.09 16,108.54- C 58,545.63 I
6,723.0000	SWEDBANK AB	102,378.42	24.3403	163,640.25	61,261.83 27,499.17- C 88,761.00 I
1,400.0000	SWEDISH MATCH AB	33,672.32	35.1767	49,247.44	15,575.12 8,640.01- C 24,215.13 I
19,682.0000	NORDEA BANK AB	204,731.78	12.7096	250,150.92	45,419.14 34,790.64- C 80,209.78 I
2,000.0000	SECURITAS AB	21,514.03	16.8355	33,671.03	12,157.00 5,907.27- C 18,064.27 I
4,182.0000	INVESTOR AB	113,414.67	48.1353	201,302.03	87,887.36 11,466.05- C 99,353.41 I

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2,647.0000	HENNES & MAURITZ AB	85,019.86	24.8857	65,872.55	19,147.31- C 7,503.09- C 11,644.22- I
14,557.0000	TELEFONAKTIEBOLAGET LM ERICSSO	86,053.47	7.1432	103,984.12	17,930.65 C 3,652.46 C 14,278.19 I
7,560.0000	TELIA CO AB	30,690.87	4.5989	34,768.00	4,077.13 C 1,221.23 C 2,855.90 I
2,845.0000	SKANSKA AB	53,760.95	23.7001	67,426.89	13,665.94 C 7,050.93- C 20,716.87 I
1,200.0000	LUNDIN PETROLEUM AB	30,539.62	19.2185	23,062.29	7,477.33- C 5,738.63- C 1,738.70- I
1,500.0000	ALFA LAVAL AB	22,545.81	20.4397	30,659.61	8,113.80 C 5,378.94- C 13,492.74 I
3,151.0000	MELCO RESORTS & ENTERTAINMENT ADR	47,968.52	22.4500	70,739.95	22,771.43 I
7,819.0000	TEVA PHARMACEUTICAL INDUSTRIES ADR	386,143.87	33.2200	259,747.18	126,396.69-I
TOTAL INVESTMENTS EQUITY		62,682,162.62		83,928,564.18	21,246,401.56 C 7,748,423.07- C 28,994,824.63 I
TOTAL INVESTMENT		63,568,844.30		84,968,455.42	21,399,611.12 C 7,788,117.04- C 29,187,728.16 I

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MONTICELLO-TOWNSEND RE
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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS REAL ESTATE					
599.8790	PRIME PROPERTY FUND LLC	6,886,001.53	21,660.4396	12,993,642.86	6,107,641.33
2,039,173.0000	FORTRESS JAPAN OPPORTUNITY DOMESTIC FUND © LP	26,368.00	0.6903	1,407,741.00	1,381,373.00
1,735,989.0000	BRAZIL REAL ESTATE OPPORTUNITIES FUND II	1,716,726.45	0.7737	1,343,195.00	373,531.45-
1,828,783.2300	BROOKFIELD REAL ESTATE FUND	0.00	0.1048	191,790.86	191,790.86
289,353.0000	EXETER INDUSTRIAL VALUE FUND II LPP	0.00	1.0291	297,785.00	297,785.00
1,839,324.0200	DIVCOWEST FUND III	0.00	0.2372	436,410.00	436,410.00
4,767,890.0000	JAMESTOWN PREMIER PROPERTY	3,782,194.71	1.6049	7,652,115.79	3,869,921.08
1,849,673.0000	BROOKFIELD FAIRFIELD MULTIFAMILY	311.00	0.3587	663,517.00	663,206.00
1,194,405.0000	CVI EUROPE REAL ESTATE PARTNER TG LLC	442,822.55	0.7410	885,135.69	442,313.14
1,410,000.0000	SAVANNA REAL ESTATE FUND IIA LP LLC	1,291,796.69	1.5961	2,250,596.69	958,800.00
8,182,468.0000	USAA EAGLE REAL ESTATE LP	7,216,962.21	1.3145	10,756,457.13	3,539,494.92
8,196,660.4400	PRISA REAL ESTATE LP	8,000,454.37	1.3318	10,916,837.00	2,916,382.63

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1,146,735.0000	GREENFIELD ACQUI RTNRS VII LP	1,032,994.00	1.1177	1,281,733.00	248,739.00
1,311,234.6100	NORTHLIGHT REAL ESTATE OPPORTUNITY FUND	1,178,226.82	1.0774	1,412,783.04	234,556.22
1,309,685.0100	H/2 SPECIAL OPPORTUNITIES III LP	1,219,981.01	1.1144	1,459,528.00	239,546.99
357,440.0000	BRV PARTNERS FUND I LP	184,045.00	1.0121	361,775.00	177,730.00
6,463,869.0000	METLIFE CORE PROPERTY FUND L P	6,104,020.00	1.0615	6,861,424.00	757,404.00
3,855,600.0000	INLAND RETAIL PROPERTY	3,855,600.00	1.0544	4,065,449.00	209,849.00
580,500.0000	ASANA PARTNERS I	580,500.00	1.0263	595,813.00	15,313.00
3,225,000.0000	HANCOCK US REAL ESTATE	3,225,000.00	1.0000	3,225,000.00	0.00
5,753,975.8900	UBS TRUMBULL PROPERTY FUND	5,127,348.84	1.3041	7,504,229.44	2,376,880.60
1,180.1100	TTG BRPTP FUND LP	0.00	0.0000	0.00	0.00
3,032,575.0000	LION INDUSTRIAL TRUST	2,942,723.01	1.1251	3,412,043.15	469,320.14
1,927,032.5800	CITIC CAPITAL CHINA	1,520,919.25	0.8301	1,599,716.29	78,797.04
TOTAL INVESTMENTS REAL ESTATE		56,334,995.44		81,574,717.94	25,239,722.50
TOTAL INVESTMENT		56,334,995.44		81,574,717.94	25,239,722.50

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WELLINGTON-MONTICELLO
EXCEL ENERGY-NDT

SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS FIXED INCOME SECURITIES					
3,983,847.0570	WTC-CTF JPM PAG EMERGING MARKETS DEBT	39,561,530.99	10.7200	42,706,840.45	3,145,309.46
TOTAL INVESTMENTS FIXED INCOME SECURITIES		39,561,530.99		42,706,840.45	3,145,309.46
TOTAL INVESTMENT		39,561,530.99		42,706,840.45	3,145,309.46

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STEPSTONE-MONTI
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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS PRIVATE EQUITY					
59,072,463.7300	STEPSTONE XL OPP FUND LP	52,234,220.29	1.2445	73,521,411.14	21,287,190.85
TOTAL INVESTMENTS PRIVATE EQUITY		52,234,220.29		73,521,411.14	21,287,190.85
TOTAL INVESTMENT		52,234,220.29		73,521,411.14	21,287,190.85

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS CASH EQUIVALENTS					
768,795.4100	BLACKROCK LIQ T FUND INSTL FUND 60	768,795.41	100.0000	768,795.41	0.00
TOTAL INVESTMENTS CASH EQUIVALENTS		768,795.41		768,795.41	0.00
INVESTMENTS FIXED INCOME SECURITIES					
500,000.0000	SOUTHERN CO GAS CAPITAL CORP 3.250% 06/15/2026 DD 05/18/16	490,950.45	98.1320	490,660.00	290.45-
370,000.0000	AT&T INC 4.350% 06/15/2045 DD 06/15/13	351,715.29	92.8110	343,400.70	8,314.59-
270,000.0000	AT&T INC 5.150% 03/15/2042 DD 03/15/16	264,526.47	102.1190	275,721.30	11,194.83
400,000.0000	ABBVIE INC 3.200% 11/06/2022 DD 05/14/15	401,670.89	102.5660	410,264.00	8,593.11
400,000.0000	AERCAP IRELAND CAPITAL DAC / A 3.750% 05/15/2019 DD 05/15/15	405,027.88	102.7130	410,852.00	5,824.12
500,000.0000	AMAZON.COM INC 2.500% 11/29/2022 DD 11/29/12	491,519.84	100.8010	504,005.00	12,485.16
400,000.0000	AMERICAN EXPRESS CREDIT CORP VAR RT 03/03/2022 DD 03/03/17	400,000.00	100.6790	402,716.00	2,716.00
400,000.0000	AMGEN INC 2.700% 05/01/2022 DD 05/01/15	397,554.61	100.5740	402,296.00	4,741.39

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500,000.0000	ANHEUSER-BUSCH INBEV FINANCE I 4.900% 02/01/2046 DD 01/25/16	573,853.71	112.8640	564,320.00	9,533.71-
500,000.0000	APPLE INC 3.350% 02/09/2027 DD 02/09/17	496,172.60	102.2330	511,165.00	14,992.40
500,000.0000	APPLE INC 3.200% 05/11/2027 DD 05/11/17	500,000.00	101.1680	505,840.00	5,840.00
1,000,000.0000	BABSON CLO LTD 2016 1A B1 144A VAR RT 004/23/2027 DD 02/23/16	1,000,000.00	100.0000	1,000,000.00	0.00
370,000.0000	BANK OF AMERICA CORP 5.650% 05/01/2018 DD 05/02/08	381,861.06	103.1400	381,618.00	243.06-
150,000.0000	BANK OF AMERICA CORP 5.700% 01/24/2022 DD 01/24/12	168,670.47	112.9960	169,494.00	823.53
600,000.0000	BANK OF AMERICA CORP 4.450% 03/03/2026 DD 03/03/16	630,276.02	104.0740	624,444.00	5,832.02-
500,000.0000	BLUEMOUNTAIN CLO 201 4A B 144A VAR RT 01/20/2027 DD 01/13/16	500,000.00	100.0000	500,000.00	0.00
500,000.0000	BRISTOL-MYERS SQUIBB CO 3.250% 02/27/2027 DD 02/27/17	492,235.01	100.8630	504,315.00	12,079.99
400,000.0000	BURLINGTON NORTHERN SANTA FE L 3.250% 06/15/2027 DD 03/09/17	399,014.72	102.1580	408,632.00	9,617.28
450,000.0000	CVS HEALTH CORP 4.750% 12/01/2022 DD 06/01/16	487,962.20	109.6090	493,240.50	5,278.30

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
400,000.0000	CHARTER COMMUNICATIONS OPERATI 4.908% 07/23/2025 DD 07/23/16	420,520.81	108.0320	432,128.00	11,607.19
200,000.0000	CITIGROUP INC 2.700% 03/30/2021 DD 03/30/16	202,196.11	100.6640	201,328.00	868.11-
500,000.0000	COMMONWEALTH BANK OF AUSTRALIA 2.300% 09/06/2019 DD 09/08/14	506,189.02	100.6460	503,230.00	2,959.02-
200,000.0000	DAIMLER FINANCE NORTH AME 144A 2.850% 01/06/2022 DD 01/06/17	199,798.18	101.2080	202,416.00	2,617.82
400,000.0000	DELL INTERNATIONAL LLC / 144A 6.020% 06/15/2026 DD 06/01/16	426,448.28	110.1510	440,604.00	14,155.72
200,000.0000	DOW CHEMICAL CO/THE 8.550% 05/15/2019 DD 05/13/09	224,894.70	112.0040	224,008.00	886.70-
800,000.0000	DUKE ENERGY CORP 2.650% 09/01/2026 DD 08/12/16	763,487.88	94.9730	759,784.00	3,703.88-
0.0020	FNMA POOL #0AO9180 3.500% 07/01/2042 DD 06/01/12	0.00	103.2140	0.00	0.00
825,000.0000	FEDEX CORP 3.300% 03/15/2027 DD 01/06/17	832,371.48	100.2180	826,798.50	5,572.98-
200,000.0000	FORD MOTOR CREDIT CO LLC 4.250% 09/20/2022 DD 09/25/12	206,455.01	105.0530	210,106.00	3,650.99
200,000.0000	FORD MOTOR CREDIT CO LLC 2.459% 03/27/2020 DD 03/27/15	201,679.48	100.0870	200,174.00	1,505.48-

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
500,000.0000	GE CAPITAL INTERNATIONAL FUNDI 4.418% 11/15/2035 DD 05/15/16	513,357.62	108.8390	544,195.00	30,837.38
525,000.0000	GENERAL MOTORS FINANCIAL CO IN 3.250% 05/15/2018 DD 11/15/13	529,932.23	101.1720	531,153.00	1,220.77
270,000.0000	GEORGIA-PACIFIC LLC 7.375% 12/01/2025 DD 12/08/95	340,567.63	127.2360	343,537.20	2,969.57
225,000.0000	GEORGIA-PACIFIC LLC 144A 5.400% 11/01/2020 DD 11/02/10	245,185.64	109.3970	246,143.25	957.61
500,000.0000	GOLDMAN SACHS GROUP INC/THE 6.150% 04/01/2018 DD 04/01/08	514,715.78	103.2090	516,045.00	1,329.22
550,000.0000	HCA INC 6.500% 02/15/2020 DD 08/01/11	595,148.72	109.1250	600,187.50	5,038.78
200,000.0000	HSBC HOLDINGS PLC 4.000% 03/30/2022 DD 03/30/12	210,270.36	105.4700	210,940.00	669.64
480,000.0000	HONEYWELL INTERNATIONAL INC 1.850% 11/01/2021 DD 10/31/16	472,121.89	98.3980	472,310.40	188.51
300,000.0000	HYUNDAI CAPITAL AMERICA 144A 2.400% 10/30/2018 DD 10/30/15	302,115.10	100.2090	300,627.00	1,488.10-
1,000,000.0000	INTEL CORP 4.100% 05/11/2047 DD 05/11/17	994,203.93	103.5240	1,035,240.00	41,036.07
500,000.0000	INTERCONTINENTAL EXCHANGE INC 4.000% 10/15/2023 DD 10/08/13	528,498.96	107.2490	536,245.01	7,746.05

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750,000.0000	JPMORGAN CHASE & CO 3.900% 07/15/2025 DD 07/21/15	772,403.14	104.2870	782,152.50	9,749.36
400,000.0000	JOHNSON & JOHNSON 3.625% 03/03/2037 DD 03/03/17	398,995.55	104.5690	418,276.00	19,280.45
520,000.0000	KRAFT HEINZ FOODS CO 5.200% 07/15/2045 DD 07/15/16	601,241.28	108.1830	562,551.60	38,689.68-
400,000.0000	KROGER CO/THE 2.650% 10/15/2026 DD 10/03/16	372,107.41	92.2240	368,896.00	3,211.41-
350,000.0000	L3 TECHNOLOGIES INC 5.200% 10/15/2019 DD 04/15/10	371,795.55	106.7510	373,628.50	1,832.95
500,000.0000	LOCKHEED MARTIN CORP 3.550% 01/15/2026 DD 11/23/15	503,035.26	103.6210	518,105.00	15,069.74
500,000.0000	MCDONALD'S CORP 4.450% 03/01/2047 DD 03/09/17	497,557.55	105.1890	525,945.00	28,387.45
400,000.0000	MICROSOFT CORP 3.300% 02/06/2027 DD 02/06/17	398,628.23	103.0070	412,028.00	13,399.77
0.0130	MINNESOTA ST HSG FIN AGY HOMEO 3.000% 09/01/2043 DD 07/25/13	0.01	99.9930	0.01	0.00
400,000.0000	MIZUHO FINANCIAL GROUP INC 3.663% 02/28/2027 DD 02/28/17	400,000.00	103.1110	412,444.00	12,444.00
500,000.0000	MORGAN STANLEY 2.375% 07/23/2019 DD 07/23/14	504,488.34	100.6930	503,465.00	1,023.34-

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
500,000.0000	NEUBERGER BERMAN CL 23A C 144A VAR RT 10/17/2027 DD 11/29/16	500,000.00	100.0000	500,000.00	0.00
500,000.0000	NEWELL BRANDS INC 4.200% 04/01/2026 DD 03/30/16	532,307.29	106.1790	530,895.00	1,412.29-
250,000.0000	NORFOLK SOUTHERN CORP 2.900% 06/15/2026 DD 06/03/16	240,720.09	98.4110	246,027.50	5,307.41
1,000,000.0000	OAKTREE EIF I SERIES A1 A 144A VAR RT 10/18/2027 DD 01/07/16	999,650.28	99.9650	999,650.28	0.00
450,000.0000	ORACLE CORP 2.800% 07/08/2021 DD 07/08/14	456,723.38	102.7020	462,159.00	5,435.62
225,000.0000	PACIFIC BELL TELEPHONE CO 7.125% 03/15/2026 DD 03/15/93	272,170.47	121.5160	273,411.00	1,240.53
450,000.0000	PACIFICORP 6.000% 01/15/2039 DD 01/08/09	570,925.72	129.8500	584,325.00	13,399.28
225,000.0000	PFIZER INC 2.750% 06/03/2026 DD 06/03/16	217,692.67	98.4310	221,469.75	3,777.08
200,000.0000	PRUDENTIAL FINANCIAL INC 5.750% 07/15/2033 DD 07/07/03	233,135.60	120.8010	241,602.00	8,466.40
650,000.0000	QUALCOMM INC 3.250% 05/20/2027 DD 05/26/17	648,311.40	100.2290	651,488.50	3,177.10
800,000.0000	ROCKWELL COLLINS INC 3.500% 03/15/2027 DD 04/10/17	815,335.45	101.4040	811,232.00	4,103.45-

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
400,000.0000	SOUTHWESTERN ELECTRIC POWER CO 3.550% 02/15/2022 DD 02/03/12	415,162.17	103.2350	412,940.00	2,222.17-
750,000.0000	SPIRIT AEROSYSTEMS INC 5.250% 03/15/2022 DD 09/15/14	781,436.12	103.7610	778,207.50	3,228.62-
580,000.0000	SYNCHRONY FINANCIAL 3.750% 08/15/2021 DD 08/11/14	583,846.33	102.7130	595,735.40	11,889.07
3,121,105.7300	US TREAS-CPI INFLAT 3.625% 04/15/2028 DD 04/15/98	4,155,712.10	130.6350	4,077,256.47	78,455.63-
1,377,420.0000	US TREAS-CPI INFLAT 3.375% 04/15/2032 DD 10/15/01	1,939,894.43	137.3860	1,892,382.24	47,512.19-
1,357,435.2000	US TREAS-CPI INFLAT 2.125% 02/15/2040 DD 02/15/10	1,692,354.20	124.3700	1,688,242.16	4,112.04-
2,672,623.5000	US TREAS-CPI INFLAT 0.750% 02/15/2042 DD 02/15/12	2,546,008.53	95.1440	2,542,840.90	3,167.63-
2,115,500.7400	US TREAS-CPI INFLAT 0.750% 02/15/2045 DD 02/15/15	2,053,481.92	93.7820	1,983,958.90	69,523.02-
1,681,963.5000	US TREAS-CPI INFLAT 1.000% 02/15/2046 DD 02/15/16	1,733,763.00	99.9100	1,680,449.73	53,313.27-
740,000.0000	U S TREASURY BOND 3.000% 02/15/2047 DD 02/15/17	761,614.94	103.1560	763,354.40	1,739.46
617,850.7000	US TREAS-CPI INFLAT 0.875% 02/15/2047 DD 02/15/17	605,482.90	97.0440	599,587.03	5,895.87-

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100,000.0000	U S TREASURY NOTE 1.750% 11/30/2021 DD 11/30/16	99,644.67	99.7380	99,738.00	93.33
130,000.0000	U S TREASURY NOTE 2.000% 12/31/2021 DD 12/31/16	130,472.46	100.7230	130,939.90	467.44
4,488,000.0000	U S TREASURY NOTE 2.250% 02/15/2027 DD 02/15/17	4,422,587.24	99.5350	4,467,130.80	44,543.56
740,000.0000	U S TREASURY NOTE 1.875% 03/31/2022 DD 03/31/17	740,027.53	100.0590	740,436.60	409.07
500,000.0000	U S TREASURY NOTE 1.875% 04/30/2022 DD 04/30/17	498,535.79	99.9810	499,905.00	1,369.21
1,000,000.0000	U S TREASURY NOTE 2.375% 05/15/2027 DD 05/15/17	997,026.70	100.6330	1,006,330.00	9,303.30
718,000.0000	UNITED TECHNOLOGIES CORP 4.500% 06/01/2042 DD 06/01/12	799,570.37	109.1950	784,020.10	15,550.27-
490,000.0000	UNITEDHEALTH GROUP INC 2.700% 07/15/2020 DD 07/23/15	505,695.39	102.1050	500,314.50	5,380.89-
600,000.0000	UNITEDHEALTH GROUP INC 4.250% 04/15/2047 DD 03/13/17	630,164.47	106.6050	639,630.00	9,465.53
200,000.0000	VERIZON COMMUNICATIONS INC 4.500% 09/15/2020 DD 09/18/13	216,685.74	106.8240	213,648.00	3,037.74-
500,000.0000	VERIZON COMMUNICATIONS INC 4.125% 03/16/2027 DD 03/16/17	496,798.70	103.2780	516,390.00	19,591.30

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FIRST PRINCIPALS MONTICELLO
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500,000.0000	VISA INC 4.300% 12/14/2045 DD 12/14/15	502,564.61	109.6770	548,385.00	45,820.39
475,000.0000	WALGREEN CO 4.400% 09/15/2042 DD 09/13/12	459,269.22	100.1270	475,603.25	16,334.03
750,000.0000	WELLS FARGO & CO 4.300% 07/22/2027 DD 07/22/15	769,370.28	104.7420	785,565.00	16,194.72
1,830,000.0000	IFL L UL CPURNSA INDEX P 2.775% 2033 JUN 07	0.00	0.0000	0.00	0.00
1,830,000.0000	IFL L UL CPURNSA INDEX P 2.7125% 2033 JUN 10	0.00	0.0000	0.00	0.00
1,830,000.0000	IRS_R US0003M P 6.75% 2038 JUN 19	59,109.00	0.4455	8,153.00	50,956.00-
3,750,000.0000	IRS_R US0003M P 6.75% 2034 JAN 27	99,375.00	0.4845	18,170.00	81,205.00-
4,500,000.0000	IFL L UL CPURNSA INDEX P 196BPS 2038 MAY 23	0.00	3.6622	164,800.00	164,800.00
2,250,000.0000	IFL L UL CPURNSA P 1.775% 2036 JUN 20	0.00	6.6827	150,361.00	150,361.00
5,260,000.0000	IFL L UL CPURNSA P 1.8475% 2038 JUN 28	0.00	5.8526	307,848.00	307,848.00
6,160,000.0000	IFL L UL CPURNSA_INDEX P 2.321% 2037 APR 06	0.00	0.0000	0.00	0.00

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FIRST PRINCIPALS MONTICELLO
XCEL ENERGY NDT

SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
7,900,000.0000	IFL L_UL CPURNSA INDEX P 2.3175% 2037 MAY 03	0.00	0.0000	0.00	0.00
TOTAL INVESTMENTS FIXED INCOME SECURITIES		57,066,048.51		57,712,257.88	646,209.37
TOTAL INVESTMENT		57,834,843.92		58,481,053.29	646,209.37
SHORT FIXED INCOME SECURITIES					
1,830,000.0000-	IFL S UL CPURNSA INDEX P 2.775% 2033 JUN 07	0.00	18.7984	344,011.00-	344,011.00-
1,830,000.0000-	IFL S UL CPURNSA INDEX P 2.7125% 2033 JUN 10	0.00	17.2695	316,033.00-	316,033.00-
1,830,000.0000-	IRS R US0003M P 6.75% 2038 JUN 19	0.00	0.0000	0.00	0.00
3,750,000.0000-	IRS R US0003M P 6.75% 2034 JAN 29	0.00	0.0000	0.00	0.00
4,500,000.0000-	IFL S UL CPURNSA INDEX P 196BPS 2038 MAY 23	0.00	0.0000	0.00	0.00
2,250,000.0000-	IFL S UL CPURNSA P 1.775% 2036 JUN 20	0.00	0.0000	0.00	0.00
5,260,000.0000-	IFL S UL CPURNSA P 1.8475% 2038 JUN 28	0.00	0.0000	0.00	0.00
6,160,000.0000-	IFL L UL CPURNSA INDEX P_2.321% 2037 APR 06	0.00	4.3284	266,633.00-	266,633.00-

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FIRST PRINCIPALS MONTICELLO
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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
7,900,000.0000-	IFL S_UL CPURNSA INDEX P 2.3175% 2037 MAY 03	0.00	4.2236	333,670.00-	333,670.00-
TOTAL SHORT FIXED INCOME SECURITIES		0.00		1,260,347.00-	1,260,347.00-
TOTAL SHORT INVESTMENT		0.00		1,260,347.00-	1,260,347.00-
TOTAL NET INVESTMENT		57,834,843.92		57,220,706.29	614,137.63-

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TITAN MASTERS LP MONTICELLO
XCEL ENERGY NDT

SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS CASH EQUIVALENTS					
3.2500	BLACKROCK LIQ T FUND INSTL FUND 60	3.25	100.0000	3.25	0.00
TOTAL INVESTMENTS CASH EQUIVALENTS		3.25		3.25	0.00
INVESTMENTS ALTERNATIVE INVESTMENTS					
23,947,273.4120	TITAN FUND LP	23,947,273.41	1.0041	24,047,192.00	99,918.59
TOTAL INVESTMENTS ALTERNATIVE INVESTMENTS		23,947,273.41		24,047,192.00	99,918.59
TOTAL INVESTMENT		23,947,276.66		24,047,195.25	99,918.59

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MAGNITUDE-MONTI
XCEL ENERGY NDT

SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS ALTERNATIVE INVESTMENTS					
12,290.1400	MAGNITUDE US PARTNERS	12,865,613.65	1,190.8651	14,635,899.00	1,770,285.35
9,741.3000	MAGNITUDE US PARTNERS (SERIES Y)	10,683,350.24	1,206.6467	11,754,308.00	1,070,957.76
9,747.8000	MAGNITUDE US PARTNERS (SERIES X)	10,700,129.24	1,198.4791	11,682,535.00	982,405.76
43.0300	MAGNITUDE US PARTNERS 04/17	43,033.20	1,005.1127	43,250.00	216.80
TOTAL INVESTMENTS ALTERNATIVE INVESTMENTS		34,292,126.33		38,115,992.00	3,823,865.67
TOTAL INVESTMENT		34,292,126.33		38,115,992.00	3,823,865.67

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CORECOMMODITY-MONTI
XCEL ENERGY NDT

SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS OTHER					
46,149,124.6600	CORE COMMODITY FUND	44,643,000.00	0.7669	35,395,713.22	9,247,286.78-
TOTAL INVESTMENTS OTHER		44,643,000.00		35,395,713.22	9,247,286.78-
TOTAL INVESTMENT		44,643,000.00		35,395,713.22	9,247,286.78-

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MARATHON EAFE-MONTI
XCEL ENERGY NDT

SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS OTHER					
22,948.7820	MARATHON EAFE	32,684,264.62	1,591.4921	36,522,805.74	3,838,541.12
TOTAL INVESTMENTS OTHER		32,684,264.62		36,522,805.74	3,838,541.12
TOTAL INVESTMENT		32,684,264.62		36,522,805.74	3,838,541.12

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GOLDMAN MONTI
XCEL ENERGY NDT

SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS FIXED INCOME SECURITIES					
359,491.0000	ISHARES IBOXX USD HIGH YIELD	31,786,341.57	88.3900	31,775,409.49	10,932.08-
TOTAL INVESTMENTS FIXED INCOME SECURITIES		31,786,341.57		31,775,409.49	10,932.08-
TOTAL INVESTMENT		31,786,341.57		31,775,409.49	10,932.08-

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NSP/XCEL ENERGY NDT

SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS UNIT OF PARTICIPATION					
29,908,119.3080	PRAIRIE #1 QUALIFIED MTU	298,347,568.65	12.9835	388,313,263.36	89,965,694.71
TOTAL INVESTMENTS UNIT OF PARTICIPATION		298,347,568.65		388,313,263.36	89,965,694.71
TOTAL INVESTMENT		298,347,568.65		388,313,263.36	89,965,694.71

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CASH - PRAIRIE I 1
XCEL ENERGY NDT

SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS CASH EQUIVALENTS					
481,461.7700	BLACKROCK LIQ T FUND INSTL FUND 60	481,461.77	100.0000	481,461.77	0.00
TOTAL INVESTMENTS CASH EQUIVALENTS		481,461.77		481,461.77	0.00
TOTAL INVESTMENT		481,461.77		481,461.77	0.00

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PARAMETRIC US - PRAIRIE I 1
XCEL ENERGY NDT

SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS CASH EQUIVALENTS					
218,361.7000	BLACKROCK LIQ T FUND INSTL FUND 60	218,361.70	100.0000	218,361.70	0.00
TOTAL INVESTMENTS CASH EQUIVALENTS		218,361.70		218,361.70	0.00
INVESTMENTS EQUITY					
439.0000	ADIENT PLC	20,633.00	65.3800	28,701.82	8,068.82
401.0000	AIRCASTLE LTD	4,896.21	21.7500	8,721.75	3,825.54
726.0000	ALLEGION PLC	15,000.95	81.1200	58,893.12	43,892.17
978.0000	ALKERMES PLC	17,198.90	57.9700	56,694.66	39,495.76
1,644.0000	ALLERGAN PLC	369,472.29	243.0900	399,639.96	30,167.67
985.0000	AMDOCS LTD	29,981.22	64.4600	63,493.10	33,511.88
1,851.0000	AON PLC	90,717.51	132.9500	246,090.45	155,372.94
1,403.0000	ARCH CAPITAL GROUP LTD	35,251.56	93.2900	130,885.87	95,634.31
227.0000	ARGO GROUP INTERNATIONAL HOLDI	4,845.28	60.6000	13,756.20	8,910.92
286.0000	ASPEN INSURANCE HOLDINGS LTD	7,107.10	49.8500	14,257.10	7,150.00
737.0000	ARRIS INTERNATIONAL PLC	8,077.52	28.0200	20,650.74	12,573.22

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XCEL ENERGY NDT

SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
1,919.0000	ASSURED GUARANTY LTD	26,139.79	41.7400	80,099.06	53,959.27
770.0000	AXIS CAPITAL HOLDINGS LTD	23,669.80	64.6600	49,788.20	26,118.40
3,646.0000	ACCENTURE PLC	155,693.76	123.6800	450,937.28	295,243.52
1,750.0000	BELMOND LTD	14,284.86	13.3000	23,275.00	8,990.14
933.0000	BUNGE LTD	57,873.99	74.6000	69,601.80	11,727.81
227.0000	CARDTRONICS PLC	9,025.52	32.8600	7,459.22	1,566.30-
551.0000	CONSOLIDATED WATER CO LTD	5,052.67	12.4000	6,832.40	1,779.73
1,495.0000	DELPHI AUTOMOTIVE PLC	52,199.52	87.6500	131,036.75	78,837.23
2,412.0000	EATON CORP PLC	124,169.75	77.8300	187,725.96	63,556.21
1,570.0000	ENDO INTERNATIONAL PLC	25,057.20	11.1700	17,536.90	7,520.30-
50.0000	ENSTAR GROUP LTD	5,024.00	198.6500	9,932.50	4,908.50
733.0000	ESSENT GROUP LTD	25,786.94	37.1400	27,223.62	1,436.68
268.0000	EVEREST RE GROUP LTD	24,972.24	254.5900	68,230.12	43,257.88
2,546.0000	FRUIT OF THE LOOM INC CL A	21,603.27	8.4851	21,603.27	0.00
183.0000	HELEN OF TROY LTD	5,927.37	94.1000	17,220.30	11,292.93
653.0000	HERBALIFE LTD	24,980.22	71.3300	46,578.49	21,598.27
1,006.0000	IHS MARKIT LTD	32,976.67	44.0400	44,304.24	11,327.57

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
2,177.0000	INGERSOLL-RAND PLC	59,317.31	91.3900	198,956.03	139,638.72
5,916.0000	WEATHERFORD INTERNATIONAL PLC	35,895.57	3.8700	22,894.92	13,000.65-
3,034.0000	INVESCO LTD	75,689.72	35.1900	106,766.46	31,076.74
4,393.0000	JOHNSON CONTROLS INTERNATIONAL	185,690.15	43.3600	190,480.48	4,790.33
719.0000	MALLINCKRODT PLC	31,894.57	44.8100	32,218.39	323.82
2,368.0000	MARVELL TECHNOLOGY GROUP LTD	23,621.38	16.5200	39,119.36	15,497.98
6,639.0000	MEDTRONIC PLC	510,377.41	88.7500	589,211.25	78,833.84
731.0000	MICHAEL KORS HOLDINGS LTD	36,579.24	36.2500	26,498.75	10,080.49-
2,206.0000	NABORS INDUSTRIES LTD	29,667.59	8.1400	17,956.84	11,710.75-
758.0000	NIELSEN HOLDINGS PLC	24,234.23	38.6600	29,304.28	5,070.05
2,489.0000	NOBLE CORP PLC	23,346.82	3.6200	9,010.18	14,336.64-
1,541.0000	NORDIC AMERICAN TANKERS LTD	12,882.76	6.3400	9,769.94	3,112.82-
551.0000	NORWEGIAN CRUISE LINE HOLDINGS	24,194.41	54.2900	29,913.79	5,719.38
1,399.0000	PENTAIR PLC	52,545.31	66.5400	93,089.46	40,544.15
1,284.0000	SHIP FINANCE INTERNATIONAL LTD	13,969.92	13.6000	17,462.40	3,492.48
806.0000	SIGNET JEWELERS LTD	25,872.60	63.2400	50,971.44	25,098.84
2,598.0000	TEXTAINER GROUP HOLDINGS LTD	22,888.38	14.5000	37,671.00	14,782.62

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
117.0000	THERAVANCE BIOPHARMA INC	2,294.37	39.8400	4,661.28	2,366.91
294.0000	VALIDUS HOLDINGS LTD	8,822.94	51.9700	15,279.18	6,456.24
1,270.0000	GOLAR LNG LTD	26,109.85	22.2500	28,257.50	2,147.65
12.0000	WHITE MOUNTAINS INSURANCE GROU	4,836.12	868.6300	10,423.56	5,587.44
984.0000	PERRIGO CO PLC	72,628.77	75.5200	74,311.68	1,682.91
2,082.0000	XL GROUP LTD	43,966.30	43.8000	91,191.60	47,225.30
1,918.0000	CHUBB LTD	151,193.68	145.3800	278,838.84	127,645.16
15.0000	GARMIN LTD	471.00	51.0300	765.45	294.45
1,592.0000	TRANSOCEAN LTD	24,453.12	8.2300	13,102.16	11,350.96-
150.0000	CIMPRESS NV	5,083.50	94.5300	14,179.50	9,096.00
4,030.0000	FRANK'S INTERNATIONAL NV	32,305.45	8.2900	33,408.70	1,103.25
1,497.0000	LYONDELLBASELL INDUSTRIES NV	68,057.05	84.3900	126,331.83	58,274.78
2,493.0000	MYLAN NV	110,386.50	38.8200	96,778.26	13,608.24-
351.0000	WRIGHT MEDICAL GROUP NV	7,427.16	27.4900	9,648.99	2,221.83
806.0000	BANCO LATINOAMERICANO DE COMER	13,677.82	27.3800	22,068.28	8,390.46
4,376.0000	TRONOX LTD	24,243.04	15.1200	66,165.12	41,922.08
919.0000	ROYAL CARIBBEAN CRUISES LTD	24,280.67	109.2300	100,382.37	76,101.70

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
1,820.0000	BROADCOM LTD	106,863.18	233.0500	424,151.00	317,287.82
1,000.0000	SCORPIO TANKERS INC	4,960.00	3.9700	3,970.00	990.00-
1,748.0000	TEEKAY TANKERS LTD	5,611.08	1.8800	3,286.24	2,324.84-
316.0000	ABM INDUSTRIES INC	7,223.76	41.5200	13,120.32	5,896.56
2,665.0000	AFLAC INC	122,470.34	77.6800	207,017.20	84,546.86
589.0000	AGCO CORP	26,884.93	67.3900	39,692.71	12,807.78
2,036.0000	AES CORP/VA	25,426.81	11.1100	22,619.96	2,806.85-
299.0000	AMAG PHARMACEUTICALS INC	5,142.80	18.4000	5,501.60	358.80
29,769.0000	AT&T INC	926,957.64	37.7300	1,123,184.37	196,226.73
841.0000	AVX CORP	10,024.72	16.3400	13,741.94	3,717.22
477.0000	AARON'S INC	12,883.77	38.9000	18,555.30	5,671.53
9,877.0000	ABBOTT LABORATORIES	260,700.77	48.6100	480,120.97	219,420.20
10,535.0000	ABBVIE INC	283,915.97	72.5100	763,892.85	479,976.88
340.0000	ABIOMED INC	24,595.60	143.3000	48,722.00	24,126.40
667.0000	ACADIA HEALTHCARE CO INC	23,084.87	49.3800	32,936.46	9,851.59
751.0000	ACADIA PHARMACEUTICALS INC	25,579.06	27.8900	20,945.39	4,633.67-
244.0000	ACADIA REALTY TRUST	4,926.36	27.8000	6,783.20	1,856.84

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492.0000	ACI WORLDWIDE INC	5,180.76	22.3700	11,006.04	5,825.28
2,631.0000	ACTIVISION BLIZZARD INC	50,380.88	57.5700	151,466.67	101,085.79
258.0000	ACUITY BRANDS INC	14,107.44	203.2800	52,446.24	38,338.80
1,839.0000	ACTUA CORP	26,036.04	14.0500	25,837.95	198.09-
1,265.0000	ACXIOM CORP	16,031.23	25.9800	32,864.70	16,833.47
2,875.0000	ADOBE SYSTEMS INC	109,521.11	141.4400	406,640.00	297,118.89
539.0000	ADVANCE AUTO PARTS INC	33,342.65	116.5900	62,842.01	29,499.36
1,727.0000	AECOM	37,093.97	32.3300	55,833.91	18,739.94
592.0000	AEGION CORP	10,290.00	21.8800	12,952.96	2,662.96
183.0000	ADVANSIX INC	1,021.53	31.2400	5,716.92	4,695.39
781.0000	AEROJET ROCKETDYNE HOLDINGS IN	4,904.68	20.8000	16,244.80	11,340.12
4,445.0000	ADVANCED MICRO DEVICES INC	53,486.74	12.4800	55,473.60	1,986.86
2,256.0000	AETNA INC	88,492.72	151.8300	342,528.48	254,035.76
470.0000	AFFILIATED MANAGERS GROUP INC	56,659.08	165.8600	77,954.20	21,295.12
2,375.0000	AGILENT TECHNOLOGIES INC	53,797.96	59.3100	140,861.25	87,063.29
333.0000	AGREE REALTY CORP	9,813.51	45.8700	15,274.71	5,461.20
195.0000	AIR LEASE CORP	4,655.27	37.3600	7,285.20	2,629.93

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1,382.0000	AIR PRODUCTS & CHEMICALS INC	86,407.60	143.0600	197,708.92	111,301.32
1,096.0000	AKAMAI TECHNOLOGIES INC	36,166.27	49.8100	54,591.76	18,425.49
146.0000	ALAMO GROUP INC	4,950.86	90.8100	13,258.26	8,307.40
856.0000	ALASKA AIR GROUP INC	14,338.00	89.7600	76,834.56	62,496.56
197.0000	ALBANY INTERNATIONAL CORP	4,873.78	53.4000	10,519.80	5,646.02
536.0000	ALBEMARLE CORP	51,466.36	105.5400	56,569.44	5,103.08
648.0000	ALCOA CORP	12,757.49	32.6500	21,157.20	8,399.71
392.0000	ALERE INC	10,043.04	50.1900	19,674.48	9,631.44
571.0000	ALEXANDER & BALDWIN INC	8,493.22	41.3800	23,627.98	15,134.76
47.0000	ALEXANDER'S INC	15,356.77	421.4600	19,808.62	4,451.85
357.0000	ALEXANDRIA REAL ESTATE EQUITIE	25,139.94	120.4700	43,007.79	17,867.85
1,153.0000	ALEXION PHARMACEUTICALS INC	95,064.09	121.6700	140,285.51	45,221.42
365.0000	ALIGN TECHNOLOGY INC	8,066.50	150.1200	54,793.80	46,727.30
98.0000	ALLEGHANY CORP	28,633.04	594.8000	58,290.40	29,657.36
107.0000	ALLEGIANT TRAVEL CO	4,872.78	135.6000	14,509.20	9,636.42
107.0000	ALLETE INC	5,077.15	71.6800	7,669.76	2,592.61
288.0000	ALLIANCE DATA SYSTEMS CORP	44,856.17	256.6900	73,926.72	29,070.55

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1,340.0000	ALLIANT ENERGY CORP	30,649.35	40.1700	53,827.80	23,178.45
393.0000	ALLSCRIPTS HEALTHCARE SOLUTION	4,943.94	12.7600	5,014.68	70.74
2,169.0000	ALLSTATE CORP/THE	81,166.87	88.4400	191,826.36	110,659.49
1,044.0000	ALLY FINANCIAL INC	23,416.92	20.9000	21,819.60	1,597.32-
354.0000	ALMOST FAMILY INC	5,200.26	61.6500	21,824.10	16,623.84
820.0000	ALNYLAM PHARMACEUTICALS INC	28,138.84	79.7600	65,403.20	37,264.36
587.0000	ALON USA ENERGY INC	5,165.60	13.3200	7,818.84	2,653.24
1,380.0000	ALPHABET INC-CL C	294,608.32	908.7300	1,254,047.40	959,439.08
1,640.0000	ALPHABET INC-CL A	577,977.87	929.6800	1,524,675.20	946,697.33
2,384.0000	ALTISOURCE RESIDENTIAL CORP	22,290.40	12.9400	30,848.96	8,558.56
11,116.0000	ALTRIA GROUP INC	189,729.51	74.4700	827,808.52	638,079.01
2,005.0000	AMAZON.COM INC	296,454.21	968.0000	1,940,840.00	1,644,385.79
53.0000	AMERCO	5,074.22	366.0600	19,401.18	14,326.96
1,085.0000	AMEREN CORP	33,801.46	54.6700	59,316.95	25,515.49
2,792.0000	AMERICAN AIRLINES GROUP INC	120,221.18	50.3200	140,493.44	20,272.26
227.0000	AMERICAN ASSETS TRUST INC	5,077.99	39.3900	8,941.53	3,863.54
1,028.0000	AMERICAN AXLE & MANUFACTURING	10,248.04	15.6000	16,036.80	5,788.76

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405.0000	AMERICAN CAMPUS COMMUNITIES IN	14,021.10	47.3000	19,156.50	5,135.40
2,728.0000	AMERICAN ELECTRIC POWER CO INC	100,427.23	69.4700	189,514.16	89,086.93
401.0000	AMERICAN EQUITY INVESTMENT LIF	4,944.33	26.2800	10,538.28	5,593.95
3,114.0000	AMERICAN EXPRESS CO	179,969.31	84.2400	262,323.36	82,354.05
144.0000	AMERICAN FINANCIAL GROUP INC/O	4,982.40	99.3700	14,309.28	9,326.88
2,898.0000	AMERICAN HOMES 4 RENT	41,120.51	22.5700	65,407.86	24,287.35
7,450.0000	AMERICAN INTERNATIONAL GROUP I	263,625.72	62.5200	465,774.00	202,148.28
604.0000	AMERICAN SOFTWARE INC/GA	5,031.32	10.2900	6,215.16	1,183.84
2,286.0000	AMERICAN TOWER CORP	101,514.18	132.3200	302,483.52	200,969.34
1,132.0000	AMERICAN WATER WORKS CO INC	28,899.96	77.9500	88,239.40	59,339.44
1,128.0000	AMERISOURCEBERGEN CORP	37,000.21	94.5300	106,629.84	69,629.63
1,601.0000	AMERIPRISE FINANCIAL INC	74,763.02	127.2900	203,791.29	129,028.27
572.0000	AMERIS BANCORP	5,119.40	48.2000	27,570.40	22,451.00
1,432.0000	AMETEK INC	40,601.97	60.5700	86,736.24	46,134.27
4,375.0000	AMGEN INC	241,930.67	172.2300	753,506.25	511,575.58
1,906.0000	AMPHENOL CORP	31,153.95	73.8200	140,700.92	109,546.97
276.0000	AMTRUST FINANCIAL SERVICES INC	2,515.93	15.1400	4,178.64	1,662.71

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3,025.0000	ANADARKO PETROLEUM CORP	133,976.38	45.3400	137,153.50	3,177.12
1,849.0000	ANALOG DEVICES INC	88,349.26	77.8000	143,852.20	55,502.94
187.0000	ANDERSONS INC/THE	4,965.47	34.1500	6,386.05	1,420.58
173.0000	ANIXTER INTERNATIONAL INC	10,578.95	78.2000	13,528.60	2,949.65
3,252.0000	ANNALY CAPITAL MANAGEMENT INC	34,064.88	12.0500	39,186.60	5,121.72
547.0000	ANSYS INC	29,023.82	121.6800	66,558.96	37,535.14
919.0000	ANTERO RESOURCES CORP	23,792.91	21.6100	19,859.59	3,933.32-
1,049.0000	ANTHEM INC	74,649.18	188.1300	197,348.37	122,699.19
4,254.0000	ANWORTH MORTGAGE ASSET CORP	21,652.86	6.0100	25,566.54	3,913.68
1,754.0000	APACHE CORP	101,713.00	47.9300	84,069.22	17,643.78-
759.0000	APARTMENT INVESTMENT & MANAGEM	18,982.59	42.9700	32,614.23	13,631.64
3,394.0000	APOLLO COMMERCIAL REAL ESTATE	55,584.48	18.5500	62,958.70	7,374.22
29,308.0000	APPLE INC	328,614.55	144.0200	4,220,938.16	3,892,323.61
146.0000	APPLIED INDUSTRIAL TECHNOLOGIE	4,991.74	59.0500	8,621.30	3,629.56
5,581.0000	APPLIED MATERIALS INC	74,267.78	41.3100	230,551.11	156,283.33
1,028.0000	AQUA AMERICA INC	17,632.26	33.3000	34,232.40	16,600.14
688.0000	ARAMARK	25,504.16	40.9800	28,194.24	2,690.08

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3,793.0000	ARCHER-DANIELS-MIDLAND CO	118,389.01	41.3800	156,954.34	38,565.33
1,945.0000	ARCONIC INC	38,107.47	22.6500	44,054.25	5,946.78
195.0000	ARISTA NETWORKS INC	25,683.45	149.7900	29,209.05	3,525.60
5.0000	ARMSTRONG FLOORING INC	56.42	17.9700	89.85	33.43
10.0000	ARMSTRONG WORLD INDUSTRIES INC	383.68	46.0000	460.00	76.32
789.0000	ARROW ELECTRONICS INC	26,447.28	78.4200	61,873.38	35,426.10
236.0000	ARROW FINANCIAL CORP	4,975.44	31.6500	7,469.40	2,493.96
224.0000	ARTESIAN RESOURCES CORP	5,028.80	37.6400	8,431.36	3,402.56
294.0000	ASBURY AUTOMOTIVE GROUP INC	5,092.08	56.5500	16,625.70	11,533.62
37.0000	ASHFORD HOSPITALITY PRIME INC	573.50	10.2900	380.73	192.77-
579.0000	ASHLAND GLOBAL HOLDINGS INC	15,946.99	65.9100	38,161.89	22,214.90
504.0000	ASPEN TECHNOLOGY INC	7,791.84	55.2600	27,851.04	20,059.20
2,277.0000	ASSOCIATED BANC-CORP	24,295.59	25.2000	57,380.40	33,084.81
109.0000	ASSOCIATED CAPITAL GROUP INC	2,270.59	34.0000	3,706.00	1,435.41
342.0000	ASSURANT INC	10,105.19	103.6900	35,461.98	25,356.79
142.0000	ASTEC INDUSTRIES INC	4,979.94	55.5100	7,882.42	2,902.48
133.0000	ASTERIAS BIOTHERAPEUTICS INC	478.79	3.5500	472.15	6.64-

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208.0000	ATHENAHEALTH INC	8,540.48	140.5500	29,234.40	20,693.92
5,454.0000	ATLANTIC POWER CORP	16,580.71	2.4000	13,089.60	3,491.11-
538.0000	ATMOS ENERGY CORP	17,382.78	82.9500	44,627.10	27,244.32
14.0000	ATRION CORP	3,289.44	643.3000	9,006.20	5,716.76
1,560.0000	AUTODESK INC	53,912.82	100.8200	157,279.20	103,366.38
2,789.0000	AUTOMATIC DATA PROCESSING INC	105,255.76	102.4600	285,760.94	180,505.18
529.0000	AUTONATION INC	11,207.50	42.1600	22,302.64	11,095.14
56.0000	AUTOZONE INC	43,052.79	570.4600	31,945.76	11,107.03-
735.0000	AVALONBAY COMMUNITIES INC	99,553.02	192.1700	141,244.95	41,691.93
495.0000	AVANGRID INC	19,181.25	44.1500	21,854.25	2,673.00
640.0000	AVERY DENNISON CORP	18,284.80	88.3700	56,556.80	38,272.00
708.0000	AVIS BUDGET GROUP INC	15,452.38	27.2700	19,307.16	3,854.78
365.0000	AVISTA CORP	9,993.70	42.4600	15,497.90	5,504.20
647.0000	AVNET INC	22,749.55	38.8800	25,155.36	2,405.81
3,866.0000	BB&T CORP	116,678.85	45.4100	175,555.06	58,876.21
481.0000	B&G FOODS INC	19,661.22	35.6000	17,123.60	2,537.62-
3,137.0000	BGC PARTNERS INC	10,728.54	12.6400	39,651.68	28,923.14

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192.0000	BOK FINANCIAL CORP	10,043.52	84.1300	16,152.96	6,109.44
630.0000	BWX TECHNOLOGIES INC	11,904.08	48.7500	30,712.50	18,808.42
315.0000	BABCOCK & WILCOX ENTERPRISES I	4,384.63	11.7600	3,704.40	680.23-
2,132.0000	BAKER HUGHES INC	110,564.94	54.5100	116,215.32	5,650.38
122.0000	BALCHEM CORP	5,055.68	77.7100	9,480.62	4,424.94
1,704.0000	BALL CORP	38,305.92	42.2100	71,925.84	33,619.92
132.0000	BANCFIRST CORP	5,043.72	96.6000	12,751.20	7,707.48
48,794.0000	BANK OF AMERICA CORP	628,432.41	24.2600	1,183,742.44	555,310.03
324.0000	BANK OF HAWAII CORP	14,878.08	82.9700	26,882.28	12,004.20
1,382.0000	BANK MUTUAL CORP	4,906.10	9.1500	12,645.30	7,739.20
42.0000	BANK OF THE OZARKS INC	527.10	46.8700	1,968.54	1,441.44
3,372.0000	BANK OF NEW YORK MELLON CORP/T	101,253.70	51.0200	172,039.44	70,785.74
766.0000	CR BARD INC	57,514.19	316.1100	242,140.26	184,626.07
171.0000	BARNES & NOBLE EDUCATION INC	1,543.48	10.6300	1,817.73	274.25
271.0000	BARNES & NOBLE INC	3,134.23	7.6000	2,059.60	1,074.63-
209.0000	BARNES GROUP INC	4,903.14	58.5300	12,232.77	7,329.63
3,403.0000	BAXTER INTERNATIONAL INC	83,185.00	60.5400	206,017.62	122,832.62

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274.0000	BEACON ROOFING SUPPLY INC	6,088.28	49.0000	13,426.00	7,337.72
2,340.0000	BEAZER HOMES USA INC	34,848.45	13.7200	32,104.80	2,743.65-
1,428.0000	BECTON DICKINSON AND CO	99,915.23	195.1100	278,617.08	178,701.85
1,565.0000	BED BATH & BEYOND INC	60,487.87	30.4000	47,576.00	12,911.87-
282.0000	BELDEN INC	9,145.26	75.4300	21,271.26	12,126.00
674.0000	BEMIS CO INC	22,290.46	46.2500	31,172.50	8,882.04
703.0000	BENCHMARK ELECTRONICS INC	10,258.48	32.3000	22,706.90	12,448.42
675.0000	BENEFICIAL BANCORP INC	5,001.59	15.0000	10,125.00	5,123.41
782.0000	WR BERKLEY CORP	21,364.24	69.1700	54,090.94	32,726.70
9,435.0000	BERKSHIRE HATHAWAY INC	855,254.77	169.3700	1,598,005.95	742,751.18
233.0000	BERKSHIRE HILLS BANCORP INC	5,063.09	35.1500	8,189.95	3,126.86
954.0000	BERRY GLOBAL GROUP INC	15,006.42	57.0100	54,387.54	39,381.12
1,450.0000	BEST BUY CO INC	17,574.00	57.3300	83,128.50	65,554.50
517.0000	BIG LOTS INC	10,407.37	48.3000	24,971.10	14,563.73
1,228.0000	BIOMARIN PHARMACEUTICAL INC	30,086.00	90.8200	111,526.96	81,440.96
974.0000	BIOGEN INC	86,875.66	271.3600	264,304.64	177,428.98
203.0000	BIO-TECHNE CORP	14,837.10	117.5000	23,852.50	9,015.40

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417.0000	BIOVERATIV INC	4,111.01	60.1700	25,090.89	20,979.88
355.0000	BLACK HILLS CORP	16,726.07	67.4700	23,951.85	7,225.78
188.0000	BLACKBAUD INC	4,998.92	85.7500	16,121.00	11,122.08
229.0000	BLACKHAWK NETWORK HOLDINGS INC	5,415.84	43.6000	9,984.40	4,568.56
619.0000	BLACKROCK INC	121,096.16	422.4100	261,471.79	140,375.63
1,502.0000	H&R BLOCK INC	22,412.96	30.9100	46,426.82	24,013.86
846.0000	BLOOMIN' BRANDS INC	13,375.26	21.2300	17,960.58	4,585.32
239.0000	BLUEBIRD BIO INC	27,009.39	105.0500	25,106.95	1,902.44-
2,183.0000	BLUEROCK RESIDENTIAL GROWTH RE	28,060.72	12.8900	28,138.87	78.15
3,360.0000	BOEING CO/THE	263,675.92	197.7500	664,440.00	400,764.08
1,633.0000	BORGWARNER INC	59,852.80	42.3600	69,173.88	9,321.08
58.0000	BOSTON BEER CO INC/THE	5,150.40	132.1500	7,664.70	2,514.30
772.0000	BOSTON PRIVATE FINANCIAL HOLDI	4,701.48	15.3500	11,850.20	7,148.72
242.0000	BOSTON PROPERTIES INC	30,149.24	123.0200	29,770.84	378.40-
7,377.0000	BOSTON SCIENTIFIC CORP	53,585.00	27.7200	204,490.44	150,905.44
216.0000	BOTTOMLINE TECHNOLOGIES DE INC	5,080.32	25.6900	5,549.04	468.72
3,821.0000	BOX INC	49,481.95	18.2400	69,695.04	20,213.09

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
1,128.0000	BOYD GAMING CORP	7,185.36	24.8100	27,985.68	20,800.32
2,159.0000	BRANDYWINE REALTY TRUST	21,629.15	17.5300	37,847.27	16,218.12
711.0000	BRINKER INTERNATIONAL INC	14,994.99	38.1000	27,089.10	12,094.11
9,844.0000	BRISTOL-MYERS SQUIBB CO	251,898.47	55.7200	548,507.68	296,609.21
685.0000	BROADRIDGE FINANCIAL SOLUTIONS	14,727.50	75.5600	51,758.60	37,031.10
3,818.0000	BROCADE COMMUNICATIONS SYSTEMS	20,708.78	12.6100	48,144.98	27,436.20
548.0000	BROOKLINE BANCORP INC	5,025.16	14.6000	8,000.80	2,975.64
691.0000	BROWN & BROWN INC	17,406.29	43.0700	29,761.37	12,355.08
1,054.0000	BROWN-FORMAN CORP	21,093.97	48.6000	51,224.40	30,130.43
50.0000	BRUNOS INC NEW	500.00	10.0000	500.00	0.00
903.0000	BRUNSWICK CORP/DE	20,341.83	62.7300	56,645.19	36,303.36
248.0000	BRYN MAWR BANK CORP	4,915.36	42.5000	10,540.00	5,624.64
272.0000	BUFFALO WILD WINGS INC	18,822.40	126.7000	34,462.40	15,640.00
1,675.0000	CBS CORP	46,612.44	63.7800	106,831.50	60,219.06
314.0000	CBOE HOLDINGS INC	7,570.54	91.4000	28,699.60	21,129.06
1,423.0000	CBRE GROUP INC	32,425.28	36.4000	51,797.20	19,371.92
929.0000	CDK GLOBAL INC	14,738.35	62.0600	57,653.74	42,915.39

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448.0000	CDW CORP/DE	25,831.68	62.5300	28,013.44	2,181.76
2,259.0000	CF INDUSTRIES HOLDINGS INC	77,937.85	27.9600	63,161.64	14,776.21-
407.0000	CH ROBINSON WORLDWIDE INC	28,978.80	68.6800	27,952.76	1,026.04-
1,820.0000	CIGNA CORP	69,943.43	167.3900	304,649.80	234,706.37
1,488.0000	CIT GROUP INC	52,677.93	48.7000	72,465.60	19,787.67
1,753.0000	CME GROUP INC	103,678.37	125.2400	219,545.72	115,867.35
1,589.0000	CMS ENERGY CORP	30,429.35	46.2500	73,491.25	43,061.90
209.0000	CSS INDUSTRIES INC	5,032.72	26.1600	5,467.44	434.72
2,691.0000	CNO FINANCIAL GROUP INC	17,478.63	20.8800	56,188.08	38,709.45
6,933.0000	CSX CORP	74,784.19	54.5600	378,264.48	303,480.29
832.0000	CSRA INC	20,359.21	31.7500	26,416.00	6,056.79
651.0000	CU BANCORP	25,721.01	36.1500	23,533.65	2,187.36-
554.0000	CVB FINANCIAL CORP	4,875.20	22.4300	12,426.22	7,551.02
7,051.0000	CVS HEALTH CORP	234,551.31	80.4600	567,323.46	332,772.15
929.0000	CA INC	21,984.69	34.4700	32,022.63	10,037.94
258.0000	CABELA'S INC	6,764.76	59.4200	15,330.36	8,565.60
12.0000	CABLE ONE INC	1,876.41	710.9000	8,530.80	6,654.39

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391.0000	CABOT CORP	15,030.04	53.4300	20,891.13	5,861.09
2,485.0000	CABOT OIL & GAS CORP	38,182.03	25.0800	62,323.80	24,141.77
1,601.0000	CADENCE DESIGN SYSTEMS INC	16,346.21	33.4900	53,617.49	37,271.28
246.0000	CALATLANTIC GROUP INC	10,049.10	35.3500	8,696.10	1,353.00-
488.0000	CALERES INC	5,016.64	27.7800	13,556.64	8,540.00
290.0000	CALGON CARBON CORP	5,060.50	15.1000	4,379.00	681.50-
279.0000	CALIFORNIA WATER SERVICE GROUP	5,091.75	36.8000	10,267.20	5,175.45
781.0000	CALLAWAY GOLF CO	4,810.96	12.7800	9,981.18	5,170.22
2,682.0000	CALPINE CORP	34,981.41	13.5300	36,287.46	1,306.05
428.0000	CAMDEN PROPERTY TRUST	22,136.16	85.5100	36,598.28	14,462.12
441.0000	CAMPBELL SOUP CO	14,893.76	52.1500	22,998.15	8,104.39
478.0000	CANADIAN IMPERIAL BANK OF COMM	11,343.33	81.1600	38,794.48	27,451.15
2,057.0000	CAPITAL ONE FINANCIAL CORP	107,744.99	82.6200	169,949.34	62,204.35
997.0000	CAPITOL FEDERAL FINANCIAL INC	11,764.60	14.2100	14,167.37	2,402.77
2,234.0000	CARDINAL HEALTH INC	105,930.77	77.9200	174,073.28	68,142.51
119.0000	CARE CAPITAL PROPERTIES INC	2,318.65	26.7000	3,177.30	858.65
1,851.0000	CARETRUST REIT INC	21,249.48	18.5400	34,317.54	13,068.06

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181.0000	CARLISLE COS INC	9,945.69	95.4000	17,267.40	7,321.71
1,537.0000	CARMAX INC	40,100.33	63.0600	96,923.22	56,822.89
1,387.0000	CARNIVAL CORP	53,900.31	65.5700	90,945.59	37,045.28
666.0000	CARS.COM INC	7,934.63	26.6300	17,735.58	9,800.95
542.0000	CARTER'S INC	22,250.67	88.9500	48,210.90	25,960.23
113.0000	CASEY'S GENERAL STORES INC	4,901.94	107.1100	12,103.43	7,201.49
3,205.0000	CATERPILLAR INC	200,099.37	107.4600	344,409.30	144,309.93
471.0000	CATHAY GENERAL BANCORP	6,579.87	37.9500	17,874.45	11,294.58
467.0000	CAVIUM INC	13,954.43	62.1300	29,014.71	15,060.28
1,122.0000	CELANESE CORP	36,431.34	94.9400	106,522.68	70,091.34
5,273.0000	CELGENE CORP	143,276.50	129.8700	684,804.51	541,528.01
947.0000	CENTENE CORP	25,112.18	79.8800	75,646.36	50,534.18
3,850.0000	CENTERPOINT ENERGY INC	55,009.40	27.3800	105,413.00	50,403.60
794.0000	CENTERSTATE BANKS INC	5,065.72	24.8600	19,738.84	14,673.12
1,057.0000	CENTRAL GARDEN & PET CO	22,123.01	30.0200	31,731.14	9,608.13
371.0000	CENTRAL PACIFIC FINANCIAL CORP	4,889.59	31.4700	11,675.37	6,785.78
659.0000	CENTURY ALUMINUM CO	4,751.39	15.5800	10,267.22	5,515.83

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2,395.0000	CENTURYLINK INC	66,759.06	23.8800	57,192.60	9,566.46-
1,633.0000	CERNER CORP	45,747.40	66.4700	108,545.51	62,798.11
1,130.0000	CHARTER COMMUNICATIONS INC	66,921.55	336.8500	380,640.50	313,718.95
608.0000	CHATHAM LODGING TRUST	10,019.84	20.0900	12,214.72	2,194.88
166.0000	CHEESECAKE FACTORY INC/THE	5,132.72	50.3000	8,349.80	3,217.08
272.0000	CHEMICAL FINANCIAL CORP	4,972.16	48.4100	13,167.52	8,195.36
1,072.0000	CHEMOURS CO/THE	11,221.47	37.9200	40,650.24	29,428.77
966.0000	CHENIERE ENERGY INC	22,907.61	48.7100	47,053.86	24,146.25
5,212.0000	CHESAPEAKE ENERGY CORP	23,558.24	4.9700	25,903.64	2,345.40
366.0000	CHESAPEAKE UTILITIES CORP	13,240.44	74.9500	27,431.70	14,191.26
10,093.0000	CHEVRON CORP	653,547.59	104.3300	1,053,002.69	399,455.10
586.0000	CHICAGO BRIDGE & IRON CO NV	20,427.96	19.7300	11,561.78	8,866.18-
1,205.0000	CHICO'S FAS INC	14,508.20	9.4200	11,351.10	3,157.10-
248.0000	CHILDREN'S PLACE INC/THE	15,214.32	102.1000	25,320.80	10,106.48
2,436.0000	CHIMERA INVESTMENT CORP	32,886.00	18.6300	45,382.68	12,496.68
214.0000	CHIPOTLE MEXICAN GRILL INC	58,373.12	416.1000	89,045.40	30,672.28
1,672.0000	CHURCH & DWIGHT CO INC	41,186.43	51.8800	86,743.36	45,556.93

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115.0000	CHURCHILL DOWNS INC	4,940.40	183.3000	21,079.50	16,139.10
1,727.0000	CIENA CORP	25,278.11	25.0200	43,209.54	17,931.43
608.0000	CIMAREX ENERGY CO	36,698.88	94.0100	57,158.08	20,459.20
328.0000	CINCINNATI BELL INC	5,100.40	19.5500	6,412.40	1,312.00
607.0000	CINCINNATI FINANCIAL CORP	17,080.98	72.4500	43,977.15	26,896.17
553.0000	CINEMARK HOLDINGS INC	11,082.12	38.8500	21,484.05	10,401.93
23,495.0000	CISCO SYSTEMS INC	582,814.78	31.3000	735,393.50	152,578.72
266.0000	CIRRUS LOGIC INC	3,777.20	62.7200	16,683.52	12,906.32
753.0000	CINTAS CORP	26,575.77	126.0400	94,908.12	68,332.35
13,324.0000	CITIGROUP INC	551,708.89	66.8800	891,109.12	339,400.23
786.0000	CITIZENS FINANCIAL GROUP INC	26,716.14	35.6800	28,044.48	1,328.34
1,336.0000	CITRIX SYSTEMS INC	39,401.13	79.5800	106,318.88	66,917.75
156.0000	CITY HOLDING CO	4,907.76	65.8700	10,275.72	5,367.96
146.0000	CLEARWATER PAPER CORP	5,212.20	46.7500	6,825.50	1,613.30
1,068.0000	CLOROX CO/THE	68,030.53	133.2400	142,300.32	74,269.79
307.0000	CLOVIS ONCOLOGY INC	27,227.83	93.6300	28,744.41	1,516.58
1,233.0000	COACH INC	41,395.73	47.3400	58,370.22	16,974.49

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795.0000	COBIZ FINANCIAL INC	4,984.65	17.4000	13,833.00	8,848.35
158.0000	COCA-COLA BOTTLING CO CONSOLID	9,996.66	228.8700	36,161.46	26,164.80
19,793.0000	COCA-COLA CO/THE	475,130.46	44.8500	887,716.05	412,585.59
6,419.0000	COEUR MINING INC	80,209.52	8.5800	55,075.02	25,134.50-
560.0000	COGENT COMMUNICATIONS HOLDINGS	15,031.20	40.1000	22,456.00	7,424.80
300.0000	COGNEX CORP	5,055.00	84.9000	25,470.00	20,415.00
3,947.0000	COGNIZANT TECHNOLOGY SOLUTIONS	80,491.66	66.4000	262,080.80	181,589.14
97.0000	COHERENT INC	5,028.48	224.9900	21,824.03	16,795.55
631.0000	COLFAX CORP	24,691.03	39.3700	24,842.47	151.44
5,123.0000	COLGATE-PALMOLIVE CO	160,496.40	74.1300	379,767.99	219,271.59
5,165.0000	COLONY NORTHSTAR INC	50,296.36	14.0900	72,774.85	22,478.49
761.0000	COLONY STARWOOD HOMES	25,820.73	34.3100	26,109.91	289.18
529.0000	COLUMBIA BANKING SYSTEM INC	9,517.21	39.8500	21,080.65	11,563.44
27,216.0000	COMCAST CORP	333,302.56	38.9200	1,059,246.72	725,944.16
426.0000	COMERICA INC	14,809.16	73.2400	31,200.24	16,391.08
1,032.0000	COMMERCE BANCSHARES INC/MO	28,806.51	56.8300	58,648.56	29,842.05
91.0000	COMMERCEHUB INC	330.72	17.4200	1,585.22	1,254.50

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183.0000	COMMERCEHUB INC	670.45	17.4400	3,191.52	2,521.07
1,375.0000	COMMERCIAL METALS CO	19,717.50	19.4300	26,716.25	6,998.75
219.0000	COMMUNITY BANK SYSTEM INC	5,315.13	55.7700	12,213.63	6,898.50
205.0000	COMMUNITY TRUST BANCORP INC	5,029.95	43.7500	8,968.75	3,938.80
2,257.0000	CONAGRA BRANDS INC	42,856.92	35.7600	80,710.32	37,853.40
697.0000	CONCHO RESOURCES INC	36,369.46	121.5300	84,706.41	48,336.95
1,288.0000	CONDUENT INC	15,504.48	15.9400	20,530.72	5,026.24
170.0000	CONNECTICUT WATER SERVICE INC	5,026.90	55.5100	9,436.70	4,409.80
6,791.0000	CONOCOPHILLIPS	307,354.24	43.9600	298,532.36	8,821.88-
1,637.0000	CONSOL ENERGY INC	23,425.47	14.9400	24,456.78	1,031.31
306.0000	CONSOLIDATED COMMUNICATIONS HO	5,055.12	21.4700	6,569.82	1,514.70
1,483.0000	CONSOLIDATED EDISON INC	73,093.39	80.8200	119,856.06	46,762.67
789.0000	CONSTELLATION BRANDS INC	33,960.30	193.7300	152,852.97	118,892.67
514.0000	CONTINENTAL RESOURCES INC/OK	20,103.78	32.3300	16,617.62	3,486.16-
1,136.0000	CONVERGYS CORP	14,972.48	23.7800	27,014.08	12,041.60
92.0000	COOPER COS INC/THE	6,992.92	239.4200	22,026.64	15,033.72
364.0000	COOPER TIRE & RUBBER CO	6,329.96	36.1000	13,140.40	6,810.44

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440.0000	COPART INC	4,946.70	31.7900	13,987.60	9,040.90
558.0000	CORE-MARK HOLDING CO INC	25,235.55	33.0600	18,447.48	6,788.07-
263.0000	CORESITE REALTY CORP	22,139.34	103.5300	27,228.39	5,089.05
192.0000	CORELOGIC INC/UNITED STATES	5,018.88	43.3800	8,328.96	3,310.08
991.0000	CORECIVIC INC	23,230.29	27.5800	27,331.78	4,101.49
4,480.0000	CORNING INC	55,819.66	30.0500	134,624.00	78,804.34
1,028.0000	CORPORATE OFFICE PROPERTIES TR	22,338.44	35.0300	36,010.84	13,672.40
2,572.0000	COSTCO WHOLESALE CORP	128,783.64	159.9300	411,339.96	282,556.32
88.0000	COSTAR GROUP INC	4,916.56	263.6000	23,196.80	18,280.24
2,372.0000	COTY INC	45,084.86	18.7600	44,498.72	586.14-
1,089.0000	COVANTA HOLDING CORP	20,789.01	13.2000	14,374.80	6,414.21-
104.0000	CRANE CO	4,877.60	79.3800	8,255.52	3,377.92
1,846.0000	CROWN CASTLE INTERNATIONAL COR	76,770.64	100.1800	184,932.28	108,161.64
531.0000	CROWN HOLDINGS INC	18,044.86	59.6600	31,679.46	13,634.60
591.0000	CUBESMART	6,081.39	24.0400	14,207.64	8,126.25
497.0000	CUMMINS INC	24,037.52	162.2200	80,623.34	56,585.82
158.0000	CURTISS-WRIGHT CORP	4,942.24	91.7800	14,501.24	9,559.00

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425.0000	CYRUSONE INC	21,896.00	55.7500	23,693.75	1,797.75
365.0000	DCT INDUSTRIAL TRUST INC	7,475.20	53.4400	19,505.60	12,030.40
1,732.0000	DDR CORP	22,621.30	9.0700	15,709.24	6,912.06-
1,729.0000	DR HORTON INC	24,185.23	34.5700	59,771.53	35,586.30
194.0000	DST SYSTEMS INC	4,959.61	61.7000	11,969.80	7,010.19
1,473.0000	DTE ENERGY CO	61,570.23	105.7900	155,828.67	94,258.44
204.0000	DSW INC	5,049.00	17.7000	3,610.80	1,438.20-
1,409.0000	DXC TECHNOLOGY CO	42,479.28	76.7200	108,098.48	65,619.20
933.0000	DANA INC	11,447.91	22.3300	20,833.89	9,385.98
3,426.0000	DANAHER CORP	89,503.72	84.3900	289,120.14	199,616.42
480.0000	DARDEN RESTAURANTS INC	18,366.12	90.4400	43,411.20	25,045.08
1,553.0000	DARLING INGREDIENTS INC	23,051.12	15.7400	24,444.22	1,393.10
1,010.0000	DAVITA INC	28,274.95	64.7600	65,407.60	37,132.65
545.0000	DEAN FOODS CO	6,202.92	17.0000	9,265.00	3,062.08
108.0000	DECKERS OUTDOOR CORP	5,114.88	68.2600	7,372.08	2,257.20
1,281.0000	DEERE & CO	54,291.54	123.5900	158,318.79	104,027.25
1,098.0000	DELL TECHNOLOGIES INC CLASS V	51,098.21	61.1100	67,098.78	16,000.57

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5,690.0000	DELTA AIR LINES INC	74,803.06	53.7400	305,780.60	230,977.54
306.0000	DELUXE CORP	7,203.24	69.2200	21,181.32	13,978.08
1,279.0000	DENNY'S CORP	4,898.57	11.7700	15,053.83	10,155.26
1,430.0000	DENTSPLY SIRONA INC	41,952.38	64.8400	92,721.20	50,768.82
742.0000	DERMIRA INC	21,451.22	29.1400	21,621.88	170.66
2,774.0000	DEVON ENERGY CORP	135,707.17	31.9700	88,684.78	47,022.39-
453.0000	DEXCOM INC	36,581.00	73.1500	33,136.95	3,444.05-
66.0000	DIAMOND HILL INVESTMENT GROUP	5,039.10	199.4000	13,160.40	8,121.30
419.0000	DIAMONDBACK ENERGY INC	36,473.95	88.8100	37,211.39	737.44
1,551.0000	DIAMONDROCK HOSPITALITY CO	15,154.80	10.9500	16,983.45	1,828.65
662.0000	DIGITAL REALTY TRUST INC	38,318.86	112.9500	74,772.90	36,454.04
280.0000	DILLARD'S INC	16,599.17	57.6900	16,153.20	445.97-
7,547.0000	WALT DISNEY CO/THE	259,931.21	106.2500	801,868.75	541,937.54
1,040.0000	DISCOVERY COMMUNICATIONS INC	31,638.19	25.8300	26,863.20	4,774.99-
241.0000	DISCOVERY COMMUNICATIONS INC	4,831.36	25.2100	6,075.61	1,244.25
1,495.0000	DISH NETWORK CORP	37,576.96	62.7600	93,826.20	56,249.24
3,192.0000	DISCOVER FINANCIAL SERVICES	76,838.66	62.1900	198,510.48	121,671.82

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297.0000	DOLBY LABORATORIES INC	9,771.30	48.9600	14,541.12	4,769.82
1,292.0000	DOLLAR GENERAL CORP	74,688.64	72.0900	93,140.28	18,451.64
1,113.0000	DOLLAR TREE INC	46,578.41	69.9200	77,820.96	31,242.55
3,181.0000	DOMINION ENERGY INC	122,925.93	76.6300	243,760.03	120,834.10
368.0000	DOMINO'S PIZZA INC	9,126.40	211.5300	77,843.04	68,716.64
548.0000	DOMTAR CORP	20,974.70	38.4200	21,054.16	79.46
678.0000	DONALDSON CO INC	19,695.90	45.5400	30,876.12	11,180.22
122.0000	RR DONNELLEY & SONS CO	2,580.33	12.5400	1,529.88	1,050.45-
45.0000	DONNELLEY FINANCIAL SOLUTIONS	990.95	22.9600	1,033.20	42.25
941.0000	DOUGLAS EMMETT INC	15,272.43	38.2100	35,955.61	20,683.18
352.0000	DOUGLAS DYNAMICS INC	5,047.68	32.9000	11,580.80	6,533.12
1,328.0000	DOVER CORP	52,825.09	80.2200	106,532.16	53,707.07
4,627.0000	DOW CHEMICAL CO/THE	164,370.07	63.0700	291,824.89	127,454.82
1,281.0000	DR PEPPER SNAPPLE GROUP INC	31,429.72	91.1100	116,711.91	85,282.19
201.0000	DRIL-QUIP INC	15,041.95	48.8000	9,808.80	5,233.15-
4,418.0000	EI DU PONT DE NEMOURS & CO	181,645.93	80.7100	356,576.78	174,930.85
3,365.0000	DUKE ENERGY CORP	178,374.92	83.5900	281,280.35	102,905.43

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2,075.0000	DUKE REALTY CORP	24,341.05	27.9500	57,996.25	33,655.20
491.0000	DUN & BRADSTREET CORP/THE	37,710.62	108.1500	53,101.65	15,391.03
851.0000	DUNKIN' BRANDS GROUP INC	27,538.36	55.1200	46,907.12	19,368.76
350.0000	DUPONT FABROS TECHNOLOGY INC	8,708.00	61.1600	21,406.00	12,698.00
321.0000	DYCOM INDUSTRIES INC	4,798.95	89.5200	28,735.92	23,936.97
3,281.0000	EOG RESOURCES INC	136,245.91	90.5200	296,996.12	160,750.21
799.0000	EQT CORP	40,195.51	58.5900	46,813.41	6,617.90
278.0000	EPR PROPERTIES	12,782.44	71.8700	19,979.86	7,197.42
166.0000	EAGLE BANCORP INC	1,933.15	63.3000	10,507.80	8,574.65
1,013.0000	E*TRADE FINANCIAL CORP	9,035.96	38.0300	38,524.39	29,488.43
227.0000	EAGLE MATERIALS INC	14,862.68	92.4200	20,979.34	6,116.66
952.0000	EAST WEST BANCORP INC	17,678.64	58.5800	55,768.16	38,089.52
304.0000	EASTMAN CHEMICAL CO	18,231.76	83.9900	25,532.96	7,301.20
6,217.0000	EBAY INC	74,670.96	34.9200	217,097.64	142,426.68
541.0000	ECHOSTAR CORP	10,898.07	60.7000	32,838.70	21,940.63
1,513.0000	ECOLAB INC	68,501.50	132.7500	200,850.75	132,349.25
301.0000	EDGEWELL PERSONAL CARE CO	21,245.58	76.0200	22,882.02	1,636.44

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2,402.0000	EDISON INTERNATIONAL	99,825.54	78.1900	187,812.38	87,986.84
199.0000	EDUCATION REALTY TRUST INC	4,955.10	38.7500	7,711.25	2,756.15
1,073.0000	EDWARDS LIFESCIENCES CORP	105,744.15	118.2400	126,871.52	21,127.37
584.0000	EL PASO ELECTRIC CO	23,414.48	51.7000	30,192.80	6,778.32
1,799.0000	ELECTRONIC ARTS INC	32,481.90	105.7200	190,190.28	157,708.38
309.0000	ELECTRONICS FOR IMAGING INC	5,101.59	47.3800	14,640.42	9,538.83
358.0000	PERRY ELLIS INTERNATIONAL INC	5,083.60	19.4600	6,966.68	1,883.08
398.0000	EMCOR GROUP INC	11,311.16	65.3800	26,021.24	14,710.08
1,565.0000	EMERSON ELECTRIC CO	79,663.91	59.6200	93,305.30	13,641.39
315.0000	EMPLOYERS HOLDINGS INC	5,021.10	42.3000	13,324.50	8,303.40
220.0000	ENCORE WIRE CORP	5,108.40	42.7000	9,394.00	4,285.60
417.0000	ENERGEN CORP	19,623.06	49.3700	20,587.29	964.23
198.0000	ENERGIZER HOLDINGS INC	3,887.05	48.0200	9,507.96	5,620.91
202.0000	ENERSYS	5,369.16	72.4500	14,634.90	9,265.74
800.0000	ENTEGRIS INC	7,832.00	21.9500	17,560.00	9,728.00
390.0000	ENTERPRISE FINANCIAL SERVICES	5,190.90	40.8000	15,912.00	10,721.10
365.0000	ENVISION HEALTHCARE CORP	16,634.65	62.6700	22,874.55	6,239.90

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576.0000	EQUIFAX INC	21,032.64	137.4200	79,153.92	58,121.28
294.0000	EQUINIX INC	38,809.40	429.1600	126,173.04	87,363.64
1,944.0000	EQUITY COMMONWEALTH	54,672.72	31.6000	61,430.40	6,757.68
292.0000	EQUITY LIFESTYLE PROPERTIES IN	9,962.80	86.3400	25,211.28	15,248.48
2,034.0000	EQUITY RESIDENTIAL	102,719.72	65.8300	133,898.22	31,178.50
408.0000	ESSEX PROPERTY TRUST INC	69,266.16	257.2700	104,966.16	35,700.00
242.0000	ETHAN ALLEN INTERIORS INC	5,055.38	32.3000	7,816.60	2,761.22
321.0000	EURONET WORLDWIDE INC	4,827.84	87.3700	28,045.77	23,217.93
623.0000	EVERCORE PARTNERS INC	16,135.62	70.5000	43,921.50	27,785.88
1,700.0000	EVERSOURCE ENERGY	57,489.19	60.7100	103,207.00	45,717.81
1,031.0000	EXACT SCIENCES CORP	10,907.98	35.3700	36,466.47	25,558.49
4,053.0000	EXELON CORP	129,590.62	36.0700	146,191.71	16,601.09
1,173.0000	EXELIXIS INC	25,863.78	24.6300	28,890.99	3,027.21
719.0000	EXPEDIA INC	30,646.08	148.9500	107,095.05	76,448.97
422.0000	EXPEDITORS INTERNATIONAL OF WA	19,023.76	56.4800	23,834.56	4,810.80
372.0000	EXPONENT INC	9,830.10	58.3000	21,687.60	11,857.50
4,036.0000	EXPRESS SCRIPTS HOLDING CO	137,368.02	63.8400	257,658.24	120,290.22

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559.0000	EXTRA SPACE STORAGE INC	11,453.91	78.0000	43,602.00	32,148.09
2,028.0000	EXTRACTION OIL & GAS INC	27,210.62	13.4500	27,276.60	65.98
5,106.0000	EZCORP INC	59,280.66	7.7000	39,316.20	19,964.46-
20,897.0000	EXXON MOBIL CORP	1,429,678.02	80.7300	1,687,014.81	257,336.79
712.0000	FLIR SYSTEMS INC	25,354.32	34.6600	24,677.92	676.40-
371.0000	FMC CORP	26,114.69	73.0500	27,101.55	986.86
3,702.0000	FNB CORP/PA	42,149.55	14.1600	52,420.32	10,270.77
165.0000	FTD COS INC	3,787.68	20.0000	3,300.00	487.68-
11,518.0000	FACEBOOK INC	455,959.55	150.9800	1,738,987.64	1,283,028.09
238.0000	FAIR ISAAC CORP	6,899.62	139.4100	33,179.58	26,279.96
2,284.0000	FAIRPOINT COMMUNICATIONS INC	31,224.79	15.6500	35,744.60	4,519.81
123.0000	FARO TECHNOLOGIES INC	5,098.35	37.8000	4,649.40	448.95-
867.0000	FASTENAL CO	38,952.28	43.5300	37,740.51	1,211.77-
173.0000	FEDERAL REALTY INVESTMENT TRUS	17,032.80	126.3900	21,865.47	4,832.67
1,803.0000	FEDEX CORP	194,332.46	217.3300	391,845.99	197,513.53
3,634.0000	FELCOR LODGING TRUST INC	16,825.42	7.2100	26,201.14	9,375.72
511.0000	F5 NETWORKS INC	43,737.58	127.0600	64,927.66	21,190.08

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1,023.0000	FIDELITY & GUARANTY LIFE	24,459.93	31.0500	31,764.15	7,304.22
1,973.0000	FIDELITY NATIONAL INFORMATION	47,244.14	85.4000	168,494.20	121,250.06
1,493.0000	FNF GROUP	17,087.75	44.8300	66,931.19	49,843.44
497.0000	FNFV GROUP	2,365.68	15.8000	7,852.60	5,486.92
4,197.0000	FIFTH THIRD BANCORP	61,639.71	25.9600	108,954.12	47,314.41
5,880.0000	FIFTH STREET ASSET MANAGEMENT	35,406.42	4.8500	28,518.00	6,888.42-
724.0000	FINANCIAL ENGINES INC	15,001.28	36.6000	26,498.40	11,497.12
311.0000	FINANCIAL INSTITUTIONS INC	5,010.21	29.8000	9,267.80	4,257.59
626.0000	FIRST AMERICAN FINANCIAL CORP	9,615.36	44.6900	27,975.94	18,360.58
5,524.0000	FIRST BANCORP/PUERTO RICO	22,537.92	5.7900	31,983.96	9,446.04
322.0000	FIRST BUSEY CORP	5,119.80	29.3200	9,441.04	4,321.24
77.0000	FIRST CITIZENS BANCSHARES INC/	15,462.06	372.7000	28,697.90	13,235.84
1,067.0000	FIRST COMMONWEALTH FINANCIAL C	5,217.63	12.6800	13,529.56	8,311.93
366.0000	FIRST DEFIANCE FINANCIAL CORP	5,223.11	52.6800	19,280.88	14,057.77
376.0000	FIRST FINANCIAL BANKSHARES INC	6,282.96	44.2000	16,619.20	10,336.24
349.0000	FIRST FINANCIAL BANCORP	5,772.46	27.7000	9,667.30	3,894.84
557.0000	FIRST HORIZON NATIONAL CORP	5,590.54	17.4200	9,702.94	4,112.40

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465.0000	FIRST INDUSTRIAL REALTY TRUST	4,998.75	28.6200	13,308.30	8,309.55
426.0000	FIRST OF LONG ISLAND CORP/THE	5,097.33	28.6000	12,183.60	7,086.27
974.0000	FIRST MIDWEST BANCORP INC/IL	10,412.72	23.3100	22,703.94	12,291.22
2,184.0000	FIRST POTOMAC REALTY TRUST	23,368.80	11.1100	24,264.24	895.44
440.0000	FIRST REPUBLIC BANK/CA	12,878.80	100.1000	44,044.00	31,165.20
820.0000	FIRST SOLAR INC	33,229.86	39.8800	32,701.60	528.26-
269.0000	1ST SOURCE CORP	4,912.90	47.9400	12,895.86	7,982.96
187.0000	FIRSTCASH INC	7,278.04	58.3000	10,902.10	3,624.06
2,219.0000	FISERV INC	52,357.75	122.3400	271,472.46	219,114.71
3,203.0000	FIRSTENERGY CORP	104,298.40	29.1600	93,399.48	10,898.92-
341.0000	FLEETCOR TECHNOLOGIES INC	51,405.39	144.2100	49,175.61	2,229.78-
527.0000	FLOTEK INDUSTRIES INC	4,774.62	8.9400	4,711.38	63.24-
831.0000	FLUOR CORP	33,781.15	45.7800	38,043.18	4,262.03
264.0000	FLOWERS FOODS INC	4,996.64	17.3100	4,569.84	426.80-
921.0000	FOOT LOCKER INC	22,334.25	49.2800	45,386.88	23,052.63
17,420.0000	FORD MOTOR CO	148,516.13	11.1900	194,929.80	46,413.67
521.0000	FOREST CITY REALTY TRUST INC	8,268.27	24.1700	12,592.57	4,324.30

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305.0000	FORESTAR GROUP INC	4,901.35	17.1500	5,230.75	329.40
1,713.0000	FORTIVE CORP	29,205.83	63.3500	108,518.55	79,312.72
1,350.0000	FORTUNE BRANDS HOME & SECURITY	30,829.20	65.2400	88,074.00	57,244.80
153.0000	FORWARD AIR CORP	4,974.03	53.2800	8,151.84	3,177.81
640.0000	FOUR CORNERS PROPERTY TRUST IN	13,309.87	25.1100	16,070.40	2,760.53
230.0000	FRANKLIN ELECTRIC CO INC	5,146.25	41.4000	9,522.00	4,375.75
2,096.0000	FRANKLIN RESOURCES INC	72,062.42	44.7900	93,879.84	21,817.42
421.0000	FRANKLIN STREET PROPERTIES COR	5,195.14	11.0800	4,664.68	530.46-
6,072.0000	FREEPORT-MCMORAN INC	30,299.28	12.0100	72,924.72	42,625.44
228.0000	HB FULLER CO	5,344.32	51.1100	11,653.08	6,308.76
2,206.0000	FULTON FINANCIAL CORP	22,721.80	19.0000	41,914.00	19,192.20
109.0000	GAMCO INVESTORS INC	2,613.70	29.6000	3,226.40	612.70
135.0000	GATX CORP	4,895.10	64.2700	8,676.45	3,781.35
556.0000	GCP APPLIED TECHNOLOGIES INC	5,265.95	30.5000	16,958.00	11,692.05
2,957.0000	GGP INC	40,741.76	23.5600	69,666.92	28,925.16
1,705.0000	GNC HOLDINGS INC	22,812.90	8.4300	14,373.15	8,439.75-
766.0000	G-III APPAREL GROUP LTD	24,504.34	24.9500	19,111.70	5,392.64-

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1,231.0000	GTT COMMUNICATIONS INC	22,514.99	31.6500	38,961.15	16,446.16
658.0000	ARTHUR J GALLAGHER & CO	18,443.74	57.2500	37,670.50	19,226.76
802.0000	GAMING AND LEISURE PROPERTIES	20,831.62	37.6700	30,211.34	9,379.72
841.0000	GAMESTOP CORP	21,975.33	21.6100	18,174.01	3,801.32-
1,000.0000	GANNETT CO INC	5,051.35	8.7200	8,720.00	3,668.65
1,933.0000	GAP INC/THE	44,676.83	21.9900	42,506.67	2,170.16-
848.0000	GARTNER INC	36,692.84	123.5100	104,736.48	68,043.64
269.0000	GENERAC HOLDINGS INC	5,054.51	36.1300	9,718.97	4,664.46
1,877.0000	GENERAL DYNAMICS CORP	135,135.17	198.1000	371,833.70	236,698.53
45,617.0000	GENERAL ELECTRIC CO	1,123,206.56	27.0100	1,232,115.17	108,908.61
4,189.0000	GENERAL MILLS INC	119,272.77	55.4000	232,070.60	112,797.83
5,791.0000	GENERAL MOTORS CO	164,676.60	34.9300	202,279.63	37,603.03
111.0000	GENESCO INC	5,663.22	33.9000	3,762.90	1,900.32-
336.0000	GENESEE & WYOMING INC	23,574.76	68.3900	22,979.04	595.72-
277.0000	GENUINE PARTS CO	12,696.29	92.7600	25,694.52	12,998.23
4,094.0000	GENWORTH FINANCIAL INC	21,206.92	3.7700	15,434.38	5,772.54-
3,206.0000	GERON CORP	5,129.60	2.7700	8,880.62	3,751.02

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457.0000	GIBRALTAR INDUSTRIES INC	4,958.45	35.6500	16,292.05	11,333.60
7,855.0000	GILEAD SCIENCES INC	181,492.88	70.7800	555,976.90	374,484.02
857.0000	GLACIER BANCORP INC	10,690.57	36.6100	31,374.77	20,684.20
1,497.0000	GLADSTONE COMMERCIAL CORP	22,385.71	21.7900	32,619.63	10,233.92
331.0000	PH GLATFELTER CO	4,981.55	19.5400	6,467.74	1,486.19
926.0000	GLOBAL NET LEASE INC	22,001.77	22.2400	20,594.24	1,407.53-
1,836.0000	GLOBAL PAYMENTS INC	41,379.59	90.3200	165,827.52	124,447.93
13,802.0000	GOLD RESOURCE CORP	61,424.42	4.0800	56,312.16	5,112.26-
1,617.0000	GOLDMAN SACHS GROUP INC/THE	266,532.92	221.9000	358,812.30	92,279.38
1,825.0000	GOODYEAR TIRE & RUBBER CO/THE	26,715.63	34.9600	63,802.00	37,086.37
556.0000	WR GRACE & CO	21,402.92	72.0100	40,037.56	18,634.64
729.0000	GRACO INC	23,524.83	109.2800	79,665.12	56,140.29
12.0000	GRAHAM HOLDINGS CO	2,925.27	599.6500	7,195.80	4,270.53
156.0000	WW GRAINGER INC	27,139.32	180.5300	28,162.68	1,023.36
1,629.0000	GRAMERCY PROPERTY TRUST	31,469.60	29.7100	48,397.59	16,927.99
377.0000	GRAND CANYON EDUCATION INC	5,108.35	78.4100	29,560.57	24,452.22
230.0000	GRANITE CONSTRUCTION INC	5,621.20	48.2400	11,095.20	5,474.00

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2,181.0000	GRAPHIC PACKAGING HOLDING CO	10,425.85	13.7800	30,054.18	19,628.33
269.0000	GREAT SOUTHERN BANCORP INC	4,898.49	53.5000	14,391.50	9,493.01
881.0000	GREAT PLAINS ENERGY INC	17,144.26	29.2800	25,795.68	8,651.42
567.0000	GREEN DOT CORP	7,189.56	38.5300	21,846.51	14,656.95
485.0000	GREEN PLAINS INC	4,951.85	20.5500	9,966.75	5,014.90
249.0000	GREENBRIER COS INC/THE	4,932.69	46.2500	11,516.25	6,583.56
511.0000	GRIFFON CORP	4,997.58	21.9500	11,216.45	6,218.87
131.0000	GROUP 1 AUTOMOTIVE INC	5,148.30	63.3200	8,294.92	3,146.62
737.0000	GRUBHUB INC	23,326.05	43.6000	32,133.20	8,807.15
414.0000	GUIDEWIRE SOFTWARE INC	23,486.22	68.7100	28,445.94	4,959.72
379.0000	H&E EQUIPMENT SERVICES INC	4,839.83	20.4100	7,735.39	2,895.56
572.0000	HCA HEALTHCARE INC	45,172.41	87.2000	49,878.40	4,705.99
2,915.0000	HCP INC	95,699.45	31.9600	93,163.40	2,536.05-
637.0000	HD SUPPLY HOLDINGS INC	23,014.81	30.6300	19,511.31	3,503.50-
350.0000	HFF INC	4,802.00	34.7700	12,169.50	7,367.50
267.0000	HNI CORP	6,442.71	39.8700	10,645.29	4,202.58
163.0000	HSN INC	4,995.95	31.9000	5,199.70	203.75

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1,649.0000	HRG GROUP INC	22,162.56	17.7100	29,203.79	7,041.23
6,556.0000	HP INC	72,018.24	17.4800	114,598.88	42,580.64
517.0000	HAIN CELESTIAL GROUP INC/THE	21,822.16	38.8200	20,069.94	1,752.22-
4,891.0000	HALLIBURTON CO	140,389.29	42.7100	208,894.61	68,505.32
758.0000	HALOZYME THERAPEUTICS INC	4,972.48	12.8200	9,717.56	4,745.08
244.0000	HALYARD HEALTH INC	5,303.86	39.2800	9,584.32	4,280.46
3,440.0000	HANESBRANDS INC	25,923.08	23.1600	79,670.40	53,747.32
136.0000	HANOVER INSURANCE GROUP INC/TH	4,955.84	88.6300	12,053.68	7,097.84
416.0000	HARLEY-DAVIDSON INC	24,839.36	54.0200	22,472.32	2,367.04-
999.0000	HARRIS CORP	38,806.55	109.0800	108,970.92	70,164.37
2,153.0000	HARTFORD FINANCIAL SERVICES GR	52,917.27	52.5700	113,183.21	60,265.94
435.0000	HASBRO INC	22,277.95	111.5100	48,506.85	26,228.90
879.0000	HAWAIIAN HOLDINGS INC	5,054.25	46.9500	41,269.05	36,214.80
290.0000	HAWAIIAN TELCOM HOLDCO INC	5,744.90	24.9900	7,247.10	1,502.20
380.0000	HEALTHSOUTH CORP	10,028.20	48.4000	18,392.00	8,363.80
238.0000	HEALTHCARE REALTY TRUST INC	4,874.24	34.1500	8,127.70	3,253.46
456.0000	HEALTHCARE TRUST OF AMERICA IN	10,177.92	31.1100	14,186.16	4,008.24

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9,775.0000	HECLA MINING CO	22,678.00	5.1000	49,852.50	27,174.50
196.0000	HEICO CORP	5,343.74	71.8400	14,080.64	8,736.90
853.0000	HELMERICH & PAYNE INC	34,565.69	54.3400	46,352.02	11,786.33
514.0000	JACK HENRY & ASSOCIATES INC	15,060.20	103.8700	53,389.18	38,328.98
985.0000	HERITAGE COMMERCE CORP	4,869.25	13.7800	13,573.30	8,704.05
136.0000	HERC HOLDINGS INC	5,271.81	39.3200	5,347.52	75.71
1,099.0000	HERITAGE FINANCIAL CORP/WA	16,066.78	26.5000	29,123.50	13,056.72
229.0000	HERSHA HOSPITALITY TRUST	4,983.04	18.5100	4,238.79	744.25-
612.0000	HERSHEY CO/THE	33,932.30	107.3700	65,710.44	31,778.14
1,590.0000	HESS CORP	73,107.57	43.8700	69,753.30	3,354.27-
7,290.0000	HEWLETT PACKARD ENTERPRISE CO	75,262.13	16.5900	120,941.10	45,678.97
238.0000	HEXCEL CORP	4,990.86	52.7900	12,564.02	7,573.16
151.0000	HIGHWOODS PROPERTIES INC	4,898.44	50.7100	7,657.21	2,758.77
149.0000	HILL-ROM HOLDINGS INC	5,264.17	79.6100	11,861.89	6,597.72
215.0000	HILLENBRAND INC	4,882.65	36.1000	7,761.50	2,878.85
215.0000	HILLTOP HOLDINGS INC	4,321.50	26.2100	5,635.15	1,313.65
1,984.0000	HOLOGIC INC	36,485.40	45.3800	90,033.92	53,548.52

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836.0000	HOME BANCSHARES INC/AR	4,932.40	24.9000	20,816.40	15,884.00
7,155.0000	HOME DEPOT INC/THE	261,661.93	153.4000	1,097,577.00	835,915.07
338.0000	HOMESTREET INC	4,912.76	27.6750	9,354.15	4,441.39
4,599.0000	HONEYWELL INTERNATIONAL INC	189,237.54	133.2900	613,000.71	423,763.17
1,335.0000	HOPE BANCORP INC	10,325.32	18.6500	24,897.75	14,572.43
331.0000	HORACE MANN EDUCATORS CORP	4,951.76	37.8000	12,511.80	7,560.04
1,006.0000	HORMEL FOODS CORP	20,941.61	34.1100	34,314.66	13,373.05
1,240.0000	HOSPITALITY PROPERTIES TRUST	28,796.72	29.1500	36,146.00	7,349.28
3,222.0000	HOST HOTELS & RESORTS INC	53,611.81	18.2700	58,865.94	5,254.13
2,202.0000	HOUGHTON MIFFLIN HARCOURT CO	23,803.62	12.3000	27,084.60	3,280.98
28,247.0000	HOVNANIAN ENTERPRISES INC	54,516.71	2.8000	79,091.60	24,574.89
185.0000	HOWARD HUGHES CORP/THE	15,117.50	122.8400	22,725.40	7,607.90
136.0000	HUB GROUP INC	4,920.48	38.3500	5,215.60	295.12
568.0000	HUDSON PACIFIC PROPERTIES INC	8,792.64	34.1900	19,419.92	10,627.28
1,046.0000	HUMANA INC	66,756.45	240.6200	251,688.52	184,932.07
544.0000	JB HUNT TRANSPORT SERVICES INC	24,871.68	91.3800	49,710.72	24,839.04
10,092.0000	HUNTINGTON BANCSHARES INC/OH	61,809.11	13.5200	136,443.84	74,634.73

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371.0000	HUNTINGTON INGALLS INDUSTRIES	13,890.61	186.1600	69,065.36	55,174.75
165.0000	HURON CONSULTING GROUP INC	4,851.00	43.2000	7,128.00	2,277.00
263.0000	HYATT HOTELS CORP	10,325.38	56.2100	14,783.23	4,457.85
29.0000	HYSTER-YALE MATERIALS HANDLING	903.94	70.2500	2,037.25	1,133.31
437.0000	IAC/INTERACTIVECORP	15,950.50	103.2400	45,115.88	29,165.38
198.0000	ICF INTERNATIONAL INC	4,950.00	47.1000	9,325.80	4,375.80
449.0000	ILG INC	4,392.75	27.4900	12,343.01	7,950.26
2,377.0000	ISTAR INC	15,359.36	12.0400	28,619.08	13,259.72
809.0000	ITT INC	15,859.06	40.1800	32,505.62	16,646.56
315.0000	IDACORP INC	15,032.32	85.3500	26,885.25	11,852.93
287.0000	IDEX CORP	14,860.69	113.0100	32,433.87	17,573.18
684.0000	IDEXX LABORATORIES INC	25,571.34	161.4200	110,411.28	84,839.94
2,697.0000	ILLINOIS TOOL WORKS INC	121,557.84	143.2500	386,345.25	264,787.41
752.0000	ILLUMINA INC	29,561.12	173.5200	130,487.04	100,925.92
1,021.0000	INCYTE CORP	16,407.47	125.9100	128,554.11	112,146.64
2,913.0000	INDEPENDENCE REALTY TRUST INC	23,595.30	9.8700	28,751.31	5,156.01
190.0000	INDEPENDENT BANK CORP/ROCKLAND	4,932.40	66.6500	12,663.50	7,731.10

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4,365.0000	INFINERA CORP	44,043.31	10.6700	46,574.55	2,531.24
259.0000	INGEVITY CORP	4,733.04	57.4000	14,866.60	10,133.56
301.0000	INGLES MARKETS INC	4,809.98	33.3000	10,023.30	5,213.32
455.0000	INGREDION INC	24,374.35	119.2100	54,240.55	29,866.20
305.0000	INSIGHT ENTERPRISES INC	5,072.15	39.9900	12,196.95	7,124.80
156.0000	INNOSPEC INC	4,873.11	65.5500	10,225.80	5,352.69
1,491.0000	INNERWORKINGS INC	10,362.45	11.6000	17,295.60	6,933.15
245.0000	INSULET CORP	5,049.45	51.3100	12,570.95	7,521.50
2,154.0000	INTEGRATED DEVICE TECHNOLOGY I	13,311.72	25.7900	55,551.66	42,239.94
24,722.0000	INTEL CORP	515,352.30	33.7400	834,120.28	318,767.98
629.0000	INTER PARFUMS INC	10,258.99	36.6500	23,052.85	12,793.86
1,474.0000	INTERACTIVE BROKERS GROUP INC	24,203.52	37.4200	55,157.08	30,953.56
3,103.0000	INTERCONTINENTAL EXCHANGE INC	123,725.01	65.9200	204,549.76	80,824.75
1,103.0000	INTERNATIONAL BANCSHARES CORP	17,780.36	35.0500	38,660.15	20,879.79
4,230.0000	INTERNATIONAL BUSINESS MACHINE	352,716.63	153.8300	650,700.90	297,984.27
762.0000	INTERNATIONAL FLAVORS & FRAGRA	30,228.77	135.0000	102,870.00	72,641.23
1,997.0000	INTERNATIONAL PAPER CO	69,043.58	56.6100	113,050.17	44,006.59

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590.0000	INTERNATIONAL SPEEDWAY CORP	14,974.20	37.5500	22,154.50	7,180.30
3,469.0000	INTERPUBLIC GROUP OF COS INC/T	34,237.99	24.6000	85,337.40	51,099.41
1,584.0000	INTRA-CELLULAR THERAPIES INC	24,251.04	12.4200	19,673.28	4,577.76-
228.0000	INTUITIVE SURGICAL INC	62,985.48	935.3700	213,264.36	150,278.88
2,106.0000	INTUIT INC	68,708.46	132.8100	279,697.86	210,989.40
611.0000	INVESCO MORTGAGE CAPITAL INC	9,691.26	16.7100	10,209.81	518.55
925.0000	INVESTORS BANCORP INC	5,045.78	13.3600	12,358.00	7,312.22
727.0000	IONIS PHARMACEUTICALS INC	25,296.66	50.8700	36,982.49	11,685.83
4,789.0000	IRIDIUM COMMUNICATIONS INC	38,654.72	11.0500	52,918.45	14,263.73
1,266.0000	IRON MOUNTAIN INC	31,628.68	34.3600	43,499.76	11,871.08
524.0000	ITRON INC	19,209.84	67.7500	35,501.00	16,291.16
85.0000	J ALEXANDER'S HOLDINGS INC	344.94	12.2500	1,041.25	696.31
20,321.0000	JPMORGAN CHASE & CO	822,021.40	91.4000	1,857,339.40	1,035,318.00
1,169.0000	JABIL INC	20,656.23	29.1900	34,123.11	13,466.88
225.0000	JACK IN THE BOX INC	5,033.25	98.5000	22,162.50	17,129.25
670.0000	JACOBS ENGINEERING GROUP INC	27,365.06	54.3900	36,441.30	9,076.24
852.0000	JETBLUE AIRWAYS CORP	4,311.12	22.8300	19,451.16	15,140.04

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13,629.0000	JOHNSON & JOHNSON	955,568.04	132.2900	1,802,980.41	847,412.37
441.0000	JONES LANG LASALLE INC	32,828.04	125.0000	55,125.00	22,296.96
180.0000	J2 GLOBAL INC	4,905.00	85.0900	15,316.20	10,411.20
1,751.0000	JUNIPER NETWORKS INC	30,244.13	27.8800	48,817.88	18,573.75
1,329.0000	JUNO THERAPEUTICS INC	23,749.23	29.8900	39,723.81	15,974.58
487.0000	KLX INC	8,064.93	50.0000	24,350.00	16,285.07
97.0000	KAISER ALUMINUM CORP	5,134.21	88.5200	8,586.44	3,452.23
357.0000	KANSAS CITY SOUTHERN	22,727.02	104.6500	37,360.05	14,633.03
646.0000	KAPSTONE PAPER AND PACKAGING C	5,151.85	20.6300	13,326.98	8,175.13
530.0000	KATE SPADE & CO	9,778.50	18.4900	9,799.70	21.20
1,511.0000	KB HOME	12,254.21	23.9700	36,218.67	23,964.46
1,037.0000	KELLOGG CO	51,706.58	69.4600	72,030.02	20,323.44
320.0000	KELLY SERVICES INC	5,027.20	22.4500	7,184.00	2,156.80
329.0000	KEMPER CORP	9,298.36	38.6000	12,699.40	3,401.04
6,524.0000	KEYCORP	48,212.36	18.7400	122,259.76	74,047.40
1,187.0000	KEYSIGHT TECHNOLOGIES INC	20,815.68	38.9300	46,209.91	25,394.23
380.0000	KFORCE INC	4,913.40	19.6000	7,448.00	2,534.60

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348.0000	KILROY REALTY CORP	13,241.40	75.1500	26,152.20	12,910.80
1,959.0000	KIMBERLY-CLARK CORP	122,849.74	129.1100	252,926.49	130,076.75
2,422.0000	KIMCO REALTY CORP	43,813.98	18.3500	44,443.70	629.72
9,750.0000	KINDER MORGAN INC/DE	174,464.32	19.1600	186,810.00	12,345.68
320.0000	KIRBY CORP	17,798.40	66.8500	21,392.00	3,593.60
329.0000	KITE PHARMA INC	25,737.67	103.6700	34,107.43	8,369.76
267.0000	KITE REALTY GROUP TRUST	4,891.44	18.9300	5,054.31	162.87
306.0000	KNIGHT TRANSPORTATION INC	4,938.84	37.0500	11,337.30	6,398.46
665.0000	KNOWLES CORP	10,420.51	16.9200	11,251.80	831.29
1,404.0000	KOHL'S CORP	55,431.33	38.6700	54,292.68	1,138.65-
3,176.0000	KRAFT HEINZ CO/THE	94,272.39	85.6400	271,992.64	177,720.25
7,550.0000	KROGER CO/THE	86,141.74	23.3200	176,066.00	89,924.26
1,782.0000	L BRANDS INC	48,353.87	53.8900	96,031.98	47,678.11
391.0000	LHC GROUP INC	5,106.46	67.8900	26,544.99	21,438.53
684.0000	LKQ CORP	17,583.48	32.9500	22,537.80	4,954.32
450.0000	LPL FINANCIAL HOLDINGS INC	15,174.00	42.4600	19,107.00	3,933.00
132.0000	LTC PROPERTIES INC	4,909.08	51.3900	6,783.48	1,874.40

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45.0000	LSC COMMUNICATIONS INC	1,288.48	21.4000	963.00	325.48-
514.0000	LA-Z-BOY INC	4,821.32	32.5000	16,705.00	11,883.68
206.0000	LABORATORY CORP OF AMERICA HOL	13,784.66	154.1400	31,752.84	17,968.18
306.0000	LAKELAND BANCORP INC	2,728.33	18.8500	5,768.10	3,039.77
346.0000	LAKELAND FINANCIAL CORP	5,102.35	45.8800	15,874.48	10,772.13
1,072.0000	LAM RESEARCH CORP	26,299.73	141.4300	151,612.96	125,313.23
725.0000	LAMAR ADVERTISING CO	17,624.75	73.5700	53,338.25	35,713.50
752.0000	LAMB WESTON HOLDINGS INC	12,444.91	44.0400	33,118.08	20,673.17
68.0000	LANCASTER COLONY CORP	4,872.20	122.6200	8,338.16	3,465.96
110.0000	LANDSTAR SYSTEM INC	4,950.00	85.6000	9,416.00	4,466.00
1,219.0000	LAS VEGAS SANDS CORP	46,558.51	63.8900	77,881.91	31,323.40
723.0000	LASALLE HOTEL PROPERTIES	17,967.86	29.8000	21,545.40	3,577.54
555.0000	ESTEE LAUDER COS INC/THE	45,557.89	95.9800	53,268.90	7,711.01
769.0000	LEAR CORP	35,204.07	142.0800	109,259.52	74,055.45
645.0000	LEGGETT & PLATT INC	14,847.90	52.5300	33,881.85	19,033.95
367.0000	LEGACYTEXAS FINANCIAL GROUP IN	4,965.51	38.1300	13,993.71	9,028.20
637.0000	LEGG MASON INC	18,066.78	38.1600	24,307.92	6,241.14

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830.0000	LEIDOS HOLDINGS INC	24,715.57	51.6900	42,902.70	18,187.13
4,456.0000	LENDINGCLUB CORP	21,745.28	5.5100	24,552.56	2,807.28
1,244.0000	LENNAR CORP	47,296.88	53.3200	66,330.08	19,033.20
507.0000	LENNOX INTERNATIONAL INC	22,782.20	183.6400	93,105.48	70,323.28
1,958.0000	LEUCADIA NATIONAL CORP	36,373.23	26.1600	51,221.28	14,848.05
1,420.0000	LEVEL 3 COMMUNICATIONS INC	37,765.21	59.3000	84,206.00	46,440.79
1,405.0000	LEXINGTON REALTY TRUST	11,522.34	9.9100	13,923.55	2,401.21
580.0000	LIBERTY EXPEDIA HOLDINGS INC	14,283.19	54.0200	31,331.60	17,048.41
3,710.0000	LIBERTY INTERACTIVE CORP QVC G	43,774.05	24.5400	91,043.40	47,269.35
551.0000	LIBERTY VENTURES	5,579.35	52.2900	28,811.79	23,232.44
735.0000	LIBERTY PROPERTY TRUST	22,785.00	40.7100	29,921.85	7,136.85
392.0000	LIBERTY TRIPADVISOR HOLDINGS I	3,586.72	11.6000	4,547.20	960.48
312.0000	LIFEPOINT HEALTH INC	11,821.68	67.1500	20,950.80	9,129.12
298.0000	LIFE STORAGE INC	19,937.37	74.1000	22,081.80	2,144.43
4,589.0000	ELI LILLY & CO	294,212.78	82.3000	377,674.70	83,461.92
421.0000	LINCOLN ELECTRIC HOLDINGS INC	14,010.88	92.0900	38,769.89	24,759.01
1,252.0000	LINCOLN NATIONAL CORP	37,987.69	67.5800	84,610.16	46,622.47

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80.0000	LINDSAY CORP	4,973.60	89.2500	7,140.00	2,166.40
447.0000	LIONS GATE ENTERTAINMENT CORP	7,159.58	28.2200	12,614.34	5,454.76
447.0000	LIONS GATE ENTERTAINMENT CORP	6,920.92	26.2800	11,747.16	4,826.24
89.0000	LITTELFUSE INC	4,903.90	165.0000	14,685.00	9,781.10
238.0000	LIVE NATION ENTERTAINMENT INC	2,606.10	34.8500	8,294.30	5,688.20
902.0000	LOCKHEED MARTIN CORP	202,333.53	277.6100	250,404.22	48,070.69
1,714.0000	LOEWS CORP	65,020.59	46.8100	80,232.34	15,211.75
229.0000	LOGMEIN INC	9,902.13	104.5000	23,930.50	14,028.37
6,472.0000	LOWE'S COS INC	185,574.89	77.5300	501,774.16	316,199.27
524.0000	LULULEMON ATHLETICA INC	29,350.04	59.6700	31,267.08	1,917.04
429.0000	LUMENTUM HOLDINGS INC	26,795.34	57.0500	24,474.45	2,320.89-
350.0000	M&T BANK CORP	35,739.14	161.9500	56,682.50	20,943.36
323.0000	MB FINANCIAL INC	6,137.00	44.0400	14,224.92	8,087.92
1,123.0000	MDU RESOURCES GROUP INC	24,762.15	26.2000	29,422.60	4,660.45
1,123.0000	MGE ENERGY INC	54,836.12	64.3500	72,265.05	17,428.93
1,967.0000	MGIC INVESTMENT CORP	11,861.01	11.2000	22,030.40	10,169.39
2,953.0000	MGM RESORTS INTERNATIONAL	32,134.93	31.2900	92,399.37	60,264.44

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626.0000	MGP INGREDIENTS INC	20,889.62	51.1700	32,032.42	11,142.80
310.0000	MKS INSTRUMENTS INC	7,777.90	67.3000	20,863.00	13,085.10
138.0000	MSA SAFETY INC	4,854.84	81.1700	11,201.46	6,346.62
592.0000	MSCI INC	19,662.02	102.9900	60,970.08	41,308.06
171.0000	MTS SYSTEMS CORP	9,876.96	51.8000	8,857.80	1,019.16-
832.0000	MACERICH CO/THE	36,059.04	58.0600	48,305.92	12,246.88
2,177.0000	MACY'S INC	81,325.15	23.2400	50,593.48	30,731.67-
324.0000	STEVEN MADDEN LTD	7,583.76	39.9500	12,943.80	5,360.04
649.0000	MAINSOURCE FINANCIAL GROUP INC	5,750.14	33.5100	21,747.99	15,997.85
112.0000	MANHATTAN ASSOCIATES INC	2,021.04	48.0600	5,382.72	3,361.68
1,365.0000	MANITOWOC CO INC/THE	4,176.89	6.0100	8,203.65	4,026.76
747.0000	MANPOWERGROUP INC	27,982.62	111.6500	83,402.55	55,419.93
4,383.0000	MARATHON OIL CORP	101,759.09	11.8500	51,938.55	49,820.54-
2,846.0000	MARATHON PETROLEUM CORP	76,133.26	52.3300	148,931.18	72,797.92
398.0000	MARCUS CORP/THE	5,034.70	30.2000	12,019.60	6,984.90
103.0000	MARKEL CORP	38,804.94	975.8600	100,513.58	61,708.64
208.0000	MARKETAXESS HOLDINGS INC	5,002.40	201.1000	41,828.80	36,826.40

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228.0000	MARRIOTT VACATIONS WORLDWIDE C	8,796.24	117.7500	26,847.00	18,050.76
3,194.0000	MARSH & MCLENNAN COS INC	93,046.70	77.9600	249,004.24	155,957.54
2,558.0000	MARRIOTT INTERNATIONAL INC/MD	118,150.17	100.3100	256,592.98	138,442.81
744.0000	MARTEN TRANSPORT LTD	9,869.66	27.4000	20,385.60	10,515.94
263.0000	MARTIN MARIETTA MATERIALS INC	24,547.70	222.5800	58,538.54	33,990.84
2,790.0000	MASCO CORP	34,572.91	38.2100	106,605.90	72,032.99
336.0000	MASTEC INC	6,132.00	45.1500	15,170.40	9,038.40
6,247.0000	MASTERCARD INC	215,469.18	121.4500	758,698.15	543,228.97
571.0000	MATSON INC	10,212.74	30.0400	17,152.84	6,940.10
1,937.0000	MATTEL INC	36,237.04	21.5300	41,703.61	5,466.57
151.0000	MATTHEWS INTERNATIONAL CORP	5,013.20	61.2500	9,248.75	4,235.55
1,184.0000	MAXIM INTEGRATED PRODUCTS INC	28,131.84	44.9000	53,161.60	25,029.76
248.0000	MAXIMUS INC	4,969.30	62.6300	15,532.24	10,562.94
770.0000	MCCORMICK & CO INC/MD	38,243.12	97.5100	75,082.70	36,839.58
4,457.0000	MCDONALD'S CORP	177,119.85	153.1600	682,634.12	505,514.27
186.0000	MCGRATH RENTCORP	5,025.72	34.6300	6,441.18	1,415.46
1,566.0000	MCKESSON CORP	83,676.54	164.5400	257,669.64	173,993.10

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1,404.0000	MEDIA GEN INC CVR	0.00	0.0000	0.00	0.00
1,490.0000	MEDICAL PROPERTIES TRUST INC	20,675.26	12.8700	19,176.30	1,498.96-
571.0000	MEDICINES CO/THE	15,047.24	38.0100	21,703.71	6,656.47
476.0000	MEDNAX INC	19,747.21	60.3700	28,736.12	8,988.91
16,722.0000	MERCK & CO INC	703,917.33	64.0900	1,071,712.98	367,795.65
160.0000	MEREDITH CORP	4,865.60	59.4500	9,512.00	4,646.40
221.0000	MERITAGE HOMES CORP	5,049.85	42.2000	9,326.20	4,276.35
828.0000	MERITOR INC	4,148.28	16.6100	13,753.08	9,604.80
94.0000	MESA LABORATORIES INC	5,018.66	143.3100	13,471.14	8,452.48
2,810.0000	METLIFE INC	110,912.48	54.9400	154,381.40	43,468.92
191.0000	METTLER-TOLEDO INTERNATIONAL I	30,401.47	588.5400	112,411.14	82,009.67
40,843.0000	MICROSOFT CORP	1,116,722.20	68.9300	2,815,307.99	1,698,585.79
830.0000	MICROCHIP TECHNOLOGY INC	29,986.38	77.1800	64,059.40	34,073.02
5,321.0000	MICRON TECHNOLOGY INC	45,059.45	29.8600	158,885.06	113,825.61
621.0000	MICROSEMI CORP	13,367.26	46.8000	29,062.80	15,695.54
643.0000	MID-AMERICA APARTMENT COMMUNIT	41,919.18	105.3800	67,759.34	25,840.16
462.0000	MIDDLEBY CORP/THE	15,559.41	121.5100	56,137.62	40,578.21

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233.0000	MIDDLESEX WATER CO	4,499.23	39.6000	9,226.80	4,727.57
3,705.0000	MINDBODY INC	62,144.34	27.2000	100,776.00	38,631.66
274.0000	MINERALS TECHNOLOGIES INC	8,787.18	73.2000	20,056.80	11,269.62
250.0000	MOBILE MINI INC	5,067.50	29.8500	7,462.50	2,395.00
2,748.0000	MODEL N INC	35,773.79	13.3000	36,548.40	774.61
748.0000	MODINE MANUFACTURING CO	5,071.44	16.5500	12,379.40	7,307.96
339.0000	MOHAWK INDUSTRIES INC	19,329.78	241.6900	81,932.91	62,603.13
831.0000	MOLSON COORS BREWING CO	43,216.13	86.3400	71,748.54	28,532.41
9,882.0000	MONDELEZ INTERNATIONAL INC	185,251.81	43.1900	426,803.58	241,551.77
584.0000	MONMOUTH REAL ESTATE INVESTMEN	4,905.60	15.0500	8,789.20	3,883.60
2,205.0000	MONOGRAM RESIDENTIAL TRUST INC	22,380.75	9.7100	21,410.55	970.20-
345.0000	MONOLITHIC POWER SYSTEMS INC	5,226.75	96.4000	33,258.00	28,031.25
148.0000	MONRO MUFFLER BRAKE INC	5,046.80	41.7500	6,179.00	1,132.20
2,832.0000	MONSANTO CO	134,135.13	118.3600	335,195.52	201,060.39
2,204.0000	MONSTER BEVERAGE CORP	47,406.38	49.6800	109,494.72	62,088.34
1,393.0000	MOODY'S CORP	45,467.52	121.6800	169,500.24	124,032.72
270.0000	MOOG INC	11,134.80	71.7200	19,364.40	8,229.60

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6,241.0000	MORGAN STANLEY	126,518.60	44.5600	278,098.96	151,580.36
1,045.0000	MOSAIC CO/THE	31,004.25	22.8300	23,857.35	7,146.90-
297.0000	MOTOROLA SOLUTIONS INC	21,719.61	86.7400	25,761.78	4,042.17
294.0000	MOVADO GROUP INC	4,933.32	25.2500	7,423.50	2,490.18
450.0000	MUELLER INDUSTRIES INC	8,181.00	30.4500	13,702.50	5,521.50
733.0000	MURPHY OIL CORP	31,617.09	25.6300	18,786.79	12,830.30-
307.0000	MURPHY USA INC	8,906.37	74.1100	22,751.77	13,845.40
231.0000	NBT BANCORP INC	5,058.90	36.9500	8,535.45	3,476.55
449.0000	NCI BUILDING SYSTEMS INC	4,992.88	16.7000	7,498.30	2,505.42
943.0000	NCR CORP	17,200.32	40.8400	38,512.12	21,311.80
1,290.0000	NCS MULTISTAGE HOLDINGS INC	31,051.95	25.1800	32,482.20	1,430.25
1,909.0000	NRG ENERGY INC	31,352.17	17.2200	32,872.98	1,520.81
1,500.0000	NRG YIELD INC	22,485.00	17.6000	26,400.00	3,915.00
22.0000	NVR INC	15,137.32	2,410.6100	53,033.42	37,896.10
55.0000	NACCO INDUSTRIES INC	1,640.63	70.8500	3,896.75	2,256.12
790.0000	NASDAQ INC	26,129.25	71.4900	56,477.10	30,347.85
211.0000	NATIONAL HEALTHCARE CORP	9,881.13	70.1400	14,799.54	4,918.41

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1,722.0000	NATIONAL OILWELL VARCO INC	59,581.02	32.9400	56,722.68	2,858.34-
346.0000	NATIONAL RETAIL PROPERTIES INC	9,935.06	39.1000	13,528.60	3,593.54
1,062.0000	NATIONAL STORAGE AFFILIATES TR	21,760.38	23.1100	24,542.82	2,782.44
283.0000	NATURAL GAS SERVICES GROUP INC	4,944.01	24.8500	7,032.55	2,088.54
507.0000	NAVIGANT CONSULTING INC	5,070.00	19.7600	10,018.32	4,948.32
1,873.0000	NAVIENT CORP	19,133.35	16.6500	31,185.45	12,052.10
1,849.0000	NEKTAR THERAPEUTICS	22,650.25	19.5500	36,147.95	13,497.70
233.0000	NELNET INC	5,039.79	47.0100	10,953.33	5,913.54
618.0000	NETAPP INC	25,745.88	40.0500	24,750.90	994.98-
2,163.0000	NETFLIX INC	17,285.46	149.4100	323,173.83	305,888.37
244.0000	NETSCOUT SYSTEMS INC	4,862.92	34.4000	8,393.60	3,530.68
858.0000	NEUROCRINE BIOSCIENCES INC	39,193.44	46.0000	39,468.00	274.56
220.0000	NEW JERSEY RESOURCES CORP	4,907.10	39.7000	8,734.00	3,826.90
1,495.0000	NEW RESIDENTIAL INVESTMENT COR	23,546.25	15.5600	23,262.20	284.05-
2,617.0000	NEW YORK COMMUNITY BANCORP INC	31,508.68	13.1300	34,361.21	2,852.53
3,654.0000	NEW YORK MORTGAGE TRUST INC	28,683.90	6.2200	22,727.88	5,956.02-
1,492.0000	NEW YORK TIMES CO/THE	11,785.88	17.7000	26,408.40	14,622.52

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1,976.0000	NEWELL BRANDS INC	38,136.34	53.6200	105,953.12	67,816.78
920.0000	NEWFIELD EXPLORATION CO	22,194.32	28.4600	26,183.20	3,988.88
28.0000	NEWMARKET CORP	6,298.54	460.4800	12,893.44	6,594.90
3,577.0000	NEWMONT MINING CORP	111,794.72	32.3900	115,859.03	4,064.31
564.0000	NEWPARK RESOURCES INC	4,980.12	7.3500	4,145.40	834.72-
2,841.0000	NEWS CORP	25,202.85	13.7000	38,921.70	13,718.85
496.0000	NEWSTAR FINANCIAL INC	4,786.40	10.5000	5,208.00	421.60
175.0000	NEXSTAR MEDIA GROUP INC	10,736.22	59.8000	10,465.00	271.22-
2,655.0000	NEXTERA ENERGY INC	122,289.36	140.1300	372,045.15	249,755.79
6,179.0000	NIKE INC	128,566.56	59.0000	364,561.00	235,994.44
1,797.0000	NISOURCE INC	14,563.49	25.3600	45,571.92	31,008.43
2,391.0000	NOBLE ENERGY INC	85,781.00	28.3000	67,665.30	18,115.70-
1,083.0000	NORDSTROM INC	46,697.13	47.8300	51,799.89	5,102.76
2,212.0000	NORFOLK SOUTHERN CORP	95,264.87	121.7000	269,200.40	173,935.53
457.0000	NORTHERN TRUST CORP	39,690.74	97.2100	44,424.97	4,734.23
506.0000	NORTHFIELD BANCORP INC	5,089.21	17.1500	8,677.90	3,588.69
1,620.0000	NORTHROP GRUMMAN CORP	99,427.41	256.7100	415,870.20	316,442.79

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2,200.0000	NORTHSTAR REALTY EUROPE CORP	22,750.51	12.6800	27,896.00	5,145.49
631.0000	NORTHWEST BANCSHARES INC	7,666.65	15.6100	9,849.91	2,183.26
127.0000	NORTHWESTERN CORP	4,991.10	61.0200	7,749.54	2,758.44
324.0000	NOW INC	5,806.76	16.0800	5,209.92	596.84-
423.0000	NU SKIN ENTERPRISES INC	20,306.26	62.8400	26,581.32	6,275.06
463.0000	NUCOR CORP	21,492.46	57.8700	26,793.81	5,301.35
2,870.0000	NVIDIA CORP	183,383.20	144.5600	414,887.20	231,504.00
730.0000	OGE ENERGY CORP	19,800.98	34.7900	25,396.70	5,595.72
260.0000	O'REILLY AUTOMOTIVE INC	24,086.40	218.7400	56,872.40	32,786.00
420.0000	OFG BANCORP	4,863.60	10.0000	4,200.00	663.60-
2,314.0000	OASIS PETROLEUM INC	23,672.22	8.0500	18,627.70	5,044.52-
4,674.0000	OCCIDENTAL PETROLEUM CORP	215,825.45	59.8700	279,832.38	64,006.93
256.0000	OCEANEERING INTERNATIONAL INC	10,759.38	22.8400	5,847.04	4,912.34-
384.0000	OCEANFIRST FINANCIAL CORP	4,995.84	27.1200	10,414.08	5,418.24
4,141.0000	OFFICE DEPOT INC	9,603.60	5.6400	23,355.24	13,751.64
241.0000	OIL STATES INTERNATIONAL INC	9,971.45	27.1500	6,543.15	3,428.30-
207.0000	OLD DOMINION FREIGHT LINE INC	4,987.32	95.2400	19,714.68	14,727.36

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563.0000	OLD NATIONAL BANCORP/IN	5,804.53	17.2500	9,711.75	3,907.22
2,881.0000	OLD REPUBLIC INTERNATIONAL COR	26,706.87	19.5300	56,265.93	29,559.06
1,616.0000	OMNICOM GROUP INC	75,605.60	82.9000	133,966.40	58,360.80
604.0000	OMEGA HEALTHCARE INVESTORS INC	12,321.60	33.0200	19,944.08	7,622.48
962.0000	OMEGA PROTEIN CORP	6,195.28	17.9000	17,219.80	11,024.52
1,997.0000	ON SEMICONDUCTOR CORP	16,013.97	14.0400	28,037.88	12,023.91
391.0000	ONE GAS INC	4,511.97	69.8100	27,295.71	22,783.74
316.0000	ONE LIBERTY PROPERTIES INC	4,964.36	23.4300	7,403.88	2,439.52
2,485.0000	1-800-FLOWERS.COM INC	14,288.75	9.7500	24,228.75	9,940.00
1,562.0000	ONEOK INC	31,937.21	52.1600	81,473.92	49,536.71
2,508.0000	OPKO HEALTH INC	9,954.42	6.5800	16,502.64	6,548.22
20,664.0000	ORACLE CORP	369,211.95	50.1400	1,036,092.96	666,881.01
237.0000	ORBITAL ATK INC	7,446.80	98.3600	23,311.32	15,864.52
4,748.0000	ORCHID ISLAND CAPITAL INC	43,349.24	9.8600	46,815.28	3,466.04
853.0000	ORION GROUP HOLDINGS INC	5,263.01	7.4700	6,371.91	1,108.90
394.0000	ORITANI FINANCIAL CORP	4,988.04	17.0500	6,717.70	1,729.66
502.0000	ORMAT TECHNOLOGIES INC	9,957.56	58.6800	29,457.36	19,499.80

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216.0000	OSHKOSH CORP	8,340.48	68.8800	14,878.08	6,537.60
164.0000	OWENS & MINOR INC	4,995.44	32.1900	5,279.16	283.72
922.0000	OWENS CORNING	27,927.17	66.9200	61,700.24	33,773.07
166.0000	PDC ENERGY INC	4,926.88	43.1100	7,156.26	2,229.38
2,152.0000	PG&E CORP	96,366.69	66.3700	142,828.24	46,461.55
813.0000	PHH CORP	13,605.15	13.7700	11,195.01	2,410.14-
1,739.0000	PNC FINANCIAL SERVICES GROUP I	126,791.70	124.8700	217,148.93	90,357.23
1,383.0000	PNM RESOURCES INC	25,490.37	38.2500	52,899.75	27,409.38
1,500.0000	PPG INDUSTRIES INC	50,790.90	109.9600	164,940.00	114,149.10
1,319.0000	PPL CORP	39,298.88	38.6600	50,992.54	11,693.66
123.0000	PRA GROUP INC	4,940.09	37.9000	4,661.70	278.39-
497.0000	PVH CORP	38,153.27	114.5000	56,906.50	18,753.23
708.0000	PTC INC	16,156.56	55.1200	39,024.96	22,868.40
2,393.0000	PACCAR INC	90,780.85	66.0400	158,033.72	67,252.87
4,360.0000	PACIFIC BIOSCIENCES OF CALIFOR	23,500.40	3.5600	15,521.60	7,978.80-
736.0000	PACIRA PHARMACEUTICALS INC/DE	23,320.16	47.7000	35,107.20	11,787.04
303.0000	PACKAGING CORP OF AMERICA	10,062.45	111.3900	33,751.17	23,688.72

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1,123.0000	PACWEST BANCORP	28,747.17	46.7000	52,444.10	23,696.93
494.0000	PALO ALTO NETWORKS INC	38,930.81	133.8100	66,102.14	27,171.33
1,618.0000	PANDORA MEDIA INC	17,342.30	8.9200	14,432.56	2,909.74-
1,114.0000	PARATEK PHARMACEUTICALS INC	25,966.77	24.1000	26,847.40	880.63
350.0000	PAREXEL INTERNATIONAL CORP	7,808.50	86.9100	30,418.50	22,610.00
253.0000	PARK-OHIO HOLDINGS CORP	5,039.76	38.1000	9,639.30	4,599.54
1,007.0000	PARKER-HANNIFIN CORP	52,493.70	159.8200	160,938.74	108,445.04
814.0000	PARSLEY ENERGY INC	25,738.68	27.7500	22,588.50	3,150.18-
1,393.0000	PATTERN ENERGY GROUP INC	31,814.40	23.8400	33,209.12	1,394.72
304.0000	PATTERSON COS INC	9,228.30	46.9500	14,272.80	5,044.50
665.0000	PAYCOM SOFTWARE INC	23,328.20	68.4100	45,492.65	22,164.45
1,787.0000	PAYCHEX INC	56,823.68	56.9400	101,751.78	44,928.10
6,217.0000	PAYPAL HOLDINGS INC	110,955.68	53.6700	333,666.39	222,710.71
248.0000	PEBBLEBROOK HOTEL TRUST	4,816.16	32.2400	7,995.52	3,179.36
403.0000	PENN NATIONAL GAMING INC	3,428.84	21.4000	8,624.20	5,195.36
4,094.0000	JC PENNEY CO INC	34,530.70	4.6500	19,037.10	15,493.60-
302.0000	PENNS WOODS BANCORP INC	12,360.86	41.1800	12,436.36	75.50

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976.0000	PENNSYLVANIA REAL ESTATE INVES	13,459.04	11.3200	11,048.32	2,410.72-
301.0000	PENNYMAC MORTGAGE INVESTMENT T	4,894.26	18.2900	5,505.29	611.03
265.0000	PENSKE AUTOMOTIVE GROUP INC	5,708.10	43.9100	11,636.15	5,928.05
1,268.0000	PEOPLE'S UNITED FINANCIAL INC	5,163.35	17.6600	22,392.88	17,229.53
6,604.0000	PEPSICO INC	499,612.78	115.4900	762,695.96	263,083.18
441.0000	PERKINELMER INC	14,886.81	68.1400	30,049.74	15,162.93
28,040.0000	PFIZER INC	806,542.91	33.5900	941,863.60	135,320.69
7,892.0000	PHILIP MORRIS INTERNATIONAL IN	325,549.66	117.4500	926,915.40	601,365.74
3,803.0000	PHILLIPS 66	103,310.27	82.6900	314,470.07	211,159.80
1,452.0000	PHYSICIANS REALTY TRUST	23,449.80	20.1400	29,243.28	5,793.48
1,117.0000	PILGRIM'S PRIDE CORP	5,683.25	21.9200	24,484.64	18,801.39
322.0000	PINNACLE FINANCIAL PARTNERS IN	4,842.88	62.8000	20,221.60	15,378.72
538.0000	PINNACLE ENTERTAINMENT INC	6,014.84	19.7600	10,630.88	4,616.04
454.0000	PINNACLE WEST CAPITAL CORP	19,893.33	85.1600	38,662.64	18,769.31
828.0000	PIONEER NATURAL RESOURCES CO	110,201.46	159.5800	132,132.24	21,930.78
142.0000	PLANTRONICS INC	4,955.80	52.3100	7,428.02	2,472.22
2,374.0000	PLATFORM SPECIALTY PRODUCTS CO	23,407.64	12.6800	30,102.32	6,694.68

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158.0000	PLEXUS CORP	5,040.20	52.5700	8,306.06	3,265.86
517.0000	POLARIS INDUSTRIES INC	31,479.88	92.2300	47,682.91	16,203.03
409.0000	POLYONE CORP	9,742.38	38.7400	15,844.66	6,102.28
286.0000	POOL CORP	8,196.76	117.5700	33,625.02	25,428.26
599.0000	POPULAR INC	9,326.43	41.7100	24,984.29	15,657.86
197.0000	PORTLAND GENERAL ELECTRIC CO	4,934.85	45.6900	9,000.93	4,066.08
434.0000	POST HOLDINGS INC	18,659.63	77.6500	33,700.10	15,040.47
171.0000	POWER INTEGRATIONS INC	6,279.12	72.9000	12,465.90	6,186.78
1,884.0000	PRAXAIR INC	112,074.06	132.5500	249,724.20	137,650.14
2,318.0000	PREFERRED APARTMENT COMMUNITIE	25,988.95	15.7500	36,508.50	10,519.55
1,884.0000	T ROWE PRICE GROUP INC	89,739.25	74.2100	139,811.64	50,072.39
255.0000	PRICELINE GROUP INC/THE	95,568.68	1,870.5200	476,982.60	381,413.92
1,342.0000	PRINCIPAL FINANCIAL GROUP INC	40,511.83	64.0700	85,981.94	45,470.11
13,512.0000	PROCTER & GAMBLE CO/THE	908,961.02	87.1500	1,177,570.80	268,609.78
2,268.0000	PROGRESSIVE CORP/THE	44,656.92	44.0900	99,996.12	55,339.20
2,702.0000	PROLOGIS INC	75,744.25	58.6400	158,445.28	82,701.03
278.0000	PROSPERITY BANCSHARES INC	11,801.10	64.2400	17,858.72	6,057.62

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359.0000	PROVIDENT FINANCIAL SERVICES I	4,957.79	25.3800	9,111.42	4,153.63
1,245.0000	PRUDENTIAL FINANCIAL INC	87,384.13	108.1400	134,634.30	47,250.17
3,279.0000	PUBLIC SERVICE ENTERPRISE GROU	100,870.89	43.0100	141,029.79	40,158.90
661.0000	PUBLIC STORAGE	70,642.22	208.5300	137,838.33	67,196.11
1,140.0000	PULTEGROUP INC	22,357.50	24.5300	27,964.20	5,606.70
2,042.0000	PZENA INVESTMENT MANAGEMENT IN	17,635.28	10.1600	20,746.72	3,111.44
1,207.0000	QEP RESOURCES INC	22,703.67	10.1000	12,190.70	10,512.97-
1,804.0000	QTS REALTY TRUST INC	51,594.40	52.3300	94,403.32	42,808.92
991.0000	QORVO INC	11,289.87	63.3200	62,750.12	51,460.25
9,341.0000	QUALCOMM INC	353,796.40	55.2200	515,810.02	162,013.62
583.0000	QUALITY CARE PROPERTIES INC	17,985.55	18.3100	10,674.73	7,310.82-
311.0000	QUANEX BUILDING PRODUCTS CORP	4,948.01	21.1500	6,577.65	1,629.64
1,366.0000	QUANTA SERVICES INC	31,598.99	32.9200	44,968.72	13,369.73
281.0000	RLJ LODGING TRUST	4,804.00	19.8700	5,583.47	779.47
20.0000	RMR GROUP INC/THE	260.00	48.6500	973.00	713.00
859.0000	RPM INTERNATIONAL INC	24,731.52	54.5500	46,858.45	22,126.93
649.0000	RSP PERMIAN INC	22,403.48	32.2700	20,943.23	1,460.25-

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933.0000	RADIAN GROUP INC	9,665.88	16.3500	15,254.55	5,588.67
366.0000	RALPH LAUREN CORP	30,625.05	73.8000	27,010.80	3,614.25-
680.0000	RAMCO-GERSHENSON PROPERTIES TR	10,145.60	12.9000	8,772.00	1,373.60-
1,076.0000	RANGE RESOURCES CORP	41,715.89	23.1700	24,930.92	16,784.97-
609.0000	RAYMOND JAMES FINANCIAL INC	18,702.39	80.2200	48,853.98	30,151.59
1,787.0000	RAYTHEON CO	85,851.23	161.4800	288,564.76	202,713.53
841.0000	REALOGY HOLDINGS CORP	26,519.63	32.4500	27,290.45	770.82
1,212.0000	REALTY INCOME CORP	66,051.61	55.1800	66,878.16	826.55
611.0000	RED HAT INC	39,281.19	95.7500	58,503.25	19,222.06
148.0000	REGAL BELOIT CORP	9,713.24	81.5500	12,069.40	2,356.16
418.0000	REGAL ENTERTAINMENT GROUP	4,928.22	20.4600	8,552.28	3,624.06
531.0000	REGENCY CENTERS CORP	21,824.10	62.6400	33,261.84	11,437.74
366.0000	REGENERON PHARMACEUTICALS INC	141,628.20	491.1400	179,757.24	38,129.04
7,014.0000	REGIONS FINANCIAL CORP	48,588.92	14.6400	102,684.96	54,096.04
345.0000	REINSURANCE GROUP OF AMERICA I	18,554.10	128.3900	44,294.55	25,740.45
447.0000	RELIANCE STEEL & ALUMINUM CO	22,028.16	72.8100	32,546.07	10,517.91
345.0000	RENASANT CORP	4,988.70	43.7400	15,090.30	10,101.60

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1,866.0000	REPUBLIC SERVICES INC	46,899.63	63.7300	118,920.18	72,020.55
915.0000	RESMED INC	23,601.94	77.8700	71,251.05	47,649.11
418.0000	RESOURCES CONNECTION INC	5,082.88	13.7000	5,726.60	643.72
384.0000	RETAIL OPPORTUNITY INVESTMENTS	5,026.56	19.1900	7,368.96	2,342.40
579.0000	REXNORD CORP	12,280.59	23.2500	13,461.75	1,181.16
4,003.0000	REYNOLDS AMERICAN INC	139,866.44	65.0400	260,355.12	120,488.68
1,044.0000	RICE ENERGY INC	23,197.68	26.6300	27,801.72	4,604.04
3,125.0000	RIGEL PHARMACEUTICALS INC	9,750.00	2.7300	8,531.25	1,218.75-
227.0000	RIGNET INC	4,939.52	16.0500	3,643.35	1,296.17-
1,228.0000	RINGCENTRAL INC	16,504.32	36.5500	44,883.40	28,379.08
2,242.0000	RING ENERGY INC	26,614.40	13.0000	29,146.00	2,531.60
3,958.0000	RITE AID CORP	31,171.04	2.9500	11,676.10	19,494.94-
873.0000	ROBERT HALF INTERNATIONAL INC	25,047.88	47.9300	41,842.89	16,795.01
1,001.0000	ROCKWELL AUTOMATION INC	57,419.76	161.9600	162,121.96	104,702.20
760.0000	ROCKWELL COLLINS INC	53,652.25	105.0800	79,860.80	26,208.55
110.0000	ROGERS CORP	4,951.10	108.6200	11,948.20	6,997.10
321.0000	ROPER TECHNOLOGIES INC	63,403.03	231.5300	74,321.13	10,918.10

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708.0000	ROSETTA STONE INC	5,210.88	10.7800	7,632.24	2,421.36
1,676.0000	ROSS STORES INC	96,360.79	57.7300	96,755.48	394.69
350.0000	ROYAL GOLD INC	19,143.81	78.1700	27,359.50	8,215.69
344.0000	RYDER SYSTEM INC	17,888.72	71.9800	24,761.12	6,872.40
488.0000	RYMAN HOSPITALITY PROPERTIES I	13,519.13	64.0100	31,236.88	17,717.75
281.0000	S&T BANCORP INC	4,979.32	35.8600	10,076.66	5,097.34
949.0000	S&P GLOBAL INC	70,596.80	145.9900	138,544.51	67,947.71
577.0000	SBA COMMUNICATIONS CORP	21,135.51	134.9000	77,837.30	56,701.79
872.0000	SEI INVESTMENTS CO	14,640.88	53.7800	46,896.16	32,255.28
316.0000	SEACOR MARINE HOLDINGS INC	7,955.65	20.3600	6,433.76	1,521.89-
214.0000	SJW GROUP	4,962.66	49.1800	10,524.52	5,561.86
686.0000	SL GREEN REALTY CORP	39,657.66	105.8000	72,578.80	32,921.14
3,528.0000	SLM CORP	20,584.41	11.5000	40,572.00	19,987.59
483.0000	SP PLUS CORP	10,007.76	30.5500	14,755.65	4,747.89
255.0000	SVB FINANCIAL GROUP	14,614.05	175.7900	44,826.45	30,212.40
695.0000	SAFEWAY CASA LEY CVR	705.36	1.0100	701.95	3.41-
695.0000	SAFEWAY PDC LLC CVR	22.10	0.0300	20.85	1.25-

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352.0000	ST JOE CO/THE	5,079.36	18.7500	6,600.00	1,520.64
3,185.0000	SALESFORCE.COM INC	101,075.20	86.6000	275,821.00	174,745.80
3,204.0000	SANCHEZ ENERGY CORP	21,979.44	7.1800	23,004.72	1,025.28
109.0000	SANDERSON FARMS INC	5,261.43	115.6500	12,605.85	7,344.42
276.0000	SANDY SPRING BANCORP INC	4,832.76	40.6600	11,222.16	6,389.40
1,333.0000	SANMINA CORP	12,210.93	38.1000	50,787.30	38,576.37
130.0000	SAUL CENTERS INC	4,982.90	57.9800	7,537.40	2,554.50
753.0000	SCANA CORP	27,245.81	67.0100	50,458.53	23,212.72
515.0000	HENRY SCHEIN INC	40,663.39	183.0200	94,255.30	53,591.91
8,506.0000	SCHLUMBERGER LTD	526,783.48	65.8400	560,035.04	33,251.56
194.0000	SCHOLASTIC CORP	4,834.48	43.5900	8,456.46	3,621.98
6,043.0000	CHARLES SCHWAB CORP/THE	106,767.19	42.9600	259,607.28	152,840.09
190.0000	SCHWEITZER-MAUDUIT INTERNATION	5,102.45	37.2300	7,073.70	1,971.25
165.0000	SCIENCE APPLICATIONS INTERNATI	4,839.30	69.4200	11,454.30	6,615.00
515.0000	SCIENTIFIC GAMES CORP	5,000.65	26.1000	13,441.50	8,440.85
1,023.0000	EW SCRIPPS CO/THE	7,948.87	17.8100	18,219.63	10,270.76
621.0000	SEACOAST BANKING CORP OF FLORI	4,685.76	24.1000	14,966.10	10,280.34

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315.0000	SEACOR HOLDINGS INC	12,031.06	34.3000	10,804.50	1,226.56-
899.0000	SEALED AIR CORP	19,824.16	44.7600	40,239.24	20,415.08
886.0000	SEATTLE GENETICS INC	19,069.78	51.7400	45,841.64	26,771.86
297.0000	SELECT COMFORT CORP	4,814.37	35.4900	10,540.53	5,726.16
600.0000	SELECT MEDICAL HOLDINGS CORP	5,106.00	15.3500	9,210.00	4,104.00
321.0000	SELECTIVE INSURANCE GROUP INC	5,091.06	50.0500	16,066.05	10,974.99
190.0000	SEMGROUP CORP	4,866.93	27.0000	5,130.00	263.07
1,416.0000	SEMPRA ENERGY	75,155.45	112.7500	159,654.00	84,498.55
136.0000	SENSIENT TECHNOLOGIES CORP	4,944.96	80.5300	10,952.08	6,007.12
1,420.0000	SERVICE CORP INTERNATIONAL/US	15,804.60	33.4500	47,499.00	31,694.40
581.0000	SERVICENOW INC	17,406.76	106.0000	61,586.00	44,179.24
2,457.0000	SERVICESOURCE INTERNATIONAL IN	9,926.28	3.8800	9,533.16	393.12-
112.0000	SHERWIN-WILLIAMS CO/THE	29,968.99	350.9600	39,307.52	9,338.53
458.0000	SHUTTERFLY INC	13,593.44	47.5000	21,755.00	8,161.56
246.0000	SIGNATURE BANK/NEW YORK NY	13,731.72	143.5300	35,308.38	21,576.66
248.0000	SILICON LABORATORIES INC	9,936.20	68.3500	16,950.80	7,014.60
588.0000	SILGAN HOLDINGS INC	11,780.58	31.7800	18,686.64	6,906.06

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202.0000	SIMMONS FIRST NATIONAL CORP	4,930.82	52.9000	10,685.80	5,754.98
1,380.0000	SIMON PROPERTY GROUP INC	117,345.95	161.7600	223,228.80	105,882.85
168.0000	SIMPSON MANUFACTURING CO INC	4,935.84	43.7100	7,343.28	2,407.44
22,006.0000	SIRIUS XM HOLDINGS INC	43,119.42	5.4700	120,372.82	77,253.40
148.0000	SIX FLAGS ENTERTAINMENT CORP	4,997.96	59.6100	8,822.28	3,824.32
1,053.0000	SKECHERS U.S.A. INC	4,794.66	29.5000	31,063.50	26,268.84
1,709.0000	SKYWORKS SOLUTIONS INC	27,531.54	95.9500	163,978.55	136,447.01
1,824.0000	AO SMITH CORP	28,189.92	56.3300	102,745.92	74,556.00
312.0000	JM SMUCKER CO/THE	27,727.44	118.3300	36,918.96	9,191.52
159.0000	SNAP-ON INC	9,926.66	158.0000	25,122.00	15,195.34
229.0000	SNYDER'S-LANCE INC	4,813.58	34.6200	7,927.98	3,114.40
375.0000	SONIC AUTOMOTIVE INC	5,231.25	19.4500	7,293.75	2,062.50
534.0000	SONOCO PRODUCTS CO	17,336.55	51.4200	27,458.28	10,121.73
174.0000	SOUTH STATE CORP	4,840.68	85.7000	14,911.80	10,071.12
4,072.0000	SOUTHERN CO/THE	153,419.76	47.8800	194,967.36	41,547.60
345.0000	SOUTHSIDE BANCSHARES INC	5,037.90	34.9400	12,054.30	7,016.40
3,990.0000	SOUTHWEST AIRLINES CO	45,283.11	62.1400	247,938.60	202,655.49

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272.0000	SOUTHWEST GAS HOLDINGS INC	10,194.56	73.0600	19,872.32	9,677.76
2,519.0000	SOUTHWESTERN ENERGY CO	31,587.36	6.0800	15,315.52	16,271.84-
363.0000	SPEEDWAY MOTORSPORTS INC	5,027.55	18.2700	6,632.01	1,604.46
384.0000	SPIRE INC	22,282.34	69.7500	26,784.00	4,501.66
1,117.0000	SPIRIT AEROSYSTEMS HOLDINGS IN	22,330.82	57.9400	64,718.98	42,388.16
415.0000	SPIRIT AIRLINES INC	4,988.47	51.6500	21,434.75	16,446.28
3,283.0000	SPIRIT REALTY CAPITAL INC	31,738.98	7.4100	24,327.03	7,411.95-
671.0000	SPLUNK INC	33,438.80	56.8900	38,173.19	4,734.39
7,545.0000	SPRINT CORP	39,156.10	8.2100	61,944.45	22,788.35
887.0000	SPROUTS FARMERS MARKET INC	23,088.61	22.6700	20,108.29	2,980.32-
1,176.0000	SQUARE INC	28,058.48	23.4600	27,588.96	469.52-
1,186.0000	STANLEY BLACK & DECKER INC	68,473.54	140.7300	166,905.78	98,432.24
2,453.0000	STAPLES INC	24,284.70	10.0700	24,701.71	417.01
8,740.0000	STARBUCKS CORP	149,663.32	58.3100	509,629.40	359,966.08
554.0000	STARWOOD PROPERTY TRUST INC	11,102.16	22.3900	12,404.06	1,301.90
1,390.0000	STATE STREET CORP	83,669.38	89.7300	124,724.70	41,055.32
1,291.0000	STEEL DYNAMICS INC	19,704.08	35.8100	46,230.71	26,526.63

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605.0000	STERICYCLE INC	38,965.96	76.3200	46,173.60	7,207.64
1,202.0000	STERLING BANCORP/DE	9,804.58	23.2500	27,946.50	18,141.92
827.0000	STIFEL FINANCIAL CORP	32,320.81	45.9800	38,025.46	5,704.65
327.0000	STOCK YARDS BANCORP INC	4,907.18	38.9000	12,720.30	7,813.12
686.0000	STONEGATE BANK	17,499.86	46.1800	31,679.48	14,179.62
854.0000	STORE CAPITAL CORP	22,161.30	22.4500	19,172.30	2,989.00-
2,020.0000	STRYKER CORP	100,430.20	138.7800	280,335.60	179,905.40
79.0000	STURM RUGER & CO INC	2,193.04	62.1500	4,909.85	2,716.81
431.0000	SUN BANCORP INC/NJ	5,348.71	24.6500	10,624.15	5,275.44
355.0000	SUN COMMUNITIES INC	22,741.35	87.6900	31,129.95	8,388.60
216.0000	SUNCOKE ENERGY INC	2,608.06	10.9000	2,354.40	253.66-
1,431.0000	SUNSTONE HOTEL INVESTORS INC	11,913.91	16.1200	23,067.72	11,153.81
2,689.0000	SUNTRUST BANKS INC	68,076.91	56.7200	152,520.08	84,443.17
1,214.0000	SUPERIOR ENERGY SERVICES INC	22,823.20	10.4300	12,662.02	10,161.18-
633.0000	SWIFT TRANSPORTATION CO	9,944.43	26.5000	16,774.50	6,830.07
1,438.0000	SYMANTEC CORP	32,891.02	28.2500	40,623.50	7,732.48
194.0000	SYNAPTICS INC	4,855.82	51.7100	10,031.74	5,175.92

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342.0000	SYNOPSYS INC	9,919.68	72.9300	24,942.06	15,022.38
1,368.0000	SYNOVUS FINANCIAL CORP	17,524.08	44.2400	60,520.32	42,996.24
130.0000	SYNNEX CORP	4,956.90	119.9600	15,594.80	10,637.90
3,751.0000	SYNCHRONY FINANCIAL	106,404.77	29.8200	111,854.82	5,450.05
1,253.0000	SYSCO CORP	42,876.29	50.3300	63,063.49	20,187.20
2,163.0000	TCF FINANCIAL CORP	22,062.60	15.9400	34,478.22	12,415.62
1,514.0000	TD AMERITRADE HOLDING CORP	28,160.40	42.9900	65,086.86	36,926.46
1,554.0000	TFS FINANCIAL CORP	25,840.25	15.4700	24,040.38	1,799.87-
2,526.0000	TJX COS INC/THE	52,320.11	72.1700	182,301.42	129,981.31
2,525.0000	T-MOBILE US INC	55,914.29	60.6200	153,065.50	97,151.21
948.0000	TAILORED BRANDS INC	24,791.10	11.1600	10,579.68	14,211.42-
437.0000	TAKE-TWO INTERACTIVE SOFTWARE	6,471.97	73.3800	32,067.06	25,595.09
183.0000	TANGER FACTORY OUTLET CENTERS	4,884.27	25.9800	4,754.34	129.93-
2,698.0000	TARGET CORP	151,033.77	52.2900	141,078.42	9,955.35-
1,034.0000	TARGA RESOURCES CORP	34,000.12	45.2000	46,736.80	12,736.68
186.0000	TAUBMAN CENTERS INC	7,456.74	59.5500	11,076.30	3,619.56
223.0000	TEAM INC	4,995.20	23.4500	5,229.35	234.15

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277.0000	TECH DATA CORP	12,772.47	101.0000	27,977.00	15,204.53
2,000.0000	TEGNA INC	13,706.07	14.4100	28,820.00	15,113.93
754.0000	TELADOC INC	24,625.64	34.7000	26,163.80	1,538.16
102.0000	TELEDYNE TECHNOLOGIES INC	4,876.62	127.6500	13,020.30	8,143.68
144.0000	TELEFLEX INC	9,796.02	207.7600	29,917.44	20,121.42
1,863.0000	TELEPHONE & DATA SYSTEMS INC	45,502.19	27.7500	51,698.25	6,196.06
388.0000	TEMPUR SEALY INTERNATIONAL INC	15,357.04	53.3900	20,715.32	5,358.28
106.0000	TENNANT CO	4,983.06	73.8000	7,822.80	2,839.74
671.0000	TENNECO INC	18,150.55	57.8300	38,803.93	20,653.38
1,170.0000	TERADYNE INC	16,169.40	30.0300	35,135.10	18,965.70
556.0000	TEREX CORP	14,190.44	37.5000	20,850.00	6,659.56
2,392.0000	TERRENO REALTY CORP	42,955.92	33.6600	80,514.72	37,558.80
267.0000	TESARO INC	9,972.45	139.8600	37,342.62	27,370.17
689.0000	TESLA INC	66,419.76	361.6100	249,149.29	182,729.53
573.0000	TESORO CORP	14,607.06	93.6000	53,632.80	39,025.74
370.0000	TETRA TECH INC	8,376.80	45.7500	16,927.50	8,550.70
5,432.0000	TETRAPHASE PHARMACEUTICALS INC	23,792.16	7.1300	38,730.16	14,938.00

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6,700.0000	TEXAS INSTRUMENTS INC	224,685.83	76.9300	515,431.00	290,745.17
1,348.0000	TEXTRON INC	37,364.20	47.1000	63,490.80	26,126.60
2,460.0000	THERMO FISHER SCIENTIFIC INC	96,752.51	174.4700	429,196.20	332,443.69
264.0000	THOR INDUSTRIES INC	6,293.76	104.5200	27,593.28	21,299.52
1,204.0000	3D SYSTEMS CORP	21,684.04	18.7000	22,514.80	830.76
3,378.0000	3M CO	252,771.69	208.1900	703,265.82	450,494.13
906.0000	TIFFANY & CO	30,337.41	93.8700	85,046.22	54,708.81
4,563.0000	TILLY'S INC	35,910.70	10.1500	46,314.45	10,403.75
697.0000	TIME INC	8,393.70	14.3500	10,001.95	1,608.25
5,580.0000	TIME WARNER INC	203,652.12	100.4100	560,287.80	356,635.68
2,384.0000	TITAN INTERNATIONAL INC	23,625.44	12.0100	28,631.84	5,006.40
2,974.0000	TIVO CORP	58,914.94	18.6500	55,465.10	3,449.84-
820.0000	TIVITY HEALTH INC	5,584.20	39.8500	32,677.00	27,092.80
1,241.0000	TOLL BROTHERS INC	27,612.41	39.5100	49,031.91	21,419.50
130.0000	TOMPKINS FINANCIAL CORP	5,062.20	78.7200	10,233.60	5,171.40
310.0000	TOPBUILD CORP	4,479.13	53.0700	16,451.70	11,972.57
819.0000	TORCHMARK CORP	22,753.64	76.5000	62,653.50	39,899.86

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736.0000	TORO CO/THE	10,992.16	69.2900	50,997.44	40,005.28
891.0000	TOTAL SYSTEM SERVICES INC	19,795.33	58.2500	51,900.75	32,105.42
249.0000	TOWNE BANK/PORTSMOUTH VA	3,215.24	30.8000	7,669.20	4,453.96
595.0000	TRACTOR SUPPLY CO	25,024.53	54.2100	32,254.95	7,230.42
57.0000	TRANSDIGM GROUP INC	4,891.17	268.8700	15,325.59	10,434.42
2,086.0000	TRAVELERS COS INC/THE	96,978.76	126.5300	263,941.58	166,962.82
85.0000	TREEHOUSE FOODS INC	4,606.15	81.6900	6,943.65	2,337.50
2.0000	TREX CO INC	25.86	67.6600	135.32	109.46
422.0000	TRICO BANCSHARES	6,055.70	35.1500	14,833.30	8,777.60
1,458.0000	TRIMBLE INC	27,024.03	35.6700	52,006.86	24,982.83
1,299.0000	TRINITY INDUSTRIES INC	20,398.01	28.0300	36,410.97	16,012.96
735.0000	TRIPADVISOR INC	26,729.35	38.2000	28,077.00	1,347.65
345.0000	TRUEBLUE INC	5,023.20	26.5000	9,142.50	4,119.30
150.0000	TRUSTMARK CORP	3,406.50	32.1600	4,824.00	1,417.50
314.0000	TUPPERWARE BRANDS CORP	14,974.66	70.2300	22,052.22	7,077.56
11,508.0000	TWENTY-FIRST CENTURY FOX INC	197,578.78	28.3400	326,136.72	128,557.94
3,246.0000	TWITTER INC	53,618.38	17.8700	58,006.02	4,387.64

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86.0000	TYLER TECHNOLOGIES INC	4,999.18	175.6700	15,107.62	10,108.44
2,338.0000	TYSON FOODS INC	38,339.08	62.6300	146,428.94	108,089.86
1,181.0000	UDR INC	26,938.61	38.9700	46,023.57	19,084.96
286.0000	UGI CORP	5,960.24	48.4100	13,845.26	7,885.02
190.0000	UMB FINANCIAL CORP	7,607.60	74.8600	14,223.40	6,615.80
6,138.0000	US BANCORP	212,682.43	51.9200	318,684.96	106,002.53
2,244.0000	UMH PROPERTIES INC	21,205.80	17.0500	38,260.20	17,054.40
366.0000	USANA HEALTH SCIENCES INC	14,231.91	64.1000	23,460.60	9,228.69
412.0000	US SILICA HOLDINGS INC	4,865.72	35.4900	14,621.88	9,756.16
269.0000	ULTA BEAUTY INC	16,901.27	287.3400	77,294.46	60,393.19
269.0000	ULTIMATE SOFTWARE GROUP INC/TH	23,379.35	210.0600	56,506.14	33,126.79
2,104.0000	UMPQUA HOLDINGS CORP	22,409.37	18.3600	38,629.44	16,220.07
1,435.0000	UNDER ARMOUR INC	15,081.68	21.7600	31,225.60	16,143.92
1,449.0000	UNDER ARMOUR INC	14,635.71	20.1600	29,211.84	14,576.13
97.0000	UNIFIRST CORP/MA	4,938.27	140.7000	13,647.90	8,709.63
802.0000	UNION BANKSHARES CORP	9,587.27	33.9000	27,187.80	17,600.53
3,830.0000	UNION PACIFIC CORP	83,603.92	108.9100	417,125.30	333,521.38

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773.0000	UNITED COMMUNITY BANKS INC/GA	5,094.07	27.8000	21,489.40	16,395.33
586.0000	UNITED BANKSHARES INC/WV	10,942.20	39.2000	22,971.20	12,029.00
1,783.0000	UNITED CONTINENTAL HOLDINGS IN	43,817.39	75.2500	134,170.75	90,353.36
942.0000	UNITED FINANCIAL BANCORP INC	9,977.00	16.6900	15,721.98	5,744.98
277.0000	UNITED FIRE GROUP INC	4,855.81	44.0600	12,204.62	7,348.81
322.0000	UNITED NATURAL FOODS INC	14,770.35	36.7000	11,817.40	2,952.95-
2,748.0000	UNITED PARCEL SERVICE INC	218,789.75	110.5900	303,901.32	85,111.57
789.0000	UNITED RENTALS INC	27,392.69	112.7100	88,928.19	61,535.50
554.0000	UNITED STATES CELLULAR CORP	24,481.26	38.3200	21,229.28	3,251.98-
1,236.0000	UNITED STATES STEEL CORP	23,623.02	22.1400	27,365.04	3,742.02
5,059.0000	UNITED TECHNOLOGIES CORP	322,158.63	122.1100	617,754.49	295,595.86
548.0000	UNITED THERAPEUTICS CORP	24,908.59	129.7300	71,092.04	46,183.45
5,552.0000	UNITEDHEALTH GROUP INC	275,245.28	185.4200	1,029,451.84	754,206.56
1,234.0000	UNITI GROUP INC	25,531.46	25.1400	31,022.76	5,491.30
537.0000	UNITIL CORP	14,936.01	48.3100	25,942.47	11,006.46
300.0000	UNIVERSAL DISPLAY CORP	25,518.00	109.2500	32,775.00	7,257.00
184.0000	UNIVERSAL FOREST PRODUCTS INC	4,852.08	87.3100	16,065.04	11,212.96

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451.0000	UNIVERSAL HEALTH REALTY INCOME	21,738.20	79.5400	35,872.54	14,134.34
410.0000	UNIVERSAL HEALTH SERVICES INC	24,507.64	122.0800	50,052.80	25,545.16
2,183.0000	UNUM GROUP	42,731.57	46.6300	101,793.29	59,061.72
166.0000	URBAN EDGE PROPERTIES	2,591.56	23.7300	3,939.18	1,347.62
477.0000	URBAN OUTFITTERS INC	14,707.10	18.5400	8,843.58	5,863.52-
228.0000	VCA INC	5,002.32	92.3100	21,046.68	16,044.36
1,653.0000	VF CORP	62,918.13	57.6000	95,212.80	32,294.67
370.0000	VSE CORP	4,713.80	44.9800	16,642.60	11,928.80
208.0000	VAIL RESORTS INC	9,195.68	202.8300	42,188.64	32,992.96
2,657.0000	VALERO ENERGY CORP	76,545.87	67.4600	179,241.22	102,695.35
187.0000	VALMONT INDUSTRIES INC	19,106.48	149.6000	27,975.20	8,868.72
1,589.0000	VALVOLINE INC	15,933.02	23.7200	37,691.08	21,758.06
370.0000	VANTIV INC	10,019.60	63.3400	23,435.80	13,416.20
399.0000	VAREX IMAGING CORP	5,758.51	33.8000	13,486.20	7,727.69
998.0000	VARIAN MEDICAL SYSTEMS INC	42,646.59	103.1900	102,983.62	60,337.03
92.0000	VECTRUS INC	1,180.67	32.3200	2,973.44	1,792.77
1,483.0000	VENTAS INC	77,501.50	69.4800	103,038.84	25,537.34

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7,770.0000	VEREIT INC	71,714.28	8.1400	63,247.80	8,466.48-
1,225.0000	VERISIGN INC	28,840.42	92.9600	113,876.00	85,035.58
19,304.0000	VERIZON COMMUNICATIONS INC	705,887.70	44.6600	862,116.64	156,228.94
145.0000	VERINT SYSTEMS INC	5,067.75	40.7000	5,901.50	833.75
740.0000	VERISK ANALYTICS INC	36,444.00	84.3700	62,433.80	25,989.80
45.0000	VERITIV CORP	1,140.41	45.0000	2,025.00	884.59
1,450.0000	VERTEX PHARMACEUTICALS INC	59,787.33	128.8700	186,861.50	127,074.17
691.0000	VERSUM MATERIALS INC	6,925.07	32.5000	22,457.50	15,532.43
117.0000	VIASAT INC	4,891.77	66.2000	7,745.40	2,853.63
3,184.0000	VIACOM INC	118,909.35	33.5700	106,886.88	12,022.47-
8,827.0000	VISA INC	218,970.52	93.7800	827,796.06	608,825.54
1,523.0000	VISHAY INTERTECHNOLOGY INC	14,377.12	16.6000	25,281.80	10,904.68
376.0000	VISTA OUTDOOR INC	7,257.20	22.5100	8,463.76	1,206.56
85.0000	VISTEON CORP	4,961.45	102.0600	8,675.10	3,713.65
304.0000	VLASIC FOODS INTL INC COM	3,211.50	10.5641	3,211.50	0.00
5,930.0000	VONAGE HOLDINGS CORP	11,207.70	6.5400	38,782.20	27,574.50
333.0000	VORNADO REALTY TRUST	25,018.58	93.9000	31,268.70	6,250.12

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773.0000	VOYA FINANCIAL INC	22,123.26	36.8900	28,515.97	6,392.71
664.0000	VULCAN MATERIALS CO	36,410.98	126.6800	84,115.52	47,704.54
90.0000	WD-40 CO	4,888.80	110.3500	9,931.50	5,042.70
313.0000	WGL HOLDINGS INC	19,836.65	83.4300	26,113.59	6,276.94
213.0000	WABCO HOLDINGS INC	14,611.56	127.5100	27,159.63	12,548.07
384.0000	WSFS FINANCIAL CORP	4,825.60	45.3500	17,414.40	12,588.80
2,104.0000	WEC ENERGY GROUP INC	46,908.39	61.3800	129,143.52	82,235.13
1,221.0000	WABASH NATIONAL CORP	10,036.73	21.9800	26,837.58	16,800.85
270.0000	WABTEC CORP/DE	18,324.99	91.5000	24,705.00	6,380.01
6,711.0000	WAL-MART STORES INC	365,960.40	75.6800	507,888.48	141,928.08
4,127.0000	WALGREENS BOOTS ALLIANCE INC	184,909.82	78.3100	323,185.37	138,275.55
664.0000	WASHINGTON FEDERAL INC	13,638.56	33.2000	22,044.80	8,406.24
809.0000	WASHINGTON PRIME GROUP INC	9,469.09	8.3700	6,771.33	2,697.76-
218.0000	WASHINGTON TRUST BANCORP INC	4,848.32	51.5500	11,237.90	6,389.58
643.0000	WASTE MANAGEMENT INC	23,102.99	73.3500	47,164.05	24,061.06
95.0000	WATERS CORP	8,628.85	183.8400	17,464.80	8,835.95
70.0000	WATSCO INC	5,804.40	154.2000	10,794.00	4,989.60

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149.0000	WATTS WATER TECHNOLOGIES INC	4,936.37	63.2000	9,416.80	4,480.43
367.0000	WAYFAIR INC	27,345.17	76.8800	28,214.96	869.79
696.0000	WEBSTER FINANCIAL CORP	13,671.32	52.2200	36,345.12	22,673.80
780.0000	WEINGARTEN REALTY INVESTORS	18,166.20	30.1000	23,478.00	5,311.80
130.0000	WEIS MARKETS INC	4,803.50	48.7200	6,333.60	1,530.10
1,365.0000	WELBILT INC	13,182.40	18.8500	25,730.25	12,547.85
253.0000	WELLCARE HEALTH PLANS INC	12,419.77	179.5600	45,428.68	33,008.91
24,833.0000	WELLS FARGO & CO	864,740.84	55.4100	1,375,996.53	511,255.69
1,740.0000	WELLTOWER INC	86,473.75	74.8500	130,239.00	43,765.25
3,177.0000	WENDY'S CO/THE	14,804.82	15.5100	49,275.27	34,470.45
261.0000	WESBANCO INC	4,909.41	39.5400	10,319.94	5,410.53
551.0000	WESCO INTERNATIONAL INC	19,494.38	57.3000	31,572.30	12,077.92
164.0000	WEST PHARMACEUTICAL SERVICES I	4,991.34	94.5200	15,501.28	10,509.94
831.0000	WESTAR ENERGY INC	30,016.82	53.0200	44,059.62	14,042.80
729.0000	WESTERN ALLIANCE BANCORP	4,891.59	49.2000	35,866.80	30,975.21
3,722.0000	WESTERN ASSET MORTGAGE CAPITAL	52,852.40	10.3000	38,336.60	14,515.80-
1,752.0000	WESTERN DIGITAL CORP	50,390.92	88.6000	155,227.20	104,836.28

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472.0000	WESTLAKE CHEMICAL CORP	18,799.76	66.2100	31,251.12	12,451.36
2,929.0000	WESTMORELAND COAL CO	22,289.69	4.8700	14,264.23	8,025.46-
1,557.0000	WESTROCK CO	44,296.54	56.6600	88,219.62	43,923.08
135.0000	WESTWOOD HOLDINGS GROUP INC	4,885.65	56.6900	7,653.15	2,767.50
229.0000	WEX INC	11,216.42	104.2700	23,877.83	12,661.41
4,346.0000	WEYERHAEUSER CO	74,342.04	33.5000	145,591.00	71,248.96
453.0000	WHIRLPOOL CORP	38,455.39	191.6200	86,803.86	48,348.47
1,862.0000	WHITESTONE REIT	22,101.45	12.2500	22,809.50	708.05
2,010.0000	WHITING PETROLEUM CORP	23,617.50	5.5100	11,075.10	12,542.40-
1,035.0000	WHOLE FOODS MARKET INC	31,106.44	42.1100	43,583.85	12,477.41
3,711.0000	WILLIAMS COS INC/THE	72,216.83	30.2800	112,369.08	40,152.25
553.0000	WILLIAMS-SONOMA INC	19,887.91	48.5000	26,820.50	6,932.59
390.0000	WINTRUST FINANCIAL CORP	11,633.70	76.4400	29,811.60	18,177.90
2,098.0000	WISDOMTREE INVESTMENTS INC	22,511.54	10.1700	21,336.66	1,174.88-
248.0000	WOLVERINE WORLD WIDE INC	5,023.24	28.0100	6,946.48	1,923.24
365.0000	WOODWARD INC	11,815.05	67.5800	24,666.70	12,851.65
490.0000	WORKDAY INC	39,316.22	97.0000	47,530.00	8,213.78

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227.0000	WORLD FUEL SERVICES CORP	7,792.91	38.4500	8,728.15	935.24
342.0000	WORTHINGTON INDUSTRIES INC	6,730.56	50.2200	17,175.24	10,444.68
2,203.0000	WPX ENERGY INC	26,735.91	9.6600	21,280.98	5,454.93-
1,042.0000	WYNDHAM WORLDWIDE CORP	37,453.86	100.4100	104,627.22	67,173.36
450.0000	WYNN RESORTS LTD	42,630.70	134.1200	60,354.00	17,723.30
896.0000	XPO LOGISTICS INC	20,590.08	64.6300	57,908.48	37,318.40
1,678.0000	XILINX INC	42,099.64	64.3200	107,928.96	65,829.32
1,610.0000	XEROX CORP	36,708.96	28.7300	46,255.30	9,546.34
950.0000	XYLEM INC/NY	24,870.03	55.4300	52,658.50	27,788.47
265.0000	XPERI CORP	4,285.05	29.8000	7,897.00	3,611.95
2,560.0000	YELP INC	67,315.64	30.0200	76,851.20	9,535.56
503.0000	YORK WATER CO/THE	8,910.09	34.8500	17,529.55	8,619.46
1,359.0000	YUM! BRANDS INC	25,416.78	73.7600	100,239.84	74,823.06
1,359.0000	YUM CHINA HOLDINGS INC	10,352.57	39.4300	53,585.37	43,232.80
848.0000	ZAYO GROUP HOLDINGS INC	22,285.44	30.9000	26,203.20	3,917.76
745.0000	ZEBRA TECHNOLOGIES CORP	22,305.30	100.5200	74,887.40	52,582.10
644.0000	ZILLOW GROUP INC	13,458.53	49.0100	31,562.44	18,103.91

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1,270.0000	ZIMMER BIOMET HOLDINGS INC	82,266.71	128.4000	163,068.00	80,801.29
1,713.0000	ZIONS BANCORPORATION	26,568.63	43.9100	75,217.83	48,649.20
1,157.0000	ZOETIS INC	55,316.17	62.3800	72,173.66	16,857.49
3,400.0000	ZYNGA INC	8,364.00	3.6400	12,376.00	4,012.00
TOTAL INVESTMENTS EQUITY		65,498,605.14		133,257,265.03	67,758,659.89
TOTAL INVESTMENT		65,716,966.84		133,475,626.73	67,758,659.89

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INVESTMENTS CASH EQUIVALENTS					
227,600.3600	BLACKROCK LIQ T FUND INSTL FUND 60	227,600.36	100.0000	227,600.36	0.00
TOTAL INVESTMENTS CASH EQUIVALENTS		227,600.36		227,600.36	0.00
INVESTMENTS FIXED INCOME SECURITIES					
115,507.8900	ADVANCED DISPOSAL 10/16 COV-LITE TLB	115,507.89	100.3040	115,859.03	351.14
100,000.0000	AES CORP/VA 4.875% 05/15/2023 DD 04/30/13	101,275.92	101.8750	101,875.00	599.08
100,000.0000	AES CORP/VA 5.500% 04/15/2025 DD 04/06/15	99,180.21	104.6250	104,625.00	5,444.79
25,000.0000	AK STEEL CORP 7.000% 03/15/2027 DD 03/23/17	25,000.00	103.2500	25,812.50	812.50
100,000.0000	AMC NETWORKS INC 5.000% 04/01/2024 DD 03/30/16	100,000.00	102.3750	102,375.00	2,375.00
25,000.0000	AMN HEALTHCARE INC 144A 5.125% 10/01/2024 DD 10/03/16	25,000.00	101.2500	25,312.50	312.50
75,000.0000	AMERICAN TIRE DISTRIBUTOR 144A 10.250% 03/01/2022 DD 02/25/15	68,794.90	103.5000	77,625.00	8,830.10
50,000.0000	ACADIA HEALTHCARE CO INC 6.500% 03/01/2024 DD 02/16/16	50,086.97	106.7500	53,375.00	3,288.03

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50,000.0000	AECOM 5.750% 10/15/2022 DD 10/15/15	49,947.41	104.6250	52,312.50	2,365.09
50,000.0000	AECOM 5.875% 10/15/2024 DD 10/15/15	49,344.00	108.7500	54,375.00	5,031.00
50,000.0000	AECOM 5.125% 03/15/2027 DD 02/21/17	50,000.00	100.3750	50,187.50	187.50
50,000.0000	ADVANCED DISPOSAL SERVICE 144A 5.625% 11/15/2024 DD 11/10/16	50,000.00	103.0000	51,500.00	1,500.00
100,000.0000	ALBERTSONS COS LLC / SAFE 144A 5.750% 03/15/2025 DD 08/09/16	100,000.00	93.0000	93,000.00	7,000.00-
100,000.0000	ALLIANCE DATA SYSTEMS COR 144A 5.250% 12/01/2017 DD 11/20/12	100,454.95	100.7500	100,750.00	295.05
50,000.0000	ALLIANCE DATA SYSTEMS COR 144A 5.875% 11/01/2021 DD 10/27/16	50,000.00	103.5000	51,750.00	1,750.00
50,000.0000	ALLY FINANCIAL INC 4.750% 09/10/2018 DD 09/09/13	51,363.70	102.7500	51,375.00	11.30
100,000.0000	ALLY FINANCIAL INC 4.625% 05/19/2022 DD 05/19/15	99,567.96	104.0000	104,000.00	4,432.04
25,000.0000	ALPHA 3 BV / ALPHA US BID 144A 6.250% 02/01/2025 DD 01/31/17	25,000.00	102.8750	25,718.75	718.75
30,000.0000	ALPINE FINANCE MERGER SUB 144A 6.875% 08/01/2025 DD 07/12/17	30,000.00	101.7500	30,525.00	525.00

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200,000.0000	ALTICE LUXEMBOURG SA 144A 7.750% 05/15/2022 DD 05/08/14	210,424.00	106.1250	212,250.00	1,826.00
45,000.0000	AMERICAN AXLE & MANUFACTURING 7.750% 11/15/2019 DD 11/03/11	49,667.47	109.7500	49,387.50	279.97-
25,000.0000	AMERICAN AXLE & MANUFACTU 144A 6.250% 04/01/2025 DD 03/23/17	25,000.00	97.5000	24,375.00	625.00-
25,000.0000	AMERICAN AXLE & MANUFACTU 144A 6.500% 04/01/2027 DD 03/23/17	25,000.00	97.2500	24,312.50	687.50-
52,000.0000	AMERICAN BUILDERS & CONTR 144A 5.625% 04/15/2021 DD 04/16/13	52,308.63	102.8750	53,495.00	1,186.37
25,000.0000	AMERIGAS PARTNERS LP / AMERIGA 5.750% 05/20/2027 DD 02/13/17	25,000.00	101.2500	25,312.50	312.50
13,500.0000	ANCESTRY.COM 10/16 2ND LIEN COV-LITE TL	13,372.43	102.0830	13,781.21	408.78
19,800.0000	ANCESTRY.COM 2/17 TL	19,710.53	100.3330	19,865.93	155.40
75,000.0000	ANGLO AMERICAN CAPITAL PL 144A 9.375% 04/08/2019 DD 04/08/09	84,390.42	111.8750	83,906.25	484.17-
100,000.0000	ARAMARK SERVICES INC 5.125% 01/15/2024 DD 12/17/15	100,000.00	105.1250	105,125.00	5,125.00
400,000.0000	ARDAGH PACKAGING FINANCE 144A 6.000% 02/15/2025 DD 01/30/17	404,848.81	105.0000	420,000.00	15,151.19
200,000.0000	PETSMART INC 144A 7.125% 03/15/2023 DD 03/04/15	201,880.15	89.0000	178,000.00	23,880.15-

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25,000.0000	ASCENT RESOURCES UTICA HO 144A 10.000% 04/01/2022 DD 04/05/17	25,000.00	100.0000	25,000.00	0.00
100,000.0000	BASS PRO SHOPS 11/16 COV-LITE TLB	99,042.86	97.0500	97,050.00	1,992.86-
150,000.0000	BAYTEX ENERGY CORP 144A 5.125% 06/01/2021 DD 06/06/14	134,446.14	88.7500	133,125.00	1,321.14-
25,000.0000	BLOCK COMMUNICATIONS INC 144A 6.875% 02/15/2025 DD 02/16/17	25,000.00	107.2500	26,812.50	1,812.50
100,000.0000	BLUE RACER MIDSTREAM LLC 144A 6.125% 11/15/2022 DD 11/13/14	101,152.67	100.7500	100,750.00	402.67-
125,000.0000	BLUESCOPE STEEL FINANCE L 144A 6.500% 05/15/2021 DD 05/05/16	132,504.85	105.5000	131,875.00	629.85-
50,000.0000	BOMBARDIER INC 144A 6.000% 10/15/2022 DD 04/03/14	50,121.49	100.0000	50,000.00	121.49-
40,000.0000	BRAND ENERGY & INFRASTRUC 144A 8.500% 07/15/2025 DD 06/21/17	40,000.00	103.5000	41,400.00	1,400.00
105,000.0000	BWAY HOLDING CO 144A 5.500% 04/15/2024 DD 04/03/17	105,000.00	102.1250	107,231.25	2,231.25
105,000.0000	BWAY HOLDING CO 144A 7.250% 04/15/2025 DD 04/03/17	105,000.00	101.5000	106,575.00	1,575.00
50,000.0000	CCO HOLDINGS LLC / CCO HO 144A 5.875% 04/01/2024 DD 02/19/16	50,000.00	106.7500	53,375.00	3,375.00

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200,000.0000	CCO HOLDINGS LLC / CCO HO 144A 5.125% 05/01/2027 DD 02/06/17	199,756.07	102.2500	204,500.00	4,743.93
50,000.0000	CBS RADIO INC 144A 7.250% 11/01/2024 DD 10/17/16	50,999.40	103.0000	51,500.00	500.60
25,000.0000	OUTFRONT MEDIA CAPITAL LLC / O 5.625% 02/15/2024 DD 11/15/14	25,000.00	104.3750	26,093.75	1,093.75
100,000.0000	CDW LLC / CDW FINANCE CORP 5.000% 09/01/2023 DD 03/03/15	100,562.60	104.1250	104,125.00	3,562.40
100,000.0000	CHS/COMMUNITY HEALTH SYSTEMS I 6.250% 03/31/2023 DD 03/16/17	100,429.56	103.2350	103,235.00	2,805.44
25,000.0000	CNH INDUSTRIAL CAPITAL LLC 4.375% 04/05/2022 DD 04/10/17	25,000.00	104.6500	26,162.50	1,162.50
45,000.0000	CTR PARTNERSHIP LP / CARETRUST 5.250% 06/01/2025 DD 05/24/17	45,000.00	103.0000	46,350.00	1,350.00
100,000.0000	CST BRANDS INC 5.000% 05/01/2023 DD 11/01/13	100,204.20	105.0200	105,020.00	4,815.80
75,000.0000	CABLEVISION SYSTEMS CORP 7.750% 04/15/2018 DD 04/15/10	75,058.13	103.7500	77,812.50	2,754.37
50,000.0000	CABLEVISION SYSTEMS CORP 8.000% 04/15/2020 DD 04/15/10	55,482.67	111.3750	55,687.50	204.83
100,000.0000	CABLEVISION SYSTEMS CORP 5.875% 09/15/2022 DD 09/27/12	85,857.59	105.1250	105,125.00	19,267.41

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25,000.0000	CALATLANTIC GROUP INC 5.000% 06/15/2027 DD 06/09/17	25,000.00	100.2500	25,062.50	62.50
50,000.0000	CALPINE CORP 5.375% 01/15/2023 DD 07/22/14	50,000.00	97.5000	48,750.00	1,250.00-
100,000.0000	CALPINE CORP 144A 5.250% 06/01/2026 DD 05/31/16	100,000.00	98.0000	98,000.00	2,000.00-
50,000.0000	CAMELOT FINANCE SA 144A 7.875% 10/15/2024 DD 10/03/16	50,000.00	107.7500	53,875.00	3,875.00
50,000.0000	CENTENE CORP 4.750% 05/15/2022 DD 04/29/14	50,734.80	104.3750	52,187.50	1,452.70
100,000.0000	CENTENE CORP 4.750% 01/15/2025 DD 11/09/16	100,000.00	102.7500	102,750.00	2,750.00
175,000.0000	CENTURYLINK INC 5.625% 04/01/2025 DD 10/01/15	175,000.00	99.8330	174,707.75	292.25-
132,000.0000	CEQUEL COMMUNICATIONS HOL 144A 6.375% 09/15/2020 DD 10/25/12	128,966.50	102.0000	134,640.00	5,673.50
50,000.0000	CHANGE HEALTHCARE HOLDING 144A 5.750% 03/01/2025 DD 02/15/17	50,000.00	102.0000	51,000.00	1,000.00
50,000.0000	CHENIERE CORPUS CHRISTI HOLDIN 5.875% 03/31/2025 DD 12/09/16	50,000.00	106.6250	53,312.50	3,312.50
50,000.0000	CHENIERE CORPUS CHRISTI H 144A 5.125% 06/30/2027 DD 05/19/17	50,000.00	102.5000	51,250.00	1,250.00

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61,000.0000	CHESAPEAKE ENERGY CORP 144A 8.000% 12/15/2022 DD 12/23/15	62,521.85	105.7500	64,507.50	1,985.65
150,000.0000	CHURCHILL DOWNS INC 5.375% 12/15/2021 DD 12/16/13	151,153.62	103.7500	155,625.00	4,471.38
100,000.0000	FRONTIER COMMUNICATIONS CORP 7.125% 03/15/2019 DD 03/23/07	103,168.58	104.2500	104,250.00	1,081.42
100,000.0000	CLEAR CHANNEL WORLDWIDE HOLDIN 6.500% 11/15/2022 DD 05/15/13	103,349.64	102.7700	102,770.00	579.64-
50,000.0000	COGENT COMMUNICATIONS GRO 144A 5.375% 03/01/2022 DD 02/20/15	50,168.50	105.0000	52,500.00	2,331.50
100,000.0000	COMMSCOPE TECHNOLOGIES LL 144A 6.000% 06/15/2025 DD 06/11/15	100,000.00	106.7500	106,750.00	6,750.00
25,000.0000	UNITI GROUP INC / CSL CAP 144A 7.125% 12/15/2024 DD 12/15/16	25,000.00	99.2820	24,820.50	179.50-
50,000.0000	COTT HOLDINGS INC 144A 5.500% 04/01/2025 DD 03/22/17	50,000.00	102.0000	51,000.00	1,000.00
15,000.0000	COVANTA HOLDING CORP 5.875% 07/01/2025 DD 03/16/17	15,000.00	97.0000	14,550.00	450.00-
50,000.0000	CRESTWOOD MIDSTREAM PARTN 144A 5.750% 04/01/2025 DD 03/14/17	50,000.00	99.7500	49,875.00	125.00-
150,000.0000	CROWNROCK LP / CROWNROCK 144A 7.125% 04/15/2021 DD 04/15/13	140,035.47	102.7500	154,125.00	14,089.53

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25,000.0000	CYRUSONE LP / CYRUSONE FI 144A 5.000% 03/15/2024 DD 03/17/17	25,000.00	103.0000	25,750.00	750.00
15,000.0000	CYRUSONE LP / CYRUSONE FI 144A 5.375% 03/15/2027 DD 03/17/17	15,000.00	104.1250	15,618.75	618.75
100,000.0000	DANA INC 5.375% 09/15/2021 DD 08/02/13	102,411.61	102.8750	102,875.00	463.39
155,000.0000	DAVITA INC 5.750% 08/15/2022 DD 08/28/12	160,025.52	102.7500	159,262.50	763.02-
75,000.0000	DENBURY RESOURCES INC 144A 9.000% 05/15/2021 DD 05/10/16	78,309.44	95.2500	71,437.50	6,871.94-
200,000.0000	DISH DBS CORP 7.875% 09/01/2019 DD 08/17/09	200,801.69	110.2500	220,500.00	19,698.31
50,000.0000	DISH DBS CORP 5.875% 07/15/2022 DD 05/16/12	50,961.74	107.5000	53,750.00	2,788.26
25,000.0000	DOLE FOOD CO INC 144A 7.250% 06/15/2025 DD 04/06/17	25,000.00	104.0000	26,000.00	1,000.00
125,000.0000	RR DONNELLEY & SONS CO 6.000% 04/01/2024 DD 03/20/14	123,564.98	97.3750	121,718.75	1,846.23-
100,000.0000	DYNEGY INC 5.875% 06/01/2023 DD 12/01/13	98,887.86	93.5000	93,500.00	5,387.86-
100,000.0000	DYNEGY INC 7.375% 11/01/2022 DD 05/01/15	99,442.13	98.7500	98,750.00	692.13-

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
75,000.0000	EMC CORP 2.650% 06/01/2020 DD 06/06/13	72,871.01	98.1230	73,592.25	721.24
25,000.0000	ELDORADO RESORTS INC 144A 6.000% 04/01/2025 DD 03/29/17	25,000.00	106.0000	26,500.00	1,500.00
150,000.0000	ENDO FINANCE LLC / ENDO F 144A VAR RT 01/15/2022 DD 05/06/14	151,966.14	95.7500	143,625.00	8,341.14-
25,000.0000	ENPRO INDUSTRIES INC 144A 5.875% 09/15/2022 DD 03/15/17	25,239.17	104.2500	26,062.50	823.33
150,000.0000	ENTEGRIS INC 144A 6.000% 04/01/2022 DD 04/01/14	150,000.00	104.6250	156,937.50	6,937.50
50,000.0000	EQUINIX INC 5.375% 05/15/2027 DD 03/22/17	50,000.00	106.6250	53,312.50	3,312.50
100,000.0000	TRONOX FINANCE LLC 144A 7.500% 03/15/2022 DD 03/19/15	100,000.00	103.0000	103,000.00	3,000.00
50,000.0000	EXTRACTION OIL & GAS INC 144A 7.875% 07/15/2021 DD 07/18/16	50,000.00	102.7500	51,375.00	1,375.00
25,000.0000	FMG RESOURCES AUGUST 2006 144A 4.750% 05/15/2022 DD 05/12/17	25,000.00	100.3750	25,093.75	93.75
50,000.0000	FMG RESOURCES AUGUST 2006 144A 5.125% 05/15/2024 DD 05/12/17	50,000.00	100.0000	50,000.00	0.00
150,000.0000	FTI CONSULTING INC 6.000% 11/15/2022 DD 05/15/13	150,000.00	103.7500	155,625.00	5,625.00

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
100,000.0000	FELCOR LODGING LP 5.625% 03/01/2023 DD 03/01/13	100,000.00	103.7500	103,750.00	3,750.00
75,000.0000	FERRELLGAS LP / FERRELLGAS FIN VAR RT 06/15/2023 DD 06/15/16	75,000.00	93.2500	69,937.50	5,062.50-
125,000.0000	FIRST DATA CORP 144A 5.375% 08/15/2023 DD 08/11/15	125,000.00	104.5000	130,625.00	5,625.00
150,000.0000	FIRST QUALITY FINANCE CO 144A 4.625% 05/15/2021 DD 05/14/13	150,000.00	100.8750	151,312.50	1,312.50
10,000.0000	FIRSTCASH INC 144A 5.375% 06/01/2024 DD 05/30/17	10,000.00	104.3750	10,437.50	437.50
50,000.0000	FLEX ACQUISITION CO INC 144A 6.875% 01/15/2025 DD 01/17/17	50,000.00	104.0000	52,000.00	2,000.00
125,000.0000	FREEPORT-MCMORAN INC 3.875% 03/15/2023 DD 09/15/13	115,525.99	93.0000	116,250.00	724.01
15,000.0000	FRESENIUS MEDICAL CARE US 144A 5.625% 07/31/2019 DD 01/26/12	15,981.08	105.7500	15,862.50	118.58-
150,000.0000	FRESENIUS US FINANCE II I 144A 4.500% 01/15/2023 DD 09/25/15	150,000.00	105.0000	157,500.00	7,500.00
100,000.0000	FRONTIER COMMUNICATIONS CORP 7.125% 01/15/2023 DD 08/15/12	93,796.60	83.2500	83,250.00	10,546.60-
75,000.0000	GFL ENVIRONMENTAL INC 144A 5.625% 05/01/2022 DD 05/12/17	75,243.94	102.2500	76,687.50	1,443.56

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
100,000.0000	TEGNA INC 5.125% 07/15/2020 DD 07/29/13	102,888.85	102.5000	102,500.00	388.85-
200,000.0000	GARDA WORLD SECURITY CORP 144A 7.250% 11/15/2021 DD 11/08/13	203,505.90	101.1250	202,250.00	1,255.90-
100,000.0000	GENESIS ENERGY LP / GENESIS EN 6.000% 05/15/2023 DD 05/21/15	100,000.00	98.0000	98,000.00	2,000.00-
175,000.0000	GIBSON ENERGY INC 144A 6.750% 07/15/2021 DD 06/28/13	173,503.55	103.2500	180,687.50	7,183.95
150,000.0000	GOODYEAR TIRE & RUBBER CO/THE 5.000% 05/31/2026 DD 05/13/16	150,000.00	103.5000	155,250.00	5,250.00
45,000.0000	GOODYEAR TIRE & RUBBER CO/THE 4.875% 03/15/2027 DD 03/07/17	45,000.00	101.5000	45,675.00	675.00
93,720.9246	WHEELABRATOR TECHNOLOGIES 10/14 TLB	92,289.75	100.3750	94,072.38	1,782.63
1,372.5800	WHEELABRATOR TECHNOLOGIES 10/14 TLC	1,351.61	100.3750	1,377.73	26.12
25,000.0000	GENESYS TELECOMMUNICATION 144A 10.000% 11/30/2024 DD 12/01/16	25,000.00	112.3750	28,093.75	3,093.75
49,749.9800	GENESYS 1/17 (USD) COV-LT TLB 0.000% 12/01/2023 DD 01/09/17	49,105.86	100.2250	49,861.92	756.06
100,000.0000	GRINDING MEDIA INC / MOLY 144A 7.375% 12/15/2023 DD 12/16/16	100,445.45	108.7500	108,750.00	8,304.55

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
200,000.0000	GROUP 1 AUTOMOTIVE INC VAR RT 06/01/2022 DD 06/01/15	200,693.59	101.5000	203,000.00	2,306.41
25,000.0000	GULFPORT ENERGY CORP 144A 6.000% 10/15/2024 DD 10/14/16	25,000.00	97.2500	24,312.50	687.50-
100,000.0000	GULFPORT ENERGY CORP 144A 6.375% 05/15/2025 DD 12/21/16	100,000.00	98.5000	98,500.00	1,500.00-
100,000.0000	HCA INC 4.500% 02/15/2027 DD 08/15/16	100,116.62	102.8750	102,875.00	2,758.38
100,000.0000	HCA INC 5.500% 06/15/2047 DD 06/22/17	100,000.00	103.5000	103,500.00	3,500.00
150,000.0000	HCA INC 6.500% 02/15/2020 DD 08/01/11	163,844.46	109.1250	163,687.50	156.96-
150,000.0000	HCA INC 5.875% 05/01/2023 DD 10/23/12	162,114.20	108.8750	163,312.50	1,198.30
100,000.0000	HD SUPPLY INC 144A 5.750% 04/15/2024 DD 04/11/16	100,000.00	106.2500	106,250.00	6,250.00
150,000.0000	HALYARD HEALTH INC 6.250% 10/15/2022 DD 04/15/15	150,000.00	104.2500	156,375.00	6,375.00
50,000.0000	HERTZ CORP/THE 5.875% 10/15/2020 DD 10/16/12	50,512.85	96.7500	48,375.00	2,137.85-
50,000.0000	HERTZ CORP/THE 144A 7.625% 06/01/2022 DD 06/06/17	50,000.00	99.7600	49,880.00	120.00-

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
84,000.0000	HERC RENTALS INC 144A 7.500% 06/01/2022 DD 06/09/16	84,000.00	105.5000	88,620.00	4,620.00
25,000.0000	HILL-ROM HOLDINGS INC 144A 5.000% 02/15/2025 DD 02/14/17	25,000.00	102.0000	25,500.00	500.00
50,000.0000	HOLLY ENERGY PARTNERS LP 144A 6.000% 08/01/2024 DD 07/19/16	50,000.00	104.0000	52,000.00	2,000.00
115,000.0000	HOLOGIC INC 144A 5.250% 07/15/2022 DD 07/02/15	115,000.00	105.0000	120,750.00	5,750.00
125,000.0000	HUNTSMAN INTERNATIONAL LLC 4.875% 11/15/2020 DD 11/19/12	130,746.06	105.2500	131,562.50	816.44
200,000.0000	INFOR US INC 6.500% 05/15/2022 DD 11/15/15	202,668.83	103.5000	207,000.00	4,331.17
250,000.0000	INMARSAT FINANCE PLC 144A 4.875% 05/15/2022 DD 06/04/14	241,077.72	101.5000	253,750.00	12,672.28
50,000.0000	INTELSAT JACKSON HOLDINGS SA 7.250% 04/01/2019 DD 10/01/11	43,157.12	100.0250	50,012.50	6,855.38
50,000.0000	INTELSAT JACKSON HOLDINGS SA 7.500% 04/01/2021 DD 10/01/11	41,503.42	92.2500	46,125.00	4,621.58
75,000.0000	INTELSAT JACKSON HOLDINGS SA 5.500% 08/01/2023 DD 06/05/13	63,745.58	82.7500	62,062.50	1,683.08-
75,000.0000	INVENTIV GROUP HOLDINGS I 144A 7.500% 10/01/2024 DD 10/14/16	75,000.00	108.5000	81,375.00	6,375.00

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
150,000.0000	IRON MOUNTAIN INC 6.000% 08/15/2023 DD 08/13/13	153,267.78	106.2500	159,375.00	6,107.22
50,000.0000	PATHEON HOLDINGS I BV 144A 7.500% 02/01/2022 DD 02/05/14	52,911.15	106.2500	53,125.00	213.85
20,000.0000	J2 CLOUD SERVICES LLC / J 144A 6.000% 07/15/2025 DD 06/27/17	20,000.00	103.0000	20,600.00	600.00
25,000.0000	RP CROWN PARENT LLC 144A 7.375% 10/15/2024 DD 10/06/16	25,000.00	104.0000	26,000.00	1,000.00
10,000.0000	JONAH ENERGY 5/14 COV-LITE 2ND LIEN TL	9,700.00	95.1670	9,516.70	183.30-
50,000.0000	JUPITER RESOURCES INC 144A 8.500% 10/01/2022 DD 09/18/14	48,478.46	75.0000	37,500.00	10,978.46-
125,000.0000	KFC HOLDING CO/PIZZA HUT 144A 5.000% 06/01/2024 DD 06/16/16	125,000.00	104.2500	130,312.50	5,312.50
25,000.0000	KFC HOLDING CO/PIZZA HUT 144A 4.750% 06/01/2027 DD 06/15/17	25,000.00	102.1250	25,531.25	531.25
100,000.0000	KLX INC 144A 5.875% 12/01/2022 DD 12/08/14	100,000.00	105.0000	105,000.00	5,000.00
15,000.0000	KINROSS GOLD CORP 144A 4.500% 07/15/2027 DD 07/06/17	15,000.00	99.7500	14,962.50	37.50-
25,000.0000	KOPPERS INC 144A 6.000% 02/15/2025 DD 01/25/17	25,000.00	106.2500	26,562.50	1,562.50

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25,000.0000	KRONOS ACQUISITION HOLDIN 144A 9.000% 08/15/2023 DD 08/26/15	25,682.17	99.7500	24,937.50	744.67-
100,000.0000	LENNAR CORP VAR RT 12/01/2018 DD 02/04/13	102,221.27	102.2500	102,250.00	28.73
50,000.0000	LENNAR CORP 4.500% 04/30/2024 DD 04/28/17	50,000.00	103.3600	51,680.00	1,680.00
50,000.0000	LIONS GATE ENTERTAINMENT 144A 5.875% 11/01/2024 DD 10/27/16	50,477.16	105.2500	52,625.00	2,147.84
75,000.0000	MDC PARTNERS INC 144A 6.500% 05/01/2024 DD 03/23/16	75,000.00	99.7500	74,812.50	187.50-
50,000.0000	MGM RESORTS INTERNATIONAL 6.750% 10/01/2020 DD 04/01/13	53,756.69	110.7900	55,395.00	1,638.31
200,000.0000	MPH ACQUISITION HOLDINGS 144A 7.125% 06/01/2024 DD 06/07/16	200,000.00	106.6250	213,250.00	13,250.00
175,000.0000	MSCI INC 144A 5.750% 08/15/2025 DD 08/13/15	176,253.69	108.3120	189,546.00	13,292.31
25,000.0000	MALLINCKRODT INTERNATIONA 144A 5.500% 04/15/2025 DD 04/15/15	25,000.00	87.5000	21,875.00	3,125.00-
150,000.0000	MEDIACOM BROADBAND LLC / MEDIA 5.500% 04/15/2021 DD 03/17/14	150,000.00	102.2500	153,375.00	3,375.00
100,000.0000	MICRON TECHNOLOGY INC 144A 5.250% 01/15/2024 DD 04/30/15	100,000.00	103.5000	103,500.00	3,500.00

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
50,000.0000	MIDAS INTERMEDIATE HOLDCO 144A 7.875% 10/01/2022 DD 09/24/14	50,441.03	103.0000	51,500.00	1,058.97
175,000.0000	MIDCONTINENT COMMUNICATIO 144A 6.875% 08/15/2023 DD 08/14/15	176,262.82	107.7500	188,562.50	12,299.68
65,000.0000	MOLINA HEALTHCARE INC VAR RT 11/15/2022 DD 05/15/16	65,000.00	105.8750	68,818.75	3,818.75
25,000.0000	MOLINA HEALTHCARE INC 144A 4.875% 06/15/2025 DD 06/06/17	25,000.00	100.7500	25,187.50	187.50
150,000.0000	NATURE'S BOUNTY CO/THE 144A 7.625% 05/15/2021 DD 05/05/16	150,000.00	106.2500	159,375.00	9,375.00
125,000.0000	NCR CORP 4.625% 02/15/2021 DD 02/15/13	125,189.60	102.0000	127,500.00	2,310.40
75,000.0000	NGL ENERGY PARTNERS LP / 144A 7.500% 11/01/2023 DD 10/24/16	75,000.00	98.6250	73,968.75	1,031.25-
75,000.0000	NGL ENERGY PARTNERS LP / 144A 6.125% 03/01/2025 DD 02/22/17	75,000.00	91.5000	68,625.00	6,375.00-
150,000.0000	NRG ENERGY INC 6.625% 03/15/2023 DD 03/15/13	151,520.94	102.7500	154,125.00	2,604.06
150,000.0000	NRG ENERGY INC 6.250% 07/15/2022 DD 07/15/14	153,289.77	102.6250	153,937.50	647.73
300,000.0000	NAVISTAR INTERNATIONAL CORP 8.250% 11/01/2021 DD 10/28/09	302,897.07	101.0000	303,000.00	102.93

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50,000.0000	NAVIENT CORP 5.000% 10/26/2020 DD 11/06/14	50,000.00	103.7500	51,875.00	1,875.00
75,000.0000	NAVIENT CORP 7.250% 09/25/2023 DD 09/16/16	74,912.84	107.7500	80,812.50	5,899.66
70,000.0000	NAVIENT CORP 6.500% 06/15/2022 DD 03/07/17	70,469.37	106.0000	74,200.00	3,730.63
200,000.0000	CSC HOLDINGS LLC 144A 10.875% 10/15/2025 DD 10/09/15	200,000.00	120.3750	240,750.00	40,750.00
75,000.0000	NFP CORP 144A 6.875% 07/15/2025 DD 07/12/17	75,000.00	101.0000	75,750.00	750.00
75,000.0000	NIELSEN FINANCE LLC / NIELSEN 4.500% 10/01/2020 DD 04/01/13	76,605.52	101.5280	76,146.00	459.52-
50,000.0000	NIELSEN FINANCE LLC / NIE 144A 5.000% 04/15/2022 DD 04/11/14	50,501.82	103.7500	51,875.00	1,373.18
50,000.0000	NOVA CHEMICALS CORP 144A 4.875% 06/01/2024 DD 06/09/17	50,000.00	99.6250	49,812.50	187.50-
25,000.0000	NOVA CHEMICALS CORP 144A 5.250% 06/01/2027 DD 06/09/17	25,000.00	99.5000	24,875.00	125.00-
200,000.0000	NOVELIS CORP 144A 6.250% 08/15/2024 DD 08/29/16	200,000.00	105.0000	210,000.00	10,000.00
21,000.0000	NUANCE COMMUNICATIONS INC 144A 5.375% 08/15/2020 DD 08/14/12	21,379.99	101.6250	21,341.25	38.74-

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25,000.0000	NUANCE COMMUNICATIONS INC 144A 5.625% 12/15/2026 DD 12/22/16	24,774.92	106.7500	26,687.50	1,912.58
200,000.0000	SFR GROUP SA 144A 6.000% 05/15/2022 DD 05/08/14	203,679.25	104.6250	209,250.00	5,570.75
200,000.0000	OASIS PETROLEUM INC 6.500% 11/01/2021 DD 11/10/11	195,688.39	97.0000	194,000.00	1,688.39-
25,000.0000	1011778 BC ULC / NEW RED 144A 4.250% 05/15/2024 DD 05/17/17	25,000.00	99.3690	24,842.25	157.75-
125,000.0000	ORBITAL ATK INC 5.500% 10/01/2023 DD 04/01/16	125,000.00	105.2500	131,562.50	6,562.50
25,000.0000	ORCHESTRA BORROWER LLC / 144A 6.750% 06/15/2022 DD 06/16/17	25,000.00	103.0400	25,760.00	760.00
50,000.0000	PTC INC 6.000% 05/15/2024 DD 05/12/16	50,000.00	108.2500	54,125.00	4,125.00
25,000.0000	PARK AEROSPACE HOLDINGS L 144A 5.250% 08/15/2022 DD 02/03/17	25,000.00	104.5320	26,133.00	1,133.00
25,000.0000	PARK AEROSPACE HOLDINGS L 144A 5.500% 02/15/2024 DD 02/03/17	25,000.00	104.4500	26,112.50	1,112.50
25,000.0000	PEABODY ENERGY CORP 144A 6.375% 03/31/2025 DD 02/15/17	25,000.00	98.5000	24,625.00	375.00-
150,000.0000	PENSKE AUTOMOTIVE GROUP INC 5.750% 10/01/2022 DD 04/01/13	150,481.37	103.2500	154,875.00	4,393.63

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50,000.0000	PETSMART INC 144A 5.875% 06/01/2025 DD 05/31/17	50,000.00	96.3750	48,187.50	1,812.50-
150,000.0000	PLATFORM SPECIALTY PRODUC 144A 6.500% 02/01/2022 DD 02/02/15	143,823.05	103.2500	154,875.00	11,051.95
150,000.0000	POLYONE CORP 5.250% 03/15/2023 DD 09/15/13	150,360.72	105.0000	157,500.00	7,139.28
50,000.0000	QUEBECOR MEDIA INC 5.750% 01/15/2023 DD 12/15/12	50,000.00	105.5000	52,750.00	2,750.00
100,000.0000	RSI HOME PRODUCTS INC 144A 6.500% 03/15/2023 DD 03/16/15	100,000.00	105.2500	105,250.00	5,250.00
75,000.0000	RADIATE HOLDCO LLC / RADI 144A 6.625% 02/15/2025 DD 02/01/17	75,140.47	100.0000	75,000.00	140.47-
100,000.0000	RANGE RESOURCES CORP 4.875% 05/15/2025 DD 11/15/15	90,428.30	95.0000	95,000.00	4,571.70
100,000.0000	REALOGY GROUP LLC / REALO 144A 4.500% 04/15/2019 DD 04/07/14	101,744.51	103.2500	103,250.00	1,505.49
100,000.0000	REGIONALCARE HOSPITAL PAR 144A 8.250% 05/01/2023 DD 04/29/16	103,194.05	107.2500	107,250.00	4,055.95
64,813.5500	REYNOLDS GROUP ISSUER INC / RE VAR RT 02/15/2021 DD 02/15/12	66,417.71	102.7500	66,595.92	178.21
50,000.0000	REYNOLDS GROUP ISSUER INC / RE 5.750% 10/15/2020 DD 09/28/12	51,403.63	102.3340	51,167.00	236.63-

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
25,000.0000	ROCKIES EXPRESS PIPELINE 144A 6.000% 01/15/2019 DD 01/17/13	26,232.69	104.2500	26,062.50	170.19-
5,000.0000	SBA COMMUNICATIONS CORP 4.875% 09/01/2024 DD 03/01/17	4,962.68	101.7500	5,087.50	124.82
175,000.0000	SESI LLC 6.375% 05/01/2019 DD 11/01/11	161,657.96	98.7500	172,812.50	11,154.54
25,000.0000	NAVIENT CORP 7.250% 01/25/2022 DD 01/27/12	25,518.51	109.2500	27,312.50	1,793.99
150,000.0000	SM ENERGY CO 6.500% 01/01/2023 DD 06/29/12	145,803.00	95.2500	142,875.00	2,928.00-
50,000.0000	SPX FLOW INC 144A 5.625% 08/15/2024 DD 08/10/16	51,158.97	103.0000	51,500.00	341.03
50,000.0000	SEAGATE HDD CAYMAN 144A 4.875% 03/01/2024 DD 02/03/17	49,680.54	101.9210	50,960.50	1,279.96
50,000.0000	SEMGROUP CORP 144A 6.375% 03/15/2025 DD 03/15/17	49,255.63	96.7500	48,375.00	880.63-
125,000.0000	SENSATA TECHNOLOGIES BV 144A 5.000% 10/01/2025 DD 03/26/15	125,000.00	104.5800	130,725.00	5,725.00
100,000.0000	SERVICE CORP INTERNATIONAL/US 7.625% 10/01/2018 DD 10/03/06	100,329.23	106.7500	106,750.00	6,420.77
150,000.0000	SHEA HOMES LP / SHEA HOME 144A 5.875% 04/01/2023 DD 03/23/15	150,000.00	102.9500	154,425.00	4,425.00

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225,000.0000	SIGNODE INDUSTRIAL GROUP 144A 6.375% 05/01/2022 DD 04/29/14	224,271.37	104.5000	235,125.00	10,853.63
125,000.0000	SIRIUS XM RADIO INC 144A 6.000% 07/15/2024 DD 05/06/14	127,489.88	106.2500	132,812.50	5,322.62
25,000.0000	SIRIUS XM RADIO INC 144A 5.000% 08/01/2027 DD 07/05/17	25,000.00	100.7500	25,187.50	187.50
40,000.0000	SIX FLAGS ENTERTAINMENT C 144A 4.875% 07/31/2024 DD 06/16/16	39,610.15	100.6120	40,244.80	634.65
25,000.0000	SONIC AUTOMOTIVE INC 144A 6.125% 03/15/2027 DD 03/10/17	25,000.00	99.5000	24,875.00	125.00-
25,000.0000	SPECTRUM BRANDS INC 6.125% 12/15/2024 DD 12/15/15	25,000.00	107.1250	26,781.25	1,781.25
225,000.0000	SPRINGLEAF FINANCE CORP 6.000% 06/01/2020 DD 12/01/13	220,413.55	105.5000	237,375.00	16,961.45
50,000.0000	SPRINT CAPITAL CORP 6.900% 05/01/2019 DD 05/06/99	53,533.43	106.7450	53,372.50	160.93-
25,000.0000	SPRINT COMMUNICATIONS INC 7.000% 08/15/2020 DD 08/14/12	27,087.18	110.0000	27,500.00	412.82
150,000.0000	SPRINT COMMUNICATIONS INC 6.000% 11/15/2022 DD 11/14/12	135,483.95	106.0000	159,000.00	23,516.05
100,000.0000	SPRINT CORP 7.250% 09/15/2021 DD 09/15/14	83,503.66	111.1250	111,125.00	27,621.34

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100,000.0000	SPRINT CORP 7.875% 09/15/2023 DD 09/15/14	99,433.30	115.0000	115,000.00	15,566.70
100,000.0000	SPRINT CORP 7.125% 06/15/2024 DD 06/15/14	98,155.59	111.2500	111,250.00	13,094.41
25,000.0000	CALATLANTIC GROUP INC 8.375% 05/15/2018 DD 05/03/10	26,359.47	105.1250	26,281.25	78.22-
25,000.0000	STARWOOD PROPERTY TRUST I 144A 5.000% 12/15/2021 DD 12/16/16	25,000.00	104.0000	26,000.00	1,000.00
75,000.0000	STERIGENICS-NORDION TOPCO 144A 8.125% 11/01/2021 DD 11/01/16	75,000.00	102.5000	76,875.00	1,875.00
100,000.0000	SUBURBAN PROPANE PARTNERS LP/S 5.500% 06/01/2024 DD 05/27/14	100,744.16	99.5000	99,500.00	1,244.16-
100,000.0000	SUMMIT MATERIALS LLC / SUMMIT 6.125% 07/15/2023 DD 07/08/15	99,484.27	104.7500	104,750.00	5,265.73
25,000.0000	SUMMIT MIDSTREAM HOLDINGS LLC 5.750% 04/15/2025 DD 02/15/17	25,000.00	100.5000	25,125.00	125.00
50,000.0000	SUNCOKE ENERGY PARTNERS L 144A 7.500% 06/15/2025 DD 05/24/17	49,263.67	98.7500	49,375.00	111.33
50,000.0000	THC ESCROW CORP III 144A 4.625% 07/15/2024 DD 06/14/17	50,000.00	100.2700	50,135.00	135.00
75,000.0000	THC ESCROW CORP III 144A 5.125% 05/01/2025 DD 06/14/17	75,000.00	100.3750	75,281.25	281.25

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50,000.0000	THC ESCROW CORP III 144A 7.000% 08/01/2025 DD 06/14/17	50,000.00	99.6250	49,812.50	187.50-
50,000.0000	T-MOBILE USA INC 6.125% 01/15/2022 DD 11/21/13	52,835.27	105.0940	52,547.00	288.27-
100,000.0000	T-MOBILE USA INC 6.500% 01/15/2026 DD 11/05/15	100,000.00	110.3750	110,375.00	10,375.00
25,000.0000	T-MOBILE USA INC 5.375% 04/15/2027 DD 03/16/17	25,000.00	107.2500	26,812.50	1,812.50
25,000.0000	TRI POINTE GROUP INC 5.250% 06/01/2027 DD 06/08/17	25,000.00	100.2500	25,062.50	62.50
50,000.0000	TALLGRASS ENERGY PARTNERS 144A 5.500% 09/15/2024 DD 09/01/16	50,000.00	101.2500	50,625.00	625.00
145,000.0000	TECK RESOURCES LTD 4.750% 01/15/2022 DD 07/05/11	132,083.50	103.5000	150,075.00	17,991.50
200,000.0000	TELECOM ITALIA SPA/MILANO 144A 5.303% 05/30/2024 DD 05/30/14	198,105.97	107.2500	214,500.00	16,394.03
50,000.0000	TELESAT CANADA / TELESAT 144A 8.875% 11/15/2024 DD 11/17/16	50,000.00	112.2500	56,125.00	6,125.00
50,000.0000	TEMPO ACQUISITION LLC / T 144A 6.750% 06/01/2025 DD 05/01/17	50,000.00	102.2500	51,125.00	1,125.00
75,000.0000	TENET HEALTHCARE CORP 8.125% 04/01/2022 DD 09/27/13	77,924.96	106.1250	79,593.75	1,668.79

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25,000.0000	TENET HEALTHCARE CORP 144A 7.500% 01/01/2022 DD 12/01/16	25,000.00	108.4800	27,120.00	2,120.00
40,000.0000	TENET HEALTHCARE CORP 144A 4.625% 07/15/2024 DD 06/14/17	40,000.00	100.1250	40,050.00	50.00
125,000.0000	TEAM HEALTH HOLDINGS INC 144A 6.375% 02/01/2025 DD 02/01/17	121,896.86	97.0000	121,250.00	646.86-
50,000.0000	TEREX CORP 144A 5.625% 02/01/2025 DD 01/31/17	50,000.00	102.8750	51,437.50	1,437.50
150,000.0000	TESORO LOGISTICS LP / TESORO L 5.500% 10/15/2019 DD 10/15/15	149,091.75	105.5000	158,250.00	9,158.25
250,000.0000	TOWNSQUARE MEDIA INC 144A 6.500% 04/01/2023 DD 04/01/15	250,000.00	100.5000	251,250.00	1,250.00
150,000.0000	TRANSDIGM INC 6.000% 07/15/2022 DD 06/04/14	154,425.55	103.0000	154,500.00	74.45
25,000.0000	TRINIDAD DRILLING LTD 144A 6.625% 02/15/2025 DD 02/08/17	25,000.00	95.0000	23,750.00	1,250.00-
100,000.0000	TRONOX FINANCE LLC 6.375% 08/15/2020 DD 08/15/13	90,926.17	100.2500	100,250.00	9,323.83
25,000.0000	USG CORP 144A 4.875% 06/01/2027 DD 05/15/17	25,000.00	102.8750	25,718.75	718.75
25,000.0000	ULTRA RESOURCES INC 144A 6.875% 04/15/2022 DD 04/12/17	25,000.00	99.2500	24,812.50	187.50-

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25,000.0000	ULTRA RESOURCES INC 144A 7.125% 04/15/2025 DD 04/12/17	24,634.48	98.6250	24,656.25	21.77
25,000.0000	UNITED RENTALS NORTH AMERICA I 5.875% 09/15/2026 DD 05/13/16	26,123.79	106.5000	26,625.00	501.21
50,000.0000	UNITED RENTALS NORTH AMERICA I 5.500% 05/15/2027 DD 11/07/16	50,670.39	103.0000	51,500.00	829.61
25,000.0000	UNITI GROUP INC / UNITI F 144A 7.125% 12/15/2024 DD 12/15/16	25,123.05	99.1250	24,781.25	341.80-
100,000.0000	UNIVERSAL HEALTH SERVICES 144A 4.750% 08/01/2022 DD 08/07/14	101,263.37	103.3750	103,375.00	2,111.63
100,000.0000	UNIVISION COMMUNICATIONS 144A 5.125% 05/15/2023 DD 05/21/13	102,243.15	100.9680	100,968.00	1,275.15-
50,000.0000	UNIVISION COMMUNICATIONS 144A 5.125% 02/15/2025 DD 02/19/15	47,473.74	99.1250	49,562.50	2,088.76
75,000.0000	USIS MERGER SUB INC 144A 6.875% 05/01/2025 DD 04/18/17	75,000.00	101.7500	76,312.50	1,312.50
25,000.0000	VALEANT PHARMACEUTICALS I 144A 6.500% 03/15/2022 DD 03/21/17	25,000.00	104.8750	26,218.75	1,218.75
25,000.0000	VERISIGN INC 144A 4.750% 07/15/2027 DD 07/05/17	25,000.00	101.1250	25,281.25	281.25
200,000.0000	VIASAT INC 6.875% 06/15/2020 DD 06/15/12	201,606.72	101.9680	203,936.00	2,329.28

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150,000.0000	VIKING CRUISES LTD 144A 8.500% 10/15/2022 DD 10/19/12	142,378.71	105.0000	157,500.00	15,121.29
150,000.0000	VISTA OUTDOOR INC 5.875% 10/01/2023 DD 10/01/16	150,000.00	102.7500	154,125.00	4,125.00
150,000.0000	VALEANT PHARMACEUTICALS I 144A 7.500% 07/15/2021 DD 07/12/13	150,000.00	96.8750	145,312.50	4,687.50-
96,000.0000	WMG ACQUISITION CORP 144A 5.625% 04/15/2022 DD 04/09/14	96,120.69	103.5000	99,360.00	3,239.31
50,000.0000	WAVEDIVISION ESCROW LLC / 144A 8.125% 09/01/2020 DD 08/21/12	51,644.23	103.5800	51,790.00	145.77
100,000.0000	WEATHERFORD INTERNATIONAL LTD 7.750% 06/15/2021 DD 06/17/16	102,955.91	100.5000	100,500.00	2,455.91-
25,000.0000	WEATHERFORD INTERNATIONAL 144A 9.875% 02/15/2024 DD 11/18/16	25,249.84	104.5000	26,125.00	875.16
75,000.0000	WELLCARE HEALTH PLANS INC 5.250% 04/01/2025 DD 03/22/17	75,000.00	104.7500	78,562.50	3,562.50
150,000.0000	WESCO DISTRIBUTION INC 5.375% 06/15/2024 DD 12/15/16	150,000.00	104.3750	156,562.50	6,562.50
200,000.0000	WHITING PETROLEUM CORP 5.750% 03/15/2021 DD 09/12/13	187,191.88	94.0000	188,000.00	808.12
50,000.0000	WHITING PETROLEUM CORP 6.250% 04/01/2023 DD 03/27/15	48,068.25	91.7500	45,875.00	2,193.25-

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153,000.0000	WIDEOPENWEST FINANCE LLC / WID 10.250% 07/15/2019 DD 01/15/13	158,293.25	103.0000	157,590.00	703.25-
25,000.0000	WILDHORSE RESOURCE DEVELO 144A 6.875% 02/01/2025 DD 02/01/17	24,818.50	94.0000	23,500.00	1,318.50-
200,000.0000	WIND ACQUISITION FINANCE 144A 4.750% 07/15/2020 DD 07/10/14	202,778.62	101.0500	202,100.00	678.62-
200,000.0000	WPX ENERGY INC 6.000% 01/15/2022 DD 11/14/11	181,295.02	99.0000	198,000.00	16,704.98
200,000.0000	ZF NORTH AMERICA CAPITAL 144A 4.750% 04/29/2025 DD 04/29/15	201,457.48	105.5000	211,000.00	9,542.52
50,000.0000	ZAYO GROUP LLC / ZAYO CAP 144A 5.750% 01/15/2027 DD 01/27/17	50,000.00	104.6250	52,312.50	2,312.50
125,000.0000	BRAND ENERGY 6/17 TL 0.000% 06/21/2024 DD 06/01/17	123,751.47	99.7810	124,726.25	974.78
TOTAL INVESTMENTS FIXED INCOME SECURITIES		24,870,364.78		25,594,141.87	723,777.09
TOTAL INVESTMENT		25,097,965.14		25,821,742.23	723,777.09

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INVESTMENTS CASH EQUIVALENTS					
17.6700	BLACKROCK LIQ T FUND INSTL FUND 60	17.67	100.0000	17.67	0.00
TOTAL INVESTMENTS CASH EQUIVALENTS		17.67		17.67	0.00
INVESTMENTS EQUITY					
1,052,241.5830	PARAMETRIC TX-MGD EM MK-INST	48,513,090.82	47.7400	50,234,013.17	1,720,922.35
TOTAL INVESTMENTS EQUITY		48,513,090.82		50,234,013.17	1,720,922.35
TOTAL INVESTMENT		48,513,108.49		50,234,030.84	1,720,922.35

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INVESTMENTS CASH EQUIVALENTS					
72.2900	AUD (AUSTRALIAN DOLLARS)	54.95	0.0000	55.45	0.50 C
283.4500	NZD (NEW ZEALAND DOLLAR)	206.22	0.0000	207.54	1.32 C
53.0100	CHF (SWISS FRANC)	54.43	0.0000	55.35	0.92 C
25,872.1900	GBP (GREAT BRITISH POUNDS)	33,075.56	0.0000	33,606.68	531.12 C
21,089.1100	HKD (HONG KONG DOLLARS)	2,703.69	0.0000	2,701.50	2.19-C
10,000,770.0000	JPY (JAPANESE YEN)	89,263.92	0.0000	89,006.49	257.43-C
858.6000	SGD (SINGAPORE DOLLARS)	619.01	0.0000	623.60	4.59 C
727.5200	ILS (ISRAELI SHEKEL)	196.92	0.0000	208.48	11.56 C
6,285.6800	DKK (DANISH KRONE)	943.84	0.0000	964.24	20.40 C
4,267.8000	NOK (NORWEGIAN KRONE)	505.43	0.0000	509.49	4.06 C
446.6600	SEK (SWEDISH KRONA)	51.17	0.0000	52.96	1.79 C
23,622.5200	EUR (EURO)	26,650.99	0.0000	26,942.67	291.68 C
305,926.6200	BLACKROCK LIQ T FUND INSTL FUND 60	305,926.62	100.0000	305,926.62	0.00
TOTAL INVESTMENTS CASH EQUIVALENTS		460,252.75		460,861.07	608.32 608.32 C 0.00 I

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XCEL ENERGY NDT

SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS PREFERRED SECURITIES					
713.0000	HENKEL AG & CO KGAA	39,255.97	137.4362	97,992.06	58,736.09 18,317.43- C 77,053.52 I
424.0000	VOLKSWAGEN AG	39,923.73	152.0923	64,487.15	24,563.42 12,054.40- C 36,617.82 I
438.0000	BAYERISCHE MOTOREN WERKE AG	15,786.09	82.3248	36,058.31	20,272.22 6,740.27- C 27,012.49 I
TOTAL INVESTMENTS PREFERRED SECURITIES		94,965.79		198,537.52	103,571.73 37,112.10- C 140,683.83 I
INVESTMENTS EQUITY					
31,105.0000	SCENTRE GROUP	94,852.88	3.1065	96,629.32	1,776.44 18,224.94- C 20,001.38 I
4,619.0000	AGL ENERGY LTD	54,419.33	19.5597	90,346.60	35,927.27 11,393.79- C 47,321.06 I
58,193.0000	SOUTH32 LTD	118,637.56	2.0556	119,627.00	989.44 959.06 C 30.38 I

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XCEL ENERGY NDT

SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
41,007.0000	VICINITY CENTRES	91,523.99	1.9713	80,837.86	10,686.13- C 710.04 C 11,396.17- I
6,637.0000	TATTS GROUP LTD	14,981.11	3.2062	21,280.01	6,298.90 4,266.83- C 10,565.73 I
11,261.0000	GOODMAN GROUP	45,560.27	6.0366	67,979.09	22,418.82 5,901.74- C 28,320.56 I
3,380.0000	DEXUS	15,136.42	7.2716	24,578.12	9,441.70 4,928.13- C 14,369.83 I
1,634.0000	MACQUARIE GROUP LTD	63,116.65	67.8839	110,922.33	47,805.68 26,460.15- C 74,265.83 I
1,986.0000	CROWN RESORTS LTD	14,820.75	9.4193	18,706.88	3,886.13 3,750.88- C 7,637.01 I
2,284.0000	JAMES HARDIE INDUSTRIES PLC	15,066.60	15.7245	35,914.82	20,848.22 7,201.23- C 28,049.45 I
2,571.0000	TREASURY WINE ESTATES LTD	8,929.90	10.0943	25,952.65	17,022.75 10,647.67- C 27,670.42 I
5,234.0000	SYDNEY AIRPORT	10,743.15	5.4383	28,464.50	17,721.35 4,774.61- C 22,495.96 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS	
15,315.0000	AURIZON HOLDINGS LTD	50,004.51	4.1113	62,965.91	12,961.40	
					9,502.14-	C
					22,463.54	I
806.0000	RAMSAY HEALTH CARE LTD	30,447.59	56.4548	45,502.63	15,055.04	
					11,259.23-	C
					26,314.27	I
6,000.0000	AUSTRALIA & NEW ZEALAND BANKIN	121,654.20	22.0296	132,178.06	10,523.86	
					3,985.16-	C
					14,509.02	I
3,160.0000	AMCOR LTD/AUSTRALIA	21,041.79	12.4338	39,291.06	18,249.27	
					11,460.21-	C
					29,709.48	I
7,822.0000	WESTPAC BANKING CORP	188,333.66	23.4026	183,055.88	5,277.78-	
					10,872.64-	C
					5,594.86	I
3,052.0000	BANK OF QUEENSLAND LTD	29,376.02	8.7827	26,804.87	2,571.15-	
					1,880.06-	C
					691.09-	I
18,373.0000	FORTESCUE METALS GROUP LTD	63,789.00	4.0040	73,565.51	9,776.51	
					1,743.44	C
					8,033.07	I
17,411.0000	TELSTRA CORP LTD	48,122.81	3.2983	57,426.96	9,304.15	
					11,514.59-	C
					20,818.74	I
1,652.0000	BENDIGO & ADELAIDE BANK LTD	15,296.14	8.4989	14,040.21	1,255.93-	
					2,815.17-	C
					1,559.24	I

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XCEL ENERGY NDT

SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS	
689.0000	ASX LTD	21,512.80	41.1215	28,332.75	6,819.95	
					5,680.96-	C
					12,500.91	I
5,898.0000	BHP BILLITON LTD	106,204.02	17.8569	105,320.14	883.88-	
					1,536.39	C
					2,420.27-	I
10,886.0000	MIRVAC GROUP	14,642.90	1.6338	17,785.73	3,142.83	
					3,566.18-	C
					6,709.01	I
4,462.0000	HARVEY NORMAN HOLDINGS LTD	15,004.74	2.9301	13,074.24	1,930.50-	
					2,621.51-	C
					691.01	I
3,485.0000	COMPUTERSHARE LTD	29,580.61	10.8460	37,798.61	8,218.00	
					1,547.32	C
					6,670.68	I
2,434.0000	CSL LTD	87,373.88	105.8759	257,701.97	170,328.09	
					43,326.27-	C
					213,654.36	I
818.0000	REA GROUP LTD	29,597.06	50.9321	41,662.47	12,065.41	
					7,989.77-	C
					20,055.18	I
14,158.0000	TRANSURBAN GROUP	92,279.61	9.0895	128,689.74	36,410.13	
					6,403.71-	C
					42,813.84	I
226.0000	COCHLEAR LTD	15,087.34	119.2379	26,947.77	11,860.43	
					5,403.25-	C
					17,263.68	I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
7,311.0000	ORIGIN ENERGY LTD	31,523.48	5.2619	38,470.21	6,946.73 945.39 C 6,001.34 I
7,694.0000	COMMONWEALTH BANK OF AUSTRALIA	402,077.86	63.5194	488,718.34	86,640.48 80,066.77- C 166,707.25 I
1,285.0000	RIO TINTO LTD	60,390.49	48.5312	62,362.66	1,972.17 1,810.84- C 3,783.01 I
5,231.0000	APA GROUP	30,146.87	7.0338	36,794.06	6,647.19 9,104.38- C 15,751.57 I
3,015.0000	ARISTOCRAT LEISURE LTD	30,333.42	17.3046	52,173.51	21,840.09 1,282.14 C 20,557.95 I
8,312.0000	INSURANCE AUSTRALIA GROUP LTD	30,019.09	5.2005	43,227.38	13,208.29 8,667.45- C 21,875.74 I
7,418.0000	GPT GROUP/THE	19,990.81	3.6741	27,254.99	7,264.18 5,464.85- C 12,729.03 I
5,112.0000	LENDLEASE GROUP	47,131.83	12.7713	65,287.31	18,155.48 4,839.43- C 22,994.91 I
5,081.0000	SUNCORP GROUP LTD	40,539.00	11.3676	57,759.19	17,220.19 11,581.20- C 28,801.39 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS	
5,204.0000	NATIONAL AUSTRALIA BANK LTD	126,926.07	22.6970	118,115.24	8,810.83-	
					13,868.62-	C
					5,057.79	I
4,156.0000	NEWCREST MINING LTD	45,678.53	15.4637	64,267.25	18,588.72	
					2,429.77-	C
					21,018.49	I
17,101.0000	OIL SEARCH LTD	89,151.75	5.2312	89,460.14	308.39	
					2,935.71	C
					2,627.32-	I
5,341.0000	QANTAS AIRWAYS LTD	14,882.68	4.3875	23,433.78	8,551.10	
					4,698.66-	C
					13,249.76	I
5,136.0000	QBE INSURANCE GROUP LTD	43,196.29	9.0588	46,526.31	3,330.02	
					1,759.03-	C
					5,089.05	I
1,475.0000	SONIC HEALTHCARE LTD	19,568.63	18.5779	27,402.48	7,833.85	
					5,494.42-	C
					13,328.27	I
4,848.0000	WESFARMERS LTD	143,928.07	30.7740	149,192.58	5,264.51	
					26,826.43-	C
					32,090.94	I
9,755.0000	ALUMINA LTD	15,862.74	1.4727	14,366.54	1,496.20-	
					2,880.62-	C
					1,384.42	I
375.0000	WOODSIDE PETROLEUM LTD	8,989.03	22.9117	8,591.92	397.11-	
					88.50	C
					485.61-	I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
6,947.0000	AUCKLAND INTERNATIONAL AIRPORT	25,143.09	5.2205	36,267.41	11,124.32 6,112.26- C 17,236.58 I
9,783.0000	SPARK NEW ZEALAND LTD	11,456.03	2.7677	27,076.57	15,620.54 935.59 C 14,684.95 I
1,285.0000	OMV AG	44,222.28	51.8208	66,589.85	22,367.57 4,463.46 C 17,904.11 I
2,277.0000	ERSTE GROUP BANK AG	60,057.76	38.2369	87,065.52	27,007.76 9,110.87- C 36,118.63 I
245.0000	IMMOFINANZ AG	0.00	2.2822	559.15	559.15 I
3,229.0000	ANHEUSER-BUSCH INBEV SA/NV	166,276.98	110.3025	356,167.06	189,890.08 69,304.84- C 259,194.92 I
1,737.0000	AGEAS	59,674.89	40.2157	69,854.83	10,179.94 9,566.91- C 19,746.85 I
422.0000	UMICORE SA	15,349.46	69.4594	29,311.91	13,962.45 5,479.18- C 19,441.63 I
1,206.0000	KBC GROUP NV	61,950.22	75.7439	91,347.17	29,396.95 18,016.42- C 47,413.37 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
280.0000	SOLVAY SA	29,235.57	134.0146	37,524.10	8,288.53 7,014.27- C 15,302.80 I
369.0000	UCB SA	16,023.06	68.6953	25,348.58	9,325.52 4,738.33- C 14,063.85 I
2,905.0000	VONOVIA SE	94,028.23	39.6512	115,186.80	21,158.57 5,281.13 C 15,877.44 I
889.0000	QIAGEN NV	21,513.07	33.2185	29,531.27	8,018.20 5,520.21- C 13,538.41 I
1,907.0000	DEUTSCHE WOHNEN AG	37,687.83	38.1970	72,841.72	35,153.89 15,110.56- C 50,264.45 I
631.0000	LANXESS AG	29,060.45	75.6070	47,708.05	18,647.60 4,254.01- C 22,901.61 I
507.0000	BRENNTAG AG	19,442.18	57.8030	29,306.16	9,863.98 7,452.76- C 17,316.74 I
13,861.0000	TELEFONICA DEUTSCHLAND HOLDING	59,322.60	4.9876	69,133.47	9,810.87 4,633.95 C 5,176.92 I
354.0000	OSRAM LICHT AG	10,258.82	79.5533	28,161.89	17,903.07 5,085.47- C 22,988.54 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
1,036.0000	ADIDAS AG	65,806.43	191.3272	198,215.04	132,408.61 34,800.99- C 167,209.60 I
1,998.0000	FRESENIUS SE & CO KGAA	57,849.16	85.6096	171,048.15	113,198.99 28,511.81- C 141,710.80 I
980.0000	UNITED INTERNET AG	15,204.65	54.9117	53,813.54	38,608.89 10,059.20- C 48,668.09 I
302.0000	HANNOVER RUECK SE	15,281.62	119.7007	36,149.62	20,868.00 6,757.36- C 27,625.36 I
656.0000	GEA GROUP AG	15,646.56	40.8659	26,808.03	11,161.47 5,011.16- C 16,172.63 I
464.0000	CONTINENTAL AG	46,835.25	215.5069	99,995.21	53,159.96 14,190.69- C 67,350.65 I
3,383.0000	DEUTSCHE POST AG	59,680.89	37.4328	126,635.33	66,954.44 23,671.60- C 90,626.04 I
463.0000	MERCK KGAA	26,460.71	120.6131	55,843.89	29,383.18 9,095.57- C 38,478.75 I
3,393.0000	SAP SE	167,117.92	104.3032	353,901.09	186,783.17 66,153.80- C 252,936.97 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
3,848.0000	E.ON SE	29,552.83	9.4072	36,199.12	6,646.29 1,899.54 C 4,746.75 I
520.0000	HENKEL AG & CO KGAA	24,485.06	120.7842	62,807.81	38,322.75 11,740.50- C 50,063.25 I
954.0000	METRO AG	29,919.53	33.7089	32,158.34	2,238.81 181.86 C 2,056.95 I
3,306.0000	BAYER AG	226,752.51	129.1102	426,838.52	200,086.01 79,787.78- C 279,873.79 I
3,672.0000	BASF SE	233,752.41	92.4872	339,613.00	105,860.59 63,482.97- C 169,343.56 I
180.0000	HOCHTIEF AG	15,546.92	182.9442	32,929.96	17,383.04 6,155.50- C 23,538.54 I
563.0000	HEIDELBERGCEMENT AG	32,103.03	96.5475	54,356.27	22,253.24 10,160.68- C 32,413.92 I
971.0000	FRESENIUS MEDICAL CARE AG & CO	54,716.77	96.0000	93,216.09	38,499.32 17,424.66- C 55,923.98 I
1,815.0000	ALLIANZ SE	231,078.78	196.6308	356,884.94	125,806.16 66,711.57- C 192,517.73 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
1,024.0000	MUENCHENER RUECKVERSICHERUNGS-	169,897.91	201.3641	206,196.84	36,298.93 26,785.90- C 63,084.83 I
68.0000	VOLKSWAGEN AG	6,594.43	154.8296	10,528.42	3,933.99 1,968.05- C 5,902.04 I
3,895.0000	DAIMLER AG	190,386.59	72.2766	281,517.57	91,130.98 51,399.71- C 142,530.69 I
386.0000	THYSSENKRUPP AG	9,747.99	28.3711	10,951.28	1,203.29 2,285.21- C 3,488.50 I
3,039.0000	SIEMENS AG	293,120.12	137.2651	417,148.92	124,028.80 60,288.62- C 184,317.42 I
954.0000	LINDE AG	121,691.01	189.1031	180,404.44	58,713.43 18,519.19- C 77,232.62 I
1,919.0000	DEUTSCHE BANK AG	37,189.49	17.7070	33,979.81	3,209.68- 1,103.68 C 4,313.36- I
1,324.0000	BAYERISCHE MOTOREN WERKE AG	63,042.09	92.7039	122,739.97	59,697.88 22,943.45- C 82,641.33 I
11,333.0000	DEUTSCHE TELEKOM AG	153,804.20	17.9294	203,194.41	49,390.21 37,982.61- C 87,372.82 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS	
6,285.0000	INFINEON TECHNOLOGIES AG	54,946.54	21.0830	132,507.08	77,560.54	
					25,075.12-	C
					102,635.66	I
3,004.0000	RED ELECTRICA CORP SA	34,763.94	20.8663	62,682.55	27,918.61	
					10,413.87-	C
					38,332.48	I
5,512.0000	INDUSTRIA DE DISENO TEXTIL SA	78,389.29	38.3338	211,296.38	132,907.09	
					43,792.40-	C
					176,699.49	I
350.0000	AENA SA	29,942.47	194.8629	68,202.04	38,259.57	
					4,789.79	C
					33,469.78	I
3,079.0000	GRIFOLS SA	33,238.60	27.8123	85,634.11	52,395.51	
					1,771.98-	C
					54,167.49	I
5,449.0000	FERROVIAL SA	84,944.66	22.1665	120,785.75	35,841.09	
					2,908.24	C
					32,932.85	I
11,039.0000	CAIXABANK SA	31,765.11	4.7674	52,628.42	20,863.31	
					2,491.73	C
					18,371.58	I
16,642.0000	IBERDROLA SA	107,573.11	7.9074	131,595.51	24,022.40	
					7,026.22-	C
					31,048.62	I
1,158.0000	AMADEUS IT GROUP SA	23,116.04	59.7077	69,141.62	46,025.58	
					10,275.31-	C
					56,300.89	I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
14,405.0000	INTERNATIONAL CONSOLIDATED AIR	69,376.46	7.9256	114,169.45	44,792.99 2,768.04- C 47,561.03 I
2,074.0000	DISTRIBUIDORA INTERNACIONAL DE	10,199.43	6.2171	12,894.34	2,694.91 3,457.74- C 6,152.65 I
2,355.0000	ENDESA SA	44,418.51	23.0048	54,176.52	9,758.01 3,804.77 C 5,953.24 I
1,786.0000	BANKINTER SA	9,732.00	9.1985	16,428.58	6,696.58 3,070.96- C 9,767.54 I
24,829.0000	BANCO BILBAO VIZCAYA ARGENTARI	177,693.26	8.2860	205,735.48	28,042.22 813.11- C 28,855.33 I
922.0000	GAS NATURAL SDG SA	16,606.98	23.3698	21,547.02	4,940.04 4,027.73- C 8,967.77 I
1,989.0000	REPSOL SA	29,377.03	15.2833	30,398.62	1,021.59 1,595.15 C 573.56- I
38,089.0000	BANCO SANTANDER SA	216,194.55	6.6060	251,618.43	35,423.88 7,763.95 C 27,659.93 I
11,245.0000	TELEFONICA SA	108,515.04	10.3082	115,916.73	7,401.69 6,082.70 C 1,318.99 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
3,795.0000	ENAGAS SA	96,388.64	28.0005	106,261.91	9,873.27 3,459.71 C 6,413.56 I
1,077.0000	VALEO SA	38,162.13	67.2810	72,461.68	34,299.55 15,031.72- C 49,331.27 I
2,806.0000	ENGIE SA	33,671.44	15.0723	42,293.07	8,621.63 2,219.31 C 6,402.32 I
470.0000	ARKEMA SA	31,027.95	106.5615	50,083.95	19,056.00 5,186.08- C 24,242.08 I
252.0000	IMERYS SA	15,816.57	86.8528	21,886.93	6,070.36 4,091.27- C 10,161.63 I
750.0000	SAFRAN SA	19,945.62	91.5177	68,638.30	48,692.68 12,830.36- C 61,523.04 I
13,977.0000	NATIXIS SA	78,728.90	6.7030	93,688.00	14,959.10 1,836.44 C 13,122.66 I
662.0000	SCOR SE	16,982.19	39.5884	26,207.58	9,225.39 4,898.92- C 14,124.31 I
2,761.0000	VINCI SA	164,818.64	85.2333	235,329.15	70,510.51 35,715.54- C 106,226.05 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
1,367.0000	AIR LIQUIDE SA	129,706.65	123.4075	168,698.07	38,991.42 29,016.00- C 68,007.42 I
1,533.0000	DANONE SA	94,390.25	75.0595	115,066.36	20,676.11 21,509.06- C 42,185.17 I
480.0000	LEGRAND SA	15,534.73	69.8586	33,532.17	17,997.44 6,268.09- C 24,265.53 I
295.0000	EIFFAGE SA	15,626.63	90.7421	26,768.94	11,142.31 5,003.83- C 16,146.14 I
6,451.0000	TOTAL SA	338,992.43	49.3687	318,477.53	20,514.90- 13,071.86- C 7,443.04- I
187.0000	AEROPORTS DE PARIS	15,622.18	161.1597	30,136.87	14,514.69 5,633.40- C 20,148.09 I
1,628.0000	BUREAU VERITAS SA	29,434.12	22.0981	35,975.80	6,541.68 6,235.96- C 12,777.64 I
2,598.0000	EDENRED	55,708.08	26.0387	67,648.69	11,940.61 712.27 C 11,228.34 I
3,278.0000	AIRBUS SE	125,831.14	82.1196	269,188.05	143,356.91 19,158.24- C 162,515.15 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS	
5,563.0000	VEOLIA ENVIRONNEMENT SA	96,188.61	21.1001	117,380.27	21,191.66	
					6,876.00	C
					14,315.66	I
942.0000	L'OREAL SA	100,755.47	208.0363	195,970.21	95,214.74	
					36,632.20-	C
					131,846.94	I
1,249.0000	LVMH MOET HENNESSY LOUIS VUITT	159,381.12	248.9820	310,978.60	151,597.48	
					38,873.76-	C
					190,471.24	I
377.0000	THALES SA	15,183.26	107.4854	40,522.01	25,338.75	
					7,574.65-	C
					32,913.40	I
809.0000	CAPGEMINI SE	40,722.86	103.1969	83,486.34	42,763.48	
					15,605.89-	C
					58,369.37	I
882.0000	CASINO GUICHARD PERRACHON SA	47,730.04	59.1489	52,169.35	4,439.31	
					2,737.56	C
					1,701.75	I
350.0000	INGENICO GROUP SA	29,629.13	90.6623	31,731.81	2,102.68	
					1,665.13	C
					437.55	I
474.0000	PUBLICIS GROUPE SA	20,473.33	74.4893	35,307.94	14,834.61	
					6,600.02-	C
					21,434.63	I
919.0000	CIE GENERALE DES ETABLISSEMENT	73,487.50	132.7600	122,006.46	48,518.96	
					9,639.64-	C
					58,158.60	I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS	
791.0000	PERNOD RICARD SA	68,566.50	133.7294	105,780.02	37,213.52	
					19,773.18-	C
					56,986.70	I
649.0000	RENAULT SA	31,205.32	90.3885	58,662.19	27,456.87	
					10,965.58-	C
					38,422.45	I
1,886.0000	SCHNEIDER ELECTRIC SE	112,216.96	76.7247	144,702.97	32,486.01	
					27,048.95-	C
					59,534.96	I
1,828.0000	VIVENDI SA	33,582.43	22.2293	40,635.20	7,052.77	
					2,132.32	C
					4,920.45	I
4,433.0000	ORANGE SA	66,050.42	15.8422	70,228.65	4,178.23	
					139.89	C
					4,038.34	I
43.0000	HERMES INTERNATIONAL	5,910.71	493.4589	21,218.74	15,308.03	
					3,966.39-	C
					19,274.42	I
640.0000	DASSAULT SYSTEMES SE	19,313.04	89.5217	57,293.93	37,980.89	
					10,709.79-	C
					48,690.68	I
454.0000	KERING	71,925.69	340.1120	154,410.85	82,485.16	
					14,917.50-	C
					97,402.66	I
3,512.0000	CARREFOUR SA	81,066.72	25.2631	88,724.30	7,657.58	
					130.87	C
					7,526.71	I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
301.0000	ATOS SE	15,655.00	140.1735	42,192.25	26,537.25
					7,886.86- C
					34,424.11 I
3,191.0000	SANOFI	237,608.67	95.5324	304,844.11	67,235.44
					55,651.12- C
					122,886.56 I
586.0000	ACCOR SA	21,975.91	46.8138	27,432.93	5,457.02
					5,127.98- C
					10,585.00 I
4,216.0000	NOKIA OYJ	27,418.81	6.1213	25,807.53	1,611.28-
					2,147.33 C
					3,758.61- I
1,555.0000	STMICROELECTRONICS NV	15,796.00	14.3367	22,293.59	6,497.59
					4,167.28- C
					10,664.87 I
2,721.0000	SOCIETE GENERALE SA	88,216.42	53.7313	146,202.90	57,986.48
					1,401.71 C
					56,584.77 I
376.0000	SODEXO SA	22,942.37	129.1102	48,545.46	25,603.09
					9,074.48- C
					34,677.57 I
472.0000	UNIBAIL-RODAMCO SE	85,689.07	251.6623	118,784.63	33,095.56
					11,839.22- C
					44,934.78 I
8,069.0000	AXA SA	184,114.31	27.3161	220,414.20	36,299.89
					33,060.78- C
					69,360.67 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
4,097.0000	PEUGEOT SA	59,025.69	19.9197	81,611.04	22,585.35 4,354.27- C 26,939.62 I
803.0000	ESSILOR INTERNATIONAL SA	51,905.94	127.0572	102,026.99	50,121.05 19,071.63- C 69,192.68 I
2,262.0000	CREDIT AGRICOLE SA	28,662.92	16.0646	36,338.23	7,675.31 3,240.19- C 10,915.50 I
970.0000	ZODIAC AEROSPACE	19,567.36	27.0880	26,275.42	6,708.06 2,076.82- C 8,784.88 I
2,695.0000	BNP PARIBAS SA	173,523.65	71.9230	193,832.71	20,309.06 3,841.90- C 24,150.96 I
1,164.0000	CIE DE SAINT-GOBAIN	48,271.51	53.3549	62,105.14	13,833.63 2,408.46- C 16,242.09 I
332.0000	WENDEL SA	36,231.34	147.8152	49,074.67	12,843.33 4,375.87- C 17,219.20 I
389.0000	KLEPIERRE	15,409.88	40.9286	15,921.25	511.37 2,945.16- C 3,456.53 I
133.0000	GECINA SA	15,050.60	156.6545	20,835.05	5,784.45 3,894.65- C 9,679.10 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
190.0000	ILIAD SA	34,313.61	236.2079	44,879.50	10,565.89 6,431.59- C 16,997.48 I
155.0000	BANCA MONTE DEI PASCHI DI SIEN	29,223.11	0.0000	0.00	29,223.11-I
2,514.0000	CNH INDUSTRIAL NV	19,352.89	11.3085	28,429.70	9,076.81 1,195.21 C 7,881.60 I
147.0000	FERRARI NV	7,210.19	85.7123	12,599.71	5,389.52 447.96 C 4,941.56 I
8,643.0000	FIAT CHRYSLER AUTOMOBILES NV	74,625.10	10.5272	90,987.25	16,362.15 6,098.79 C 10,263.36 I
10,190.0000	UNICREDIT SPA	167,678.00	18.6479	190,023.04	22,345.04 8,339.83 C 14,005.21 I
727.0000	EXOR NV	29,454.72	54.0506	39,294.83	9,840.11 8,199.71- C 18,039.82 I
1,741.0000	LEONARDO SPA	23,653.35	16.5950	28,891.90	5,238.55 4,722.84- C 9,961.39 I
14,800.0000	TERNA RETE ELETTRICA NAZIONALE	66,109.66	5.3902	79,775.54	13,665.88 584.80- C 14,250.68 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
1,306.0000	PRYSMIAN SPA	20,667.44	29.3691	38,356.13	17,688.69 8,059.29- C 25,747.98 I
37,642.0000	INTESA SANPAOLO SPA	96,882.96	3.1661	119,180.85	22,297.89 7,663.29- C 29,961.18 I
561.0000	LUXOTTICA GROUP SPA	15,181.47	57.7688	32,408.33	17,226.86 6,058.01- C 23,284.87 I
26,098.0000	ENEL SPA	110,614.02	5.3537	139,721.95	29,107.93 2,469.39- C 31,577.32 I
12,801.0000	ENI SPA	200,576.81	15.0096	192,138.38	8,438.43- 8,571.14 C 17,009.57- I
1,964.0000	TENARIS SA	27,729.75	15.5685	30,576.55	2,846.80 2,726.43- C 5,573.23 I
2,206.0000	ATLANTIA SPA	48,276.85	28.1031	61,995.55	13,718.70 2,872.42- C 16,591.12 I
5,882.0000	KONINKLIJKE AHOLD DELHAIZE NV	94,071.11	19.0928	112,303.89	18,232.78 20,992.69- C 39,225.47 I
5,336.0000	ARCELORMITTAL	109,959.26	22.6513	120,867.46	10,908.20 4,423.05 C 6,485.15 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
1,443.0000	ABN AMRO GROUP NV	23,978.69	26.4721	38,199.33	14,220.64 916.01 C 13,304.63 I
278.0000	ALTICE NV	4,967.94	23.0448	6,406.46	1,438.52 1,230.67- C 2,669.19 I
4,750.0000	ALTICE NV	81,742.21	23.0391	109,435.77	27,693.56 1,524.63 C 26,168.93 I
19,742.0000	ING GROEP NV	217,688.53	17.2223	340,002.75	122,314.22 44,126.95- C 166,441.17 I
1,235.0000	KONINKLIJKE DSM NV	58,851.34	72.5846	89,641.98	30,790.64 4,676.39- C 35,467.03 I
5,823.0000	UNILEVER NV	182,185.72	55.1113	320,913.54	138,727.82 59,987.54- C 198,715.36 I
1,328.0000	ASML HOLDING NV	41,296.66	130.1367	172,821.61	131,524.95 36,037.26- C 167,562.21 I
4,451.0000	RELX NV	35,469.91	20.5299	91,378.58	55,908.67 17,080.90- C 72,989.57 I
146.0000	RANDSTAD HOLDING NV	7,172.26	58.3049	8,512.52	1,340.26 1,591.22- C 2,931.48 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS	
923.0000	AKZO NOBEL NV	53,693.34	86.7844	80,102.05	26,408.71	
					14,973.26-	C
					41,381.97	I
1,113.0000	WOLTERS KLUWER NV	24,519.12	42.2744	47,051.51	22,532.39	
					8,795.21-	C
					31,327.60	I
564.0000	KONINKLIJKE VOPAK NV	25,558.26	46.3063	26,116.77	558.51	
					1,750.58	C
					1,192.07-	I
2,496.0000	KONINKLIJKE KPN NV	7,289.03	3.1946	7,973.93	684.90	
					534.49	C
					150.41	I
624.0000	KONINKLIJKE PHILIPS NV	17,668.95	35.4654	22,130.41	4,461.46	
					125.15	C
					4,336.31	I
947.0000	HEINEKEN NV	48,708.35	97.0950	91,948.99	43,240.64	
					17,187.79-	C
					60,428.43	I
1,446.0000	JERONIMO MARTINS SGPS SA	14,761.22	19.4920	28,185.43	13,424.21	
					5,268.62-	C
					18,692.83	I
3,864.0000	BANCO ESPIRITO SANTO SA	10,159.42	0.0001	0.44	10,158.98-	
					0.09-	C
					10,158.89-	I
2,156.0000	CIE FINANCIERE RICHEMONT SA	88,667.57	82.4936	177,856.21	89,188.64	
					13,994.62	C
					75,194.02	I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS	
592.0000	IDORSIA LTD	4,747.52	18.9004	11,189.06	6,441.54	
					101.30	C
					6,340.24	I
14,948.0000	UBS GROUP AG	243,638.12	16.9581	253,490.86	9,852.74	
					17,802.24	C
					7,949.50-	I
968.0000	PARGESA HOLDING SA	63,442.00	76.1760	73,738.42	10,296.42	
					3,915.30	C
					6,381.12	I
267.0000	SWISS PRIME SITE AG	20,353.83	90.9518	24,284.13	3,930.30	
					223.93-	C
					4,154.23	I
155.0000	GEBERIT AG	28,368.29	466.9764	72,381.35	44,013.06	
					6,167.46	C
					37,845.60	I
194.0000	SCHINDLER HOLDING AG	17,521.30	211.8728	41,103.33	23,582.03	
					3,502.33	C
					20,079.70	I
115.0000	PARTNERS GROUP HOLDING AG	30,129.42	620.7904	71,390.90	41,261.48	
					4,149.13-	C
					45,410.61	I
177.0000	KUEHNE + NAGEL INTERNATIONAL A	18,218.87	167.0756	29,572.39	11,353.52	
					2,519.81	C
					8,833.71	I
827.0000	JULIUS BAER GROUP LTD	30,690.61	52.6810	43,567.22	12,876.61	
					3,712.28	C
					9,164.33	I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS	
1,887.0000	SWISS RE AG	98,300.90	91.5261	172,709.81	74,408.91	
					6,932.49	C
					67,476.42	I
10.0000	SIKA AG	18,597.62	6,432.4126	64,324.13	45,726.51	
					1,537.44	C
					44,189.07	I
22.0000	SGS SA	31,118.38	2,424.6854	53,343.08	22,224.70	
					4,545.26	C
					17,679.44	I
94.0000	SWISSCOM AG	34,677.50	483.1619	45,417.22	10,739.72	
					3,869.91	C
					6,869.81	I
31.0000	GIVAUDAN SA	27,523.91	2,002.8194	62,087.40	34,563.49	
					5,290.33	C
					29,273.16	I
201.0000	ZURICH INSURANCE GROUP AG	49,561.95	291.4425	58,579.96	9,018.01	
					4,991.48	C
					4,026.53	I
8,793.0000	NOVARTIS AG	476,740.31	83.3289	732,711.74	255,971.43	
					59,080.21	C
					196,891.22	I
3,237.0000	ABB LTD	67,155.40	24.7271	80,041.94	12,886.54	
					2,187.12	C
					10,699.42	I
2,694.0000	ROCHE HOLDING AG	440,277.34	254.9992	686,967.89	246,690.55	
					58,535.16	C
					188,155.39	I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS	
491.0000	ADECCO GROUP AG	28,742.22	76.1238	37,376.81	8,634.59	
					3,184.80	C
					5,449.79	I
911.0000	LAFARGEHOLCIM LTD	48,870.87	57.3278	52,225.66	3,354.79	
					1,532.47	C
					1,822.32	I
12,354.0000	NESTLE SA	635,217.58	87.1403	1,076,532.45	441,314.87	
					91,729.19	C
					349,585.68	I
199.0000	BALOISE HOLDING AG	18,010.91	154.7538	30,796.01	12,785.10	
					2,624.06	C
					10,161.04	I
6,094.0000	CREDIT SUISSE GROUP AG	92,636.06	14.4729	88,198.03	4,438.03-	
					2,588.02	C
					7,026.05-	I
421.0000	LONZA GROUP AG	34,970.24	216.4673	91,132.77	56,162.53	
					2,808.11-	C
					58,970.64	I
352.0000	SWISS LIFE HOLDING AG	82,025.22	337.9105	118,944.50	36,919.28	
					7,048.42	C
					29,870.86	I
12,309.0000	NATIONAL GRID PLC	124,713.15	12.3634	152,181.16	27,468.01	
					27,950.74-	C
					55,418.75	I
8,394.0000	COMPASS GROUP PLC	91,143.84	21.0429	176,634.86	85,491.02	
					30,708.67-	C
					116,199.69	I

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2,134.0000	INTERCONTINENTAL HOTELS GROUP	82,020.93	55.4261	118,279.50	36,258.57 1,317.67- C 37,576.24 I
1,050.0000	WOLSELEY PLC	27,819.99	61.2195	64,280.49	36,460.50 11,347.26- C 47,807.76 I
61,185.0000	VODAFONE GROUP PLC	164,677.54	2.8284	173,059.55	8,382.01 324.03- C 8,706.04 I
16,810.0000	STANDARD LIFE PLC	71,491.39	5.1841	87,144.88	15,653.49 3,995.05- C 19,648.54 I
578.0000	CRODA INTERNATIONAL PLC	20,951.73	50.4642	29,168.31	8,216.58 5,546.45- C 13,763.03 I
0.7000	IGAS ENERGY PLC	17.30	0.9384	0.66	16.64- 0.16- C 16.48- I
773.0000	JOHNSON MATTHEY PLC	23,576.49	37.2928	28,827.38	5,250.89 5,088.80- C 10,339.69 I
885.0000	LONDON STOCK EXCHANGE GROUP PL	29,110.43	47.3597	41,913.35	12,802.92 11,345.10- C 24,148.02 I
360.0000	RANDGOLD RESOURCES LTD	28,734.77	88.3935	31,821.68	3,086.91 5,617.39- C 8,704.30 I

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4,646.0000	J SAINSBURY PLC	16,344.79	3.2694	15,189.90	1,154.89-	
					2,352.79-	C
					1,197.90	I
1,631.0000	BERKELEY GROUP HOLDINGS PLC	58,619.72	41.9171	68,366.82	9,747.10	
					1,607.92	C
					8,139.18	I
17,514.0000	ROYAL DUTCH SHELL PLC A SHS	505,646.38	26.4336	462,958.64	42,687.74-	
					64,881.76-	C
					22,194.02	I
17,157.0000	ROYAL DUTCH SHELL PLC B SHS	417,442.31	26.7908	459,650.51	42,208.20	
					63,409.08-	C
					105,617.28	I
10,532.0000	CENTRICA PLC	29,885.18	2.6004	27,388.44	2,496.74-	
					861.32	C
					3,358.06-	I
1,362.0000	BUNZL PLC	15,489.17	29.7199	40,478.61	24,989.44	
					7,145.59-	C
					32,135.03	I
7,735.0000	INMARSAT PLC	72,854.75	9.9954	77,314.58	4,459.83	
					1,818.35	C
					2,641.48	I
2,802.0000	MONDI PLC	56,607.12	26.1608	73,302.71	16,695.59	
					1,724.01	C
					14,971.58	I

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945.0000	SEVERN TRENT PLC	17,543.38	28.3430	26,784.22	9,240.84 4,728.15- C 13,968.99 I
700.0000	WHITBREAD PLC	16,104.15	51.5293	36,070.54	19,966.39 6,367.44- C 26,333.83 I
1,558.0000	SMITHS GROUP PLC	27,438.02	20.7442	32,319.51	4,881.49 5,705.28- C 10,586.77 I
3,510.0000	3I GROUP PLC	15,826.38	11.7230	41,147.81	25,321.43 7,263.73- C 32,585.16 I
5,131.0000	UNILEVER PLC	155,721.97	53.9713	276,927.11	121,205.14 48,885.18- C 170,090.32 I
1,151.0000	TUI AG	13,633.18	14.5352	16,730.07	3,096.89 2,953.31- C 6,050.20 I
5,943.0000	EXPERIAN PLC	71,269.42	20.4584	121,584.64	50,315.22 15,803.66- C 66,118.88 I
4,848.0000	RELX PLC	39,186.98	21.5625	104,535.34	65,348.36 18,453.35- C 83,801.71 I
2,242.0000	SHIRE PLC	49,639.68	55.0495	123,420.98	73,781.30 21,787.15- C 95,568.45 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
1,180.0000	FRESNILLO PLC	15,740.56	19.3023	22,776.83	7,036.27 4,020.72- C 11,056.99 I
2,980.0000	RECKITT BENCKISER GROUP PLC	162,486.31	101.1102	301,308.60	138,822.29 54,109.66- C 192,931.95 I
2,725.0000	UNITED UTILITIES GROUP PLC	23,744.01	11.2683	30,706.37	6,962.36 5,420.52- C 12,382.88 I
23,038.0000	GLENCORE PLC	62,258.44	3.7305	85,945.21	23,686.77 7,683.61- C 31,370.38 I
6,750.0000	SEGRO PLC	35,908.15	6.3544	42,892.63	6,984.48 2,137.89- C 9,122.37 I
7,413.0000	ROLLS-ROYCE HOLDINGS PLC	69,601.92	11.5736	85,795.43	16,193.51 15,145.21- C 31,338.72 I
18,462.0000	OLD MUTUAL PLC	40,076.89	2.5121	46,379.67	6,302.78 8,187.28- C 14,490.06 I
4,990.0000	SAGE GROUP PLC/THE	19,468.25	8.9367	44,594.51	25,126.26 7,872.13- C 32,998.39 I
5,960.0000	MEDICLINIC INTERNATIONAL PLC	56,554.65	9.6317	57,405.02	850.37 1,350.11 C 499.74- I

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5,012.0000	WPP PLC	52,955.76	20.9650	105,076.85	52,121.09	
					18,548.92-	C
					70,670.01	I
20,315.0000	ABERDEEN ASSET MANAGEMENT PLC	66,646.60	3.9228	79,692.27	13,045.67	
					1,008.67	C
					12,037.00	I
7,487.0000	ANTOFAGASTA PLC	71,392.36	10.3851	77,753.29	6,360.93	
					1,459.46	C
					4,901.47	I
2,263.0000	ASHTEAD GROUP PLC	39,620.01	20.6403	46,709.03	7,089.02	
					9,442.86-	C
					16,531.88	I
1,117.0000	BHP BILLITON PLC	20,312.51	15.2756	17,062.90	3,249.61-	
					536.59	C
					3,786.20-	I
3,453.0000	BRITISH LAND CO PLC/THE	25,852.71	7.8651	27,158.34	1,305.63	
					4,794.18-	C
					6,099.81	I
4,555.0000	SKY PLC	42,873.27	12.9115	58,812.17	15,938.90	
					10,381.95-	C
					26,320.85	I
16,276.0000	AVIVA PLC	93,390.41	6.8324	111,205.40	17,814.99	
					13,427.15-	C
					31,242.14	I
10,005.0000	DIAGEO PLC	172,654.22	29.4666	294,814.15	122,159.93	
					52,042.73-	C
					174,202.66	I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
703.0000	SCHRODERS PLC	15,460.18	40.3194	28,344.54	12,884.36 5,003.60- C 17,887.96 I
14,153.0000	BAE SYSTEMS PLC	81,296.60	8.2288	116,462.90	35,166.30 20,558.86- C 55,725.16 I
7,982.0000	BRITISH AMERICAN TOBACCO PLC	279,472.83	67.9870	542,672.58	263,199.75 95,796.45- C 358,996.20 I
13,594.0000	HAMMERSON PLC	93,875.38	7.4624	101,444.79	7,569.41 769.84- C 8,339.25 I
10,480.0000	STANDARD CHARTERED PLC	97,605.25	10.0954	105,800.20	8,194.95 1,362.49- C 9,557.44 I
4,865.0000	IMPERIAL BRANDS PLC	155,605.53	44.7942	217,924.23	62,318.70 41,136.56- C 103,455.26 I
60,543.0000	HSBC HOLDINGS PLC	542,171.42	9.2446	559,697.46	17,526.04 62,640.48- C 80,166.52 I
22,756.0000	LEGAL & GENERAL GROUP PLC	31,035.70	3.3551	76,350.66	45,314.96 13,477.92- C 58,792.88 I
11,827.0000	MEGGITT PLC	71,393.43	6.1946	73,264.62	1,871.19 1,723.10 C 148.09 I

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10,935.0000	WM MORRISON SUPERMARKETS PLC	28,897.79	3.1330	34,260.09	5,362.30	
					6,926.15-	C
					12,288.45	I
1,425.0000	ASSOCIATED BRITISH FOODS PLC	21,504.73	38.1371	54,345.47	32,840.74	
					9,593.47-	C
					42,434.21	I
4,036.0000	PERSIMMON PLC	88,094.76	29.1224	117,538.24	29,443.48	
					2,587.07-	C
					32,030.55	I
10,123.0000	PRUDENTIAL PLC	88,434.91	22.8745	231,558.66	143,123.75	
					40,876.41-	C
					184,000.16	I
3,510.0000	RIO TINTO PLC	150,341.06	42.1119	147,812.98	2,528.08-	
					7,244.32-	C
					4,716.24	I
3,690.0000	SSE PLC	62,544.47	18.8737	69,644.11	7,099.64	
					12,294.08-	C
					19,393.72	I
53,775.0000	BP PLC	400,884.47	5.7517	309,300.39	91,584.08-	
					37,991.49-	C
					53,592.59-	I
163,141.0000	LLOYDS BANKING GROUP PLC	130,141.50	0.8592	140,179.79	10,038.29	
					2,829.07	C
					7,209.22	I
3,541.0000	SMITH & NEPHEW PLC	35,478.79	17.2110	60,944.46	25,465.67	
					10,758.37-	C
					36,224.04	I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
13,118.0000	GLAXOSMITHKLINE PLC	253,385.07	21.2443	278,683.08	25,298.01 49,195.14- C 74,493.15 I
5,310.0000	ASTRAZENECA PLC	240,384.40	66.7010	354,182.75	113,798.35 62,522.88- C 176,321.23 I
7,326.0000	GKN PLC	20,170.55	4.2345	31,022.51	10,851.96 6,562.99- C 17,414.95 I
30,991.0000	BT GROUP PLC	59,434.39	3.8286	118,653.85	59,219.46 20,945.63- C 80,165.09 I
842.0000	CARNIVAL PLC	36,792.37	65.9866	55,560.77	18,768.40 6,721.13- C 25,489.53 I
40,139.0000	BARCLAYS PLC	105,847.84	2.6336	105,710.92	136.92- 2,717.53 C 2,854.45- I
1,452.0000	INTERTEK GROUP PLC	49,553.74	54.7767	79,535.80	29,982.06 15,826.96- C 45,809.02 I
1,734.0000	BURBERRY GROUP PLC	19,319.59	21.5755	37,412.02	18,092.43 6,604.21- C 24,696.64 I
3,023.0000	LAND SECURITIES GROUP PLC	31,496.72	13.1583	39,777.73	8,281.01 7,021.84- C 15,302.85 I

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788.0000	NEXT PLC	26,435.13	50.0875	39,468.96	13,033.83
					6,967.34- C
					20,001.17 I
21,170.0000	KINGFISHER PLC	83,184.46	3.9059	82,688.81	495.65-
					3,604.66- C
					3,109.01 I
29,194.0000	ITV PLC	37,427.53	2.3562	68,789.69	31,362.16
					5,990.11- C
					37,352.27 I
5,151.0000	CRH PLC	136,328.33	35.3285	181,977.30	45,648.97
					21,117.38- C
					66,766.35 I
805.0000	KERRY GROUP PLC	25,659.93	85.9176	69,163.69	43,503.76
					12,928.61- C
					56,432.37 I
12,392.0000	CHEUNG KONG PROPERTY HOLDINGS	54,195.47	7.8332	97,069.83	42,874.36
					489.89- C
					43,364.25 I
13,392.0000	CK HUTCHISON HOLDINGS LTD	102,627.94	12.5537	168,119.44	65,491.50
					855.62- C
					66,347.12 I
4,000.0000	CK INFRASTRUCTURE HOLDINGS LTD	18,780.87	8.4033	33,613.23	14,832.36
					87.63- C
					14,919.99 I
13,360.0000	LINK REIT	57,751.01	7.6090	101,657.48	43,906.47
					589.90- C
					44,496.37 I

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9,000.0000	TECHTRONIC INDUSTRIES CO LTD	30,343.27	4.5987	41,388.85	11,045.58 286.41- C 11,331.99 I
47,800.0000	AIA GROUP LTD	150,684.05	7.3080	349,325.24	198,641.19 1,806.66- C 200,447.85 I
10,000.0000	SANDS CHINA LTD	16,457.09	4.5795	45,795.46	29,338.37 231.14- C 29,569.51 I
2,100.0000	SWIRE PROPERTIES LTD	3,862.12	3.2985	6,926.96	3,064.84 34.51- C 3,099.35 I
8,500.0000	CLP HOLDINGS LTD	61,660.43	10.5809	89,938.45	28,278.02 453.89- C 28,731.91 I
4,700.0000	HONG KONG EXCHANGES & CLEARING	80,061.03	25.8504	121,496.97	41,435.94 613.18- C 42,049.12 I
6,000.0000	MTR CORP LTD	22,820.12	5.6299	33,779.76	10,959.64 170.47- C 11,130.11 I
1,000.0000	HANG SENG BANK LTD	14,049.24	20.9185	20,918.60	6,869.36 105.58- C 6,974.94 I
8,169.0000	HENDERSON LAND DEVELOPMENT CO	35,839.84	5.5787	45,572.56	9,732.72 230.43- C 9,963.15 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
6,000.0000	POWER ASSETS HOLDINGS LTD	35,939.52	8.8324	52,994.64	17,055.12 267.45- C 17,322.57 I
7,000.0000	WHARF HOLDINGS LTD/THE	41,758.36	8.2880	58,016.13	16,257.77 306.27- C 16,564.04 I
34,568.0000	HONG KONG & CHINA GAS CO LTD	41,290.02	1.8804	65,004.99	23,714.97 329.61- C 24,044.58 I
10,000.0000	GALAXY ENTERTAINMENT GROUP LTD	18,442.23	6.0719	60,719.02	42,276.79 229.15- C 42,505.94 I
15,000.0000	BOC HONG KONG HOLDINGS LTD	36,200.02	4.7845	71,767.58	35,567.56 362.19- C 35,929.75 I
13,000.0000	YUE YUEN INDUSTRIAL HOLDINGS L	45,976.57	4.1504	53,955.38	7,978.81 310.05- C 8,288.86 I
4,000.0000	WHEELOCK & CO LTD	12,241.68	7.5450	30,180.17	17,938.49 152.31- C 18,090.80 I
12,200.0000	CONCORDIA FINANCIAL GROUP LTD	60,820.16	5.0427	61,521.18	701.02 3,265.33- C 3,966.35 I
4,680.0000	MEBUKI FINANCIAL GROUP INC	17,332.47	3.7201	17,410.47	78.00 2,013.05- C 2,091.05 I

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3,000.0000	RECRUIT HOLDINGS CO LTD	28,731.79	17.1858	51,557.49	22,825.70 2,628.06 C 20,197.64 I
5,082.0000	JAPAN POST HOLDINGS CO LTD	68,102.64	12.4065	63,050.09	5,052.55- 1,594.36 C 6,646.91- I
7,200.0000	JAPAN POST BANK CO LTD	84,102.81	12.7981	92,146.67	8,043.86 1,305.44 C 6,738.42 I
3,000.0000	SEVEN & I HOLDINGS CO LTD	74,071.28	41.1890	123,567.10	49,495.82 24,182.18- C 73,678.00 I
1,500.0000	BANDAI NAMCO HOLDINGS INC	28,614.24	34.0868	51,130.29	22,516.05 7,666.15- C 30,182.20 I
4,500.0000	MITSUBISHI CHEMICAL HOLDINGS C	23,285.01	8.2778	37,250.35	13,965.34 7,289.92- C 21,255.26 I
2,600.0000	ELECTRIC POWER DEVELOPMENT CO	65,847.70	24.7241	64,282.66	1,565.04- 1,625.53 C 3,190.57- I
1,200.0000	SEGA SAMMY HOLDINGS INC	14,488.46	13.4567	16,148.09	1,659.63 3,160.21- C 4,819.84 I
1,700.0000	NOMURA REAL ESTATE HOLDINGS IN	28,832.35	19.6155	33,346.39	4,514.04 1,699.78 C 2,814.26 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
1,000.0000	YAMAGUCHI FINANCIAL GROUP INC	10,806.72	12.0772	12,077.25	1,270.53 2,363.54- C 3,634.07 I
10,000.0000	AOZORA BANK LTD	22,321.02	3.8091	38,091.85	15,770.83 14,662.97- C 30,433.80 I
17,000.0000	FUKUOKA FINANCIAL GROUP INC	80,003.08	4.7525	80,793.87	790.79 358.18- C 1,148.97 I
2,100.0000	INPEX CORP	21,925.31	9.6208	20,203.81	1,721.50- 1,029.86 C 2,751.36- I
1,400.0000	ISETAN MITSUKOSHI HOLDINGS LTD	15,338.08	10.0213	14,029.90	1,308.18- 2,745.66- C 1,437.48 I
1,000.0000	J FRONT RETAILING CO LTD	12,095.00	15.3435	15,343.54	3,248.54 3,002.73- C 6,251.27 I
2,300.0000	OTSUKA HOLDINGS CO LTD	65,923.65	42.6308	98,050.90	32,127.25 28,156.21- C 60,283.46 I
600.0000	MEIJI HOLDINGS CO LTD	11,706.38	81.0786	48,647.20	36,940.82 9,520.28- C 46,461.10 I
6,300.0000	DAI-ICHI LIFE HOLDINGS INC	81,981.59	18.0357	113,625.40	31,643.81 20,205.81- C 51,849.62 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
900.0000	SOMPO HOLDINGS INC	25,711.52	38.6169	34,755.25	9,043.73 12,654.00- C 21,697.73 I
5,100.0000	JXTG HOLDINGS INC	16,886.17	4.3672	22,272.78	5,386.61 4,358.81- C 9,745.42 I
300.0000	JAPAN AIRLINES CO LTD	7,510.23	30.9184	9,275.54	1,765.31 1,303.56- C 3,068.87 I
800.0000	AISIN SEIKI CO LTD	23,721.54	51.1747	40,939.83	17,218.29 8,011.94- C 25,230.23 I
3,000.0000	AJINOMOTO CO INC	29,769.06	21.5957	64,787.29	35,018.23 12,678.94- C 47,697.17 I
2,000.0000	AMADA HOLDINGS CO LTD	17,141.70	11.5521	23,104.31	5,962.61 4,521.54- C 10,484.15 I
10,700.0000	ACOM CO LTD	30,200.49	4.5656	48,852.79	18,652.30 2,490.19 C 16,162.11 I
1,600.0000	ASAHI GROUP HOLDINGS LTD	29,760.53	37.6290	60,206.48	30,445.95 11,782.45- C 42,228.40 I
6,000.0000	ASAHI KASEI CORP	32,835.39	10.7467	64,480.24	31,644.85 12,618.83- C 44,263.68 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS	
1,200.0000	ASAHI GLASS CO LTD	31,762.44	42.0968	50,516.20	18,753.76	
					2,310.34	C
					16,443.42	I
4,000.0000	HIROSHIMA BANK LTD/THE	16,950.05	4.4321	17,728.73	778.68	
					3,469.53-	C
					4,248.21	I
9,000.0000	BANK OF KYOTO LTD/THE	72,645.92	9.4339	84,905.66	12,259.74	
					182.60	C
					12,077.14	I
3,000.0000	NTT DATA CORP	19,803.45	11.1249	33,374.87	13,571.42	
					6,531.49-	C
					20,102.91	I
6,700.0000	NTT DOCOMO INC	102,969.54	23.6027	158,138.12	55,168.58	
					29,697.22-	C
					84,865.80	I
2,500.0000	BRIDGESTONE CORP	41,736.30	43.0758	107,689.56	65,953.26	
					21,074.94-	C
					87,028.20	I
1,300.0000	BROTHER INDUSTRIES LTD	15,765.03	23.0776	30,000.89	14,235.86	
					5,871.19-	C
					20,107.05	I
1,000.0000	CANON INC	29,728.38	33.9622	33,962.26	4,233.88	
					64.85	C
					4,169.03	I
700.0000	CENTRAL JAPAN RAILWAY CO	53,139.24	162.9583	114,070.84	60,931.60	
					22,323.74-	C
					83,255.34	I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
4,000.0000	CHIBA BANK LTD/THE	23,891.90	7.2445	28,978.28	5,086.38 5,671.07- C 10,757.45 I
2,900.0000	CHUBU ELECTRIC POWER CO INC	36,469.89	13.2831	38,521.27	2,051.38 1,761.74 C 289.64 I
2,000.0000	CHUGOKU BANK LTD/THE	27,000.83	14.9519	29,903.88	2,903.05 5,852.21- C 8,755.26 I
900.0000	CHUGAI PHARMACEUTICAL CO LTD	17,152.34	37.4243	33,681.91	16,529.57 6,591.59- C 23,121.16 I
2,900.0000	RAKUTEN INC	20,995.91	11.7657	34,120.68	13,124.77 6,677.44- C 19,802.21 I
7,200.0000	KDDI CORP	62,221.16	26.4773	190,637.23	128,416.07 37,307.88- C 165,723.95 I
400.0000	DAITO TRUST CONSTRUCTION CO LT	19,398.86	155.7048	62,281.95	42,883.09 12,188.62- C 55,071.71 I
1,000.0000	DAIKIN INDUSTRIES LTD	42,055.71	102.0825	102,082.59	60,026.88 19,977.64- C 80,004.52 I
3,000.0000	DAIWA HOUSE INDUSTRY CO LTD	33,953.32	34.1580	102,474.19	68,520.87 20,054.25- C 88,575.12 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
7,000.0000	DAIWA SECURITIES GROUP INC	36,742.85	5.9255	41,479.17	4,736.32 8,117.52- C 12,853.84 I
200.0000	LAWSON INC	8,549.55	69.9537	13,990.74	5,441.19 2,738.01- C 8,179.20 I
4,200.0000	MITSUBISHI UFJ LEASE & FINANCE	15,159.21	5.4645	22,951.23	7,792.02 4,491.57- C 12,283.59 I
500.0000	EAST JAPAN RAILWAY CO	34,602.80	95.6301	47,815.06	13,212.26 9,357.45- C 22,569.71 I
1,100.0000	EISAI CO LTD	39,468.48	55.2242	60,746.70	21,278.22 11,888.18- C 33,166.40 I
200.0000	FAST RETAILING CO LTD	35,539.73	333.0366	66,607.33	31,067.60 13,035.09- C 44,102.69 I
58,400.0000	MITSUBISHI UFJ FINANCIAL GROUP	302,154.77	6.7176	392,313.26	90,158.49 65,879.14- C 156,037.63 I
3,000.0000	SUBARU CORP	15,395.58	33.6952	101,085.79	85,690.21 19,782.55- C 105,472.76 I
1,000.0000	FUJIFILM HOLDINGS CORP	32,595.17	35.9558	35,955.85	3,360.68 1,644.41 C 1,716.27 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
500.0000	MIRACA HOLDINGS INC	18,947.95	44.9448	22,472.41	3,524.46 7,985.98- C 11,510.44 I
600.0000	FANUC CORP	65,223.61	192.7287	115,637.23	50,413.62 22,630.30- C 73,043.92 I
847.0000	NOMURA RESEARCH INSTITUTE LTD	15,949.23	39.3823	33,356.84	17,407.61 6,527.97- C 23,935.58 I
6.0000	NIPPON BUILDING FUND INC	25,552.84	5,108.5793	30,651.48	5,098.64 5,998.52- C 11,097.16 I
3.0000	JAPAN REAL ESTATE INVESTMENT C	12,568.81	4,975.0798	14,925.24	2,356.43 2,920.90- C 5,277.33 I
13,000.0000	HACHIJUNI BANK LTD/THE	76,760.70	6.3456	82,493.77	5,733.07 1,337.36- C 7,070.43 I
1,400.0000	HAMAMATSU PHOTONICS KK	31,350.22	30.7048	42,986.83	11,636.61 4,531.50- C 16,168.11 I
1,000.0000	HANKYU HANSHIN HOLDINGS INC	23,104.03	35.9558	35,955.85	12,851.82 7,036.61- C 19,888.43 I
700.0000	DENTSU INC	18,595.01	47.7928	33,454.96	14,859.95 6,547.17- C 21,407.12 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
9,000.0000	RESONA HOLDINGS INC	45,879.59	5.5046	49,541.65	3,662.06 12,214.09- C 15,876.15 I
210.0000	HIROSE ELECTRIC CO LTD	23,444.73	142.5774	29,941.26	6,496.53 5,859.53- C 12,356.06 I
18,000.0000	HITACHI LTD	70,525.83	6.1356	110,441.43	39,915.60 21,613.49- C 61,529.09 I
1,445.0000	SUMITOMO MITSUI TRUST HOLDINGS	55,300.00	35.7689	51,686.14	3,613.86- 1,342.27- C 2,271.59- I
2,600.0000	HONDA MOTOR CO LTD	87,047.84	27.2694	70,900.67	16,147.17- 6,867.79- C 9,279.38- I
1,700.0000	HOYA CORP	46,372.00	51.9134	88,252.93	41,880.93 17,271.17- C 59,152.10 I
9,000.0000	IHI CORP	16,385.75	3.3997	30,598.08	14,212.33 5,988.06- C 20,200.39 I
3,000.0000	ISUZU MOTORS LTD	16,353.81	12.3353	37,006.05	20,652.24 7,242.10- C 27,894.34 I
9,200.0000	ITOCHU CORP	90,603.96	14.8540	136,657.17	46,053.21 13,689.42- C 59,742.63 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
3,600.0000	JAPAN TOBACCO INC	66,501.25	35.1281	126,461.37	59,960.12 24,748.57- C 84,708.69 I
2,600.0000	AEON CO LTD	30,173.64	15.1922	39,499.82	9,326.18 7,730.15- C 17,056.33 I
7,000.0000	KAJIMA CORP	17,290.75	8.4371	59,060.16	41,769.41 11,558.11- C 53,327.52 I
4,000.0000	KANEKA CORP	23,423.87	7.6183	30,473.48	7,049.61 11,918.50- C 18,968.11 I
3,300.0000	KANSAI ELECTRIC POWER CO INC/T	31,643.91	13.7682	45,435.21	13,791.30 2,077.95 C 11,713.35 I
2,000.0000	KANSAI PAINT CO LTD	33,218.05	23.0064	46,012.81	12,794.76 2,022.16 C 10,772.60 I
3,000.0000	KAO CORP	83,734.73	59.3805	178,141.68	94,406.95 31,651.26- C 126,058.21 I
6,000.0000	KAWASAKI HEAVY INDUSTRIES LTD	16,481.58	2.9547	17,728.73	1,247.15 3,469.53- C 4,716.68 I
2,000.0000	KEIKYU CORP	16,375.11	12.0416	24,083.30	7,708.19 4,713.13- C 12,421.32 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
2,000.0000	KIKKOMAN CORP	23,529.90	31.9508	63,901.74	40,371.84 12,505.62- C 52,877.46 I
440.0000	KEYENCE CORP	48,358.74	439.1242	193,214.66	144,855.92 37,812.26- C 182,668.18 I
7,000.0000	KINTETSU GROUP HOLDINGS CO LTD	21,687.96	3.8536	26,975.79	5,287.83 5,279.18- C 10,567.01 I
3,000.0000	KOMATSU LTD	63,051.62	25.4049	76,214.84	13,163.22 14,915.31- C 28,078.53 I
800.0000	KONAMI HOLDINGS CORP	15,527.61	55.5357	44,428.62	28,901.01 8,694.74- C 37,595.75 I
1,300.0000	JTEKT CORP	15,875.76	14.6137	18,997.86	3,122.10 3,717.90- C 6,840.00 I
5,000.0000	KUBOTA CORP	46,048.34	16.7986	83,993.41	37,945.07 16,437.59- C 54,382.66 I
1,500.0000	KURARAY CO LTD	20,170.77	18.1381	27,207.19	7,036.42 5,324.47- C 12,360.89 I
100.0000	KYOCERA CORP	4,987.09	57.9031	5,790.32	803.23 146.43 C 656.80 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
2,700.0000	KYOWA HAKKO KIRIN CO LTD	30,956.67	18.5742	50,150.41	19,193.74 5,745.52- C 24,939.26 I
2,900.0000	TOKIO MARINE HOLDINGS INC	80,865.14	41.3937	120,041.82	39,176.68 23,492.28- C 62,668.96 I
1,000.0000	MAKITA CORP	16,981.98	36.9793	36,979.35	19,997.37 7,236.88- C 27,234.25 I
6,100.0000	SUMITOMO MITSUI FINANCIAL GROU	202,012.52	38.9729	237,734.95	35,722.43 35,830.65- C 71,553.08 I
2,100.0000	MARUI GROUP CO LTD	15,628.74	14.7383	30,950.51	15,321.77 6,057.04- C 21,378.81 I
800.0000	PANASONIC CORP	7,749.24	13.5635	10,850.84	3,101.60 1,626.90- C 4,728.50 I
130,600.0000	MIZUHO FINANCIAL GROUP INC	236,600.91	1.8280	238,743.67	2,142.76 27,916.17- C 30,058.93 I
1,000.0000	CREDIT SAISON CO LTD	15,129.41	19.5265	19,526.52	4,397.11 3,821.37- C 8,218.48 I
5,100.0000	MITSUBISHI CORP	103,072.16	20.9683	106,938.41	3,866.25 5,961.81- C 9,828.06 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
1,500.0000	MITSUBISHI GAS CHEMICAL CO INC	18,270.28	21.1374	31,706.12	13,435.84 6,204.92- C 19,640.76 I
8,000.0000	MITSUBISHI ELECTRIC CORP	73,251.46	14.3778	115,023.13	41,771.67 22,510.12- C 64,281.79 I
13,000.0000	MITSUBISHI HEAVY INDUSTRIES LT	54,672.42	4.0922	53,198.64	1,473.78- 10,411.03- C 8,937.25 I
2,100.0000	MITSUBISHI MATERIALS CORP	67,109.21	30.2598	63,545.74	3,563.47- 1,494.02- C 2,069.45- I
4,200.0000	MITSUI & CO LTD	61,293.78	14.2888	60,013.35	1,280.43- 3,280.08- C 1,999.65 I
5,000.0000	MITSUI CHEMICALS INC	15,384.93	5.2954	26,477.39	11,092.46 5,181.65- C 16,274.11 I
18,000.0000	MITSUI OSK LINES LTD	52,179.63	2.9369	52,865.79	686.16 1,336.83 C 650.67- I
3,000.0000	MITSUI FUDOSAN CO LTD	51,520.90	23.8563	71,569.06	20,048.16 14,006.12- C 34,054.28 I
1,100.0000	MURATA MANUFACTURING CO LTD	74,737.89	151.9223	167,114.62	92,376.73 20,556.27- C 112,933.00 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
2,000.0000	SEIKO EPSON CORP	15,832.11	22.2410	44,482.02	28,649.91 8,705.18- C 37,355.09 I
600.0000	NINTENDO CO LTD	73,591.25	335.3506	201,210.39	127,619.14 22,525.84- C 150,144.98 I
1,900.0000	DENSO CORP	56,338.67	42.2036	80,186.90	23,848.23 15,692.63- C 39,540.86 I
800.0000	NIDEC CORP	42,375.12	102.4385	81,950.87	39,575.75 16,037.85- C 55,613.60 I
1,000.0000	NH FOODS LTD	12,882.89	30.3933	30,393.38	17,510.49 5,948.01- C 23,458.50 I
1,210.0000	NISSHIN SEIFUN GROUP INC	13,074.53	16.4204	19,868.72	6,794.19 3,888.32- C 10,682.51 I
4,000.0000	NIPPON TELEGRAPH & TELEPHONE C	84,217.89	47.2588	189,035.24	104,817.35 36,994.34- C 141,811.69 I
3,000.0000	NSK LTD	32,238.25	12.4866	37,459.95	5,221.70 160.85- C 5,382.55 I
1,000.0000	NISSAN CHEMICAL INDUSTRIES LTD	14,192.47	33.0188	33,018.87	18,826.40 6,461.83- C 25,288.23 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
400.0000	NISSIN FOODS HOLDINGS CO LTD	13,330.06	62.4777	24,991.10	11,661.04 4,890.77- C 16,551.81 I
600.0000	NITTO DENKO CORP	23,380.84	82.2356	49,341.40	25,960.56 9,656.14- C 35,616.70 I
3,000.0000	NIPPON EXPRESS CO LTD	13,127.77	6.2566	18,770.02	5,642.25 3,673.32- C 9,315.57 I
1,100.0000	YAMAHA CORP	14,440.55	34.5318	37,985.05	23,544.50 7,433.72- C 30,978.22 I
2,000.0000	MINEBEA MITSUMI INC	12,329.24	16.0644	32,128.87	19,799.63 6,287.63- C 26,087.26 I
1,255.0000	NIPPON STEEL & SUMITOMO METAL	26,849.32	22.5881	28,348.08	1,498.76 7,352.45- C 8,851.21 I
1,000.0000	NIPPON ELECTRIC GLASS CO LTD	28,598.11	36.3563	36,356.35	7,758.24 919.35 C 6,838.89 I
4,000.0000	NISSAN MOTOR CO LTD	34,624.09	9.9501	39,800.64	5,176.55 7,789.01- C 12,965.56 I
300.0000	NITORI HOLDINGS CO LTD	11,339.06	133.8554	40,156.64	28,817.58 7,858.66- C 36,676.24 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
800.0000	ORIENTAL LAND CO LTD/JAPAN	13,841.12	67.7109	54,168.74	40,327.62 10,600.87- C 50,928.49 I
3,000.0000	OBAYASHI CORP	13,255.53	11.7568	35,270.56	22,015.03 6,902.48- C 28,917.51 I
2,000.0000	OJI HOLDINGS CORP	8,837.02	5.1619	10,323.96	1,486.94 2,020.40- C 3,507.34 I
900.0000	OLYMPUS CORP	22,763.58	36.4898	32,840.87	10,077.29 10,246.45- C 20,323.74 I
800.0000	OMRON CORP	18,457.66	43.3873	34,709.86	16,252.20 6,792.75- C 23,044.95 I
1,300.0000	ONO PHARMACEUTICAL CO LTD	11,377.40	21.8138	28,357.96	16,980.56 5,549.68- C 22,530.24 I
6,500.0000	ORIX CORP	66,734.81	15.4859	100,658.59	33,923.78 6,918.27- C 40,842.05 I
7,000.0000	OSAKA GAS CO LTD	24,818.19	4.0895	28,626.73	3,808.54 5,602.29- C 9,410.83 I
1,200.0000	ALFRESA HOLDINGS CORP	13,095.82	19.2862	23,143.47	10,047.65 4,529.17- C 14,576.82 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
2,000.0000	JAPAN EXCHANGE GROUP INC	23,115.52	18.1114	36,222.85	13,107.33 4,661.13- C 17,768.46 I
2,900.0000	T&D HOLDINGS INC	34,272.73	15.2144	44,122.02	9,849.29 8,634.70- C 18,483.99 I
200.0000	SMC CORP/JAPAN	27,128.60	303.9337	60,786.75	33,658.15 11,896.03- C 45,554.18 I
4,100.0000	SOFTBANK GROUP CORP	118,382.05	80.9629	331,948.19	213,566.14 59,207.26- C 272,773.40 I
2,000.0000	SANTEN PHARMACEUTICAL CO LTD	12,031.12	13.5635	27,127.09	15,095.97 5,308.78- C 20,404.75 I
700.0000	SECOM CO LTD	30,855.05	75.8721	53,110.54	22,255.49 10,393.77- C 32,649.26 I
2,000.0000	SEKISUI CHEMICAL CO LTD	13,670.77	17.8978	35,795.66	22,124.89 7,005.24- C 29,130.13 I
2,000.0000	SEKISUI HOUSE LTD	19,888.62	17.6174	35,234.96	15,346.34 6,895.50- C 22,241.84 I
1,000.0000	SHIMADZU CORP	8,070.43	19.0281	19,028.12	10,957.69 3,723.80- C 14,681.49 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
3,000.0000	SHIMIZU CORP	12,520.89	10.5998	31,799.57	19,278.68 6,223.20- C 25,501.88 I
800.0000	SHIN-ETSU CHEMICAL CO LTD	45,924.37	90.6461	72,516.91	26,592.54 12,118.71- C 38,711.25 I
1,900.0000	SHIONOGI & CO LTD	45,108.18	55.7048	105,839.26	60,731.08 4,709.80- C 65,440.88 I
300.0000	SHIMANO INC	13,351.35	158.2413	47,472.41	34,121.06 9,290.36- C 43,411.42 I
6,000.0000	SHIZUOKA BANK LTD/THE	52,717.81	9.0334	54,200.78	1,482.97 2,056.41- C 3,539.38 I
2,900.0000	SHOWA SHELL SEKIYU KK	19,797.65	9.2737	26,893.91	7,096.26 12,455.02- C 19,551.28 I
1,900.0000	SONY CORP	45,592.45	38.1452	72,475.97	26,883.52 3,314.64 C 23,568.88 I
700.0000	STANLEY ELECTRIC CO LTD	13,467.41	30.1708	21,119.61	7,652.20 4,133.14- C 11,785.34 I
11,000.0000	SUMITOMO CHEMICAL CO LTD	54,772.56	5.7493	63,243.14	8,470.58 5,185.94- C 13,656.52 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
2,000.0000	SUMITOMO HEAVY INDUSTRIES LTD	12,095.00	6.5948	13,189.75	1,094.75 2,581.23- C 3,675.98 I
7,000.0000	SUMITOMO METAL MINING CO LTD	100,540.17	13.3543	93,480.77	7,059.40- 6,485.70- C 573.70- I
820.0000	SUMITOMO REALTY & DEVELOPMENT	15,680.07	30.8383	25,287.47	9,607.40 4,948.78- C 14,556.18 I
7,400.0000	SUMITOMO CORP	81,714.63	13.0117	96,286.93	14,572.30 9,059.30- C 23,631.60 I
2,100.0000	SUMITOMO RUBBER INDUSTRIES LTD	22,012.72	16.8743	35,436.10	13,423.38 13,640.69- C 27,064.07 I
1,000.0000	SURUGA BANK LTD	8,975.43	24.2257	24,225.70	15,250.27 4,741.00- C 19,991.27 I
1,400.0000	SUZUKI MOTOR CORP	31,182.97	47.4368	66,411.53	35,228.56 12,996.78- C 48,225.34 I
600.0000	THK CO LTD	13,095.82	28.3018	16,981.13	3,885.31 3,323.21- C 7,208.52 I
6,000.0000	TAISEI CORP	13,223.59	9.1313	54,788.18	41,564.59 10,722.08- C 52,286.67 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
1,000.0000	TAKASHIMAYA CO LTD	8,421.78	9.5140	9,514.06	1,092.28 1,861.91- C 2,954.19 I
600.0000	TAKEDA PHARMACEUTICAL CO LTD	24,626.51	50.8098	30,485.94	5,859.43 13,565.00- C 19,424.43 I
1,000.0000	MITSUBISHI TANABE PHARMA CORP	14,181.83	23.1043	23,104.31	8,922.48 4,521.54- C 13,444.02 I
800.0000	TEIJIN LTD	13,500.42	19.2328	15,386.26	1,885.84 3,011.11- C 4,896.95 I
800.0000	SYSMEX CORP	26,540.74	59.7187	47,775.01	21,234.27 7,163.07- C 28,397.34 I
900.0000	TOHO CO LTD/TOKYO	14,383.04	30.7938	27,714.49	13,331.45 5,423.73- C 18,755.18 I
6,000.0000	TOHO GAS CO LTD	29,762.75	7.2801	43,681.02	13,918.27 2,226.57 C 11,691.70 I
8,700.0000	TOKYO ELECTRIC POWER CO HOLDIN	29,343.63	4.1206	35,849.94	6,506.31 850.90- C 7,357.21 I
9,000.0000	TOKYO GAS CO LTD	39,670.78	5.2002	46,802.24	7,131.46 9,159.24- C 16,290.70 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
1,000.0000	TOKYO ELECTRON LTD	69,770.23	134.9234	134,923.45	65,153.22 11,016.38- C 76,169.60 I
7,926.0000	TOKYU CORP	36,585.38	7.6272	60,453.74	23,868.36 18,496.29- C 42,364.65 I
3,000.0000	TOPPAN PRINTING CO LTD	27,149.98	10.9647	32,894.27	5,744.29 3,105.79- C 8,850.08 I
9,000.0000	TORAY INDUSTRIES INC	54,538.06	8.3686	75,317.73	20,779.67 13,106.39- C 33,886.06 I
1,000.0000	TOTO LTD	13,670.77	38.1808	38,180.85	24,510.08 7,472.03- C 31,982.11 I
1,000.0000	LIXIL GROUP CORP	20,484.86	24.9999	25,000.00	4,515.14 4,892.52- C 9,407.66 I
700.0000	TOYOTA INDUSTRIES CORP	19,884.36	52.5987	36,819.15	16,934.79 7,205.55- C 24,140.34 I
900.0000	TOYOTA TSUSHO CORP	14,287.22	29.9483	26,953.54	12,666.32 5,274.83- C 17,941.15 I
11,260.0000	TOYOTA MOTOR CORP	445,463.67	52.4474	590,558.71	145,095.04 118,305.72- C 263,400.76 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
900.0000	UNICHARM CORP	9,710.07	25.1156	22,604.13	12,894.06 4,423.62- C 17,317.68 I
600.0000	WEST JAPAN RAILWAY CO	20,729.73	70.6301	42,378.07	21,648.34 8,293.42- C 29,941.76 I
8,400.0000	YAMADA DENKI CO LTD	32,761.71	4.9661	41,715.91	8,954.20 1,907.85 C 7,046.35 I
500.0000	YAKULT HONSHA CO LTD	13,228.91	68.0847	34,042.36	20,813.45 6,662.11- C 27,475.56 I
900.0000	YAMAHA MOTOR CO LTD	13,271.50	25.7920	23,212.89	9,941.39 4,542.77- C 14,484.16 I
9,000.0000	ASTELLAS PHARMA INC	65,447.20	12.2330	110,097.00	44,649.80 21,546.09- C 66,195.89 I
800.0000	YAMATO HOLDINGS CO LTD	11,277.31	20.2785	16,222.85	4,945.54 3,174.81- C 8,120.35 I
1,000.0000	YASKAWA ELECTRIC CORP	9,294.84	21.1908	21,190.81	11,895.97 4,147.07- C 16,043.04 I
1,700.0000	YOKOGAWA ELECTRIC CORP	15,004.83	16.0288	27,249.02	12,244.19 5,332.65- C 17,576.84 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS	
43,600.0000	SINGAPORE TELECOMMUNICATIONS L	104,220.55	2.8252	123,182.63	18,962.08	
					2,545.39	C
					16,416.69	I
14,100.0000	STARHUB LTD	29,752.05	1.9755	27,854.89	1,897.16-	
					631.72	C
					2,528.88-	I
11,800.0000	KEPPEL CORP LTD	51,725.95	4.5683	53,907.11	2,181.16	
					1,222.56	C
					958.60	I
30,100.0000	GLOBAL LOGISTIC PROPERTIES LTD	48,631.38	2.0772	62,523.88	13,892.50	
					513.46-	C
					14,405.96	I
7,000.0000	SINGAPORE TECHNOLOGIES ENGINEE	16,346.20	2.6727	18,709.37	2,363.17	
					273.81	C
					2,089.36	I
11,200.0000	DBS GROUP HOLDINGS LTD	114,359.05	15.0633	168,709.74	54,350.69	
					2,766.18	C
					51,584.51	I
1,000.0000	JARDINE CYCLE & CARRIAGE LTD	22,406.17	32.2112	32,211.21	9,805.04	
					471.43	C
					9,333.61	I
23,000.0000	GENTING SINGAPORE PLC	14,662.87	0.7880	18,124.70	3,461.83	
					265.26	C
					3,196.57	I
12,000.0000	CAPITALAND MALL TRUST	15,455.50	1.4344	17,213.20	1,757.70	
					253.39	C
					1,504.31	I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS	
9,500.0000	HONGKONG LAND HOLDINGS LTD	59,485.50	7.3600	69,920.00	10,434.50	I
11,000.0000	ASCENDAS REAL ESTATE INVESTMEN	15,238.53	1.8956	20,851.94	5,613.41	
					311.94	C
					5,301.47	I
20,000.0000	COMFORTDELGRO CORP LTD	30,872.78	1.6704	33,409.59	2,536.81	
					3,733.62-	C
					6,270.43	I
500.0000	UNITED OVERSEAS BANK LTD	6,894.03	16.7919	8,395.98	1,501.95	
					203.30-	C
					1,705.25	I
4,983.0000	BANK HAPOALIM BM	20,845.61	6.7455	33,613.15	12,767.54	
					2,424.69	C
					10,342.85	I
7,787.0000	BANK LEUMI LE-ISRAEL BM	30,792.57	4.8628	37,867.26	7,074.69	
					3,398.26	C
					3,676.43	I
701.0000	NICE LTD	20,040.18	80.1788	56,205.35	36,165.17	
					3,901.41	C
					32,263.76	I
1,591.0000	AERCAP HOLDINGS NV	63,888.56	46.4300	73,870.13	9,981.57	I
2,417.0000	MOBILEYE NV	89,452.11	62.8000	151,787.60	62,335.49	I
1,363.0000	NXP SEMICONDUCTORS NV	117,854.98	109.4500	149,180.35	31,325.37	I
8,500.0000	NOVO NORDISK A/S	135,253.36	42.7686	363,533.17	228,279.81	
					62,532.75-	C
					290,812.56	I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
1,500.0000	DSV A/S	28,012.01	61.3609	92,041.48	64,029.47 14,617.61- C 78,647.08 I
416.0000	PANDORA A/S	30,445.75	93.1919	38,767.87	8,322.12 7,680.75- C 16,002.87 I
1,000.0000	NOVOZYMES A/S	26,215.68	43.7043	43,704.36	17,488.68 6,940.92- C 24,429.60 I
500.0000	COLOPLAST A/S	14,432.49	83.4509	41,725.47	27,292.98 8,697.65- C 35,990.63 I
49.0000	AP MOLLER - MAERSK A/S	76,045.58	2,008.0382	98,393.88	22,348.30 6,609.82 C 15,738.48 I
9.0000	AP MOLLER - MAERSK A/S	14,242.97	1,906.7926	17,161.13	2,918.16 2,413.17- C 5,331.33 I
3,418.0000	DANSKE BANK A/S	76,178.70	38.4119	131,292.14	55,113.44 19,054.27- C 74,167.71 I
1,239.0000	VESTAS WIND SYSTEMS A/S	56,290.56	92.1948	114,229.46	57,938.90 13,556.45- C 71,495.35 I
862.0000	NESTE OYJ	15,247.76	39.3375	33,908.98	18,661.22 6,338.52- C 24,999.74 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
578.0000	NOKIAN RENKAAT OYJ	15,030.89	41.3335	23,890.78	8,859.89 4,465.84- C 13,325.73 I
1,228.0000	KONE OYJ	25,879.95	50.8000	62,382.52	36,502.57 11,661.00- C 48,163.57 I
1,119.0000	ORION OYJ	30,466.09	63.7567	71,343.80	40,877.71 14,887.39- C 55,765.10 I
672.0000	WARTSILA OYJ ABP	17,489.02	59.0234	39,663.77	22,174.75 7,414.25- C 29,589.00 I
2,079.0000	UPM-KYMMENE OYJ	28,102.21	28.4681	59,185.24	31,083.03 11,063.33- C 42,146.36 I
2,779.0000	STORA ENSO OYJ	21,925.24	12.8996	35,848.05	13,922.81 4,358.62- C 18,281.43 I
1,121.0000	SAMPO OYJ	30,472.53	51.1764	57,368.83	26,896.30 10,723.80- C 37,620.10 I
729.0000	ELISA OYJ	15,096.99	38.6988	28,211.47	13,114.48 5,273.49- C 18,387.97 I
511.0000	METSO OYJ	13,530.68	34.6270	17,694.45	4,163.77 3,307.56- C 7,471.33 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS	
16,027.0000	NOKIA OYJ	71,915.50	6.1076	97,887.24	25,971.74	
					5,136.61	C
					20,835.13	I
17,726.0000	NORSK HYDRO ASA	91,187.58	5.5248	97,934.05	6,746.47	
					5,296.01-	C
					12,042.48	I
4,700.0000	DNB ASA	61,333.08	16.9518	79,673.86	18,340.78	
					25,070.74-	C
					43,411.52	I
413.0000	TELENOR ASA	6,511.37	16.5340	6,828.57	317.20	
					30.88	C
					286.32	I
2,857.0000	SCHIBSTED ASA	59,310.68	24.0669	68,759.13	9,448.45	
					310.92	C
					9,137.53	I
1,173.0000	INTERNATIONAL PETROLEUM CORP/S	3,019.86	2.9639	3,476.77	456.91	
					210.38	C
					246.53	I
865.0000	KINNEVIK AB	23,637.11	30.5766	26,448.77	2,811.66	
					6,947.55-	C
					9,759.21	I
2,200.0000	ESSITY AB	24,712.88	27.3280	60,121.76	35,408.88	
					10,547.79-	C
					45,956.67	I
2,600.0000	ATLAS COPCO AB	39,190.12	38.2948	99,566.66	60,376.54	
					17,468.02-	C
					77,844.56	I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
1,661.0000	ATLAS COPCO AB	25,866.16	34.5128	57,325.77	31,459.61 7,495.75- C 38,955.36 I
6,000.0000	SVENSKA HANDELSBANKEN AB	59,536.55	14.2983	85,790.00	26,253.45 15,051.03- C 41,304.48 I
4,200.0000	ASSA ABLOY AB	27,660.10	21.9454	92,170.89	64,510.79 16,170.52- C 80,681.31 I
331.0000	ELECTROLUX AB	7,587.27	32.7344	10,835.09	3,247.82 1,900.91- C 5,148.73 I
7,547.0000	VOLVO AB	82,486.19	17.0252	128,489.27	46,003.08 6,809.82- C 52,812.90 I
3,038.0000	INDUSTRIVARDEN AB	55,593.87	23.9491	72,757.41	17,163.54 5,666.26 C 11,497.28 I
3,195.0000	SVENSKA CELLULOSA AB SCA	12,396.56	7.5581	24,148.44	11,751.88 1,741.19- C 13,493.07 I
1,300.0000	BOLIDEN AB	20,046.99	27.2569	35,434.02	15,387.03 9,403.33- C 24,790.36 I
1,159.0000	HEXAGON AB	19,908.24	47.4832	55,033.11	35,124.87 11,092.16- C 46,217.03 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
6,200.0000	SKANDINAVISKA ENSKILDA BANKEN	40,284.08	12.0812	74,903.82	34,619.74 13,141.17- C 47,760.91 I
2,500.0000	SWEDBANK AB	26,108.25	24.3403	60,850.91	34,742.66 10,675.72- C 45,418.38 I
1,200.0000	SWEDISH MATCH AB	28,861.98	35.1767	42,212.09	13,350.11 7,405.71- C 20,755.82 I
13,000.0000	NORDEA BANK AB	133,225.25	12.7096	165,225.18	31,999.93 28,987.19- C 60,987.12 I
1,600.0000	SECURITAS AB	17,211.22	16.8355	26,936.83	9,725.61 4,725.80- C 14,451.41 I
3,095.0000	INVESTOR AB	76,513.48	48.1353	148,978.90	72,465.42 11,385.35- C 83,850.77 I
5,046.0000	TELEFONAKTIEBOLAGET LM ERICSSO	29,829.35	7.1432	36,044.78	6,215.43 1,266.07 C 4,949.36 I
1,600.0000	SKANSKA AB	29,626.06	23.7001	37,920.22	8,294.16 6,652.75- C 14,946.91 I
3,521.0000	LUNDIN PETROLEUM AB	44,351.64	19.2185	67,668.59	23,316.95 6,542.49- C 29,859.44 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
1,300.0000	ALFA LAVAL AB	19,539.70	20.4397	26,571.66	7,031.96 4,661.74- C 11,693.70 I
2,696.0000	MELCO RESORTS & ENTERTAINMENT ADR	45,414.12	22.4500	60,525.20	15,111.08 I
2,222.0000	TEVA PHARMACEUTICAL INDUSTRIES ADR	74,996.00	33.2200	73,814.84	1,181.16-I
TOTAL INVESTMENTS EQUITY		33,248,705.60		49,206,427.52	15,957,721.92 5,202,006.73- C 21,159,728.65 I
TOTAL INVESTMENT		33,803,924.14		49,865,826.11	16,061,901.97 5,238,510.51- C 21,300,412.48 I

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PRAIRIE I -TOWNSEND RE
EXCEL ENERGY NDT

SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS REAL ESTATE					
365.4840	PRIME PROPERTY FUND LLC	3,613,290.58	22,334.0281	8,162,729.93	4,549,439.35
1,631,341.0000	FORTRESS JAPAN OPPORTUNITY DOMESTIC FUND © LP	21,090.00	0.6903	1,126,194.00	1,105,104.00
1,388,791.0000	BRAZIL REAL ESTATE OPPORTUNITIES FUND II	1,373,380.96	0.7737	1,074,557.00	298,823.96-
1,463,026.5900	BROOKFIELD REAL ESTATE FUND	0.00	0.1048	153,434.89	153,434.89
231,482.0000	EXETER INDUSTRIAL VALUE FUND II LPP	0.00	1.0291	238,228.00	238,228.00
1,471,453.6400	DIVCOWEST FUND III	0.00	0.2372	349,126.00	349,126.00
2,702,602.7550	JAMESTOWN PREMIER PROPERTY	2,068,696.15	1.7888	4,834,631.64	2,765,935.49
1,479,839.0000	BROOKFIELD FAIRFIELD MULTIFAMILY	231.00	0.3586	530,814.00	530,583.00
955,518.0000	CVI EUROPE REAL ESTATE PARTNER TG LLC	354,253.46	0.7410	708,102.85	353,849.39
1,128,000.0000	SAVANNA REAL ESTATE FUND IIA LP LLC	1,033,437.35	1.5961	1,800,475.35	767,038.00
5,414,950.4850	USAA EAGLE REAL ESTATE LP	4,730,136.22	1.3447	7,281,817.95	2,551,681.73
4,947,645.6900	PRISA REAL ESTATE LP	4,824,165.22	1.3886	6,870,410.00	2,046,244.78

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
917,387.0000	GREENFIELD ACQUI RTNRS VII LP	826,394.00	1.1177	1,025,386.00	198,992.00
1,048,987.7100	NORTHLIGHT REAL ESTATE OPPORTUNITY FUND	942,581.48	1.0774	1,130,226.23	187,644.75
1,047,748.0000	H/2 SPECIAL OPPORTUNITIES III LP	975,985.00	1.1144	1,167,624.00	191,639.00
285,951.0000	BRV PARTNERS FUND I LP	147,235.00	1.0121	289,421.00	142,186.00
4,047,685.0200	METLIFE CORE PROPERTY FUND L P	3,806,617.86	1.0687	4,325,988.00	519,370.14
2,386,800.0000	INLAND RETAIL PROPERTY	2,386,800.00	1.0544	2,516,706.00	129,906.00
364,500.0000	ASANA PARTNERS I	364,500.00	1.0263	374,115.00	9,615.00
2,025,000.0000	HANCOCK US REAL ESTATE	2,025,000.00	1.0000	2,025,000.00	0.00
3,496,151.6220	UBS TRUMBULL PROPERTY FUND	3,042,093.91	1.3598	4,754,188.48	1,712,094.57
944.0800	TTG BRPTP FUND LP	0.00	0.0000	0.00	0.00
1,904,175.0000	LION INDUSTRIAL TRUST	1,847,756.33	1.1251	2,142,445.03	294,688.70
1,541,626.0800	CITIC CAPITAL CHINA	1,216,735.41	0.8301	1,279,773.24	63,037.83
TOTAL INVESTMENTS REAL ESTATE		35,600,379.93		54,161,394.59	18,561,014.66
TOTAL INVESTMENT		35,600,379.93		54,161,394.59	18,561,014.66

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WELLINGTON-PI 1
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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS FIXED INCOME SECURITIES					
2,753,401.6160	WTC-CTF JPM PAG EMERGING MARKETS DEBT	27,300,049.39	10.7200	29,516,465.32	2,216,415.93
TOTAL INVESTMENTS FIXED INCOME SECURITIES		27,300,049.39		29,516,465.32	2,216,415.93
TOTAL INVESTMENT		27,300,049.39		29,516,465.32	2,216,415.93

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XCEL ENERGY NDT

SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS PRIVATE EQUITY					
47,189,579.3200	STEPSTONE XL OPP FUND LP	41,726,990.02	1.2446	58,732,433.56	17,005,443.54
TOTAL INVESTMENTS PRIVATE EQUITY		41,726,990.02		58,732,433.56	17,005,443.54
TOTAL INVESTMENT		41,726,990.02		58,732,433.56	17,005,443.54

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FIRST PRINCIPALS CAP-PI 1
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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS CASH EQUIVALENTS					
51,963.2700	BLACKROCK LIQ T FUND INSTL FUND 60	51,963.27	100.0000	51,963.27	0.00
TOTAL INVESTMENTS CASH EQUIVALENTS		51,963.27		51,963.27	0.00
INVESTMENTS FIXED INCOME SECURITIES					
350,000.0000	AT&T INC 4.350% 06/15/2045 DD 06/15/13	332,703.66	92.8110	324,838.50	7,865.16-
150,000.0000	AT&T INC 5.150% 03/15/2042 DD 03/15/16	146,959.15	102.1190	153,178.50	6,219.35
300,000.0000	ABBVIE INC 3.200% 11/06/2022 DD 05/14/15	301,253.17	102.5660	307,698.00	6,444.83
300,000.0000	AERCAP IRELAND CAPITAL DAC / A 3.750% 05/15/2019 DD 05/15/15	303,770.92	102.7130	308,139.00	4,368.08
300,000.0000	AMAZON.COM INC 2.500% 11/29/2022 DD 11/29/12	294,911.90	100.8010	302,403.00	7,491.10
300,000.0000	AMERICAN EXPRESS CREDIT CORP VAR RT 03/03/2022 DD 03/03/17	300,000.00	100.6790	302,037.00	2,037.00
300,000.0000	AMGEN INC 2.700% 05/01/2022 DD 05/01/15	298,165.96	100.5740	301,722.00	3,556.04
500,000.0000	ANHEUSER-BUSCH INBEV FINANCE I 4.900% 02/01/2046 DD 01/25/16	573,853.71	112.8640	564,320.00	9,533.71-

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
250,000.0000	APPLE INC 3.350% 02/09/2027 DD 02/09/17	248,086.30	102.2330	255,582.50	7,496.20
250,000.0000	BANK OF AMERICA CORP 5.700% 01/24/2022 DD 01/24/12	281,117.45	112.9960	282,490.00	1,372.55
250,000.0000	BANK OF AMERICA CORP 4.450% 03/03/2026 DD 03/03/16	262,615.01	104.0740	260,185.00	2,430.01-
250,000.0000	BRISTOL-MYERS SQUIBB CO 3.250% 02/27/2027 DD 02/27/17	246,117.52	100.8630	252,157.50	6,039.98
300,000.0000	BURLINGTON NORTHERN SANTA FE L 3.250% 06/15/2027 DD 03/09/17	299,261.03	102.1580	306,474.00	7,212.97
275,000.0000	CVS HEALTH CORP 4.750% 12/01/2022 DD 06/01/16	298,199.14	109.6090	301,424.75	3,225.61
300,000.0000	CHARTER COMMUNICATIONS OPERATI 4.908% 07/23/2025 DD 07/23/16	315,390.61	108.0320	324,096.00	8,705.39
300,000.0000	CITIGROUP INC 2.700% 03/30/2021 DD 03/30/16	303,294.16	100.6640	301,992.00	1,302.16-
500,000.0000	COMMONWEALTH BANK OF AUSTRALIA 2.300% 09/06/2019 DD 09/08/14	506,189.02	100.6460	503,230.00	2,959.02-
150,000.0000	DAIMLER FINANCE NORTH AME 144A 2.850% 01/06/2022 DD 01/06/17	149,848.62	101.2080	151,812.00	1,963.38
300,000.0000	DELL INTERNATIONAL LLC / 144A 6.020% 06/15/2026 DD 06/01/16	319,836.20	110.1510	330,453.00	10,616.80

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
325,000.0000	DUKE ENERGY CORP 2.650% 09/01/2026 DD 08/12/16	310,166.95	94.9730	308,662.25	1,504.70-
325,000.0000	FEDEX CORP 3.300% 03/15/2027 DD 01/06/17	327,903.92	100.2180	325,708.50	2,195.42-
200,000.0000	FORD MOTOR CREDIT CO LLC 4.250% 09/20/2022 DD 09/25/12	206,455.01	105.0530	210,106.00	3,650.99
175,000.0000	FORD MOTOR CREDIT CO LLC 2.459% 03/27/2020 DD 03/27/15	176,469.55	100.0870	175,152.25	1,317.30-
250,000.0000	GENERAL MOTORS FINANCIAL CO IN 3.250% 05/15/2018 DD 11/15/13	252,348.69	101.1720	252,930.00	581.31
150,000.0000	GEORGIA-PACIFIC LLC 7.375% 12/01/2025 DD 12/08/95	189,204.24	127.2360	190,854.00	1,649.76
5,000.0000	GEORGIA-PACIFIC LLC 8.000% 01/15/2024 DD 12/11/03	6,263.90	128.3490	6,417.45	153.55
125,000.0000	GEORGIA-PACIFIC LLC 144A 5.400% 11/01/2020 DD 11/02/10	136,214.25	109.3970	136,746.25	532.00
203,000.0000	GOLDMAN SACHS GROUP INC/THE 5.750% 01/24/2022 DD 01/24/12	228,853.17	112.5870	228,551.61	301.56-
250,000.0000	GOLDMAN SACHS GROUP INC/THE 3.750% 02/25/2026 DD 02/25/16	259,276.17	101.8250	254,562.50	4,713.67-
350,000.0000	HCA INC 6.500% 02/15/2020 DD 08/01/11	378,731.00	109.1250	381,937.50	3,206.50

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
300,000.0000	HSBC HOLDINGS PLC 4.000% 03/30/2022 DD 03/30/12	315,405.53	105.4700	316,410.00	1,004.47
360,000.0000	HONEYWELL INTERNATIONAL INC 1.850% 11/01/2021 DD 10/31/16	354,091.42	98.3980	354,232.80	141.38
300,000.0000	HYUNDAI CAPITAL AMERICA 144A 2.400% 10/30/2018 DD 10/30/15	302,115.10	100.2090	300,627.00	1,488.10-
250,000.0000	INTERCONTINENTAL EXCHANGE INC 4.000% 10/15/2023 DD 10/08/13	264,249.48	107.2490	268,122.50	3,873.02
200,000.0000	JPMORGAN CHASE & CO 3.300% 04/01/2026 DD 03/23/16	203,952.07	99.3000	198,600.00	5,352.07-
300,000.0000	JOHNSON & JOHNSON 3.625% 03/03/2037 DD 03/03/17	299,246.65	104.5690	313,707.00	14,460.35
220,000.0000	KRAFT HEINZ FOODS CO 5.200% 07/15/2045 DD 07/15/16	254,371.32	108.1830	238,002.60	16,368.72-
300,000.0000	KROGER CO/THE 2.650% 10/15/2026 DD 10/03/16	279,080.57	92.2240	276,672.00	2,408.57-
250,000.0000	LOCKHEED MARTIN CORP 3.550% 01/15/2026 DD 11/23/15	251,517.62	103.6210	259,052.50	7,534.88
300,000.0000	MCDONALD'S CORP 4.450% 03/01/2047 DD 03/09/17	298,534.53	105.1890	315,567.00	17,032.47
300,000.0000	MICROSOFT CORP 3.300% 02/06/2027 DD 02/06/17	298,971.17	103.0070	309,021.00	10,049.83

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
300,000.0000	MIZUHO FINANCIAL GROUP INC 3.663% 02/28/2027 DD 02/28/17	300,000.00	103.1110	309,333.00	9,333.00
500,000.0000	MORGAN STANLEY 2.375% 07/23/2019 DD 07/23/14	504,488.34	100.6930	503,465.00	1,023.34-
500,000.0000	NEUBERGER BERMAN CL 23A C 144A VAR RT 10/17/2027 DD 11/29/16	500,000.00	100.0000	500,000.00	0.00
750,000.0000	NEWELL BRANDS INC 4.200% 04/01/2026 DD 03/30/16	797,848.90	106.1790	796,342.50	1,506.40-
250,000.0000	ORACLE CORP 2.800% 07/08/2021 DD 07/08/14	253,735.21	102.7020	256,755.00	3,019.79
125,000.0000	PACIFIC BELL TELEPHONE CO 7.125% 03/15/2026 DD 03/15/93	151,205.81	121.5160	151,895.00	689.19
250,000.0000	PACIFICORP 6.000% 01/15/2039 DD 01/08/09	317,180.95	129.8500	324,625.00	7,444.05
125,000.0000	PFIZER INC 2.750% 06/03/2026 DD 06/03/16	120,940.37	98.4310	123,038.75	2,098.38
375,000.0000	PRUDENTIAL FINANCIAL INC 5.750% 07/15/2033 DD 07/07/03	437,129.21	120.8010	453,003.75	15,874.54
150,000.0000	QUALCOMM INC 3.250% 05/20/2027 DD 05/26/17	149,610.32	100.2290	150,343.50	733.18
325,000.0000	ROCKWELL COLLINS INC 3.500% 03/15/2027 DD 04/10/17	331,230.03	101.4040	329,563.00	1,667.03-

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
300,000.0000	SOUTHWESTERN ELECTRIC POWER CO 3.550% 02/15/2022 DD 02/03/12	311,371.62	103.2350	309,705.00	1,666.62-
500,000.0000	SPIRIT AEROSYSTEMS INC 5.250% 03/15/2022 DD 09/15/14	520,957.41	103.7610	518,805.00	2,152.41-
1,239,577.6000	US TREAS-CPI INFLAT 3.625% 04/15/2028 DD 04/15/98	1,655,479.77	130.6350	1,619,322.20	36,157.57-
688,730.0000	US TREAS-CPI INFLAT 3.375% 04/15/2032 DD 10/15/01	971,536.49	137.3860	946,218.60	25,317.89-
803,159.1000	US TREAS-CPI INFLAT 2.125% 02/15/2040 DD 02/15/10	997,537.60	124.3700	998,888.97	1,351.37
503,153.2500	US TREAS-CPI INFLAT 0.750% 02/15/2042 DD 02/15/12	474,379.40	95.1440	478,720.13	4,340.73
1,661,280.0000	US TREAS-CPI INFLAT 0.750% 02/15/2045 DD 02/15/15	1,612,875.12	93.7820	1,557,981.61	54,893.51-
572,698.9500	US TREAS-CPI INFLAT 1.000% 02/15/2046 DD 02/15/16	588,050.98	99.9100	572,183.52	15,867.46-
130,000.0000	U S TREASURY BOND 3.000% 02/15/2047 DD 02/15/17	133,797.22	103.1560	134,102.80	305.58
144,000.0000	U S TREASURY NOTE 2.250% 02/15/2027 DD 02/15/17	140,795.07	99.5350	143,330.40	2,535.33
310,000.0000	U S TREASURY NOTE 1.875% 04/30/2022 DD 04/30/17	310,950.34	99.9810	309,941.10	1,009.24-

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
300,000.0000	UNITED TECHNOLOGIES CORP 4.500% 06/01/2042 DD 06/01/12	334,082.32	109.1950	327,585.00	6,497.32-
200,000.0000	UNITEDHEALTH GROUP INC 4.250% 04/15/2047 DD 03/13/17	210,054.83	106.6050	213,210.00	3,155.17
200,000.0000	VERIZON COMMUNICATIONS INC 4.500% 09/15/2020 DD 09/18/13	216,685.74	106.8240	213,648.00	3,037.74-
250,000.0000	VERIZON COMMUNICATIONS INC 4.125% 03/16/2027 DD 03/16/17	248,399.35	103.2780	258,195.00	9,795.65
175,000.0000	WALGREEN CO 4.400% 09/15/2042 DD 09/13/12	169,204.45	100.1270	175,222.25	6,017.80
400,000.0000	WELLS FARGO & CO 4.400% 06/14/2046 DD 06/14/16	397,695.86	101.2400	404,960.00	7,264.14
1,535,000.0000	IFL L UL CPURNSA INDEX P 2.775% 2033 JUN 07	0.00	0.0000	0.00	0.00
1,535,000.0000	IFL L UL CPURNSA INDEX P 2.7125% 2033 JUN 10	0.00	0.0000	0.00	0.00
1,535,000.0000	IRS_R US0003M P 6.75% 2038 JUN 19	49,580.50	0.4454	6,838.00	42,742.50-
3,000,000.0000	IRS_R US0003M P 6.75% VAR RT 01/27/2034 DD 01/23/14	79,500.00	0.4845	14,537.00	64,963.00-
2,700,000.0000	IFL_L UL CPURNSA INDEX P 196BPS 2038 MAY 23	0.00	3.6622	98,880.00	98,880.00

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FIRST PRINCIPALS CAP-PI 1
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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
1,350,000.0000	IFL L UL CPURNSA P_1.775% 2036 JUN 20	0.00	6.6827	90,217.00	90,217.00
1,250,000.0000	IFL L_UL CPURNSA P 1.8475% 2038 JUN 28	0.00	5.8526	73,158.00	73,158.00
3,420,000.0000	IFL L UL CPURNSA INDEX P 2.321% 2037 APR 06	0.00	0.0000	0.00	0.00
750,000.0000	IFL L UL CPURNSA INDEX P 2.3175% 2037 MAY 03	0.00	0.0000	0.00	0.00
TOTAL INVESTMENTS FIXED INCOME SECURITIES		24,661,299.05		24,819,889.54	158,590.49
TOTAL INVESTMENT		24,713,262.32		24,871,852.81	158,590.49
SHORT FIXED INCOME SECURITIES					
1,535,000.0000-	IFL S UL CPURNSA INDEX P 2.775% 2033 JUN 07	0.00	18.7984	288,556.00-	288,556.00-
1,535,000.0000-	IFL S UL CPURNSA INDEX P 2.7125% 2033 JUN 10	0.00	17.2695	265,088.00-	265,088.00-
1,535,000.0000-	IRS R US0003M P 6.75% 2038 JUN 19	0.00	0.0000	0.00	0.00
3,000,000.0000-	IRS R US0003M P 6.75% 6.750% 01/27/2034 DD 01/23/14	0.00	0.0000	0.00	0.00
2,700,000.0000-	IFL_S UL CPURNSA INDEX P 196BPS 2038 MAY 23	0.00	0.0000	0.00	0.00

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FIRST PRINCIPALS CAP-PI 1
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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
1,350,000.0000-	IFL S UL CPURNSA P_1.775% 2036 JUN 20	0.00	0.0000	0.00	0.00
1,250,000.0000-	IFL S_UL CPURNSA P 1.8475% 2038 JUN 28	0.00	0.0000	0.00	0.00
3,420,000.0000-	IFL_L UL CPURNSA INDEX P 2.321% 2037 APR 06	0.00	4.3284	148,033.00-	148,033.00-
750,000.0000-	IFL S UL CPURNSA INDEX P 2.3175% 2037 MAY 03	0.00	4.2237	31,678.00-	31,678.00-
TOTAL SHORT FIXED INCOME SECURITIES		0.00		733,355.00-	733,355.00-
TOTAL SHORT INVESTMENT		0.00		733,355.00-	733,355.00-
TOTAL NET INVESTMENT		24,713,262.32		24,138,497.81	574,764.51-

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TITAN MASTERS LP-PI 1
XCEL ENERGY NDT

SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS ALTERNATIVE INVESTMENTS					
16,877,229.0000	TITAN FUND LP	16,877,229.00	1.0387	17,531,346.00	654,117.00
TOTAL INVESTMENTS ALTERNATIVE INVESTMENTS		16,877,229.00		17,531,346.00	654,117.00
TOTAL INVESTMENT		16,877,229.00		17,531,346.00	654,117.00

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MAGNITUDE-PI 1
XCEL ENERGY NDT

SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS ALTERNATIVE INVESTMENTS					
6,394.3200	MAGNITUDE US PARTNERS	6,394,322.93	1,190.8661	7,614,779.00	1,220,456.07
5,056.3100	MAGNITUDE US PARTNERS (SERIES Y)	5,327,093.30	1,206.6455	6,101,174.00	774,080.70
5,083.5200	MAGNITUDE US PARTNERS (SERIES X)	5,325,894.74	1,198.4784	6,092,489.00	766,594.26
22.4300	MAGNITUDE US PARTNERS 04/17	22,428.66	1,004.9933	22,542.00	113.34
TOTAL INVESTMENTS ALTERNATIVE INVESTMENTS		17,069,739.63		19,830,984.00	2,761,244.37
TOTAL INVESTMENT		17,069,739.63		19,830,984.00	2,761,244.37

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CORECOMMODITY-PI 1
XCEL ENERGY NDT

SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS OTHER					
30,240,000.0000	CORE COMMODITY FUND	30,240,000.00	0.7670	23,195,312.08	7,044,687.92-
TOTAL INVESTMENTS OTHER		30,240,000.00		23,195,312.08	7,044,687.92-
TOTAL INVESTMENT		30,240,000.00		23,195,312.08	7,044,687.92-

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MARATHON EAFE-PI 1
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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS OTHER					
13,348.1690	MARATHON EAFE	19,225,261.40	1,591.4922	21,243,506.95	2,018,245.55
TOTAL INVESTMENTS OTHER		19,225,261.40		21,243,506.95	2,018,245.55
TOTAL INVESTMENT		19,225,261.40		21,243,506.95	2,018,245.55

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GOLDMAN PI1
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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS FIXED INCOME SECURITIES					
179,178.0000	ISHARES IBOXX USD HIGH YIELD	15,842,984.70	88.3900	15,837,543.42	5,441.28-
TOTAL INVESTMENTS FIXED INCOME SECURITIES		15,842,984.70		15,837,543.42	5,441.28-
TOTAL INVESTMENT		15,842,984.70		15,837,543.42	5,441.28-

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NSP/XCEL ENERGY NDT

SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS UNIT OF PARTICIPATION					
33,460,105.5150	PRAIRIE #2 QUALIFIED MTU	337,452,777.82	13.0545	436,807,122.35	99,354,344.53
TOTAL INVESTMENTS UNIT OF PARTICIPATION		337,452,777.82		436,807,122.35	99,354,344.53
TOTAL INVESTMENT		337,452,777.82		436,807,122.35	99,354,344.53

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CASH - PRAIRIE I 2
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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS CASH EQUIVALENTS					
479,943.4700	BLACKROCK LIQ T FUND INSTL FUND 60	479,943.47	100.0000	479,943.47	0.00
TOTAL INVESTMENTS CASH EQUIVALENTS		479,943.47		479,943.47	0.00
TOTAL INVESTMENT		479,943.47		479,943.47	0.00

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XCEL ENERGY NDT

SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS CASH EQUIVALENTS					
251,342.7900	BLACKROCK LIQ T FUND INSTL FUND 60	251,342.79	100.0000	251,342.79	0.00
TOTAL INVESTMENTS CASH EQUIVALENTS		251,342.79		251,342.79	0.00
INVESTMENTS EQUITY					
512.0000	ADIENT PLC	24,064.00	65.3800	33,474.56	9,410.56
817.0000	AIRCASTLE LTD	9,958.93	21.7500	17,769.75	7,810.82
817.0000	ALLEGION PLC	17,401.98	81.1200	66,275.04	48,873.06
1,534.0000	ALKERMES PLC	27,727.47	57.9700	88,925.98	61,198.51
1,436.0000	ALLERGAN PLC	249,795.41	243.0900	349,077.24	99,281.83
1,134.0000	AMDOCS LTD	34,523.32	64.4600	73,097.64	38,574.32
2,137.0000	AON PLC	104,734.37	132.9500	284,114.15	179,379.78
1,611.0000	ARCH CAPITAL GROUP LTD	40,345.59	93.2900	150,290.19	109,944.60
227.0000	ARGO GROUP INTERNATIONAL HOLDI	4,845.28	60.6000	13,756.20	8,910.92
445.0000	ASPEN INSURANCE HOLDINGS LTD	11,058.25	49.8500	22,183.25	11,125.00
780.0000	ARRIS INTERNATIONAL PLC	8,548.80	28.0200	21,855.60	13,306.80

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
1,804.0000	ASSURED GUARANTY LTD	24,191.64	41.7400	75,298.96	51,107.32
814.0000	AXIS CAPITAL HOLDINGS LTD	25,022.36	64.6600	52,633.24	27,610.88
3,820.0000	ACCENTURE PLC	164,380.99	123.6800	472,457.60	308,076.61
1,090.0000	BUNGE LTD	65,437.24	74.6000	81,314.00	15,876.76
272.0000	CARDTRONICS PLC	10,814.72	32.8600	8,937.92	1,876.80-
1,572.0000	DELPHI AUTOMOTIVE PLC	54,873.45	87.6500	137,785.80	82,912.35
2,577.0000	EATON CORP PLC	132,663.96	77.8300	200,567.91	67,903.95
50.0000	ENSTAR GROUP LTD	5,024.00	198.6500	9,932.50	4,908.50
3,134.0000	ENSCO PLC	22,690.16	5.1600	16,171.44	6,518.72-
76.0000	EVEREST RE GROUP LTD	9,153.44	254.5900	19,348.84	10,195.40
2,529.0000	FRUIT OF THE LOOM INC CL A	21,459.36	8.4853	21,459.36	0.00
25.0000	HELEN OF TROY LTD	809.75	94.1000	2,352.50	1,542.75
866.0000	HERBALIFE LTD	20,641.11	71.3300	61,771.78	41,130.67
2,192.0000	HORIZON PHARMA PLC	5,282.72	11.8700	26,019.04	20,736.32
1,038.0000	IHS MARKIT LTD	34,025.65	44.0400	45,713.52	11,687.87
2,452.0000	INGERSOLL-RAND PLC	68,877.08	91.3900	224,088.28	155,211.20
2,817.0000	INVESCO LTD	69,802.59	35.1900	99,130.23	29,327.64

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
2,097.0000	JOHNSON CONTROLS INTERNATIONAL	59,524.94	43.3600	90,925.92	31,400.98
4,793.0000	KOSMOS ENERGY LTD	28,182.84	6.4100	30,723.13	2,540.29
997.0000	MALLINCKRODT PLC	46,830.53	44.8100	44,675.57	2,154.96-
2,454.0000	MARVELL TECHNOLOGY GROUP LTD	24,455.34	16.5200	40,540.08	16,084.74
8,756.0000	MEDTRONIC PLC	671,881.76	88.7500	777,095.00	105,213.24
1,037.0000	MICHAEL KORS HOLDINGS LTD	46,708.53	36.2500	37,591.25	9,117.28-
1,713.0000	NIELSEN HOLDINGS PLC	56,377.60	38.6600	66,224.58	9,846.98
1,246.0000	NORDIC AMERICAN TANKERS LTD	9,830.94	6.3400	7,899.64	1,931.30-
605.0000	NORWEGIAN CRUISE LINE HOLDINGS	31,877.45	54.2900	32,845.45	968.00
388.0000	ONEBEACON INSURANCE GROUP LTD	4,904.32	18.2300	7,073.24	2,168.92
1,475.0000	PENTAIR PLC	55,187.69	66.5400	98,146.50	42,958.81
857.0000	PROTHENA CORP PLC	24,990.12	54.1200	46,380.84	21,390.72
353.0000	RENAISSANCERE HOLDINGS LTD	20,092.76	139.0500	49,084.65	28,991.89
1,049.0000	SHIP FINANCE INTERNATIONAL LTD	11,413.12	13.6000	14,266.40	2,853.28
619.0000	SIGNET JEWELERS LTD	19,869.90	63.2400	39,145.56	19,275.66
189.0000	THERAVANCE BIOPHARMA INC	3,706.29	39.8400	7,529.76	3,823.47
843.0000	VALIDUS HOLDINGS LTD	23,994.65	51.9700	43,810.71	19,816.06

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
1,160.0000	GOLAR LNG LTD	28,037.20	22.2500	25,810.00	2,227.20-
43.0000	WHITE MOUNTAINS INSURANCE GROU	17,329.43	868.6300	37,351.09	20,021.66
680.0000	PERRIGO CO PLC	56,639.57	75.5200	51,353.60	5,285.97-
1,948.0000	XL GROUP LTD	41,278.12	43.8000	85,322.40	44,044.28
189.0000	ALLIED WORLD ASSURANCE CO HOLD	5,240.61	52.9000	9,998.10	4,757.49
3,099.0000	CHUBB LTD	222,696.19	145.3800	450,532.62	227,836.43
1,406.0000	STRATASYS LTD	28,077.82	23.3100	32,773.86	4,696.04
253.0000	CIMPRESS NV	8,574.17	94.5300	23,916.09	15,341.92
1,411.0000	LYONDELLBASELL INDUSTRIES NV	100,710.19	84.3900	119,074.29	18,364.10
2,225.0000	MYLAN NV	83,723.61	38.8200	86,374.50	2,650.89
789.0000	QIAGEN NV	14,170.03	33.5300	26,455.17	12,285.14
351.0000	WRIGHT MEDICAL GROUP NV	7,427.16	27.4900	9,648.99	2,221.83
908.0000	BANCO LATINOAMERICANO DE COMER	15,408.76	27.3800	24,861.04	9,452.28
954.0000	ROYAL CARIBBEAN CRUISES LTD	36,372.20	109.2300	104,205.42	67,833.22
2,230.0000	BROADCOM LTD	234,516.24	233.0500	519,701.50	285,185.26
2,930.0000	DORIAN LPG LTD	25,256.60	8.1800	23,967.40	1,289.20-
3,252.0000	TEEKAY CORP	26,763.96	6.6700	21,690.84	5,073.12-

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
220.0000	ABM INDUSTRIES INC	5,005.00	41.5200	9,134.40	4,129.40
2,507.0000	AFLAC INC	163,545.21	77.6800	194,743.76	31,198.55
558.0000	AGCO CORP	20,210.76	67.3900	37,603.62	17,392.86
1,370.0000	AGNC INVESTMENT CORP	24,728.50	21.2900	29,167.30	4,438.80
2,864.0000	AES CORP/VA	35,050.76	11.1100	31,819.04	3,231.72-
4,412.0000	AK STEEL HOLDING CORP	13,236.00	6.5700	28,986.84	15,750.84
299.0000	AMAG PHARMACEUTICALS INC	5,142.80	18.4000	5,501.60	358.80
314.0000	AMC NETWORKS INC	11,817.91	53.4100	16,770.74	4,952.83
33,373.0000	AT&T INC	986,703.65	37.7300	1,259,163.29	272,459.64
477.0000	AV HOMES INC	3,429.63	20.0500	9,563.85	6,134.22
10,530.0000	ABBOTT LABORATORIES	287,324.16	48.6100	511,863.30	224,539.14
11,318.0000	ABBVIE INC	314,813.48	72.5100	820,668.18	505,854.70
247.0000	ABIOMED INC	24,512.28	143.3000	35,395.10	10,882.82
810.0000	ACADIA HEALTHCARE CO INC	18,160.20	49.3800	39,997.80	21,837.60
816.0000	ACADIA REALTY TRUST	23,968.24	27.8000	22,684.80	1,283.44-
492.0000	ACI WORLDWIDE INC	5,180.76	22.3700	11,006.04	5,825.28
1,298.0000	ACLARIS THERAPEUTICS INC	26,855.62	27.1200	35,201.76	8,346.14

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
2,928.0000	ACTIVISION BLIZZARD INC	53,987.84	57.5700	168,564.96	114,577.12
273.0000	ACUITY BRANDS INC	14,927.64	203.2800	55,495.44	40,567.80
924.0000	ACXIOM CORP	11,400.69	25.9800	24,005.52	12,604.83
3,110.0000	ADOBE SYSTEMS INC	109,409.67	141.4400	439,878.40	330,468.73
269.0000	ADVANCE AUTO PARTS INC	24,659.65	116.5900	31,362.71	6,703.06
190.0000	ADVISORY BOARD CO/THE	5,176.55	51.5000	9,785.00	4,608.45
1,410.0000	AECOM	30,098.87	32.3300	45,585.30	15,486.43
2,536.0000	AERIE PHARMACEUTICALS INC	52,643.00	52.5500	133,266.80	80,623.80
193.0000	ADVANSIX INC	1,079.01	31.2400	6,029.32	4,950.31
5,145.0000	ADVANCED MICRO DEVICES INC	59,615.96	12.4800	64,209.60	4,593.64
2,511.0000	AETNA INC	98,546.20	151.8300	381,245.13	282,698.93
386.0000	AFFILIATED MANAGERS GROUP INC	33,296.10	165.8600	64,021.96	30,725.86
2,530.0000	AGILENT TECHNOLOGIES INC	56,630.72	59.3100	150,054.30	93,423.58
436.0000	AIR LEASE CORP	10,221.40	37.3600	16,288.96	6,067.56
1,484.0000	AIR PRODUCTS & CHEMICALS INC	92,760.39	143.0600	212,301.04	119,540.65
1,000.0000	AKAMAI TECHNOLOGIES INC	40,851.93	49.8100	49,810.00	8,958.07
1,484.0000	AKORN INC	25,779.58	33.5400	49,773.36	23,993.78

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1,164.0000	ALASKA AIR GROUP INC	19,497.00	89.7600	104,480.64	84,983.64
197.0000	ALBANY INTERNATIONAL CORP	4,873.78	53.4000	10,519.80	5,646.02
518.0000	ALBEMARLE CORP	45,558.29	105.5400	54,669.72	9,111.43
799.0000	ALCOA CORP	16,009.68	32.6500	26,087.35	10,077.67
218.0000	ALERE INC	5,057.60	50.1900	10,941.42	5,883.82
500.0000	ALEXANDER & BALDWIN INC	7,437.14	41.3800	20,690.00	13,252.86
66.0000	ALEXANDER'S INC	26,434.66	421.4600	27,816.36	1,381.70
350.0000	ALEXANDRIA REAL ESTATE EQUITIE	38,753.13	120.4700	42,164.50	3,411.37
1,344.0000	ALEXION PHARMACEUTICALS INC	125,021.46	121.6700	163,524.48	38,503.02
387.0000	ALIGN TECHNOLOGY INC	8,552.70	150.1200	58,096.44	49,543.74
41.0000	ALLEGHANY CORP	11,979.12	594.8000	24,386.80	12,407.68
233.0000	ALLEGIANT TRAVEL CO	10,876.44	135.6000	31,594.80	20,718.36
510.0000	ALLETE INC	24,367.80	71.6800	36,556.80	12,189.00
303.0000	ALLIANCE DATA SYSTEMS CORP	47,682.44	256.6900	77,777.07	30,094.63
1,276.0000	ALLIANT ENERGY CORP	28,484.41	40.1700	51,256.92	22,772.51
2,619.0000	ALLSTATE CORP/THE	69,075.82	88.4400	231,624.36	162,548.54
1,677.0000	ALLY FINANCIAL INC	33,574.35	20.9000	35,049.30	1,474.95

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354.0000	ALMOST FAMILY INC	5,200.26	61.6500	21,824.10	16,623.84
602.0000	ALNYLAM PHARMACEUTICALS INC	31,773.56	79.7600	48,015.52	16,241.96
587.0000	ALON USA ENERGY INC	5,165.60	13.3200	7,818.84	2,653.24
1,451.0000	ALPHABET INC-CL C	310,681.74	908.7300	1,318,567.23	1,007,885.49
2,200.0000	ALPHABET INC-CL A	912,574.23	929.6800	2,045,296.00	1,132,721.77
2,684.0000	ALTISOURCE RESIDENTIAL CORP	25,095.40	12.9400	34,730.96	9,635.56
11,541.0000	ALTRIA GROUP INC	196,942.13	74.4700	859,458.27	662,516.14
2,253.0000	AMAZON.COM INC	389,751.47	968.0000	2,180,904.00	1,791,152.53
142.0000	AMERCO	12,483.47	366.0600	51,980.52	39,497.05
1,005.0000	AMEREN CORP	31,399.31	54.6700	54,943.35	23,544.04
2,686.0000	AMERICAN AIRLINES GROUP INC	112,424.35	50.3200	135,159.52	22,735.17
227.0000	AMERICAN ASSETS TRUST INC	5,077.99	39.3900	8,941.53	3,863.54
1,028.0000	AMERICAN AXLE & MANUFACTURING	10,248.04	15.6000	16,036.80	5,788.76
637.0000	AMERICAN CAMPUS COMMUNITIES IN	30,378.53	47.3000	30,130.10	248.43-
2,889.0000	AMERICAN ELECTRIC POWER CO INC	106,435.83	69.4700	200,698.83	94,263.00
1,311.0000	AMERICAN EQUITY INVESTMENT LIF	15,006.03	26.2800	34,453.08	19,447.05
4,376.0000	AMERICAN EXPRESS CO	241,865.65	84.2400	368,634.24	126,768.59

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507.0000	AMERICAN FINANCIAL GROUP INC/O	17,542.20	99.3700	50,380.59	32,838.39
1,496.0000	AMERICAN HOMES 4 RENT	24,235.20	22.5700	33,764.72	9,529.52
5,664.0000	AMERICAN INTERNATIONAL GROUP I	202,329.90	62.5200	354,113.28	151,783.38
261.0000	AMERICAN NATIONAL INSURANCE CO	30,978.09	116.4900	30,403.89	574.20-
1,100.0000	AMERICAN OUTDOOR BRANDS CORP	8,767.00	22.1600	24,376.00	15,609.00
604.0000	AMERICAN SOFTWARE INC/GA	5,031.32	10.2900	6,215.16	1,183.84
286.0000	AMERICAN STATES WATER CO	5,052.19	47.4100	13,559.26	8,507.07
2,402.0000	AMERICAN TOWER CORP	119,412.74	132.3200	317,832.64	198,419.90
1,201.0000	AMERICAN WATER WORKS CO INC	30,661.53	77.9500	93,617.95	62,956.42
383.0000	AMERICAN WOODMARK CORP	24,561.79	95.5500	36,595.65	12,033.86
1,580.0000	AMERISOURCEBERGEN CORP	34,727.76	94.5300	149,357.40	114,629.64
1,712.0000	AMERIPRISE FINANCIAL INC	79,988.74	127.2900	217,920.48	137,931.74
572.0000	AMERIS BANCORP	5,119.40	48.2000	27,570.40	22,451.00
1,519.0000	AMETEK INC	43,068.71	60.5700	92,005.83	48,937.12
4,490.0000	AMGEN INC	254,102.80	172.2300	773,312.70	519,209.90
2,002.0000	AMPHENOL CORP	38,195.60	73.8200	147,787.64	109,592.04
544.0000	AMTRUST FINANCIAL SERVICES INC	4,958.94	15.1400	8,236.16	3,277.22

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3,388.0000	ANADARKO PETROLEUM CORP	152,620.16	45.3400	153,611.92	991.76
1,878.0000	ANALOG DEVICES INC	76,209.51	77.8000	146,108.40	69,898.89
187.0000	ANDERSONS INC/THE	4,965.47	34.1500	6,386.05	1,420.58
183.0000	ANIXTER INTERNATIONAL INC	11,190.45	78.2000	14,310.60	3,120.15
16,153.0000	ANNALY CAPITAL MANAGEMENT INC	169,138.11	12.0500	194,643.65	25,505.54
464.0000	ANSYS INC	19,965.92	121.6800	56,459.52	36,493.60
1,291.0000	ANTERO RESOURCES CORP	35,212.14	21.6100	27,898.51	7,313.63-
967.0000	ANTHEM INC	102,944.36	188.1300	181,921.71	78,977.35
756.0000	APARTMENT INVESTMENT & MANAGEM	18,907.56	42.9700	32,485.32	13,577.76
981.0000	APPFOLIO INC	31,990.41	32.6000	31,980.60	9.81-
32,237.0000	APPLE INC	491,498.73	144.0200	4,642,772.74	4,151,274.01
1,294.0000	APPLE HOSPITALITY REIT INC	24,508.36	18.7100	24,210.74	297.62-
146.0000	APPLIED INDUSTRIAL TECHNOLOGIE	4,991.74	59.0500	8,621.30	3,629.56
7,326.0000	APPLIED MATERIALS INC	92,164.92	41.3100	302,637.06	210,472.14
1,088.0000	AQUA AMERICA INC	18,661.38	33.3000	36,230.40	17,569.02
841.0000	ARAMARK	30,797.42	40.9800	34,464.18	3,666.76
4,314.0000	ARCHER-DANIELS-MIDLAND CO	134,913.26	41.3800	178,513.32	43,600.06

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2,397.0000	ARCONIC INC	47,794.12	22.6500	54,292.05	6,497.93
1,758.0000	ARES COMMERCIAL REAL ESTATE CO	22,889.16	13.0900	23,012.22	123.06
286.0000	ARISTA NETWORKS INC	40,927.08	149.7900	42,839.94	1,912.86
1,717.0000	ARLINGTON ASSET INVESTMENT COR	24,055.17	13.6700	23,471.39	583.78-
219.0000	ARMSTRONG FLOORING INC	2,137.82	17.9700	3,935.43	1,797.61
439.0000	ARMSTRONG WORLD INDUSTRIES INC	14,570.03	46.0000	20,194.00	5,623.97
835.0000	ARROW ELECTRONICS INC	27,989.20	78.4200	65,480.70	37,491.50
237.0000	ARROW FINANCIAL CORP	4,996.51	31.6500	7,501.05	2,504.54
797.0000	ARTESIAN RESOURCES CORP	24,237.97	37.6400	29,999.08	5,761.11
294.0000	ASBURY AUTOMOTIVE GROUP INC	5,092.08	56.5500	16,625.70	11,533.62
1,853.0000	ASHFORD HOSPITALITY PRIME INC	22,717.78	10.2900	19,067.37	3,650.41-
633.0000	ASHLAND GLOBAL HOLDINGS INC	18,522.24	65.9100	41,721.03	23,198.79
533.0000	ASPEN TECHNOLOGY INC	8,240.18	55.2600	29,453.58	21,213.40
1,932.0000	ASSOCIATED BANC-CORP	25,239.94	25.2000	48,686.40	23,446.46
109.0000	ASSOCIATED CAPITAL GROUP INC	2,270.59	34.0000	3,706.00	1,435.41
364.0000	ASSURANT INC	10,782.18	103.6900	37,743.16	26,960.98
141.0000	ASTEC INDUSTRIES INC	4,974.48	55.5100	7,826.91	2,852.43

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324.0000	ATHENAHEALTH INC	19,058.80	140.5500	45,538.20	26,479.40
310.0000	ATMOS ENERGY CORP	10,104.45	82.9500	25,714.50	15,610.05
1,401.0000	AUTODESK INC	48,390.54	100.8200	141,248.82	92,858.28
2,932.0000	AUTOMATIC DATA PROCESSING INC	110,530.10	102.4600	300,412.72	189,882.62
258.0000	AUTONATION INC	5,462.81	42.1600	10,877.28	5,414.47
118.0000	AUTOZONE INC	73,850.08	570.4600	67,314.28	6,535.80-
802.0000	AVALONBAY COMMUNITIES INC	143,625.13	192.1700	154,120.34	10,495.21
518.0000	AVANGRID INC	20,072.50	44.1500	22,869.70	2,797.20
356.0000	AVERY DENNISON CORP	14,939.42	88.3700	31,459.72	16,520.30
397.0000	AVIS BUDGET GROUP INC	10,180.04	27.2700	10,826.19	646.15
365.0000	AVISTA CORP	9,993.70	42.4600	15,497.90	5,504.20
622.0000	AVNET INC	21,849.31	38.8800	24,183.36	2,334.05
4,256.0000	BB&T CORP	127,674.64	45.4100	193,264.96	65,590.32
317.0000	BOK FINANCIAL CORP	16,582.27	84.1300	26,669.21	10,086.94
1,111.0000	BSB BANCORP INC/MA	24,980.06	29.2500	32,496.75	7,516.69
1,026.0000	BWX TECHNOLOGIES INC	18,815.93	48.7500	50,017.50	31,201.57
513.0000	BABCOCK & WILCOX ENTERPRISES I	6,930.47	11.7600	6,032.88	897.59-

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2,964.0000	BAKER HUGHES INC	134,396.23	54.5100	161,567.64	27,171.41
838.0000	BALCHEM CORP	66,972.96	77.7100	65,120.98	1,851.98-
1,918.0000	BALL CORP	42,591.52	42.2100	80,958.78	38,367.26
132.0000	BANCFIRST CORP	5,043.72	96.6000	12,751.20	7,707.48
1,692.0000	BANCORPSOUTH INC	17,715.24	30.5000	51,606.00	33,890.76
54,113.0000	BANK OF AMERICA CORP	661,259.54	24.2600	1,312,781.38	651,521.84
453.0000	BANK OF HAWAII CORP	20,583.71	82.9700	37,585.41	17,001.70
1,382.0000	BANK MUTUAL CORP	4,906.10	9.1500	12,645.30	7,739.20
106.0000	BANK OF THE OZARKS INC	1,330.30	46.8700	4,968.22	3,637.92
5,469.0000	BANK OF NEW YORK MELLON CORP/T	185,332.22	51.0200	279,028.38	93,696.16
788.0000	CR BARD INC	59,162.72	316.1100	249,094.68	189,931.96
343.0000	BARNES GROUP INC	8,046.78	58.5300	20,075.79	12,029.01
3,510.0000	BAXTER INTERNATIONAL INC	85,752.25	60.5400	212,495.40	126,743.15
1,540.0000	BECTON DICKINSON AND CO	107,757.73	195.1100	300,469.40	192,711.67
1,569.0000	BED BATH & BEYOND INC	60,608.12	30.4000	47,697.60	12,910.52-
450.0000	BELDEN INC	14,878.89	75.4300	33,943.50	19,064.61
988.0000	BEMIS CO INC	32,700.33	46.2500	45,695.00	12,994.67

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703.0000	BENCHMARK ELECTRONICS INC	10,258.48	32.3000	22,706.90	12,448.42
675.0000	BENEFICIAL BANCORP INC	5,001.59	15.0000	10,125.00	5,123.41
720.0000	WR BERKLEY CORP	20,381.00	69.1700	49,802.40	29,421.40
11,466.0000	BERKSHIRE HATHAWAY INC	1,185,177.02	169.3700	1,941,996.42	756,819.40
620.0000	BERRY GLOBAL GROUP INC	31,254.20	57.0100	35,346.20	4,092.00
1,441.0000	BEST BUY CO INC	17,464.92	57.3300	82,612.53	65,147.61
500.0000	BIG LOTS INC	10,062.45	48.3000	24,150.00	14,087.55
896.0000	BIOMARIN PHARMACEUTICAL INC	84,417.22	90.8200	81,374.72	3,042.50-
1,275.0000	BIOGEN INC	127,995.78	271.3600	345,984.00	217,988.22
135.0000	BIO-TECHNE CORP	9,942.75	117.5000	15,862.50	5,919.75
637.0000	BIOVERATIV INC	10,845.51	60.1700	38,328.29	27,482.78
166.0000	BLACK HILLS CORP	4,968.38	67.4700	11,200.02	6,231.64
188.0000	BLACKBAUD INC	4,998.92	85.7500	16,121.00	11,122.08
175.0000	BLACKHAWK NETWORK HOLDINGS INC	4,138.74	43.6000	7,630.00	3,491.26
653.0000	BLACKROCK INC	136,911.15	422.4100	275,833.73	138,922.58
1,867.0000	H&R BLOCK INC	26,637.61	30.9100	57,708.97	31,071.36
398.0000	BLUEBIRD BIO INC	27,286.88	105.0500	41,809.90	14,523.02

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1,995.0000	BLUEROCK RESIDENTIAL GROWTH RE	22,860.71	12.8900	25,715.55	2,854.84
3,674.0000	BOEING CO/THE	290,752.53	197.7500	726,533.50	435,780.97
1,225.0000	BORGWARNER INC	45,567.39	42.3600	51,891.00	6,323.61
58.0000	BOSTON BEER CO INC/THE	5,150.40	132.1500	7,664.70	2,514.30
772.0000	BOSTON PRIVATE FINANCIAL HOLDI	4,701.48	15.3500	11,850.20	7,148.72
890.0000	BOSTON PROPERTIES INC	106,738.90	123.0200	109,487.80	2,748.90
10,921.0000	BOSTON SCIENTIFIC CORP	58,427.35	27.7200	302,730.12	244,302.77
216.0000	BOTTOMLINE TECHNOLOGIES DE INC	5,080.32	25.6900	5,549.04	468.72
1,049.0000	BRANDYWINE REALTY TRUST	12,923.68	17.5300	18,388.97	5,465.29
839.0000	BRIDGE BANCORP INC	30,589.94	33.3000	27,938.70	2,651.24-
390.0000	BRINKER INTERNATIONAL INC	9,582.30	38.1000	14,859.00	5,276.70
209.0000	BRINK'S CO/THE	5,277.25	67.0000	14,003.00	8,725.75
10,703.0000	BRISTOL-MYERS SQUIBB CO	278,388.92	55.7200	596,371.16	317,982.24
685.0000	BROADRIDGE FINANCIAL SOLUTIONS	14,727.50	75.5600	51,758.60	37,031.10
4,306.0000	BROCADE COMMUNICATIONS SYSTEMS	23,166.28	12.6100	54,298.66	31,132.38
2,537.0000	BROOKDALE SENIOR LIVING INC	30,697.70	14.7100	37,319.27	6,621.57
141.0000	BROWN & BROWN INC	3,551.79	43.0700	6,072.87	2,521.08

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1,512.0000	BROWN-FORMAN CORP	31,184.88	48.6000	73,483.20	42,298.32
49.0000	BRUNOS INC NEW	490.00	10.0000	490.00	0.00
1,091.0000	BRUNSWICK CORP/DE	28,145.61	62.7300	68,438.43	40,292.82
1,069.0000	BUCKLE INC/THE	26,468.44	17.8000	19,028.20	7,440.24-
334.0000	BUFFALO WILD WINGS INC	23,267.18	126.7000	42,317.80	19,050.62
392.0000	BURLINGTON STORES INC	24,762.64	91.9900	36,060.08	11,297.44
3,312.0000	CBS CORP	93,942.89	63.7800	211,239.36	117,296.47
332.0000	CBOE HOLDINGS INC	8,004.52	91.4000	30,344.80	22,340.28
1,484.0000	CBRE GROUP INC	34,639.38	36.4000	54,017.60	19,378.22
977.0000	CDK GLOBAL INC	15,482.97	62.0600	60,632.62	45,149.65
537.0000	CDW CORP/DE	32,123.34	62.5300	33,578.61	1,455.27
2,055.0000	CF INDUSTRIES HOLDINGS INC	57,479.31	27.9600	57,457.80	21.51-
398.0000	CH ROBINSON WORLDWIDE INC	28,982.36	68.6800	27,334.64	1,647.72-
1,790.0000	CIGNA CORP	70,576.88	167.3900	299,628.10	229,051.22
1,575.0000	CIT GROUP INC	53,802.00	48.7000	76,702.50	22,900.50
2,080.0000	CME GROUP INC	122,378.46	125.2400	260,499.20	138,120.74
3,119.0000	CMS ENERGY CORP	45,324.68	46.2500	144,253.75	98,929.07

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216.0000	CSS INDUSTRIES INC	4,965.84	26.1600	5,650.56	684.72
556.0000	CNA FINANCIAL CORP	15,050.92	48.7500	27,105.00	12,054.08
3,355.0000	CNO FINANCIAL GROUP INC	22,180.10	20.8800	70,052.40	47,872.30
6,944.0000	CSX CORP	74,903.54	54.5600	378,864.64	303,961.10
869.0000	CSRA INC	19,891.35	31.7500	27,590.75	7,699.40
563.0000	CVB FINANCIAL CORP	4,954.40	22.4300	12,628.09	7,673.69
1,176.0000	CVR ENERGY INC	27,353.76	21.7600	25,589.76	1,764.00-
7,681.0000	CVS HEALTH CORP	255,508.23	80.4600	618,013.26	362,505.03
7,531.0000	CYS INVESTMENTS INC	61,415.23	8.4100	63,335.71	1,920.48
948.0000	CA INC	31,151.28	34.4700	32,677.56	1,526.28
475.0000	CABELA'S INC	13,473.09	59.4200	28,224.50	14,751.41
19.0000	CABLE ONE INC	2,843.87	710.9000	13,507.10	10,663.23
567.0000	CABOT CORP	21,028.56	53.4300	30,294.81	9,266.25
148.0000	CABOT MICROELECTRONICS CORP	4,992.04	73.8300	10,926.84	5,934.80
3,050.0000	CABOT OIL & GAS CORP	50,242.78	25.0800	76,494.00	26,251.22
1,694.0000	CADENCE DESIGN SYSTEMS INC	17,295.74	33.4900	56,732.06	39,436.32
784.0000	CALATLANTIC GROUP INC	27,432.16	35.3500	27,714.40	282.24

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488.0000	CALERES INC	5,016.64	27.7800	13,556.64	8,540.00
472.0000	CALIFORNIA WATER SERVICE GROUP	9,888.40	36.8000	17,369.60	7,481.20
781.0000	CALLAWAY GOLF CO	4,810.96	12.7800	9,981.18	5,170.22
3,134.0000	CALLON PETROLEUM CO	32,457.57	10.6100	33,251.74	794.17
2,404.0000	CALPINE CORP	31,148.82	13.5300	32,526.12	1,377.30
349.0000	CAMDEN PROPERTY TRUST	18,050.28	85.5100	29,842.99	11,792.71
505.0000	CANADIAN IMPERIAL BANK OF COMM	11,984.07	81.1600	40,985.80	29,001.73
158.0000	CAPELLA EDUCATION CO	4,962.78	85.6000	13,524.80	8,562.02
1,434.0000	CAPITAL BANK FINANCIAL CORP	39,635.76	38.1000	54,635.40	14,999.64
2,489.0000	CAPITAL ONE FINANCIAL CORP	136,475.25	82.6200	205,641.18	69,165.93
2,130.0000	CARDINAL HEALTH INC	100,998.74	77.9200	165,969.60	64,970.86
127.0000	CARE CAPITAL PROPERTIES INC	2,835.17	26.7000	3,390.90	555.73
386.0000	CARLISLE COS INC	18,311.84	95.4000	36,824.40	18,512.56
1,674.0000	CARMAX INC	53,654.92	63.0600	105,562.44	51,907.52
2,542.0000	CARNIVAL CORP	126,127.33	65.5700	166,678.94	40,551.61
547.0000	CARPENTER TECHNOLOGY CORP	20,397.63	37.4300	20,474.21	76.58
235.0000	CARRIZO OIL & GAS INC	4,763.45	17.4200	4,093.70	669.75-

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722.0000	CARS.COM INC	8,601.81	26.6300	19,226.86	10,625.05
570.0000	CARTER'S INC	23,356.90	88.9500	50,701.50	27,344.60
173.0000	CASEY'S GENERAL STORES INC	9,824.67	107.1100	18,530.03	8,705.36
1,125.0000	CATALENT INC	28,811.25	35.1000	39,487.50	10,676.25
3,721.0000	CATCHMARK TIMBER TRUST INC	43,605.14	11.3700	42,307.77	1,297.37-
3,055.0000	CATERPILLAR INC	213,734.12	107.4600	328,290.30	114,556.18
498.0000	CATHAY GENERAL BANCORP	6,957.06	37.9500	18,899.10	11,942.04
678.0000	CAVIUM INC	27,230.40	62.1300	42,124.14	14,893.74
1,924.0000	CEDAR REALTY TRUST INC	9,985.56	4.8500	9,331.40	654.16-
1,095.0000	CELANESE CORP	35,554.65	94.9400	103,959.30	68,404.65
5,680.0000	CELGENE CORP	154,367.88	129.8700	737,661.60	583,293.72
981.0000	CENTENE CORP	25,687.80	79.8800	78,362.28	52,674.48
4,068.0000	CENTERPOINT ENERGY INC	57,228.91	27.3800	111,381.84	54,152.93
371.0000	CENTRAL PACIFIC FINANCIAL CORP	4,889.59	31.4700	11,675.37	6,785.78
2,960.0000	CENTURYLINK INC	79,770.19	23.8800	70,684.80	9,085.39-
1,984.0000	CERNER CORP	56,304.70	66.4700	131,876.48	75,571.78
688.0000	CEVA INC	31,035.68	45.4500	31,269.60	233.92

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1,334.0000	CHARTER COMMUNICATIONS INC	78,941.87	336.8500	449,357.90	370,416.03
345.0000	CHEESECAKE FACTORY INC/THE	10,196.63	50.3000	17,353.50	7,156.87
101.0000	CHEMED CORP	5,071.21	204.5300	20,657.53	15,586.32
272.0000	CHEMICAL FINANCIAL CORP	4,972.16	48.4100	13,167.52	8,195.36
1,052.0000	CHEMOURS CO/THE	25,889.72	37.9200	39,891.84	14,002.12
863.0000	CHENIERE ENERGY INC	23,681.45	48.7100	42,036.73	18,355.28
5,996.0000	CHESAPEAKE ENERGY CORP	24,343.76	4.9700	29,800.12	5,456.36
232.0000	CHESAPEAKE LODGING TRUST	5,052.96	24.4700	5,677.04	624.08
195.0000	CHESAPEAKE UTILITIES CORP	5,166.20	74.9500	14,615.25	9,449.05
11,469.0000	CHEVRON CORP	828,825.69	104.3300	1,196,560.77	367,735.08
1,607.0000	CHICO'S FAS INC	19,348.28	9.4200	15,137.94	4,210.34-
113.0000	CHILDREN'S PLACE INC/THE	4,993.47	102.1000	11,537.30	6,543.83
2,574.0000	CHIMERA INVESTMENT CORP	34,749.00	18.6300	47,953.62	13,204.62
5,339.0000	CHIMERIX INC	24,612.79	5.4500	29,097.55	4,484.76
228.0000	CHIPOTLE MEXICAN GRILL INC	56,209.41	416.1000	94,870.80	38,661.39
1,233.0000	CHURCH & DWIGHT CO INC	32,326.63	51.8800	63,968.04	31,641.41
115.0000	CHURCHILL DOWNS INC	4,940.40	183.3000	21,079.50	16,139.10

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1,253.0000	CIENA CORP	15,324.19	25.0200	31,350.06	16,025.87
547.0000	CIMAREX ENERGY CO	35,029.49	94.0100	51,423.47	16,393.98
328.0000	CINCINNATI BELL INC	5,100.40	19.5500	6,412.40	1,312.00
791.0000	CINCINNATI FINANCIAL CORP	22,258.74	72.4500	57,307.95	35,049.21
586.0000	CINEMARK HOLDINGS INC	11,743.44	38.8500	22,766.10	11,022.66
163.0000	CIRCOR INTERNATIONAL INC	5,251.86	59.3800	9,678.94	4,427.08
30,253.0000	CISCO SYSTEMS INC	753,168.18	31.3000	946,918.90	193,750.72
470.0000	CIRRUS LOGIC INC	30,850.80	62.7200	29,478.40	1,372.40-
796.0000	CINTAS CORP	25,280.96	126.0400	100,327.84	75,046.88
16,466.0000	CITIGROUP INC	696,317.39	66.8800	1,101,246.08	404,928.69
2,133.0000	CITIZENS FINANCIAL GROUP INC	76,919.18	35.6800	76,105.44	813.74-
1,417.0000	CITRIX SYSTEMS INC	41,740.96	79.5800	112,764.86	71,023.90
156.0000	CITY HOLDING CO	4,907.76	65.8700	10,275.72	5,367.96
146.0000	CLEARWATER PAPER CORP	5,212.20	46.7500	6,825.50	1,613.30
893.0000	CLOROX CO/THE	56,914.83	133.2400	118,983.32	62,068.49
361.0000	CLOVIS ONCOLOGY INC	32,017.09	93.6300	33,800.43	1,783.34
1,384.0000	COACH INC	47,845.48	47.3400	65,518.56	17,673.08

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1,773.0000	COBIZ FINANCIAL INC	30,793.14	17.4000	30,850.20	57.06
166.0000	COCA-COLA BOTTLING CO CONSOLID	10,121.02	228.8700	37,992.42	27,871.40
24,324.0000	COCA-COLA CO/THE	642,885.14	44.8500	1,090,931.40	448,046.26
8,806.0000	COEUR MINING INC	23,864.26	8.5800	75,555.48	51,691.22
320.0000	COGENT COMMUNICATIONS HOLDINGS	5,020.80	40.1000	12,832.00	7,811.20
593.0000	COGNEX CORP	17,378.58	84.9000	50,345.70	32,967.12
3,832.0000	COGNIZANT TECHNOLOGY SOLUTIONS	78,146.45	66.4000	254,444.80	176,298.35
97.0000	COHERENT INC	5,028.48	224.9900	21,824.03	16,795.55
5,922.0000	COLGATE-PALMOLIVE CO	185,496.58	74.1300	438,997.86	253,501.28
3,721.0000	COLONY NORTHSTAR INC	40,644.95	14.0900	52,428.89	11,783.94
835.0000	COLONY STARWOOD HOMES	24,849.60	34.3100	28,648.85	3,799.25
529.0000	COLUMBIA BANKING SYSTEM INC	9,517.21	39.8500	21,080.65	11,563.44
1,367.0000	COLUMBIA PROPERTY TRUST INC	30,741.99	22.3800	30,593.46	148.53-
483.0000	COMFORT SYSTEMS USA INC	5,028.03	37.1000	17,919.30	12,891.27
25,758.0000	COMCAST CORP	457,124.61	38.9200	1,002,501.36	545,376.75
630.0000	COMERICA INC	24,394.07	73.2400	46,141.20	21,747.13
1,163.0000	COMMERCE BANCSHARES INC/MO	34,100.41	56.8300	66,093.29	31,992.88

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100.0000	COMMERCEHUB INC	365.44	17.4200	1,742.00	1,376.56
201.0000	COMMERCEHUB INC	740.39	17.4400	3,505.44	2,765.05
1,005.0000	COMMERCIAL METALS CO	18,088.10	19.4300	19,527.15	1,439.05
232.0000	COMMUNITY BANK SYSTEM INC	5,630.64	55.7700	12,938.64	7,308.00
205.0000	COMMUNITY TRUST BANCORP INC	5,029.95	43.7500	8,968.75	3,938.80
2,460.0000	CONAGRA BRANDS INC	46,696.70	35.7600	87,969.60	41,272.90
775.0000	CONCHO RESOURCES INC	55,703.22	121.5300	94,185.75	38,482.53
1,548.0000	CONDUENT INC	18,816.88	15.9400	24,675.12	5,858.24
184.0000	CONMED CORP	4,999.28	50.9400	9,372.96	4,373.68
512.0000	CONNECTICUT WATER SERVICE INC	14,783.82	55.5100	28,421.12	13,637.30
7,624.0000	CONOCOPHILLIPS	345,683.36	43.9600	335,151.04	10,532.32-
1,843.0000	CONSOL ENERGY INC	26,373.33	14.9400	27,534.42	1,161.09
1,378.0000	CONSOLIDATED EDISON INC	64,322.15	80.8200	111,369.96	47,047.81
1,149.0000	CONSTELLATION BRANDS INC	24,794.71	193.7300	222,595.77	197,801.06
514.0000	CONTINENTAL RESOURCES INC/OK	20,103.78	32.3300	16,617.62	3,486.16-
1,136.0000	CONVERGYS CORP	14,972.48	23.7800	27,014.08	12,041.60
344.0000	COOPER COS INC/THE	20,708.80	239.4200	82,360.48	61,651.68

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775.0000	COOPER TIRE & RUBBER CO	13,477.25	36.1000	27,977.50	14,500.25
1,354.0000	COPART INC	21,700.32	31.7900	43,043.66	21,343.34
3,185.0000	CORCEPT THERAPEUTICS INC	5,096.00	11.8000	37,583.00	32,487.00
387.0000	CORELOGIC INC/UNITED STATES	9,845.28	43.3800	16,788.06	6,942.78
1,583.0000	CORECIVIC INC	34,567.73	27.5800	43,659.14	9,091.41
774.0000	CORNERSTONE ONDEMAND INC	21,880.98	35.7500	27,670.50	5,789.52
4,176.0000	CORNING INC	66,152.81	30.0500	125,488.80	59,335.99
1,532.0000	CORPORATE OFFICE PROPERTIES TR	35,828.10	35.0300	53,665.96	17,837.86
208.0000	CORVEL CORP	5,049.20	47.4500	9,869.60	4,820.40
2,491.0000	COSTCO WHOLESALE CORP	124,731.35	159.9300	398,385.63	273,654.28
160.0000	COSTAR GROUP INC	8,939.20	263.6000	42,176.00	33,236.80
2,539.0000	COTY INC	47,797.75	18.7600	47,631.64	166.11-
564.0000	CRANE CO	20,332.20	79.3800	44,770.32	24,438.12
2,200.0000	CROWN CASTLE INTERNATIONAL COR	122,061.42	100.1800	220,396.00	98,334.58
783.0000	CROWN HOLDINGS INC	28,362.84	59.6600	46,713.78	18,350.94
626.0000	CUBESMART	6,441.54	24.0400	15,049.04	8,607.50
757.0000	CUMMINS INC	49,133.78	162.2200	122,800.54	73,666.76

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303.0000	CURTISS-WRIGHT CORP	9,886.74	91.7800	27,809.34	17,922.60
3,166.0000	CYPRESS SEMICONDUCTOR CORP	36,894.64	13.6500	43,215.90	6,321.26
1,030.0000	DCT INDUSTRIAL TRUST INC	29,147.89	53.4400	55,043.20	25,895.31
2,016.0000	DR HORTON INC	32,323.83	34.5700	69,693.12	37,369.29
444.0000	DST SYSTEMS INC	11,350.86	61.7000	27,394.80	16,043.94
1,553.0000	DTE ENERGY CO	64,899.41	105.7900	164,291.87	99,392.46
272.0000	DSW INC	6,732.00	17.7000	4,814.40	1,917.60-
1,645.0000	DXC TECHNOLOGY CO	52,675.64	76.7200	126,204.40	73,528.76
376.0000	DANA INC	4,872.96	22.3300	8,396.08	3,523.12
3,760.0000	DANAHER CORP	101,163.73	84.3900	317,306.40	216,142.67
484.0000	DARDEN RESTAURANTS INC	26,585.32	90.4400	43,772.96	17,187.64
1,793.0000	DARLING INGREDIENTS INC	24,331.01	15.7400	28,221.82	3,890.81
577.0000	DEAN FOODS CO	6,567.12	17.0000	9,809.00	3,241.88
108.0000	DECKERS OUTDOOR CORP	5,114.88	68.2600	7,372.08	2,257.20
1,658.0000	DEERE & CO	90,266.32	123.5900	204,912.22	114,645.90
1,254.0000	DELL TECHNOLOGIES INC CLASS V	58,137.84	61.1100	76,631.94	18,494.10
5,859.0000	DELTA AIR LINES INC	48,198.43	53.7400	314,862.66	266,664.23

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1,089.0000	DELTA NATURAL GAS CO INC	24,655.07	30.4700	33,181.83	8,526.76
324.0000	DELUXE CORP	7,626.96	69.2200	22,427.28	14,800.32
1,027.0000	DENTSPLY SIRONA INC	35,743.09	64.8400	66,590.68	30,847.59
2,854.0000	DEVON ENERGY CORP	99,748.04	31.9700	91,242.38	8,505.66-
413.0000	DEXCOM INC	32,189.22	73.1500	30,210.95	1,978.27-
612.0000	DIAMONDBACK ENERGY INC	48,596.73	88.8100	54,351.72	5,754.99
1,609.0000	DIAMONDROCK HOSPITALITY CO	15,734.80	10.9500	17,618.55	1,883.75
616.0000	DICK'S SPORTING GOODS INC	31,428.32	39.8300	24,535.28	6,893.04-
773.0000	DIGITAL REALTY TRUST INC	46,114.51	112.9500	87,310.35	41,195.84
894.0000	DIGITALGLOBE INC	14,289.73	33.3000	29,770.20	15,480.47
353.0000	DIME COMMUNITY BANCSHARES INC	4,994.95	19.6000	6,918.80	1,923.85
146.0000	DILLARD'S INC	7,402.20	57.6900	8,422.74	1,020.54
289.0000	DINEEQUITY INC	15,272.21	44.0500	12,730.45	2,541.76-
9,771.0000	WALT DISNEY CO/THE	315,018.35	106.2500	1,038,168.75	723,150.40
1,382.0000	DISCOVERY COMMUNICATIONS INC	34,882.77	25.8300	35,697.06	814.29
595.0000	DISCOVERY COMMUNICATIONS INC	10,977.75	25.2100	14,999.95	4,022.20
1,137.0000	DISH NETWORK CORP	24,860.90	62.7600	71,358.12	46,497.22

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3,333.0000	DISCOVER FINANCIAL SERVICES	80,232.42	62.1900	207,279.27	127,046.85
1,305.0000	DOLBY LABORATORIES INC	65,276.10	48.9600	63,892.80	1,383.30-
1,272.0000	DOLLAR GENERAL CORP	66,204.24	72.0900	91,698.48	25,494.24
1,666.0000	DOLLAR TREE INC	53,713.75	69.9200	116,486.72	62,772.97
3,781.0000	DOMINION ENERGY INC	146,080.26	76.6300	289,738.03	143,657.77
706.0000	DOMINO'S PIZZA INC	25,725.92	211.5300	149,340.18	123,614.26
620.0000	DOMTAR CORP	19,486.60	38.4200	23,820.40	4,333.80
174.0000	DONALDSON CO INC	5,054.70	45.5400	7,923.96	2,869.26
1,302.0000	DOUGLAS EMMETT INC	20,154.96	38.2100	49,749.42	29,594.46
1,560.0000	DOVER CORP	62,055.00	80.2200	125,143.20	63,088.20
6,443.0000	DOW CHEMICAL CO/THE	289,477.60	63.0700	406,360.01	116,882.41
1,709.0000	DR PEPPER SNAPPLE GROUP INC	41,930.83	91.1100	155,706.99	113,776.16
489.0000	DRIL-QUIP INC	28,006.89	48.8000	23,863.20	4,143.69-
5,059.0000	EI DU PONT DE NEMOURS & CO	268,706.12	80.7100	408,311.89	139,605.77
4,458.0000	DUKE ENERGY CORP	240,616.29	83.5900	372,644.22	132,027.93
3,570.0000	DUKE REALTY CORP	41,840.40	27.9500	99,781.50	57,941.10
302.0000	DUN & BRADSTREET CORP/THE	23,194.72	108.1500	32,661.30	9,466.58

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849.0000	DUNKIN' BRANDS GROUP INC	27,473.64	55.1200	46,796.88	19,323.24
660.0000	CONTRA DYAX CORPORATION	0.00	0.0000	0.00	0.00
321.0000	DYCOM INDUSTRIES INC	4,798.95	89.5200	28,735.92	23,936.97
2,071.0000	EL POLLO LOCO HOLDINGS INC	24,789.87	13.8500	28,683.35	3,893.48
3,492.0000	EOG RESOURCES INC	152,807.97	90.5200	316,095.84	163,287.87
1,022.0000	EQT CORP	41,356.70	58.5900	59,878.98	18,522.28
294.0000	EPR PROPERTIES	13,518.12	71.8700	21,129.78	7,611.66
435.0000	EAGLE BANCORP INC	5,065.77	63.3000	27,535.50	22,469.73
3,452.0000	E*TRADE FINANCIAL CORP	30,791.84	38.0300	131,279.56	100,487.72
174.0000	EAGLE MATERIALS INC	14,383.28	92.4200	16,081.08	1,697.80
1,560.0000	EAST WEST BANCORP INC	28,969.20	58.5800	91,384.80	62,415.60
1,423.0000	EASTERLY GOVERNMENT PROPERTIES	25,172.87	20.9500	29,811.85	4,638.98
440.0000	EASTMAN CHEMICAL CO	35,934.80	83.9900	36,955.60	1,020.80
6,508.0000	EBAY INC	77,582.16	34.9200	227,259.36	149,677.20
573.0000	ECHOSTAR CORP	11,542.68	60.7000	34,781.10	23,238.42
1,980.0000	ECOLAB INC	89,493.64	132.7500	262,845.00	173,351.36
260.0000	EDGEWELL PERSONAL CARE CO	15,800.56	76.0200	19,765.20	3,964.64

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3,262.0000	EDISON INTERNATIONAL	142,167.79	78.1900	255,055.78	112,887.99
199.0000	EDUCATION REALTY TRUST INC	4,955.10	38.7500	7,711.25	2,756.15
1,090.0000	EDWARDS LIFESCIENCES CORP	96,773.12	118.2400	128,881.60	32,108.48
632.0000	EL PASO ELECTRIC CO	25,084.08	51.7000	32,674.40	7,590.32
2,031.0000	ELECTRONIC ARTS INC	35,830.24	105.7200	214,717.32	178,887.08
421.0000	EMCOR GROUP INC	11,964.82	65.3800	27,524.98	15,560.16
2,820.0000	EMERSON ELECTRIC CO	133,583.17	59.6200	168,128.40	34,545.23
315.0000	EMPLOYERS HOLDINGS INC	5,021.10	42.3000	13,324.50	8,303.40
220.0000	ENCORE WIRE CORP	5,108.40	42.7000	9,394.00	4,285.60
622.0000	ENERGEN CORP	33,646.56	49.3700	30,708.14	2,938.42-
2,386.0000	ENERGOUS CORP	25,554.06	16.2600	38,796.36	13,242.30
224.0000	ENERGIZER HOLDINGS INC	4,225.08	48.0200	10,756.48	6,531.40
569.0000	ENERSYS	15,124.02	72.4500	41,224.05	26,100.03
757.0000	ENTERGY CORP	55,043.28	76.7700	58,114.89	3,071.61
390.0000	ENTERPRISE FINANCIAL SERVICES	5,190.90	40.8000	15,912.00	10,721.10
515.0000	ENVISION HEALTHCARE CORP	30,010.24	62.6700	32,275.05	2,264.81
775.0000	EQUIFAX INC	26,793.85	137.4200	106,500.50	79,706.65

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354.0000	EQUINIX INC	112,456.99	429.1600	151,922.64	39,465.65
909.0000	EQUITY COMMONWEALTH	22,420.15	31.6000	28,724.40	6,304.25
156.0000	EQUITY LIFESTYLE PROPERTIES IN	4,885.92	86.3400	13,469.04	8,583.12
1,945.0000	EQUITY RESIDENTIAL	98,237.86	65.8300	128,039.35	29,801.49
464.0000	ERIE INDEMNITY CO	19,759.86	125.0700	58,032.48	38,272.62
1,701.0000	ESSENDANT INC	35,210.70	14.8300	25,225.83	9,984.87-
417.0000	ESSEX PROPERTY TRUST INC	66,306.17	257.2700	107,281.59	40,975.42
242.0000	ETHAN ALLEN INTERIORS INC	5,055.38	32.3000	7,816.60	2,761.22
323.0000	EURONET WORLDWIDE INC	4,857.92	87.3700	28,220.51	23,362.59
740.0000	EVERCORE PARTNERS INC	18,206.96	70.5000	52,170.00	33,963.04
1,979.0000	EVERSOURCE ENERGY	86,302.64	60.7100	120,145.09	33,842.45
1,502.0000	EXACT SCIENCES CORP	15,891.16	35.3700	53,125.74	37,234.58
5,932.0000	EXELON CORP	186,467.38	36.0700	213,967.24	27,499.86
1,863.0000	EXELIXIS INC	41,468.27	24.6300	45,885.69	4,417.42
579.0000	EXPEDIA INC	54,396.46	148.9500	86,242.05	31,845.59
544.0000	EXPEDITORS INTERNATIONAL OF WA	24,387.52	56.4800	30,725.12	6,337.60
4,231.0000	EXPRESS SCRIPTS HOLDING CO	142,735.79	63.8400	270,107.04	127,371.25

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701.0000	EXTRA SPACE STORAGE INC	29,870.87	78.0000	54,678.00	24,807.13
25,681.0000	EXXON MOBIL CORP	1,775,079.85	80.7300	2,073,227.13	298,147.28
750.0000	FLIR SYSTEMS INC	25,027.50	34.6600	25,995.00	967.50
611.0000	FMC CORP	39,152.19	73.0500	44,633.55	5,481.36
800.0000	FNB CORP/PA	8,088.00	14.1600	11,328.00	3,240.00
1,092.0000	FTD COS INC	27,900.60	20.0000	21,840.00	6,060.60-
13,576.0000	FACEBOOK INC	646,705.87	150.9800	2,049,704.48	1,402,998.61
251.0000	FAIR ISAAC CORP	7,276.49	139.4100	34,991.91	27,715.42
1,420.0000	FAIRPOINT COMMUNICATIONS INC	19,412.96	15.6500	22,223.00	2,810.04
1,517.0000	FASTENAL CO	66,021.21	43.5300	66,035.01	13.80
410.0000	FEDERAL REALTY INVESTMENT TRUS	45,974.01	126.3900	51,819.90	5,845.89
1,241.0000	FEDERAL SIGNAL CORP	5,174.97	17.3600	21,543.76	16,368.79
1,997.0000	FEDEX CORP	213,562.73	217.3300	434,008.01	220,445.28
4,736.0000	FELCOR LODGING TRUST INC	21,927.68	7.2100	34,146.56	12,218.88
411.0000	F5 NETWORKS INC	31,815.80	127.0600	52,221.66	20,405.86
2,102.0000	FIDELITY NATIONAL INFORMATION	50,080.54	85.4000	179,510.80	129,430.26
1,579.0000	FNF GROUP	18,072.04	44.8300	70,786.57	52,714.53

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526.0000	FNFV GROUP	2,503.71	15.8000	8,310.80	5,807.09
4,749.0000	FIFTH THIRD BANCORP	67,886.43	25.9600	123,284.04	55,397.61
934.0000	FINANCIAL ENGINES INC	19,668.68	36.6000	34,184.40	14,515.72
897.0000	FINANCIAL INSTITUTIONS INC	24,940.07	29.8000	26,730.60	1,790.53
1,439.0000	FINISAR CORP	24,765.19	25.9800	37,385.22	12,620.03
2,091.0000	FIREEYE INC	31,568.64	15.2100	31,804.11	235.47
2,510.0000	FIRST BANCORP/PUERTO RICO	9,638.40	5.7900	14,532.90	4,894.50
24.0000	FIRST CITIZENS BANCSHARES INC/	4,320.24	372.7000	8,944.80	4,624.56
1,067.0000	FIRST COMMONWEALTH FINANCIAL C	5,217.63	12.6800	13,529.56	8,311.93
366.0000	FIRST DEFIANCE FINANCIAL CORP	5,223.11	52.6800	19,280.88	14,057.77
2,112.0000	FIRST DATA CORP	25,175.04	18.2000	38,438.40	13,263.36
396.0000	FIRST FINANCIAL BANKSHARES INC	6,617.16	44.2000	17,503.20	10,886.04
2,776.0000	FIRST HORIZON NATIONAL CORP	22,715.04	17.4200	48,357.92	25,642.88
887.0000	FIRST INDUSTRIAL REALTY TRUST	10,226.50	28.6200	25,385.94	15,159.44
616.0000	FIRST REPUBLIC BANK/CA	23,695.84	100.1000	61,661.60	37,965.76
714.0000	FIRST SOLAR INC	11,345.46	39.8800	28,474.32	17,128.86
269.0000	1ST SOURCE CORP	4,912.90	47.9400	12,895.86	7,982.96

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129.0000	FIRSTCASH INC	5,020.68	58.3000	7,520.70	2,500.02
2,442.0000	FISERV INC	57,643.41	122.3400	298,754.28	241,110.87
2,475.0000	FIRSTENERGY CORP	77,275.77	29.1600	72,171.00	5,104.77-
480.0000	FLEETCOR TECHNOLOGIES INC	50,393.75	144.2100	69,220.80	18,827.05
646.0000	FLOTEK INDUSTRIES INC	4,921.03	8.9400	5,775.24	854.21
1,267.0000	FLUOR CORP	50,272.93	45.7800	58,003.26	7,730.33
1,430.0000	FLOWERS FOODS INC	27,613.30	17.3100	24,753.30	2,860.00-
832.0000	FOOT LOCKER INC	16,698.23	49.2800	41,000.96	24,302.73
22,259.0000	FORD MOTOR CO	201,763.11	11.1900	249,078.21	47,315.10
1,238.0000	FOREST CITY REALTY TRUST INC	18,322.40	24.1700	29,922.46	11,600.06
887.0000	FORTINET INC	19,986.48	37.4400	33,209.28	13,222.80
1,880.0000	FORTIVE CORP	33,010.59	63.3500	119,098.00	86,087.41
1,423.0000	FORTUNE BRANDS HOME & SECURITY	28,053.03	65.2400	92,836.52	64,783.49
135.0000	FORWARD AIR CORP	5,111.10	53.2800	7,192.80	2,081.70
153.0000	FOUR CORNERS PROPERTY TRUST IN	2,761.90	25.1100	3,841.83	1,079.93
228.0000	FRANKLIN ELECTRIC CO INC	5,180.16	41.4000	9,439.20	4,259.04
1,454.0000	FRANKLIN RESOURCES INC	55,760.01	44.7900	65,124.66	9,364.65

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7,832.0000	FREEPORT-MCMORAN INC	45,911.52	12.0100	94,062.32	48,150.80
228.0000	HB FULLER CO	5,344.32	51.1100	11,653.08	6,308.76
2,352.0000	FULTON FINANCIAL CORP	24,225.60	19.0000	44,688.00	20,462.40
109.0000	GAMCO INVESTORS INC	2,613.70	29.6000	3,226.40	612.70
293.0000	GATX CORP	10,624.18	64.2700	18,831.11	8,206.93
1,185.0000	GEO GROUP INC/THE	27,918.60	29.5700	35,040.45	7,121.85
648.0000	GCP APPLIED TECHNOLOGIES INC	6,370.38	30.5000	19,764.00	13,393.62
2,764.0000	GGP INC	38,935.12	23.5600	65,119.84	26,184.72
862.0000	G-III APPAREL GROUP LTD	27,575.38	24.9500	21,506.90	6,068.48-
1,109.0000	GAIN CAPITAL HOLDINGS INC	4,935.05	6.2300	6,909.07	1,974.02
696.0000	ARTHUR J GALLAGHER & CO	19,508.88	57.2500	39,846.00	20,337.12
894.0000	GAMING AND LEISURE PROPERTIES	29,569.81	37.6700	33,676.98	4,107.17
890.0000	GAMESTOP CORP	23,255.70	21.6100	19,232.90	4,022.80-
1,083.0000	GANNETT CO INC	5,470.61	8.7200	9,443.76	3,973.15
1,327.0000	GAP INC/THE	25,435.93	21.9900	29,180.73	3,744.80
916.0000	GARTNER INC	40,923.64	123.5100	113,135.16	72,211.52
1,910.0000	GENERAL DYNAMICS CORP	136,978.44	198.1000	378,371.00	241,392.56

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52,775.0000	GENERAL ELECTRIC CO	1,283,886.15	27.0100	1,425,452.75	141,566.60
4,469.0000	GENERAL MILLS INC	127,235.56	55.4000	247,582.60	120,347.04
8,163.0000	GENERAL MOTORS CO	237,303.85	34.9300	285,133.59	47,829.74
150.0000	GENESCO INC	7,653.00	33.9000	5,085.00	2,568.00-
89.0000	GENESEE & WYOMING INC	4,938.61	68.3900	6,086.71	1,148.10
1,473.0000	GENUINE PARTS CO	64,646.82	92.7600	136,635.48	71,988.66
816.0000	GENTHERM INC	27,588.96	38.8000	31,660.80	4,071.84
457.0000	GIBRALTAR INDUSTRIES INC	4,958.45	35.6500	16,292.05	11,333.60
9,068.0000	GILEAD SCIENCES INC	227,687.52	70.7800	641,833.04	414,145.52
882.0000	GLACIER BANCORP INC	11,015.07	36.6100	32,290.02	21,274.95
1,455.0000	GLADSTONE COMMERCIAL CORP	24,487.65	21.7900	31,704.45	7,216.80
1,043.0000	GLOBAL NET LEASE INC	24,781.69	22.2400	23,196.32	1,585.37-
1,292.0000	GLOBAL PAYMENTS INC	30,340.36	90.3200	116,693.44	86,353.08
1,975.0000	GOLDMAN SACHS GROUP INC/THE	299,376.63	221.9000	438,252.50	138,875.87
1,489.0000	GOODYEAR TIRE & RUBBER CO/THE	21,789.87	34.9600	52,055.44	30,265.57
2,991.0000	GOPRO INC	26,410.53	8.1300	24,316.83	2,093.70-
416.0000	GORMAN-RUPP CO/THE	9,771.01	25.4700	10,595.52	824.51

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648.0000	WR GRACE & CO	25,891.75	72.0100	46,662.48	20,770.73
625.0000	GRACO INC	20,168.75	109.2800	68,300.00	48,131.25
19.0000	GRAHAM HOLDINGS CO	4,433.51	599.6500	11,393.35	6,959.84
345.0000	WW GRAINGER INC	69,041.67	180.5300	62,282.85	6,758.82-
1,015.0000	GRAMERCY PROPERTY TRUST	27,283.19	29.7100	30,155.65	2,872.46
377.0000	GRAND CANYON EDUCATION INC	5,108.35	78.4100	29,560.57	24,452.22
244.0000	GRANITE CONSTRUCTION INC	5,963.36	48.2400	11,770.56	5,807.20
1,883.0000	GREAT AJAX CORP	24,463.56	13.9800	26,324.34	1,860.78
549.0000	GREAT SOUTHERN BANCORP INC	9,997.29	53.5000	29,371.50	19,374.21
932.0000	GREAT PLAINS ENERGY INC	18,136.72	29.2800	27,288.96	9,152.24
649.0000	GREEN DOT CORP	8,229.32	38.5300	25,005.97	16,776.65
485.0000	GREEN PLAINS INC	4,951.85	20.5500	9,966.75	5,014.90
249.0000	GREENBRIER COS INC/THE	4,932.69	46.2500	11,516.25	6,583.56
821.0000	GRIFFIN INDUSTRIAL REALTY INC	25,017.10	31.6700	26,001.07	983.97
1,066.0000	GRIFFON CORP	10,247.88	21.9500	23,398.70	13,150.82
152.0000	GROUP 1 AUTOMOTIVE INC	5,973.60	63.3200	9,624.64	3,651.04
6,409.0000	GROUPON INC	25,293.22	3.8400	24,610.56	682.66-

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862.0000	GRUBHUB INC	25,928.96	43.6000	37,583.20	11,654.24
434.0000	GUIDEWIRE SOFTWARE INC	24,620.82	68.7100	29,820.14	5,199.32
379.0000	H&E EQUIPMENT SERVICES INC	4,839.83	20.4100	7,735.39	2,895.56
1,092.0000	HCA HEALTHCARE INC	62,520.15	87.2000	95,222.40	32,702.25
2,947.0000	HCP INC	95,940.82	31.9600	94,186.12	1,754.70-
349.0000	HFF INC	4,788.28	34.7700	12,134.73	7,346.45
2,366.0000	HMS HOLDINGS CORP	24,559.08	18.5000	43,771.00	19,211.92
488.0000	HNI CORP	12,111.22	39.8700	19,456.56	7,345.34
163.0000	HSN INC	4,995.95	31.9000	5,199.70	203.75
1,885.0000	HRG GROUP INC	25,127.05	17.7100	33,383.35	8,256.30
8,768.0000	HP INC	107,451.12	17.4800	153,264.64	45,813.52
604.0000	HAEMONETICS CORP	18,038.46	39.4900	23,851.96	5,813.50
494.0000	HAIN CELESTIAL GROUP INC/THE	20,668.48	38.8200	19,177.08	1,491.40-
5,285.0000	HALLIBURTON CO	153,551.43	42.7100	225,722.35	72,170.92
720.0000	HALLMARK FINANCIAL SERVICES IN	4,989.60	11.2700	8,114.40	3,124.80
237.0000	HALYARD HEALTH INC	5,153.55	39.2800	9,309.36	4,155.81
3,976.0000	HANESBRANDS INC	31,517.60	23.1600	92,084.16	60,566.56

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142.0000	HANOVER INSURANCE GROUP INC/TH	6,178.42	88.6300	12,585.46	6,407.04
1,043.0000	HARLEY-DAVIDSON INC	53,543.59	54.0200	56,342.86	2,799.27
1,141.0000	HARRIS CORP	44,322.60	109.0800	124,460.28	80,137.68
2,263.0000	HARTFORD FINANCIAL SERVICES GR	55,768.39	52.5700	118,965.91	63,197.52
637.0000	HASBRO INC	16,282.40	111.5100	71,031.87	54,749.47
845.0000	HAWAIIAN ELECTRIC INDUSTRIES I	24,766.95	32.3800	27,361.10	2,594.15
879.0000	HAWAIIAN HOLDINGS INC	5,054.25	46.9500	41,269.05	36,214.80
746.0000	HAYNES INTERNATIONAL INC	31,466.28	36.3100	27,087.26	4,379.02-
205.0000	HEALTHSOUTH CORP	4,987.65	48.4000	9,922.00	4,934.35
174.0000	HEALTHCARE REALTY TRUST INC	3,563.52	34.1500	5,942.10	2,378.58
8,374.0000	HECLA MINING CO	24,200.86	5.1000	42,707.40	18,506.54
512.0000	HEICO CORP	13,959.17	71.8400	36,782.08	22,822.91
1,080.0000	HELMERICH & PAYNE INC	51,944.42	54.3400	58,687.20	6,742.78
544.0000	JACK HENRY & ASSOCIATES INC	15,939.20	103.8700	56,505.28	40,566.08
985.0000	HERITAGE COMMERCE CORP	4,869.25	13.7800	13,573.30	8,704.05
385.0000	HERITAGE FINANCIAL CORP/WA	4,966.50	26.5000	10,202.50	5,236.00
5,497.0000	HERON THERAPEUTICS INC	50,023.25	13.8500	76,133.45	26,110.20

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932.0000	HERSHEY CO/THE	49,928.96	107.3700	100,068.84	50,139.88
1,768.0000	HESS CORP	81,559.18	43.8700	77,562.16	3,997.02-
9,036.0000	HEWLETT PACKARD ENTERPRISE CO	96,343.69	16.5900	149,907.24	53,563.55
425.0000	HEXCEL CORP	10,060.43	52.7900	22,435.75	12,375.32
151.0000	HIGHWOODS PROPERTIES INC	4,898.44	50.7100	7,657.21	2,758.77
627.0000	HILL-ROM HOLDINGS INC	17,336.55	79.6100	49,915.47	32,578.92
215.0000	HILLENBRAND INC	4,882.65	36.1000	7,761.50	2,878.85
785.0000	HILLTOP HOLDINGS INC	9,252.00	26.2100	20,574.85	11,322.85
161.0000	HILTON GRAND VACATIONS INC	3,025.33	36.0600	5,805.66	2,780.33
707.0000	HILTON WORLDWIDE HOLDINGS INC	32,562.50	61.8500	43,727.95	11,165.45
1,911.0000	HOLOGIC INC	35,479.86	45.3800	86,721.18	51,241.32
836.0000	HOME BANCSHARES INC/AR	4,932.40	24.9000	20,816.40	15,884.00
8,084.0000	HOME DEPOT INC/THE	295,717.57	153.4000	1,240,085.60	944,368.03
338.0000	HOMESTREET INC	4,912.76	27.6750	9,354.15	4,441.39
4,841.0000	HONEYWELL INTERNATIONAL INC	199,472.78	133.2900	645,256.89	445,784.11
1,335.0000	HOPE BANCORP INC	10,325.32	18.6500	24,897.75	14,572.43
2,968.0000	HORMEL FOODS CORP	33,285.11	34.1100	101,238.48	67,953.37

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2,202.0000	HOSPITALITY PROPERTIES TRUST	48,928.44	29.1500	64,188.30	15,259.86
4,338.0000	HOST HOTELS & RESORTS INC	62,120.16	18.2700	79,255.26	17,135.10
2,476.0000	HOUGHTON MIFFLIN HARCOURT CO	26,765.56	12.3000	30,454.80	3,689.24
185.0000	HOWARD HUGHES CORP/THE	15,117.50	122.8400	22,725.40	7,607.90
1,170.0000	HUMANA INC	74,670.22	240.6200	281,525.40	206,855.18
450.0000	JB HUNT TRANSPORT SERVICES INC	20,574.00	91.3800	41,121.00	20,547.00
8,830.0000	HUNTINGTON BANCSHARES INC/OH	50,288.46	13.5200	119,381.60	69,093.14
344.0000	HUNTINGTON INGALLS INDUSTRIES	12,961.36	186.1600	64,039.04	51,077.68
2,133.0000	HUNTSMAN CORP	26,136.75	25.8400	55,116.72	28,979.97
165.0000	HURON CONSULTING GROUP INC	4,851.00	43.2000	7,128.00	2,277.00
514.0000	HYATT HOTELS CORP	19,943.20	56.2100	28,891.94	8,948.74
303.0000	IAC/INTERACTIVECORP	11,608.50	103.2400	31,281.72	19,673.22
198.0000	ICF INTERNATIONAL INC	4,950.00	47.1000	9,325.80	4,375.80
926.0000	ILG INC	10,432.22	27.4900	25,455.74	15,023.52
287.0000	IPG PHOTONICS CORP	25,000.57	145.1000	41,643.70	16,643.13
2,031.0000	ISTAR INC	12,348.48	12.0400	24,453.24	12,104.76
788.0000	ITT INC	15,320.78	40.1800	31,661.84	16,341.06

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315.0000	IDACORP INC	15,032.32	85.3500	26,885.25	11,852.93
287.0000	IDEX CORP	14,860.69	113.0100	32,433.87	17,573.18
724.0000	IDEXX LABORATORIES INC	27,066.74	161.4200	116,868.08	89,801.34
2,798.0000	ILLINOIS TOOL WORKS INC	126,121.80	143.2500	400,813.50	274,691.70
852.0000	ILLUMINA INC	144,546.23	173.5200	147,839.04	3,292.81
1,211.0000	INCYTE CORP	19,460.77	125.9100	152,477.01	133,016.24
190.0000	INDEPENDENT BANK CORP/ROCKLAND	4,932.40	66.6500	12,663.50	7,731.10
95.0000	INFINITY PROPERTY & CASUALTY C	5,136.65	94.0000	8,930.00	3,793.35
3,119.0000	INFINERA CORP	27,104.11	10.6700	33,279.73	6,175.62
341.0000	INGEVITY CORP	6,107.18	57.4000	19,573.40	13,466.22
337.0000	INGLES MARKETS INC	5,048.26	33.3000	11,222.10	6,173.84
412.0000	INGREDION INC	20,064.33	119.2100	49,114.52	29,050.19
305.0000	INSIGHT ENTERPRISES INC	5,072.15	39.9900	12,196.95	7,124.80
156.0000	INNOSPEC INC	4,873.11	65.5500	10,225.80	5,352.69
245.0000	INSULET CORP	5,049.45	51.3100	12,570.95	7,521.50
2,593.0000	INTEGRATED DEVICE TECHNOLOGY I	16,024.74	25.7900	66,873.47	50,848.73
28,133.0000	INTEL CORP	586,714.59	33.7400	949,207.42	362,492.83

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883.0000	INTEGER HOLDINGS CORP	26,896.18	43.2500	38,189.75	11,293.57
1,135.0000	INTERACTIVE BROKERS GROUP INC	18,637.04	37.4200	42,471.70	23,834.66
260.0000	INTERCEPT PHARMACEUTICALS INC	28,220.40	121.0700	31,478.20	3,257.80
3,229.0000	INTERCONTINENTAL EXCHANGE INC	132,866.71	65.9200	212,855.68	79,988.97
1,182.0000	INTERNATIONAL BANCSHARES CORP	19,053.84	35.0500	41,429.10	22,375.26
5,433.0000	INTERNATIONAL BUSINESS MACHINE	539,290.95	153.8300	835,758.39	296,467.44
910.0000	INTERNATIONAL FLAVORS & FRAGRA	36,099.79	135.0000	122,850.00	86,750.21
2,693.0000	INTERNATIONAL PAPER CO	93,190.33	56.6100	152,450.73	59,260.40
186.0000	INTERNATIONAL SPEEDWAY CORP	4,992.24	37.5500	6,984.30	1,992.06
3,696.0000	INTERPUBLIC GROUP OF COS INC/T	36,512.41	24.6000	90,921.60	54,409.19
2,465.0000	INTERSECT ENT INC	27,509.40	27.9500	68,896.75	41,387.35
256.0000	INTUITIVE SURGICAL INC	70,720.53	935.3700	239,454.72	168,734.19
2,235.0000	INTUIT INC	72,897.66	132.8100	296,830.35	223,932.69
4,358.0000	INVESCO MORTGAGE CAPITAL INC	64,149.76	16.7100	72,822.18	8,672.42
925.0000	INVESTORS BANCORP INC	5,045.78	13.3600	12,358.00	7,312.22
699.0000	IONIS PHARMACEUTICALS INC	32,349.72	50.8700	35,558.13	3,208.41
6,678.0000	IRIDIUM COMMUNICATIONS INC	55,360.62	11.0500	73,791.90	18,431.28

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1,375.0000	IRON MOUNTAIN INC	34,079.37	34.3600	47,245.00	13,165.63
90.0000	J ALEXANDER'S HOLDINGS INC	365.24	12.2500	1,102.50	737.26
20,434.0000	JPMORGAN CHASE & CO	826,555.30	91.4000	1,867,667.60	1,041,112.30
1,050.0000	JABIL INC	30,964.25	29.1900	30,649.50	314.75-
225.0000	JACK IN THE BOX INC	5,033.25	98.5000	22,162.50	17,129.25
488.0000	JACOBS ENGINEERING GROUP INC	25,010.00	54.3900	26,542.32	1,532.32
813.0000	JETBLUE AIRWAYS CORP	5,162.55	22.8300	18,560.79	13,398.24
15,552.0000	JOHNSON & JOHNSON	1,065,740.79	132.2900	2,057,374.08	991,633.29
376.0000	JONES LANG LASALLE INC	26,928.52	125.0000	47,000.00	20,071.48
180.0000	J2 GLOBAL INC	4,905.00	85.0900	15,316.20	10,411.20
3,428.0000	JUNIPER NETWORKS INC	59,237.94	27.8800	95,572.64	36,334.70
1,493.0000	JUNO THERAPEUTICS INC	26,679.91	29.8900	44,625.77	17,945.86
379.0000	KAR AUCTION SERVICES INC	5,040.70	41.9700	15,906.63	10,865.93
328.0000	KLX INC	5,431.82	50.0000	16,400.00	10,968.18
535.0000	KANSAS CITY SOUTHERN	35,229.71	104.6500	55,987.75	20,758.04
646.0000	KAPSTONE PAPER AND PACKAGING C	5,332.73	20.6300	13,326.98	7,994.25
1,596.0000	KB HOME	12,943.56	23.9700	38,256.12	25,312.56

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866.0000	KELLOGG CO	61,474.69	69.4600	60,152.36	1,322.33-
320.0000	KELLY SERVICES INC	5,027.20	22.4500	7,184.00	2,156.80
314.0000	KEMPER CORP	9,143.68	38.6000	12,120.40	2,976.72
6,436.0000	KEYCORP	51,101.84	18.7400	120,610.64	69,508.80
1,265.0000	KEYSIGHT TECHNOLOGIES INC	21,921.34	38.9300	49,246.45	27,325.11
667.0000	KEYW HOLDING CORP/THE	4,970.82	9.3500	6,236.45	1,265.63
426.0000	KFORCE INC	5,197.20	19.6000	8,349.60	3,152.40
369.0000	KILROY REALTY CORP	14,040.45	75.1500	27,730.35	13,689.90
1,988.0000	KIMBERLY-CLARK CORP	129,187.29	129.1100	256,670.68	127,483.39
2,883.0000	KIMCO REALTY CORP	51,500.67	18.3500	52,903.05	1,402.38
11,402.0000	KINDER MORGAN INC/DE	210,496.82	19.1600	218,462.32	7,965.50
525.0000	KIRBY CORP	20,007.75	66.8500	35,096.25	15,088.50
601.0000	KITE PHARMA INC	28,018.62	103.6700	62,305.67	34,287.05
1,113.0000	KITE REALTY GROUP TRUST	25,677.66	18.9300	21,069.09	4,608.57-
306.0000	KNIGHT TRANSPORTATION INC	4,938.84	37.0500	11,337.30	6,398.46
780.0000	KNOWLES CORP	12,222.83	16.9200	13,197.60	974.77
894.0000	KOHL'S CORP	39,928.74	38.6700	34,570.98	5,357.76-

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3,435.0000	KRAFT HEINZ CO/THE	103,389.63	85.6400	294,173.40	190,783.77
7,912.0000	KROGER CO/THE	90,643.20	23.3200	184,507.84	93,864.64
1,885.0000	L BRANDS INC	51,159.09	53.8900	101,582.65	50,423.56
390.0000	LHC GROUP INC	5,093.40	67.8900	26,477.10	21,383.70
1,271.0000	LKQ CORP	27,050.07	32.9500	41,879.45	14,829.38
622.0000	LPL FINANCIAL HOLDINGS INC	20,223.92	42.4600	26,410.12	6,186.20
514.0000	LA-Z-BOY INC	4,821.32	32.5000	16,705.00	11,883.68
831.0000	LABORATORY CORP OF AMERICA HOL	55,604.11	154.1400	128,090.34	72,486.23
346.0000	LAKELAND FINANCIAL CORP	5,102.35	45.8800	15,874.48	10,772.13
1,138.0000	LAM RESEARCH CORP	27,918.93	141.4300	160,947.34	133,028.41
766.0000	LAMAR ADVERTISING CO	18,621.46	73.5700	56,354.62	37,733.16
820.0000	LAMB WESTON HOLDINGS INC	13,565.92	44.0400	36,112.80	22,546.88
68.0000	LANCASTER COLONY CORP	4,930.68	122.6200	8,338.16	3,407.48
110.0000	LANDSTAR SYSTEM INC	4,950.00	85.6000	9,416.00	4,466.00
1,132.0000	LANNETT CO INC	28,254.72	20.4000	23,092.80	5,161.92-
2,210.0000	LAREDO PETROLEUM INC	26,387.40	10.5200	23,249.20	3,138.20-
2,223.0000	LAS VEGAS SANDS CORP	94,953.77	63.8900	142,027.47	47,073.70

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752.0000	LASALLE HOTEL PROPERTIES	18,700.40	29.8000	22,409.60	3,709.20
1,204.0000	ESTEE LAUDER COS INC/THE	91,374.74	95.9800	115,559.92	24,185.18
803.0000	LEAR CORP	38,882.32	142.0800	114,090.24	75,207.92
567.0000	LEGGETT & PLATT INC	12,978.63	52.5300	29,784.51	16,805.88
940.0000	LEGG MASON INC	29,384.40	38.1600	35,870.40	6,486.00
1,002.0000	LEIDOS HOLDINGS INC	27,957.76	51.6900	51,793.38	23,835.62
4,992.0000	LENDINGCLUB CORP	27,056.64	5.5100	27,505.92	449.28
1,012.0000	LENNAR CORP	19,885.80	53.3200	53,959.84	34,074.04
38.0000	LENNOX INTERNATIONAL INC	2,405.40	183.6400	6,978.32	4,572.92
1,278.0000	LEUCADIA NATIONAL CORP	21,514.86	26.1600	33,432.48	11,917.62
1,637.0000	LEVEL 3 COMMUNICATIONS INC	46,564.89	59.3000	97,074.10	50,509.21
403.0000	LIBERTY EXPEDIA HOLDINGS INC	4,784.60	54.0200	21,770.06	16,985.46
4,166.0000	LIBERTY INTERACTIVE CORP QVC G	49,154.36	24.5400	102,233.64	53,079.28
604.0000	LIBERTY VENTURES	6,147.14	52.2900	31,583.16	25,436.02
778.0000	LIBERTY PROPERTY TRUST	24,118.00	40.7100	31,672.38	7,554.38
862.0000	LIBERTY MEDIA CORP-LIBERTY SIR	24,045.93	41.9800	36,186.76	12,140.83
215.0000	LIBERTY MEDIA CORP-LIBERTY FOR	5,874.37	35.0300	7,531.45	1,657.08

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1,908.0000	LIBERTY TRIPADVISOR HOLDINGS I	27,096.43	11.6000	22,132.80	4,963.63-
326.0000	LIFEPOINT HEALTH INC	12,249.18	67.1500	21,890.90	9,641.72
327.0000	LIFE STORAGE INC	22,114.04	74.1000	24,230.70	2,116.66
5,216.0000	ELI LILLY & CO	361,919.20	82.3000	429,276.80	67,357.60
278.0000	LINCOLN ELECTRIC HOLDINGS INC	9,980.20	92.0900	25,601.02	15,620.82
1,312.0000	LINCOLN NATIONAL CORP	39,367.52	67.5800	88,664.96	49,297.44
279.0000	LITHIA MOTORS INC	5,354.01	94.2300	26,290.17	20,936.16
75.0000	LITTELFUSE INC	4,898.25	165.0000	12,375.00	7,476.75
1,108.0000	LOCKHEED MARTIN CORP	120,152.00	277.6100	307,591.88	187,439.88
680.0000	LOEWS CORP	25,330.00	46.8100	31,830.80	6,500.80
243.0000	LOGMEIN INC	10,495.20	104.5000	25,393.50	14,898.30
1,166.0000	LOUISIANA-PACIFIC CORP	30,734.93	24.1100	28,112.26	2,622.67-
6,611.0000	LOWE'S COS INC	189,425.65	77.5300	512,550.83	323,125.18
554.0000	LULULEMON ATHLETICA INC	33,526.26	59.6700	33,057.18	469.08-
505.0000	LUMENTUM HOLDINGS INC	31,542.30	57.0500	28,810.25	2,732.05-
1,085.0000	M&T BANK CORP	82,071.55	161.9500	175,715.75	93,644.20
344.0000	MB FINANCIAL INC	6,536.00	44.0400	15,149.76	8,613.76

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968.0000	MDU RESOURCES GROUP INC	20,031.06	26.2000	25,361.60	5,330.54
453.0000	MGE ENERGY INC	20,453.76	64.3500	29,150.55	8,696.79
3,013.0000	MGM RESORTS INTERNATIONAL	30,503.52	31.2900	94,276.77	63,773.25
203.0000	MKS INSTRUMENTS INC	5,093.27	67.3000	13,661.90	8,568.63
138.0000	MSA SAFETY INC	4,854.84	81.1700	11,201.46	6,346.62
840.0000	MSCI INC	30,204.52	102.9900	86,511.60	56,307.08
547.0000	MACOM TECHNOLOGY SOLUTIONS HOL	31,053.19	55.7700	30,506.19	547.00-
1,188.0000	MACERICH CO/THE	50,432.16	58.0600	68,975.28	18,543.12
381.0000	MACQUARIE INFRASTRUCTURE CORP	30,742.89	78.4000	29,870.40	872.49-
714.0000	STEVEN MADDEN LTD	18,714.14	39.9500	28,524.30	9,810.16
649.0000	MAINSOURCE FINANCIAL GROUP INC	5,750.14	33.5100	21,747.99	15,997.85
1,451.0000	MANITOWOC CO INC/THE	3,749.36	6.0100	8,720.51	4,971.15
412.0000	MANPOWERGROUP INC	15,714.52	111.6500	45,999.80	30,285.28
5,282.0000	MARATHON OIL CORP	84,118.74	11.8500	62,591.70	21,527.04-
2,535.0000	MARATHON PETROLEUM CORP	72,970.38	52.3300	132,656.55	59,686.17
513.0000	MARCUS CORP/THE	4,945.32	30.2000	15,492.60	10,547.28
53.0000	MARKEL CORP	19,967.59	975.8600	51,720.58	31,752.99

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208.0000	MARKETAXESS HOLDINGS INC	5,002.40	201.1000	41,828.80	36,826.40
3,608.0000	MARSH & MCLENNAN COS INC	107,513.60	77.9600	281,279.68	173,766.08
2,837.0000	MARRIOTT INTERNATIONAL INC/MD	132,546.68	100.3100	284,579.47	152,032.79
1,217.0000	MARTEN TRANSPORT LTD	19,674.95	27.4000	33,345.80	13,670.85
366.0000	MARTIN MARIETTA MATERIALS INC	58,143.06	222.5800	81,464.28	23,321.22
2,938.0000	MASCO CORP	42,183.77	38.2100	112,260.98	70,077.21
356.0000	MASTEC INC	6,497.00	45.1500	16,073.40	9,576.40
5,883.0000	MASTERCARD INC	170,523.05	121.4500	714,490.35	543,967.30
1,148.0000	MATADOR RESOURCES CO	25,588.92	21.3700	24,532.76	1,056.16-
500.0000	MATSON INC	8,942.86	30.0400	15,020.00	6,077.14
2,505.0000	MATTEL INC	46,739.54	21.5300	53,932.65	7,193.11
153.0000	MATTHEWS INTERNATIONAL CORP	4,915.89	61.2500	9,371.25	4,455.36
2,078.0000	MAXIM INTEGRATED PRODUCTS INC	49,373.28	44.9000	93,302.20	43,928.92
502.0000	MAXIMUS INC	31,093.88	62.6300	31,440.26	346.38
441.0000	MCCORMICK & CO INC/MD	23,031.29	97.5100	43,001.91	19,970.62
4,819.0000	MCDONALD'S CORP	224,974.69	153.1600	738,078.04	513,103.35
1,684.0000	MCKESSON CORP	90,057.62	164.5400	277,085.36	187,027.74

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821.0000	MEDICINES CO/THE	24,052.78	38.0100	31,206.21	7,153.43
572.0000	MEDIDATA SOLUTIONS INC	25,728.56	78.2000	44,730.40	19,001.84
514.0000	MEDNAX INC	19,905.31	60.3700	31,030.18	11,124.87
17,262.0000	MERCK & CO INC	717,882.77	64.0900	1,106,321.58	388,438.81
1,448.0000	MERCURY SYSTEMS INC	25,412.40	42.0900	60,946.32	35,533.92
128.0000	MERCURY GENERAL CORP	4,974.08	54.0000	6,912.00	1,937.92
160.0000	MEREDITH CORP	4,865.60	59.4500	9,512.00	4,646.40
984.0000	MERIDIAN BANCORP INC	5,120.14	16.9000	16,629.60	11,509.46
221.0000	MERITAGE HOMES CORP	5,049.85	42.2000	9,326.20	4,276.35
1,315.0000	MERITOR INC	6,588.15	16.6100	21,842.15	15,254.00
94.0000	MESA LABORATORIES INC	5,018.66	143.3100	13,471.14	8,452.48
4,763.0000	METLIFE INC	194,474.55	54.9400	261,679.22	67,204.67
124.0000	METTLER-TOLEDO INTERNATIONAL I	19,685.56	588.5400	72,978.96	53,293.40
43,797.0000	MICROSOFT CORP	1,237,254.74	68.9300	3,018,927.21	1,781,672.47
751.0000	MICROCHIP TECHNOLOGY INC	56,151.23	77.1800	57,962.18	1,810.95
6,065.0000	MICRON TECHNOLOGY INC	65,953.46	29.8600	181,100.90	115,147.44
827.0000	MICROSEMI CORP	15,828.23	46.8000	38,703.60	22,875.37

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911.0000	MID-AMERICA APARTMENT COMMUNIT	73,203.67	105.3800	96,001.18	22,797.51
351.0000	MIDDLEBY CORP/THE	10,661.04	121.5100	42,650.01	31,988.97
2,387.0000	MODEL N INC	31,074.90	13.3000	31,747.10	672.20
358.0000	MOHAWK INDUSTRIES INC	20,413.16	241.6900	86,525.02	66,111.86
862.0000	MOLSON COORS BREWING CO	42,668.50	86.3400	74,425.08	31,756.58
10,788.0000	MONDELEZ INTERNATIONAL INC	205,927.40	43.1900	465,933.72	260,006.32
2,411.0000	MONOGRAM RESIDENTIAL TRUST INC	24,110.00	9.7100	23,410.81	699.19-
345.0000	MONOLITHIC POWER SYSTEMS INC	5,226.75	96.4000	33,258.00	28,031.25
366.0000	MONOTYPE IMAGING HOLDINGS INC	5,025.18	18.3000	6,697.80	1,672.62
148.0000	MONRO MUFFLER BRAKE INC	5,046.80	41.7500	6,179.00	1,132.20
3,073.0000	MONSANTO CO	147,297.31	118.3600	363,720.28	216,422.97
2,643.0000	MONSTER BEVERAGE CORP	73,998.17	49.6800	131,304.24	57,306.07
1,388.0000	MOODY'S CORP	53,181.58	121.6800	168,891.84	115,710.26
221.0000	MOOG INC	9,483.64	71.7200	15,850.12	6,366.48
9,977.0000	MORGAN STANLEY	211,601.19	44.5600	444,575.12	232,973.93
83.0000	MORNINGSTAR INC	4,849.69	78.3400	6,502.22	1,652.53
657.0000	MOTOROLA SOLUTIONS INC	45,785.45	86.7400	56,988.18	11,202.73

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294.0000	MOVADO GROUP INC	4,933.32	25.2500	7,423.50	2,490.18
476.0000	MUELLER INDUSTRIES INC	8,653.68	30.4500	14,494.20	5,840.52
1,130.0000	MURPHY OIL CORP	29,899.15	25.6300	28,961.90	937.25-
350.0000	MURPHY USA INC	9,641.63	74.1100	25,938.50	16,296.87
449.0000	NCI BUILDING SYSTEMS INC	4,992.88	16.7000	7,498.30	2,505.42
1,002.0000	NCR CORP	17,446.56	40.8400	40,921.68	23,475.12
1,316.0000	NCS MULTISTAGE HOLDINGS INC	31,677.70	25.1800	33,136.88	1,459.18
544.0000	NIC INC	6,832.64	18.9500	10,308.80	3,476.16
100.0000	NN INC	614.00	27.4500	2,745.00	2,131.00
3,632.0000	NRG ENERGY INC	35,993.12	17.2200	62,543.04	26,549.92
1,646.0000	NRG YIELD INC	24,673.54	17.6000	28,969.60	4,296.06
11.0000	NVR INC	7,904.41	2,410.6100	26,516.71	18,612.30
738.0000	NASDAQ INC	22,396.95	71.4900	52,759.62	30,362.67
332.0000	NATIONAL HEALTH INVESTORS INC	16,244.76	79.2000	26,294.40	10,049.64
2,125.0000	NATIONAL OILWELL VARCO INC	75,204.96	32.9400	69,997.50	5,207.46-
766.0000	NATIONAL RETAIL PROPERTIES INC	23,034.41	39.1000	29,950.60	6,916.19
1,765.0000	NATIONAL STORAGE AFFILIATES TR	22,680.25	23.1100	40,789.15	18,108.90

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254.0000	NATIONSTAR MORTGAGE HOLDINGS I	4,937.76	17.8900	4,544.06	393.70-
216.0000	NAVIGATORS GROUP INC/THE	4,966.92	54.9000	11,858.40	6,891.48
607.0000	NATUS MEDICAL INC	5,032.03	37.3000	22,641.10	17,609.07
507.0000	NAVIGANT CONSULTING INC	5,070.00	19.7600	10,018.32	4,948.32
2,501.0000	NAVIENT CORP	26,744.53	16.6500	41,641.65	14,897.12
2,079.0000	NEKTAR THERAPEUTICS	25,467.75	19.5500	40,644.45	15,176.70
233.0000	NELNET INC	5,039.79	47.0100	10,953.33	5,913.54
1,400.0000	NETAPP INC	41,905.48	40.0500	56,070.00	14,164.52
2,296.0000	NETFLIX INC	29,739.76	149.4100	343,045.36	313,305.60
818.0000	NETSCOUT SYSTEMS INC	31,173.98	34.4000	28,139.20	3,034.78-
577.0000	NEUROCRINE BIOSCIENCES INC	30,927.20	46.0000	26,542.00	4,385.20-
1,960.0000	NEW RESIDENTIAL INVESTMENT COR	24,343.20	15.5600	30,497.60	6,154.40
2,373.0000	NEW SENIOR INVESTMENT GROUP IN	24,038.49	10.0500	23,848.65	189.84-
2,764.0000	NEW YORK COMMUNITY BANCORP INC	33,278.56	13.1300	36,291.32	3,012.76
3,972.0000	NEW YORK MORTGAGE TRUST INC	29,468.02	6.2200	24,705.84	4,762.18-
1,539.0000	NEW YORK TIMES CO/THE	12,161.41	17.7000	27,240.30	15,078.89
2,709.0000	NEWELL BRANDS INC	46,268.04	53.6200	145,256.58	98,988.54

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972.0000	NEWFIELD EXPLORATION CO	22,323.60	28.4600	27,663.12	5,339.52
2,727.0000	NEWMONT MINING CORP	65,110.82	32.3900	88,327.53	23,216.71
3,343.0000	NEWS CORP	30,581.98	13.7000	45,799.10	15,217.12
496.0000	NEWSTAR FINANCIAL INC	4,786.40	10.5000	5,208.00	421.60
2,875.0000	NEXTERA ENERGY INC	159,981.80	140.1300	402,873.75	242,891.95
1,238.0000	NEXPOINT RESIDENTIAL TRUST INC	31,604.95	24.8900	30,813.82	791.13-
7,962.0000	NIKE INC	162,169.69	59.0000	469,758.00	307,588.31
1,904.0000	NISOURCE INC	15,455.01	25.3600	48,285.44	32,830.43
2,530.0000	NOBLE ENERGY INC	90,768.51	28.3000	71,599.00	19,169.51-
1,077.0000	NORDSTROM INC	48,382.85	47.8300	51,512.91	3,130.06
2,417.0000	NORFOLK SOUTHERN CORP	104,380.57	121.7000	294,148.90	189,768.33
783.0000	NORTHERN TRUST CORP	58,848.15	97.2100	76,115.43	17,267.28
1,106.0000	NORTHROP GRUMMAN CORP	68,473.34	256.7100	283,921.26	215,447.92
453.0000	NORTHSTAR REALTY EUROPE CORP	5,232.15	12.6800	5,744.04	511.89
511.0000	NORTHWEST NATURAL GAS CO	30,869.51	59.8500	30,583.35	286.16-
422.0000	NOW INC	8,195.33	16.0800	6,785.76	1,409.57-
344.0000	NU SKIN ENTERPRISES INC	12,425.28	62.8400	21,616.96	9,191.68

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1,357.0000	NUANCE COMMUNICATIONS INC	22,770.46	17.4100	23,625.37	854.91
1,348.0000	NUCOR CORP	64,306.57	57.8700	78,008.76	13,702.19
3,473.0000	NVIDIA CORP	45,792.17	144.5600	502,056.88	456,264.71
871.0000	OGE ENERGY CORP	24,753.82	34.7900	30,302.09	5,548.27
402.0000	O'REILLY AUTOMOTIVE INC	43,292.22	218.7400	87,933.48	44,641.26
420.0000	OFG BANCORP	4,863.60	10.0000	4,200.00	663.60-
2,608.0000	OASIS PETROLEUM INC	25,819.20	8.0500	20,994.40	4,824.80-
4,892.0000	OCCIDENTAL PETROLEUM CORP	225,355.79	59.8700	292,884.04	67,528.25
384.0000	OCEANFIRST FINANCIAL CORP	4,995.84	27.1200	10,414.08	5,418.24
5,675.0000	OFFICE DEPOT INC	13,285.20	5.6400	32,007.00	18,721.80
207.0000	OLD DOMINION FREIGHT LINE INC	4,987.32	95.2400	19,714.68	14,727.36
596.0000	OLD NATIONAL BANCORP/IN	6,144.76	17.2500	10,281.00	4,136.24
1,639.0000	OLD REPUBLIC INTERNATIONAL COR	15,193.53	19.5300	32,009.67	16,816.14
3,519.0000	OLD SECOND BANCORP INC	25,006.01	11.5500	40,644.45	15,638.44
1,067.0000	OLIN CORP	27,336.54	30.2800	32,308.76	4,972.22
1,714.0000	OMNICOM GROUP INC	80,191.38	82.9000	142,090.60	61,899.22
1,069.0000	OMEGA HEALTHCARE INVESTORS INC	26,369.90	33.0200	35,298.38	8,928.48

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540.0000	ON ASSIGNMENT INC	25,088.40	54.1500	29,241.00	4,152.60
2,129.0000	ON SEMICONDUCTOR CORP	31,226.78	14.0400	29,891.16	1,335.62-
321.0000	ONE GAS INC	6,291.99	69.8100	22,409.01	16,117.02
1,285.0000	ONEOK INC	44,638.95	52.1600	67,025.60	22,386.65
2,516.0000	OPKO HEALTH INC	17,554.52	6.5800	16,555.28	999.24-
21,740.0000	ORACLE CORP	388,448.16	50.1400	1,090,043.60	701,595.44
339.0000	ORBITAL ATK INC	10,405.44	98.3600	33,344.04	22,938.60
394.0000	ORITANI FINANCIAL CORP	4,988.04	17.0500	6,717.70	1,729.66
809.0000	ORMAT TECHNOLOGIES INC	14,788.52	58.6800	47,472.12	32,683.60
833.0000	OSHKOSH CORP	15,979.90	68.8800	57,377.04	41,397.14
937.0000	OTTER TAIL CORP	25,055.38	39.6000	37,105.20	12,049.82
1,078.0000	OWENS CORNING	28,408.02	66.9200	72,139.76	43,731.74
155.0000	OXFORD INDUSTRIES INC	5,068.50	62.4900	9,685.95	4,617.45
1,022.0000	PDVWIRELESS INC	24,568.88	23.3000	23,812.60	756.28-
964.0000	PBF ENERGY INC	27,608.96	22.2600	21,458.64	6,150.32-
691.0000	PDC ENERGY INC	31,557.07	43.1100	29,789.01	1,768.06-
2,770.0000	PG&E CORP	162,718.17	66.3700	183,844.90	21,126.73

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2,176.0000	PNC FINANCIAL SERVICES GROUP I	146,634.63	124.8700	271,717.12	125,082.49
545.0000	PNM RESOURCES INC	8,910.75	38.2500	20,846.25	11,935.50
1,832.0000	PPG INDUSTRIES INC	103,567.72	109.9600	201,446.72	97,879.00
2,128.0000	PPL CORP	65,068.81	38.6600	82,268.48	17,199.67
123.0000	PRA GROUP INC	4,940.09	37.9000	4,661.70	278.39-
377.0000	PVH CORP	27,132.69	114.5000	43,166.50	16,033.81
996.0000	PTC INC	22,294.00	55.1200	54,899.52	32,605.52
2,578.0000	PACCAR INC	97,811.90	66.0400	170,251.12	72,439.22
828.0000	PACIRA PHARMACEUTICALS INC/DE	26,235.18	47.7000	39,495.60	13,260.42
525.0000	PACKAGING CORP OF AMERICA	19,952.55	111.3900	58,479.75	38,527.20
1,047.0000	PACWEST BANCORP	22,495.44	46.7000	48,894.90	26,399.46
504.0000	PALO ALTO NETWORKS INC	33,881.54	133.8100	67,440.24	33,558.70
1,812.0000	PANDORA MEDIA INC	20,063.06	8.9200	16,163.04	3,900.02-
138.0000	PANERA BREAD CO	25,062.18	314.6400	43,420.32	18,358.14
718.0000	PAPA JOHN'S INTERNATIONAL INC	12,974.26	71.7600	51,523.68	38,549.42
1,667.0000	PARAMOUNT GROUP INC	27,605.52	16.0000	26,672.00	933.52-
386.0000	PAREXEL INTERNATIONAL CORP	19,528.72	86.9100	33,547.26	14,018.54

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348.0000	PARK HOTELS & RESORTS INC	7,602.25	26.9600	9,382.08	1,779.83
81.0000	PARK NATIONAL CORP	5,158.89	103.7200	8,401.32	3,242.43
1,301.0000	PARKER-HANNIFIN CORP	67,930.06	159.8200	207,925.82	139,995.76
1,835.0000	PARSLEY ENERGY INC	49,278.34	27.7500	50,921.25	1,642.91
649.0000	PATTERSON COS INC	20,540.85	46.9500	30,470.55	9,929.70
1,502.0000	PATTERSON-UTI ENERGY INC	24,783.00	20.1900	30,325.38	5,542.38
1,703.0000	PAYCHEX INC	69,566.94	56.9400	96,968.82	27,401.88
7,044.0000	PAYPAL HOLDINGS INC	138,952.48	53.6700	378,051.48	239,099.00
879.0000	PEBBLEBROOK HOTEL TRUST	23,766.28	32.2400	28,338.96	4,572.68
427.0000	PENN NATIONAL GAMING INC	3,633.04	21.4000	9,137.80	5,504.76
8,500.0000	JC PENNEY CO INC	66,059.98	4.6500	39,525.00	26,534.98-
1,383.0000	PENNSYLVANIA REAL ESTATE INVES	19,071.57	11.3200	15,655.56	3,416.01-
1,483.0000	PENNYMAC FINANCIAL SERVICES IN	25,344.47	16.7000	24,766.10	578.37-
710.0000	PENSKE AUTOMOTIVE GROUP INC	10,799.10	43.9100	31,176.10	20,377.00
4,281.0000	PEOPLE'S UNITED FINANCIAL INC	31,153.49	17.6600	75,602.46	44,448.97
7,779.0000	PEPSICO INC	577,634.68	115.4900	898,396.71	320,762.03
335.0000	PERKINELMER INC	11,241.47	68.1400	22,826.90	11,585.43

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31,332.0000	PFIZER INC	825,276.90	33.5900	1,052,441.88	227,164.98
395.0000	PHARMERICA CORP	5,186.35	26.2500	10,368.75	5,182.40
8,854.0000	PHILIP MORRIS INTERNATIONAL IN	406,174.13	117.4500	1,039,902.30	633,728.17
4,086.0000	PHILLIPS 66	111,081.33	82.6900	337,871.34	226,790.01
1,229.0000	PHYSICIANS REALTY TRUST	25,059.31	20.1400	24,752.06	307.25-
322.0000	PINNACLE FINANCIAL PARTNERS IN	4,842.88	62.8000	20,221.60	15,378.72
361.0000	PINNACLE WEST CAPITAL CORP	14,934.57	85.1600	30,742.76	15,808.19
998.0000	PIONEER NATURAL RESOURCES CO	135,913.68	159.5800	159,260.84	23,347.16
1,055.0000	PITNEY BOWES INC	14,927.87	15.1000	15,930.50	1,002.63
287.0000	PLANTRONICS INC	10,135.20	52.3100	15,012.97	4,877.77
2,277.0000	PLATFORM SPECIALTY PRODUCTS CO	25,206.39	12.6800	28,872.36	3,665.97
336.0000	PLEXUS CORP	10,175.50	52.5700	17,663.52	7,488.02
547.0000	POLARIS INDUSTRIES INC	35,156.31	92.2300	50,449.81	15,293.50
409.0000	POLYONE CORP	9,742.38	38.7400	15,844.66	6,102.28
303.0000	POOL CORP	8,683.98	117.5700	35,623.71	26,939.73
1,294.0000	POPULAR INC	20,147.58	41.7100	53,972.74	33,825.16
584.0000	PORTLAND GENERAL ELECTRIC CO	24,790.80	45.6900	26,682.96	1,892.16

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1,482.0000	PORTOLA PHARMACEUTICALS INC	27,402.18	56.1700	83,243.94	55,841.76
366.0000	POST HOLDINGS INC	20,377.14	77.6500	28,419.90	8,042.76
181.0000	POWER INTEGRATIONS INC	6,646.32	72.9000	13,194.90	6,548.58
1,910.0000	PRAXAIR INC	113,560.77	132.5500	253,170.50	139,609.73
1,777.0000	PREFERRED APARTMENT COMMUNITIE	24,806.92	15.7500	27,987.75	3,180.83
1,841.0000	T ROWE PRICE GROUP INC	87,703.03	74.2100	136,620.61	48,917.58
306.0000	PRICELINE GROUP INC/THE	127,117.24	1,870.5200	572,379.12	445,261.88
215.0000	PRIMERICA INC	5,022.40	75.7500	16,286.25	11,263.85
1,408.0000	PRINCIPAL FINANCIAL GROUP INC	42,730.56	64.0700	90,210.56	47,480.00
16,095.0000	PROCTER & GAMBLE CO/THE	1,097,235.65	87.1500	1,402,679.25	305,443.60
3,363.0000	PROGRESSIVE CORP/THE	66,217.47	44.0900	148,274.67	82,057.20
2,901.0000	PROLOGIS INC	86,339.55	58.6400	170,114.64	83,775.09
499.0000	PROOFPOINT INC	23,148.61	86.8300	43,328.17	20,179.56
295.0000	PROSPERITY BANCSHARES INC	12,522.75	64.2400	18,950.80	6,428.05
380.0000	PROVIDENT FINANCIAL SERVICES I	5,247.80	25.3800	9,644.40	4,396.60
1,746.0000	PRUDENTIAL FINANCIAL INC	113,857.82	108.1400	188,812.44	74,954.62
3,155.0000	PUBLIC SERVICE ENTERPRISE GROU	97,082.50	43.0100	135,696.55	38,614.05

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805.0000	PUBLIC STORAGE	69,477.30	208.5300	167,866.65	98,389.35
1,297.0000	PULTEGROUP INC	23,864.80	24.5300	31,815.41	7,950.61
932.0000	PZENA INVESTMENT MANAGEMENT IN	5,070.08	10.1600	9,469.12	4,399.04
122.0000	QUAKER CHEMICAL CORP	4,941.00	145.2300	17,718.06	12,777.06
1,047.0000	QORVO INC	11,927.85	63.3200	66,296.04	54,368.19
9,631.0000	QUALCOMM INC	363,996.00	55.2200	531,823.82	167,827.82
522.0000	QUALITY CARE PROPERTIES INC	16,103.70	18.3100	9,557.82	6,545.88-
1,161.0000	QUANEX BUILDING PRODUCTS CORP	22,900.01	21.1500	24,555.15	1,655.14
1,445.0000	QUANTA SERVICES INC	33,426.46	32.9200	47,569.40	14,142.94
474.0000	QUINTILES IMS HOLDINGS INC	38,129.98	89.5000	42,423.00	4,293.02
166.0000	RLI CORP	4,999.09	54.6200	9,066.92	4,067.83
1,116.0000	RLJ LODGING TRUST	25,261.50	19.8700	22,174.92	3,086.58-
36.0000	RMR GROUP INC/THE	468.00	48.6500	1,751.40	1,283.40
752.0000	RPM INTERNATIONAL INC	19,908.98	54.5500	41,021.60	21,112.62
1,058.0000	RSP PERMIAN INC	35,570.59	32.2700	34,141.66	1,428.93-
4,385.0000	RADISYS CORP	10,077.61	3.7600	16,487.60	6,409.99
506.0000	RALPH LAUREN CORP	42,339.55	73.8000	37,342.80	4,996.75-

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680.0000	RAMCO-GERSHENSON PROPERTIES TR	10,145.60	12.9000	8,772.00	1,373.60-
1,259.0000	RANGE RESOURCES CORP	32,648.66	23.1700	29,171.03	3,477.63-
1,118.0000	RAYMOND JAMES FINANCIAL INC	34,333.78	80.2200	89,685.96	55,352.18
2,524.0000	RAYONIER INC	66,103.56	28.7700	72,615.48	6,511.92
2,345.0000	RAYTHEON CO	112,928.70	161.4800	378,670.60	265,741.90
130.0000	RBC BEARINGS INC	4,838.60	101.7600	13,228.80	8,390.20
5,493.0000	REALNETWORKS INC	24,397.71	4.3300	23,784.69	613.02-
1,018.0000	REALOGY HOLDINGS CORP	31,598.63	32.4500	33,034.10	1,435.47
1,461.0000	REALTY INCOME CORP	80,407.55	55.1800	80,617.98	210.43
915.0000	RED HAT INC	59,977.27	95.7500	87,611.25	27,633.98
603.0000	REDWOOD TRUST INC	9,919.35	17.0400	10,275.12	355.77
418.0000	REGAL ENTERTAINMENT GROUP	4,928.22	20.4600	8,552.28	3,624.06
562.0000	REGENCY CENTERS CORP	23,098.20	62.6400	35,203.68	12,105.48
432.0000	REGENERON PHARMACEUTICALS INC	158,973.82	491.1400	212,172.48	53,198.66
6,294.0000	REGIONS FINANCIAL CORP	41,552.58	14.6400	92,144.16	50,591.58
526.0000	REINSURANCE GROUP OF AMERICA I	28,049.28	128.3900	67,533.14	39,483.86
473.0000	RELIANCE STEEL & ALUMINUM CO	23,309.44	72.8100	34,439.13	11,129.69

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345.0000	RENASANT CORP	4,988.70	43.7400	15,090.30	10,101.60
880.0000	RENEWABLE ENERGY GROUP INC	6,186.40	12.9500	11,396.00	5,209.60
6,220.0000	REPUBLIC FIRST BANCORP INC	24,649.86	9.2500	57,535.00	32,885.14
2,250.0000	REPUBLIC SERVICES INC	55,838.60	63.7300	143,392.50	87,553.90
966.0000	RESMED INC	24,246.60	77.8700	75,222.42	50,975.82
1,208.0000	RETAIL OPPORTUNITY INVESTMENTS	24,764.00	19.1900	23,181.52	1,582.48-
316.0000	REVLON INC	4,954.88	23.7000	7,489.20	2,534.32
1,192.0000	REXFORD INDUSTRIAL REALTY INC	25,127.36	27.4400	32,708.48	7,581.12
4,784.0000	REYNOLDS AMERICAN INC	148,854.45	65.0400	311,151.36	162,296.91
1,176.0000	RICE ENERGY INC	26,130.72	26.6300	31,316.88	5,186.16
6,267.0000	RIGEL PHARMACEUTICALS INC	16,607.55	2.7300	17,108.91	501.36
4,113.0000	RINGCENTRAL INC	61,941.78	36.5500	150,330.15	88,388.37
2,639.0000	RING ENERGY INC	31,326.23	13.0000	34,307.00	2,980.77
924.0000	ROBERT HALF INTERNATIONAL INC	28,297.13	47.9300	44,287.32	15,990.19
1,048.0000	ROCKWELL AUTOMATION INC	60,101.96	161.9600	169,734.08	109,632.12
946.0000	ROCKWELL COLLINS INC	60,516.46	105.0800	99,405.68	38,889.22
870.0000	ROLLINS INC	23,324.70	40.7100	35,417.70	12,093.00

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433.0000	ROPER TECHNOLOGIES INC	58,181.65	231.5300	100,252.49	42,070.84
1,662.0000	ROSS STORES INC	86,500.02	57.7300	95,947.26	9,447.24
395.0000	ROYAL GOLD INC	31,287.95	78.1700	30,877.15	410.80-
275.0000	RUSH ENTERPRISES INC	5,049.00	37.1800	10,224.50	5,175.50
323.0000	RYDER SYSTEM INC	16,910.88	71.9800	23,249.54	6,338.66
603.0000	RYMAN HOSPITALITY PROPERTIES I	22,823.55	64.0100	38,598.03	15,774.48
281.0000	S&T BANCORP INC	4,979.32	35.8600	10,076.66	5,097.34
1,369.0000	S&P GLOBAL INC	98,560.03	145.9900	199,860.31	101,300.28
623.0000	SBA COMMUNICATIONS CORP	25,290.00	134.9000	84,042.70	58,752.70
1,749.0000	SEI INVESTMENTS CO	35,319.39	53.7800	94,061.22	58,741.83
248.0000	SEACOR MARINE HOLDINGS INC	6,243.68	20.3600	5,049.28	1,194.40-
214.0000	SJW GROUP	4,962.66	49.1800	10,524.52	5,561.86
837.0000	SL GREEN REALTY CORP	51,158.20	105.8000	88,554.60	37,396.40
2,501.0000	SLM CORP	14,947.14	11.5000	28,761.50	13,814.36
622.0000	SS&C TECHNOLOGIES HOLDINGS INC	5,128.39	38.4100	23,891.02	18,762.63
542.0000	SAFEWAY CASA LEY CVR	550.08	1.0100	547.42	2.66-
542.0000	SAFEWAY PDC LLC CVR	17.24	0.0300	16.26	0.98-

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120.0000	SAFETY INSURANCE GROUP INC	4,950.00	68.3000	8,196.00	3,246.00
378.0000	SAGE THERAPEUTICS INC	30,621.78	79.6400	30,103.92	517.86-
411.0000	ST JOE CO/THE	5,930.73	18.7500	7,706.25	1,775.52
3,801.0000	SALESFORCE.COM INC	143,154.09	86.6000	329,166.60	186,012.51
830.0000	SALLY BEAUTY HOLDINGS INC	15,641.11	20.2500	16,807.50	1,166.39
109.0000	SANDERSON FARMS INC	5,261.43	115.6500	12,605.85	7,344.42
276.0000	SANDY SPRING BANCORP INC	4,832.76	40.6600	11,222.16	6,389.40
1,407.0000	SANMINA CORP	12,883.59	38.1000	53,606.70	40,723.11
1,451.0000	SCANA CORP	49,643.40	67.0100	97,231.51	47,588.11
166.0000	SCANSOURCE INC	4,965.06	40.3000	6,689.80	1,724.74
466.0000	HENRY SCHEIN INC	35,281.04	183.0200	85,287.32	50,006.28
9,033.0000	SCHLUMBERGER LTD	560,509.16	65.8400	594,732.72	34,223.56
194.0000	SCHOLASTIC CORP	4,834.48	43.5900	8,456.46	3,621.98
7,756.0000	CHARLES SCHWAB CORP/THE	94,455.14	42.9600	333,197.76	238,742.62
223.0000	SCIENCE APPLICATIONS INTERNATI	6,404.61	69.4200	15,480.66	9,076.05
515.0000	SCIENTIFIC GAMES CORP	5,000.65	26.1000	13,441.50	8,440.85
112.0000	SCOTTS MIRACLE-GRO CO/THE	4,957.12	89.4600	10,019.52	5,062.40

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432.0000	SCRIPPS NETWORKS INTERACTIVE I	22,272.92	68.3100	29,509.92	7,237.00
247.0000	SEACOR HOLDINGS INC	9,433.88	34.3000	8,472.10	961.78-
885.0000	SEALED AIR CORP	24,751.46	44.7600	39,612.60	14,861.14
1,234.0000	SEATTLE GENETICS INC	27,004.51	51.7400	63,847.16	36,842.65
600.0000	SELECT MEDICAL HOLDINGS CORP	5,106.00	15.3500	9,210.00	4,104.00
340.0000	SELECTIVE INSURANCE GROUP INC	5,392.40	50.0500	17,017.00	11,624.60
702.0000	SEMGROUP CORP	25,249.65	27.0000	18,954.00	6,295.65-
1,489.0000	SEMPRA ENERGY	78,923.46	112.7500	167,884.75	88,961.29
1,419.0000	SENIOR HOUSING PROPERTIES TRUS	30,903.72	20.4400	29,004.36	1,899.36-
265.0000	SENSIENT TECHNOLOGIES CORP	9,877.89	80.5300	21,340.45	11,462.56
1,811.0000	SERVICE CORP INTERNATIONAL/US	14,958.86	33.4500	60,577.95	45,619.09
735.0000	SERVICEMASTER GLOBAL HOLDINGS	25,438.35	39.1900	28,804.65	3,366.30
852.0000	SERVICENOW INC	68,307.16	106.0000	90,312.00	22,004.84
996.0000	SHENANDOAH TELECOMMUNICATIONS	5,522.82	30.7000	30,577.20	25,054.38
393.0000	SHERWIN-WILLIAMS CO/THE	110,419.04	350.9600	137,927.28	27,508.24
574.0000	SHUTTERFLY INC	17,036.32	47.5000	27,265.00	10,228.68
260.0000	SIGNATURE BANK/NEW YORK NY	14,513.20	143.5300	37,317.80	22,804.60

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248.0000	SILGAN HOLDINGS INC	4,968.68	31.7800	7,881.44	2,912.76
202.0000	SIMMONS FIRST NATIONAL CORP	4,930.82	52.9000	10,685.80	5,754.98
1,920.0000	SIMON PROPERTY GROUP INC	195,990.96	161.7600	310,579.20	114,588.24
725.0000	SIMPSON MANUFACTURING CO INC	27,661.94	43.7100	31,689.75	4,027.81
19,708.0000	SIRIUS XM HOLDINGS INC	38,546.63	5.4700	107,802.76	69,256.13
284.0000	SIX FLAGS ENTERTAINMENT CORP	5,236.05	59.6100	16,929.24	11,693.19
1,053.0000	SKECHERS U.S.A. INC	4,794.66	29.5000	31,063.50	26,268.84
1,809.0000	SKYWORKS SOLUTIONS INC	28,039.50	95.9500	173,573.55	145,534.05
832.0000	AO SMITH CORP	12,858.56	56.3300	46,866.56	34,008.00
574.0000	JM SMUCKER CO/THE	69,916.16	118.3300	67,921.42	1,994.74-
284.0000	SNAP-ON INC	14,603.28	158.0000	44,872.00	30,268.72
229.0000	SNYDER'S-LANCE INC	4,813.58	34.6200	7,927.98	3,114.40
375.0000	SONIC AUTOMOTIVE INC	5,231.25	19.4500	7,293.75	2,062.50
693.0000	SONOCO PRODUCTS CO	21,755.05	51.4200	35,634.06	13,879.01
268.0000	SOUTH STATE CORP	6,934.43	85.7000	22,967.60	16,033.17
5,599.0000	SOUTHERN CO/THE	219,264.80	47.8800	268,080.12	48,815.32
344.0000	SOUTHSIDE BANCSHARES INC	5,031.40	34.9400	12,019.36	6,987.96

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4,521.0000	SOUTHWEST AIRLINES CO	37,786.12	62.1400	280,934.94	243,148.82
133.0000	SOUTHWEST GAS HOLDINGS INC	4,984.84	73.0600	9,716.98	4,732.14
4,005.0000	SOUTHWESTERN ENERGY CO	30,743.37	6.0800	24,350.40	6,392.97-
903.0000	SPARTANNASH CO	14,948.21	25.9600	23,441.88	8,493.67
6,217.0000	SPECTRUM PHARMACEUTICALS INC	27,541.31	7.4500	46,316.65	18,775.34
237.0000	SPECTRUM BRANDS HOLDINGS INC	24,572.16	125.0400	29,634.48	5,062.32
363.0000	SPEEDWAY MOTORSPORTS INC	5,027.55	18.2700	6,632.01	1,604.46
125.0000	SPIRE INC	4,991.25	69.7500	8,718.75	3,727.50
995.0000	SPIRIT AEROSYSTEMS HOLDINGS IN	19,907.90	57.9400	57,650.30	37,742.40
415.0000	SPIRIT AIRLINES INC	4,988.47	51.6500	21,434.75	16,446.28
4,046.0000	SPIRIT REALTY CAPITAL INC	40,055.40	7.4100	29,980.86	10,074.54-
437.0000	SPOK HOLDINGS INC	4,959.95	17.7000	7,734.90	2,774.95
643.0000	SPLUNK INC	32,310.34	56.8900	36,580.27	4,269.93
5,513.0000	SPRINT CORP	36,457.71	8.2100	45,261.73	8,804.02
1,167.0000	SPROUTS FARMERS MARKET INC	24,436.98	22.6700	26,455.89	2,018.91
1,312.0000	SQUARE INC	31,302.76	23.4600	30,779.52	523.24-
1,048.0000	STANLEY BLACK & DECKER INC	63,638.44	140.7300	147,485.04	83,846.60

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3,746.0000	STAPLES INC	35,895.15	10.0700	37,722.22	1,827.07
8,542.0000	STARBUCKS CORP	146,604.17	58.3100	498,084.02	351,479.85
1,034.0000	STARWOOD PROPERTY TRUST INC	21,920.58	22.3900	23,151.26	1,230.68
1,936.0000	STATE STREET CORP	132,308.62	89.7300	173,717.28	41,408.66
874.0000	STEEL DYNAMICS INC	25,125.13	35.8100	31,297.94	6,172.81
714.0000	STERICYCLE INC	41,276.93	76.3200	54,492.48	13,215.55
726.0000	STIFEL FINANCIAL CORP	24,700.72	45.9800	33,381.48	8,680.76
1,246.0000	STORE CAPITAL CORP	30,538.23	22.4500	27,972.70	2,565.53-
2,243.0000	STRYKER CORP	111,458.04	138.7800	311,283.54	199,825.50
115.0000	STURM RUGER & CO INC	3,192.40	62.1500	7,147.25	3,954.85
431.0000	SUN BANCORP INC/NJ	5,348.71	24.6500	10,624.15	5,275.44
361.0000	SUN COMMUNITIES INC	28,887.22	87.6900	31,656.09	2,768.87
1,473.0000	SUNSTONE HOTEL INVESTORS INC	12,284.67	16.1200	23,744.76	11,460.09
2,833.0000	SUNTRUST BANKS INC	74,836.57	56.7200	160,687.76	85,851.19
1,679.0000	SUPERIOR ENERGY SERVICES INC	24,227.97	10.4300	17,511.97	6,716.00-
1,893.0000	SUPERVALU INC	5,054.31	3.2900	6,227.97	1,173.66
2,749.0000	SYMANTEC CORP	59,536.45	28.2500	77,659.25	18,122.80

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306.0000	SYNAPTICS INC	14,800.30	51.7100	15,823.26	1,022.96
923.0000	SYNOPSYS INC	23,407.28	72.9300	67,314.39	43,907.11
691.0000	SYNOVUS FINANCIAL CORP	8,851.71	44.2400	30,569.84	21,718.13
172.0000	SYNNEX CORP	5,144.52	119.9600	20,633.12	15,488.60
4,194.0000	SYNCHRONY FINANCIAL	132,878.92	29.8200	125,065.08	7,813.84-
2,140.0000	SYSCO CORP	88,583.65	50.3300	107,706.20	19,122.55
2,285.0000	TCF FINANCIAL CORP	23,307.00	15.9400	36,422.90	13,115.90
1,077.0000	TD AMERITRADE HOLDING CORP	20,032.20	42.9900	46,300.23	26,268.03
519.0000	TFS FINANCIAL CORP	4,899.36	15.4700	8,028.93	3,129.57
2,835.0000	TJX COS INC/THE	63,836.91	72.1700	204,601.95	140,765.04
3,178.0000	T-MOBILE US INC	86,007.51	60.6200	192,650.36	106,642.85
2,508.0000	TRI POINTE GROUP INC	31,768.82	13.1900	33,080.52	1,311.70
576.0000	TABLEAU SOFTWARE INC	30,810.24	61.2700	35,291.52	4,481.28
462.0000	TAKE-TWO INTERACTIVE SOFTWARE	6,842.22	73.3800	33,901.56	27,059.34
183.0000	TANGER FACTORY OUTLET CENTERS	4,884.27	25.9800	4,754.34	129.93-
1,460.0000	TARGET CORP	109,976.44	52.2900	76,343.40	33,633.04-
979.0000	TARGA RESOURCES CORP	45,532.52	45.2000	44,250.80	1,281.72-

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180.0000	TAUBMAN CENTERS INC	7,216.20	59.5500	10,719.00	3,502.80
293.0000	TECH DATA CORP	13,510.23	101.0000	29,593.00	16,082.77
2,166.0000	TEGNA INC	14,843.68	14.4100	31,212.06	16,368.38
229.0000	TELEDYNE TECHNOLOGIES INC	14,788.97	127.6500	29,231.85	14,442.88
269.0000	TELEFLEX INC	14,883.77	207.7600	55,887.44	41,003.67
424.0000	TEMPUR SEALY INTERNATIONAL INC	25,417.76	53.3900	22,637.36	2,780.40-
8.0000	TENNANT CO	306.32	73.8000	590.40	284.08
373.0000	TENNECO INC	10,089.65	57.8300	21,570.59	11,480.94
2,492.0000	TERADATA CORP	65,863.56	29.4900	73,489.08	7,625.52
1,238.0000	TERADYNE INC	17,109.16	30.0300	37,177.14	20,067.98
1,161.0000	TEREX CORP	18,634.05	37.5000	43,537.50	24,903.45
1,110.0000	TERRENO REALTY CORP	25,241.40	33.6600	37,362.60	12,121.20
279.0000	TESARO INC	39,439.01	139.8600	39,020.94	418.07-
774.0000	TESLA INC	161,238.34	361.6100	279,886.14	118,647.80
711.0000	TESORO CORP	46,836.41	93.6000	66,549.60	19,713.19
392.0000	TETRA TECH INC	8,874.88	45.7500	17,934.00	9,059.12
7,279.0000	TEXAS INSTRUMENTS INC	244,128.67	76.9300	559,973.47	315,844.80

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1,748.0000	TEXTRON INC	31,848.56	47.1000	82,330.80	50,482.24
2,629.0000	THERMO FISHER SCIENTIFIC INC	103,380.78	174.4700	458,681.63	355,300.85
237.0000	THOR INDUSTRIES INC	7,245.09	104.5200	24,771.24	17,526.15
3,584.0000	3M CO	268,203.98	208.1900	746,152.96	477,948.98
804.0000	TIFFANY & CO	26,927.00	93.8700	75,471.48	48,544.48
709.0000	TIME INC	8,685.35	14.3500	10,174.15	1,488.80
5,673.0000	TIME WARNER INC	210,551.20	100.4100	569,625.93	359,074.73
552.0000	TIMKEN CO/THE	17,960.03	46.2500	25,530.00	7,569.97
1,306.0000	TOLL BROTHERS INC	28,007.74	39.5100	51,600.06	23,592.32
130.0000	TOMPKINS FINANCIAL CORP	5,062.20	78.7200	10,233.60	5,171.40
326.0000	TOPBUILD CORP	5,457.70	53.0700	17,300.82	11,843.12
933.0000	TORCHMARK CORP	26,189.27	76.5000	71,374.50	45,185.23
1,624.0000	TORO CO/THE	20,056.40	69.2900	112,526.96	92,470.56
1,020.0000	TOTAL SYSTEM SERVICES INC	18,125.40	58.2500	59,415.00	41,289.60
395.0000	TOWNE BANK/PORTSMOUTH VA	5,100.49	30.8000	12,166.00	7,065.51
804.0000	TRACTOR SUPPLY CO	26,097.84	54.2100	43,584.84	17,487.00
211.0000	TRANSDIGM GROUP INC	50,357.10	268.8700	56,731.57	6,374.47

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1,823.0000	TRAVELERS COS INC/THE	84,751.63	126.5300	230,664.19	145,912.56
376.0000	TREEHOUSE FOODS INC	24,496.21	81.6900	30,715.44	6,219.23
807.0000	TRIBUNE MEDIA CO	26,978.01	40.7700	32,901.39	5,923.38
422.0000	TRICO BANCSHARES	6,055.70	35.1500	14,833.30	8,777.60
1,544.0000	TRIMBLE INC	28,618.04	35.6700	55,074.48	26,456.44
1,700.0000	TRINITY INDUSTRIES INC	17,187.00	28.0300	47,651.00	30,464.00
864.0000	TRIPADVISOR INC	30,656.76	38.2000	33,004.80	2,348.04
345.0000	TRUEBLUE INC	5,023.20	26.5000	9,142.50	4,119.30
3,817.0000	TRUSTCO BANK CORP NY	30,941.78	7.7500	29,581.75	1,360.03-
434.0000	TUPPERWARE BRANDS CORP	20,697.46	70.2300	30,479.82	9,782.36
12,630.0000	TWENTY-FIRST CENTURY FOX INC	216,805.30	28.3400	357,934.20	141,128.90
4,196.0000	TWITTER INC	75,964.44	17.8700	74,982.52	981.92-
191.0000	TYLER TECHNOLOGIES INC	31,883.63	175.6700	33,552.97	1,669.34
2,472.0000	TYSON FOODS INC	40,278.10	62.6300	154,821.36	114,543.26
1,250.0000	UDR INC	28,512.50	38.9700	48,712.50	20,200.00
1,057.0000	UGI CORP	20,769.53	48.4100	51,169.37	30,399.84
9,057.0000	US BANCORP	363,688.19	51.9200	470,239.44	106,551.25

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5,482.0000	UMH PROPERTIES INC	67,209.32	17.0500	93,468.10	26,258.78
412.0000	US SILICA HOLDINGS INC	4,865.72	35.4900	14,621.88	9,756.16
321.0000	ULTA BEAUTY INC	28,047.39	287.3400	92,236.14	64,188.75
157.0000	ULTIMATE SOFTWARE GROUP INC/TH	22,295.35	210.0600	32,979.42	10,684.07
390.0000	ULTRAGENYX PHARMACEUTICAL INC	27,112.80	62.1100	24,222.90	2,889.90-
2,143.0000	UMPQUA HOLDINGS CORP	22,843.44	18.3600	39,345.48	16,502.04
1,518.0000	UNDER ARMOUR INC	15,948.61	21.7600	33,031.68	17,083.07
1,528.0000	UNDER ARMOUR INC	15,421.05	20.1600	30,804.48	15,383.43
1,210.0000	UNION BANKSHARES CORP	14,442.71	33.9000	41,019.00	26,576.29
4,281.0000	UNION PACIFIC CORP	104,326.71	108.9100	466,243.71	361,917.00
1,093.0000	UNISYS CORP	16,248.96	12.8000	13,990.40	2,258.56-
773.0000	UNITED COMMUNITY BANKS INC/GA	5,094.07	27.8000	21,489.40	16,395.33
1,089.0000	UNITED BANKSHARES INC/WV	16,376.94	39.2000	42,688.80	26,311.86
1,795.0000	UNITED CONTINENTAL HOLDINGS IN	43,020.22	75.2500	135,073.75	92,053.53
942.0000	UNITED FINANCIAL BANCORP INC	9,977.00	16.6900	15,721.98	5,744.98
277.0000	UNITED FIRE GROUP INC	4,855.81	44.0600	12,204.62	7,348.81
3,891.0000	UNITED PARCEL SERVICE INC	317,116.96	110.5900	430,305.69	113,188.73

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877.0000	UNITED RENTALS INC	29,665.30	112.7100	98,846.67	69,181.37
1,392.0000	UNITED STATES STEEL CORP	25,042.08	22.1400	30,818.88	5,776.80
5,385.0000	UNITED TECHNOLOGIES CORP	342,881.26	122.1100	657,562.35	314,681.09
577.0000	UNITED THERAPEUTICS CORP	30,322.24	129.7300	74,854.21	44,531.97
6,172.0000	UNITEDHEALTH GROUP INC	308,251.92	185.4200	1,144,412.24	836,160.32
723.0000	UNITIL CORP	19,860.65	48.3100	34,928.13	15,067.48
455.0000	UNIVERSAL CORP/VA	24,865.75	64.7000	29,438.50	4,572.75
413.0000	UNIVERSAL DISPLAY CORP	25,399.50	109.2500	45,120.25	19,720.75
322.0000	UNIVERSAL ELECTRONICS INC	5,255.04	66.8500	21,525.70	16,270.66
251.0000	UNIVERSAL FOREST PRODUCTS INC	9,814.10	87.3100	21,914.81	12,100.71
346.0000	UNIVERSAL HEALTH SERVICES INC	14,933.36	122.0800	42,239.68	27,306.32
2,315.0000	UNUM GROUP	45,314.50	46.6300	107,948.45	62,633.95
403.0000	URBAN EDGE PROPERTIES	6,400.34	23.7300	9,563.19	3,162.85
1,511.0000	URSTADT BIDDLE PROPERTIES INC	30,625.41	19.8000	29,917.80	707.61-
776.0000	VCA INC	16,594.96	92.3100	71,632.56	55,037.60
1,543.0000	VF CORP	63,002.23	57.6000	88,876.80	25,874.57
6.0000	VSE CORP	66.60	44.9800	269.88	203.28

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226.0000	VAIL RESORTS INC	9,991.46	202.8300	45,839.58	35,848.12
3,315.0000	VALERO ENERGY CORP	84,158.71	67.4600	223,629.90	139,471.19
241.0000	VALMONT INDUSTRIES INC	20,325.94	149.6000	36,053.60	15,727.66
1,737.0000	VALVOLINE INC	18,500.82	23.7200	41,201.64	22,700.82
645.0000	VANTIV INC	34,361.41	63.3400	40,854.30	6,492.89
423.0000	VAREX IMAGING CORP	6,104.89	33.8000	14,297.40	8,192.51
1,059.0000	VARIAN MEDICAL SYSTEMS INC	45,253.25	103.1900	109,278.21	64,024.96
592.0000	VECTREN CORP	24,147.68	58.4400	34,596.48	10,448.80
1,220.0000	VECTOR GROUP LTD	15,446.90	21.3200	26,010.40	10,563.50
729.0000	VEEVA SYSTEMS INC	24,530.85	61.3100	44,694.99	20,164.14
2,106.0000	VENTAS INC	115,477.96	69.4800	146,324.88	30,846.92
4,393.0000	VEREIT INC	40,301.57	8.1400	35,759.02	4,542.55-
1,677.0000	VERIFONE SYSTEMS INC	29,951.22	18.1000	30,353.70	402.48
1,238.0000	VERISIGN INC	29,146.48	92.9600	115,084.48	85,938.00
22,422.0000	VERIZON COMMUNICATIONS INC	832,703.53	44.6600	1,001,366.52	168,662.99
145.0000	VERINT SYSTEMS INC	5,067.75	40.7000	5,901.50	833.75
1,120.0000	VERISK ANALYTICS INC	52,152.76	84.3700	94,494.40	42,341.64

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51.0000	VERITIV CORP	1,289.12	45.0000	2,295.00	1,005.88
1,564.0000	VERTEX PHARMACEUTICALS INC	57,135.04	128.8700	201,552.68	144,417.64
742.0000	VERSUM MATERIALS INC	7,434.21	32.5000	24,115.00	16,680.79
149.0000	VIASAT INC	7,852.09	66.2000	9,863.80	2,011.71
3,550.0000	VIACOM INC	132,577.60	33.5700	119,173.50	13,404.10-
10,342.0000	VISA INC	259,960.13	93.7800	969,872.76	709,912.63
2,019.0000	VISHAY INTERTECHNOLOGY INC	19,059.36	16.6000	33,515.40	14,456.04
371.0000	VISHAY PRECISION GROUP INC	4,960.27	17.3000	6,418.30	1,458.03
360.0000	VISTA OUTDOOR INC	6,471.68	22.5100	8,103.60	1,631.92
258.0000	VISTEON CORP	14,889.92	102.0600	26,331.48	11,441.56
332.0000	VLASIC FOODS INTL INC COM	3,527.39	10.6246	3,527.39	0.00
471.0000	VMWARE INC	24,892.35	87.4300	41,179.53	16,287.18
7,229.0000	VONAGE HOLDINGS CORP	13,662.81	6.5400	47,277.66	33,614.85
815.0000	VORNADO REALTY TRUST	62,536.96	93.9000	76,528.50	13,991.54
673.0000	VOYA FINANCIAL INC	26,866.16	36.8900	24,826.97	2,039.19-
996.0000	VULCAN MATERIALS CO	57,455.44	126.6800	126,173.28	68,717.84
90.0000	WD-40 CO	4,888.80	110.3500	9,931.50	5,042.70

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213.0000	WABCO HOLDINGS INC	14,611.56	127.5100	27,159.63	12,548.07
384.0000	WSFS FINANCIAL CORP	4,825.60	45.3500	17,414.40	12,588.80
1,647.0000	WEC ENERGY GROUP INC	43,446.80	61.3800	101,092.86	57,646.06
545.0000	WABASH NATIONAL CORP	4,845.05	21.9800	11,979.10	7,134.05
320.0000	WABTEC CORP/DE	15,928.17	91.5000	29,280.00	13,351.83
9,425.0000	WAL-MART STORES INC	499,908.14	75.6800	713,284.00	213,375.86
4,977.0000	WALGREENS BOOTS ALLIANCE INC	303,179.47	78.3100	389,748.87	86,569.40
571.0000	WASHINGTON FEDERAL INC	9,889.72	33.2000	18,957.20	9,067.48
2,675.0000	WASHINGTON PRIME GROUP INC	27,830.62	8.3700	22,389.75	5,440.87-
218.0000	WASHINGTON TRUST BANCORP INC	4,848.32	51.5500	11,237.90	6,389.58
2,245.0000	WASTE MANAGEMENT INC	107,300.69	73.3500	164,670.75	57,370.06
320.0000	WATERS CORP	29,330.56	183.8400	58,828.80	29,498.24
1,807.0000	WATERSTONE FINANCIAL INC	25,152.36	18.8500	34,061.95	8,909.59
218.0000	WATSCO INC	30,504.74	154.2000	33,615.60	3,110.86
189.0000	WATTS WATER TECHNOLOGIES INC	6,261.57	63.2000	11,944.80	5,683.23
432.0000	WAYFAIR INC	32,188.32	76.8800	33,212.16	1,023.84
222.0000	WEBMD HEALTH CORP	5,179.26	58.6500	13,020.30	7,841.04

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721.0000	WEBSTER FINANCIAL CORP	14,170.57	52.2200	37,650.62	23,480.05
826.0000	WEINGARTEN REALTY INVESTORS	19,237.54	30.1000	24,862.60	5,625.06
1,451.0000	WELBILT INC	11,833.07	18.8500	27,351.35	15,518.28
267.0000	WELLCARE HEALTH PLANS INC	13,107.03	179.5600	47,942.52	34,835.49
28,494.0000	WELLS FARGO & CO	1,030,322.29	55.4100	1,578,852.54	548,530.25
2,852.0000	WELLTOWER INC	121,776.29	74.8500	213,472.20	91,695.91
3,177.0000	WENDY'S CO/THE	14,804.82	15.5100	49,275.27	34,470.45
261.0000	WESBANCO INC	4,909.41	39.5400	10,319.94	5,410.53
380.0000	WESCO AIRCRAFT HOLDINGS INC	5,035.00	10.8500	4,123.00	912.00-
576.0000	WESCO INTERNATIONAL INC	20,378.88	57.3000	33,004.80	12,625.92
306.0000	WEST PHARMACEUTICAL SERVICES I	9,691.02	94.5200	28,923.12	19,232.10
704.0000	WESTAR ENERGY INC	24,998.56	53.0200	37,326.08	12,327.52
729.0000	WESTERN ALLIANCE BANCORP	4,891.59	49.2000	35,866.80	30,975.21
2,116.0000	WESTERN DIGITAL CORP	59,450.09	88.6000	187,477.60	128,027.51
2,417.0000	WESTERN UNION CO/THE	47,598.62	19.0500	46,043.85	1,554.77-
636.0000	WESTLAKE CHEMICAL CORP	25,331.88	66.2100	42,109.56	16,777.68
2,048.0000	WESTROCK CO	57,100.95	56.6600	116,039.68	58,938.73

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135.0000	WESTWOOD HOLDINGS GROUP INC	4,885.65	56.6900	7,653.15	2,767.50
358.0000	WEX INC	20,422.49	104.2700	37,328.66	16,906.17
4,707.0000	WEYERHAEUSER CO	82,023.75	33.5000	157,684.50	75,660.75
357.0000	WHIRLPOOL CORP	35,735.02	191.6200	68,408.34	32,673.32
1,956.0000	WHITESTONE REIT	22,788.18	12.2500	23,961.00	1,172.82
1,724.0000	WHOLE FOODS MARKET INC	54,856.19	42.1100	72,597.64	17,741.45
137.0000	JOHN WILEY & SONS INC	4,945.70	52.7500	7,226.75	2,281.05
4,420.0000	WILLIAMS COS INC/THE	95,700.86	30.2800	133,837.60	38,136.74
615.0000	WILLIAMS-SONOMA INC	21,863.25	48.5000	29,827.50	7,964.25
221.0000	WINTRUST FINANCIAL CORP	6,917.30	76.4400	16,893.24	9,975.94
387.0000	WOODWARD INC	12,527.19	67.5800	26,153.46	13,626.27
777.0000	WORKDAY INC	57,023.66	97.0000	75,369.00	18,345.34
445.0000	WORLD FUEL SERVICES CORP	15,276.85	38.4500	17,110.25	1,833.40
361.0000	WORTHINGTON INDUSTRIES INC	7,104.48	50.2200	18,129.42	11,024.94
2,045.0000	WPX ENERGY INC	28,207.51	9.6600	19,754.70	8,452.81-
1,099.0000	WYNDHAM WORLDWIDE CORP	39,201.38	100.4100	110,350.59	71,149.21
519.0000	WYNN RESORTS LTD	42,319.12	134.1200	69,608.28	27,289.16

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1,757.0000	XO GROUP INC	31,147.82	17.6200	30,958.34	189.48-
1,214.0000	XPO LOGISTICS INC	36,038.90	64.6300	78,460.82	42,421.92
1,915.0000	XILINX INC	45,059.95	64.3200	123,172.80	78,112.85
1,935.0000	XEROX CORP	44,551.52	28.7300	55,592.55	11,041.03
1,134.0000	XYLEM INC/NY	31,196.40	55.4300	62,857.62	31,661.22
279.0000	XPERI CORP	4,511.43	29.8000	8,314.20	3,802.77
929.0000	YELP INC	25,017.97	30.0200	27,888.58	2,870.61
293.0000	YORK WATER CO/THE	5,051.32	34.8500	10,211.05	5,159.73
1,773.0000	YUM! BRANDS INC	44,183.08	73.7600	130,776.48	86,593.40
2,070.0000	YUM CHINA HOLDINGS INC	28,171.53	39.4300	81,620.10	53,448.57
962.0000	ZAYO GROUP HOLDINGS INC	25,541.10	30.9000	29,725.80	4,184.70
552.0000	ZEBRA TECHNOLOGIES CORP	16,526.88	100.5200	55,487.04	38,960.16
679.0000	ZILLOW GROUP INC	32,123.49	48.8400	33,162.36	1,038.87
838.0000	ZILLOW GROUP INC	23,553.89	49.0100	41,070.38	17,516.49
1,013.0000	ZIMMER BIOMET HOLDINGS INC	68,539.07	128.4000	130,069.20	61,530.13
1,913.0000	ZIONS BANCORPORATION	29,670.63	43.9100	83,999.83	54,329.20
2,650.0000	ZOETIS INC	128,339.85	62.3800	165,307.00	36,967.15

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TOTAL INVESTMENTS EQUITY		77,602,650.70		152,295,607.98	74,692,957.28
TOTAL INVESTMENT		77,853,993.49		152,546,950.77	74,692,957.28

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INVESTMENTS CASH EQUIVALENTS					
438,660.8400	BLACKROCK LIQ T FUND INSTL FUND 60	438,660.84	100.0000	438,660.84	0.00
TOTAL INVESTMENTS CASH EQUIVALENTS		438,660.84		438,660.84	0.00
INVESTMENTS FIXED INCOME SECURITIES					
133,182.4600	ADVANCED DISPOSAL 10/16 COV-LITE TLB	133,182.46	100.3040	133,587.33	404.87
175,000.0000	AES CORP/VA 4.875% 05/15/2023 DD 04/30/13	177,232.88	101.8750	178,281.25	1,048.37
100,000.0000	AES CORP/VA 5.500% 04/15/2025 DD 04/06/15	99,180.21	104.6250	104,625.00	5,444.79
25,000.0000	AK STEEL CORP 7.000% 03/15/2027 DD 03/23/17	25,000.00	103.2500	25,812.50	812.50
100,000.0000	AMC NETWORKS INC 5.000% 04/01/2024 DD 03/30/16	100,000.00	102.3750	102,375.00	2,375.00
25,000.0000	AMN HEALTHCARE INC 144A 5.125% 10/01/2024 DD 10/03/16	25,000.00	101.2500	25,312.50	312.50
75,000.0000	AMERICAN TIRE DISTRIBUTOR 144A 10.250% 03/01/2022 DD 02/25/15	68,794.83	103.5000	77,625.00	8,830.17
50,000.0000	ACADIA HEALTHCARE CO INC 6.500% 03/01/2024 DD 02/16/16	50,086.97	106.7500	53,375.00	3,288.03

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50,000.0000	AECOM 5.750% 10/15/2022 DD 10/15/15	49,947.41	104.6250	52,312.50	2,365.09
50,000.0000	AECOM 5.875% 10/15/2024 DD 10/15/15	49,344.00	108.7500	54,375.00	5,031.00
50,000.0000	AECOM 5.125% 03/15/2027 DD 02/21/17	50,000.00	100.3750	50,187.50	187.50
75,000.0000	ADVANCED DISPOSAL SERVICE 144A 5.625% 11/15/2024 DD 11/10/16	75,000.00	103.0000	77,250.00	2,250.00
200,000.0000	ALBERTSONS COS LLC / SAFE 144A 5.750% 03/15/2025 DD 08/09/16	200,000.00	93.0000	186,000.00	14,000.00-
100,000.0000	ALLIANCE DATA SYSTEMS COR 144A 5.250% 12/01/2017 DD 11/20/12	100,454.95	100.7500	100,750.00	295.05
50,000.0000	ALLIANCE DATA SYSTEMS COR 144A 5.875% 11/01/2021 DD 10/27/16	50,000.00	103.5000	51,750.00	1,750.00
50,000.0000	ALLY FINANCIAL INC 4.750% 09/10/2018 DD 09/09/13	51,363.70	102.7500	51,375.00	11.30
100,000.0000	ALLY FINANCIAL INC 4.625% 05/19/2022 DD 05/19/15	99,567.96	104.0000	104,000.00	4,432.04
25,000.0000	ALPHA 3 BV / ALPHA US BID 144A 6.250% 02/01/2025 DD 01/31/17	25,000.00	102.8750	25,718.75	718.75
35,000.0000	ALPINE FINANCE MERGER SUB 144A 6.875% 08/01/2025 DD 07/12/17	35,000.00	101.7500	35,612.50	612.50

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200,000.0000	ALTICE LUXEMBOURG SA 144A 7.750% 05/15/2022 DD 05/08/14	210,424.00	106.1250	212,250.00	1,826.00
65,000.0000	AMERICAN AXLE & MANUFACTURING 7.750% 11/15/2019 DD 11/03/11	71,741.90	109.7500	71,337.50	404.40-
25,000.0000	AMERICAN AXLE & MANUFACTU 144A 6.250% 04/01/2025 DD 03/23/17	25,000.00	97.5000	24,375.00	625.00-
25,000.0000	AMERICAN AXLE & MANUFACTU 144A 6.500% 04/01/2027 DD 03/23/17	25,000.00	97.2500	24,312.50	687.50-
95,000.0000	AMERICAN BUILDERS & CONTR 144A 5.625% 04/15/2021 DD 04/16/13	95,308.65	102.8750	97,731.25	2,422.60
25,000.0000	AMERIGAS PARTNERS LP / AMERIGA 5.750% 05/20/2027 DD 02/13/17	25,000.00	101.2500	25,312.50	312.50
18,000.0000	ANCESTRY.COM 10/16 2ND LIEN COV-LITE TL	17,829.91	102.0830	18,374.94	545.03
19,800.0000	ANCESTRY.COM 2/17 TL	19,710.52	100.3330	19,865.93	155.41
75,000.0000	ANGLO AMERICAN CAPITAL PL 144A 9.375% 04/08/2019 DD 04/08/09	84,390.42	111.8750	83,906.25	484.17-
25,000.0000	ANTERO MIDSTREAM PARTNERS 144A 5.375% 09/15/2024 DD 09/13/16	25,000.00	102.2500	25,562.50	562.50
100,000.0000	ARAMARK SERVICES INC 5.125% 01/15/2024 DD 12/17/15	100,000.00	105.1250	105,125.00	5,125.00
200,000.0000	ARDAGH PACKAGING FINANCE 144A 4.625% 05/15/2023 DD 05/16/16	200,000.00	102.4590	204,918.00	4,918.00

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200,000.0000	ARDAGH PACKAGING FINANCE 144A 6.000% 02/15/2025 DD 01/30/17	202,903.26	105.0000	210,000.00	7,096.74
250,000.0000	PETSMART INC 144A 7.125% 03/15/2023 DD 03/04/15	249,619.86	89.0000	222,500.00	27,119.86-
25,000.0000	ASCENT RESOURCES UTICA HO 144A 10.000% 04/01/2022 DD 04/05/17	25,000.00	100.0000	25,000.00	0.00
99,336.0400	BASS PRO SHOPS 11/16 COV-LITE TLB	98,385.26	97.0500	96,405.63	1,979.63-
150,000.0000	BAYTEX ENERGY CORP 144A 5.125% 06/01/2021 DD 06/06/14	134,446.14	88.7500	133,125.00	1,321.14-
50,000.0000	BLOCK COMMUNICATIONS INC 144A 6.875% 02/15/2025 DD 02/16/17	50,000.00	107.2500	53,625.00	3,625.00
100,000.0000	BLUE RACER MIDSTREAM LLC 144A 6.125% 11/15/2022 DD 11/13/14	101,152.67	100.7500	100,750.00	402.67-
150,000.0000	BLUESCOPE STEEL FINANCE L 144A 6.500% 05/15/2021 DD 05/05/16	159,005.82	105.5000	158,250.00	755.82-
50,000.0000	BOMBARDIER INC 144A 6.000% 10/15/2022 DD 04/03/14	50,121.49	100.0000	50,000.00	121.49-
45,000.0000	BRAND ENERGY & INFRASTRUC 144A 8.500% 07/15/2025 DD 06/21/17	45,000.00	103.5000	46,575.00	1,575.00
105,000.0000	BWAY HOLDING CO 144A 5.500% 04/15/2024 DD 04/03/17	105,000.00	102.1250	107,231.25	2,231.25

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160,000.0000	BWAY HOLDING CO 144A 7.250% 04/15/2025 DD 04/03/17	160,000.00	101.5000	162,400.00	2,400.00
50,000.0000	CCO HOLDINGS LLC / CCO HO 144A 5.875% 04/01/2024 DD 02/19/16	50,000.00	106.7500	53,375.00	3,375.00
300,000.0000	CCO HOLDINGS LLC / CCO HO 144A 5.125% 05/01/2027 DD 02/06/17	299,879.14	102.2500	306,750.00	6,870.86
55,000.0000	CBS RADIO INC 144A 7.250% 11/01/2024 DD 10/17/16	56,199.28	103.0000	56,650.00	450.72
30,000.0000	OUTFRONT MEDIA CAPITAL LLC / O 5.625% 02/15/2024 DD 11/15/14	30,000.00	104.3750	31,312.50	1,312.50
25,000.0000	CDK GLOBAL INC VAR RT 10/15/2019 DD 04/15/15	25,807.67	103.0000	25,750.00	57.67-
100,000.0000	CDW LLC / CDW FINANCE CORP 5.000% 09/01/2023 DD 03/03/15	100,562.60	104.1250	104,125.00	3,562.40
125,000.0000	CHS/COMMUNITY HEALTH SYSTEMS I 6.250% 03/31/2023 DD 03/16/17	125,859.13	103.2350	129,043.75	3,184.62
25,000.0000	CNH INDUSTRIAL CAPITAL LLC 4.375% 04/05/2022 DD 04/10/17	25,000.00	104.6500	26,162.50	1,162.50
50,000.0000	CTR PARTNERSHIP LP / CARETRUST 5.250% 06/01/2025 DD 05/24/17	50,000.00	103.0000	51,500.00	1,500.00
100,000.0000	CST BRANDS INC 5.000% 05/01/2023 DD 11/01/13	100,204.20	105.0200	105,020.00	4,815.80

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150,000.0000	CABLEVISION SYSTEMS CORP 7.750% 04/15/2018 DD 04/15/10	150,058.15	103.7500	155,625.00	5,566.85
50,000.0000	CABLEVISION SYSTEMS CORP 8.000% 04/15/2020 DD 04/15/10	55,482.67	111.3750	55,687.50	204.83
250,000.0000	CABLEVISION SYSTEMS CORP 5.875% 09/15/2022 DD 09/27/12	229,858.44	105.1250	262,812.50	32,954.06
25,000.0000	CALATLANTIC GROUP INC 5.000% 06/15/2027 DD 06/09/17	25,000.00	100.2500	25,062.50	62.50
50,000.0000	CALPINE CORP 5.375% 01/15/2023 DD 07/22/14	50,000.00	97.5000	48,750.00	1,250.00-
50,000.0000	CALPINE CORP 5.750% 01/15/2025 DD 07/22/14	50,000.00	93.7500	46,875.00	3,125.00-
100,000.0000	CALPINE CORP 144A 5.250% 06/01/2026 DD 05/31/16	100,000.00	98.0000	98,000.00	2,000.00-
50,000.0000	CAMELOT FINANCE SA 144A 7.875% 10/15/2024 DD 10/03/16	50,000.00	107.7500	53,875.00	3,875.00
50,000.0000	CENTENE CORP 4.750% 05/15/2022 DD 04/29/14	50,734.80	104.3750	52,187.50	1,452.70
150,000.0000	CENTENE CORP 6.125% 02/15/2024 DD 02/11/16	150,000.00	108.1180	162,177.00	12,177.00
125,000.0000	CENTENE CORP 4.750% 01/15/2025 DD 11/09/16	125,000.00	102.7500	128,437.50	3,437.50

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100,000.0000	CENTURYLINK INC 5.625% 04/01/2025 DD 10/01/15	100,000.00	99.8330	99,833.00	167.00-
50,000.0000	CENTURYLINK INC 7.500% 04/01/2024 DD 04/06/16	50,000.00	109.5000	54,750.00	4,750.00
132,000.0000	CEQUEL COMMUNICATIONS HOL 144A 6.375% 09/15/2020 DD 10/25/12	128,966.50	102.0000	134,640.00	5,673.50
50,000.0000	CHANGE HEALTHCARE HOLDING 144A 5.750% 03/01/2025 DD 02/15/17	50,000.00	102.0000	51,000.00	1,000.00
55,000.0000	CHENIERE CORPUS CHRISTI HOLDIN 5.875% 03/31/2025 DD 12/09/16	55,000.00	106.6250	58,643.75	3,643.75
75,000.0000	CHENIERE CORPUS CHRISTI H 144A 5.125% 06/30/2027 DD 05/19/17	75,000.00	102.5000	76,875.00	1,875.00
61,000.0000	CHESAPEAKE ENERGY CORP 144A 8.000% 12/15/2022 DD 12/23/15	62,521.85	105.7500	64,507.50	1,985.65
150,000.0000	CHURCHILL DOWNS INC 5.375% 12/15/2021 DD 12/16/13	151,153.62	103.7500	155,625.00	4,471.38
150,000.0000	FRONTIER COMMUNICATIONS CORP 7.125% 03/15/2019 DD 03/23/07	154,752.84	104.2500	156,375.00	1,622.16
100,000.0000	CLEAR CHANNEL WORLDWIDE HOLDIN 7.625% 03/15/2020 DD 03/15/12	102,215.32	99.5000	99,500.00	2,715.32-
50,000.0000	COGENT COMMUNICATIONS GRO 144A 5.375% 03/01/2022 DD 02/20/15	50,168.50	105.0000	52,500.00	2,331.50

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100,000.0000	COMMSCOPE TECHNOLOGIES LL 144A 6.000% 06/15/2025 DD 06/11/15	100,000.00	106.7500	106,750.00	6,750.00
25,000.0000	UNITI GROUP INC / CSL CAP 144A 7.125% 12/15/2024 DD 12/15/16	25,000.00	99.2820	24,820.50	179.50-
50,000.0000	COTT HOLDINGS INC 144A 5.500% 04/01/2025 DD 03/22/17	50,000.00	102.0000	51,000.00	1,000.00
20,000.0000	COVANTA HOLDING CORP 5.875% 07/01/2025 DD 03/16/17	20,000.00	97.0000	19,400.00	600.00-
50,000.0000	CRESTWOOD MIDSTREAM PARTN 144A 5.750% 04/01/2025 DD 03/14/17	50,000.00	99.7500	49,875.00	125.00-
150,000.0000	CROWNROCK LP / CROWNROCK 144A 7.125% 04/15/2021 DD 04/15/13	140,035.47	102.7500	154,125.00	14,089.53
25,000.0000	CYRUSONE LP / CYRUSONE FI 144A 5.000% 03/15/2024 DD 03/17/17	25,000.00	103.0000	25,750.00	750.00
20,000.0000	CYRUSONE LP / CYRUSONE FI 144A 5.375% 03/15/2027 DD 03/17/17	20,000.00	104.1250	20,825.00	825.00
100,000.0000	DANA INC 5.375% 09/15/2021 DD 08/02/13	102,411.61	102.8750	102,875.00	463.39
185,000.0000	DAVITA INC 5.750% 08/15/2022 DD 08/28/12	188,817.14	102.7500	190,087.50	1,270.36
75,000.0000	DENBURY RESOURCES INC 144A 9.000% 05/15/2021 DD 05/10/16	78,309.44	95.2500	71,437.50	6,871.94-

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
225,000.0000	DISH DBS CORP 7.875% 09/01/2019 DD 08/17/09	225,901.92	110.2500	248,062.50	22,160.58
100,000.0000	DISH DBS CORP 5.875% 07/15/2022 DD 05/16/12	101,923.48	107.5000	107,500.00	5,576.52
25,000.0000	DOLE FOOD CO INC 144A 7.250% 06/15/2025 DD 04/06/17	25,000.00	104.0000	26,000.00	1,000.00
150,000.0000	RR DONNELLEY & SONS CO 6.000% 04/01/2024 DD 03/20/14	148,008.31	97.3750	146,062.50	1,945.81-
100,000.0000	DYNEGY INC 5.875% 06/01/2023 DD 12/01/13	98,887.86	93.5000	93,500.00	5,387.86-
100,000.0000	DYNEGY INC 6.750% 11/01/2019 DD 05/01/15	100,809.13	103.1250	103,125.00	2,315.87
100,000.0000	EMC CORP 2.650% 06/01/2020 DD 06/06/13	97,161.35	98.1230	98,123.00	961.65
75,000.0000	ESH HOSPITALITY INC 144A 5.250% 05/01/2025 DD 05/15/15	72,017.37	103.6250	77,718.75	5,701.38
25,000.0000	ELDORADO RESORTS INC 144A 6.000% 04/01/2025 DD 03/29/17	25,000.00	106.0000	26,500.00	1,500.00
150,000.0000	ENDO FINANCE LLC / ENDO F 144A VAR RT 01/15/2022 DD 05/06/14	151,966.14	95.7500	143,625.00	8,341.14-
25,000.0000	ENPRO INDUSTRIES INC 144A 5.875% 09/15/2022 DD 03/15/17	25,239.17	104.2500	26,062.50	823.33

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200,000.0000	ENTEGRIS INC 144A 6.000% 04/01/2022 DD 04/01/14	200,000.00	104.6250	209,250.00	9,250.00
50,000.0000	EQUINIX INC 5.375% 05/15/2027 DD 03/22/17	50,000.00	106.6250	53,312.50	3,312.50
100,000.0000	TRONOX FINANCE LLC 144A 7.500% 03/15/2022 DD 03/19/15	100,000.00	103.0000	103,000.00	3,000.00
50,000.0000	EXTRACTION OIL & GAS INC 144A 7.875% 07/15/2021 DD 07/18/16	50,000.00	102.7500	51,375.00	1,375.00
25,000.0000	FMG RESOURCES AUGUST 2006 144A 4.750% 05/15/2022 DD 05/12/17	25,000.00	100.3750	25,093.75	93.75
50,000.0000	FMG RESOURCES AUGUST 2006 144A 5.125% 05/15/2024 DD 05/12/17	50,000.00	100.0000	50,000.00	0.00
150,000.0000	FTI CONSULTING INC 6.000% 11/15/2022 DD 05/15/13	150,000.00	103.7500	155,625.00	5,625.00
100,000.0000	FELCOR LODGING LP 5.625% 03/01/2023 DD 03/01/13	100,000.00	103.7500	103,750.00	3,750.00
75,000.0000	FERRELLGAS LP / FERRELLGAS FIN VAR RT 06/15/2023 DD 06/15/16	75,000.00	93.2500	69,937.50	5,062.50-
125,000.0000	FIRST DATA CORP 144A 5.375% 08/15/2023 DD 08/11/15	125,000.00	104.5000	130,625.00	5,625.00
175,000.0000	FIRST QUALITY FINANCE CO 144A 4.625% 05/15/2021 DD 05/14/13	175,000.00	100.8750	176,531.25	1,531.25

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
10,000.0000	FIRSTCASH INC 144A 5.375% 06/01/2024 DD 05/30/17	10,000.00	104.3750	10,437.50	437.50
50,000.0000	FLEX ACQUISITION CO INC 144A 6.875% 01/15/2025 DD 01/17/17	50,000.00	104.0000	52,000.00	2,000.00
125,000.0000	FREEPORT-MCMORAN INC 3.875% 03/15/2023 DD 09/15/13	115,525.99	93.0000	116,250.00	724.01
20,000.0000	FRESENIUS MEDICAL CARE US 144A 5.625% 07/31/2019 DD 01/26/12	21,308.10	105.7500	21,150.00	158.10-
150,000.0000	FRESENIUS US FINANCE II I 144A 4.500% 01/15/2023 DD 09/25/15	150,000.00	105.0000	157,500.00	7,500.00
100,000.0000	FRONTIER COMMUNICATIONS CORP 7.125% 01/15/2023 DD 08/15/12	93,796.60	83.2500	83,250.00	10,546.60-
100,000.0000	GFL ENVIRONMENTAL INC 144A 5.625% 05/01/2022 DD 05/12/17	100,365.91	102.2500	102,250.00	1,884.09
100,000.0000	TEGNA INC 5.125% 07/15/2020 DD 07/29/13	102,888.85	102.5000	102,500.00	388.85-
200,000.0000	GARDA WORLD SECURITY CORP 144A 7.250% 11/15/2021 DD 11/08/13	203,505.90	101.1250	202,250.00	1,255.90-
100,000.0000	GENESIS ENERGY LP / GENESIS EN 6.000% 05/15/2023 DD 05/21/15	100,000.00	98.0000	98,000.00	2,000.00-
200,000.0000	GIBSON ENERGY INC 144A 6.750% 07/15/2021 DD 06/28/13	198,289.73	103.2500	206,500.00	8,210.27

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200,000.0000	GOODYEAR TIRE & RUBBER CO/THE 5.000% 05/31/2026 DD 05/13/16	200,000.00	103.5000	207,000.00	7,000.00
55,000.0000	GOODYEAR TIRE & RUBBER CO/THE 4.875% 03/15/2027 DD 03/07/17	55,000.00	101.5000	55,825.00	825.00
92,926.8200	WHEELABRATOR TECHNOLOGIES 10/14 TLB	91,507.73	100.3750	93,275.30	1,767.57
1,372.5800	WHEELABRATOR TECHNOLOGIES 10/14 TLC	1,351.61	100.3750	1,377.73	26.12
25,000.0000	GENESYS TELECOMMUNICATION 144A 10.000% 11/30/2024 DD 12/01/16	25,000.00	112.3750	28,093.75	3,093.75
74,625.0000	GENESYS 1/17 (USD) COV-LT TLB 0.000% 12/01/2023 DD 01/09/17	73,658.81	100.2250	74,792.91	1,134.10
100,000.0000	GRINDING MEDIA INC / MOLY 144A 7.375% 12/15/2023 DD 12/16/16	100,445.45	108.7500	108,750.00	8,304.55
300,000.0000	GROUP 1 AUTOMOTIVE INC VAR RT 06/01/2022 DD 06/01/15	300,693.59	101.5000	304,500.00	3,806.41
25,000.0000	GULFPORT ENERGY CORP 144A 6.000% 10/15/2024 DD 10/14/16	25,000.00	97.2500	24,312.50	687.50-
50,000.0000	HCA INC 5.250% 04/15/2025 DD 10/17/14	50,885.94	107.5000	53,750.00	2,864.06
150,000.0000	HCA INC 4.500% 02/15/2027 DD 08/15/16	150,174.90	102.8750	154,312.50	4,137.60

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100,000.0000	HCA INC 5.500% 06/15/2047 DD 06/22/17	100,000.00	103.5000	103,500.00	3,500.00
50,000.0000	HCA HEALTHCARE INC 6.250% 02/15/2021 DD 12/06/12	52,011.46	109.2500	54,625.00	2,613.54
250,000.0000	HCA INC 6.500% 02/15/2020 DD 08/01/11	272,993.16	109.1250	272,812.50	180.66-
100,000.0000	HD SUPPLY INC 144A 5.750% 04/15/2024 DD 04/11/16	100,000.00	106.2500	106,250.00	6,250.00
150,000.0000	HALCON RESOURCES CORP 144A 6.750% 02/15/2025 DD 02/16/17	150,000.00	90.0000	135,000.00	15,000.00-
150,000.0000	HALYARD HEALTH INC 6.250% 10/15/2022 DD 04/15/15	150,000.00	104.2500	156,375.00	6,375.00
100,000.0000	HERTZ CORP/THE 5.875% 10/15/2020 DD 10/16/12	101,025.72	96.7500	96,750.00	4,275.72-
50,000.0000	HERTZ CORP/THE 144A 7.625% 06/01/2022 DD 06/06/17	50,000.00	99.7600	49,880.00	120.00-
138,000.0000	HERC RENTALS INC 144A 7.500% 06/01/2022 DD 06/09/16	138,000.00	105.5000	145,590.00	7,590.00
25,000.0000	HILL-ROM HOLDINGS INC 144A 5.000% 02/15/2025 DD 02/14/17	25,000.00	102.0000	25,500.00	500.00
50,000.0000	HOLLY ENERGY PARTNERS LP 144A 6.000% 08/01/2024 DD 07/19/16	50,000.00	104.0000	52,000.00	2,000.00

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135,000.0000	HOLOGIC INC 144A 5.250% 07/15/2022 DD 07/02/15	135,000.00	105.0000	141,750.00	6,750.00
25,000.0000	HUDBAY MINERALS INC 144A 7.625% 01/15/2025 DD 12/12/16	25,000.00	104.7500	26,187.50	1,187.50
125,000.0000	HUGHES SATELLITE SYSTEMS CORP 7.625% 06/15/2021 DD 12/15/11	126,836.25	113.6250	142,031.25	15,195.00
175,000.0000	HUNTSMAN INTERNATIONAL LLC 4.875% 11/15/2020 DD 11/19/12	183,038.35	105.2500	184,187.50	1,149.15
200,000.0000	INFOR US INC 6.500% 05/15/2022 DD 11/15/15	202,668.83	103.5000	207,000.00	4,331.17
250,000.0000	INMARSAT FINANCE PLC 144A 4.875% 05/15/2022 DD 06/04/14	241,077.74	101.5000	253,750.00	12,672.26
50,000.0000	INTELSAT JACKSON HOLDINGS SA 7.250% 04/01/2019 DD 10/01/11	43,157.12	100.0250	50,012.50	6,855.38
50,000.0000	INTELSAT JACKSON HOLDINGS SA 7.500% 04/01/2021 DD 10/01/11	41,503.42	92.2500	46,125.00	4,621.58
100,000.0000	INTELSAT JACKSON HOLDINGS SA 5.500% 08/01/2023 DD 06/05/13	84,709.74	82.7500	82,750.00	1,959.74-
100,000.0000	INVENTIV GROUP HOLDINGS I 144A 7.500% 10/01/2024 DD 10/14/16	100,000.00	108.5000	108,500.00	8,500.00
150,000.0000	IRON MOUNTAIN INC 6.000% 08/15/2023 DD 08/13/13	152,243.54	106.2500	159,375.00	7,131.46

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
50,000.0000	PATHEON HOLDINGS I BV 144A 7.500% 02/01/2022 DD 02/05/14	52,911.15	106.2500	53,125.00	213.85
25,000.0000	J2 CLOUD SERVICES LLC / J 144A 6.000% 07/15/2025 DD 06/27/17	25,000.00	103.0000	25,750.00	750.00
25,000.0000	RP CROWN PARENT LLC 144A 7.375% 10/15/2024 DD 10/06/16	25,000.00	104.0000	26,000.00	1,000.00
10,000.0000	JONAH ENERGY 5/14 COV-LITE 2ND LIEN TL	9,700.00	95.1670	9,516.70	183.30-
50,000.0000	JUPITER RESOURCES INC 144A 8.500% 10/01/2022 DD 09/18/14	48,478.46	75.0000	37,500.00	10,978.46-
125,000.0000	KFC HOLDING CO/PIZZA HUT 144A 5.000% 06/01/2024 DD 06/16/16	125,000.00	104.2500	130,312.50	5,312.50
25,000.0000	KFC HOLDING CO/PIZZA HUT 144A 4.750% 06/01/2027 DD 06/15/17	25,000.00	102.1250	25,531.25	531.25
100,000.0000	KLX INC 144A 5.875% 12/01/2022 DD 12/08/14	100,000.00	105.0000	105,000.00	5,000.00
20,000.0000	KINROSS GOLD CORP 144A 4.500% 07/15/2027 DD 07/06/17	20,000.00	99.7500	19,950.00	50.00-
25,000.0000	KOPPERS INC 144A 6.000% 02/15/2025 DD 01/25/17	25,000.00	106.2500	26,562.50	1,562.50
100,000.0000	KRONOS ACQUISITION HOLDIN 144A 9.000% 08/15/2023 DD 08/26/15	102,072.11	99.7500	99,750.00	2,322.11-

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100,000.0000	LENNAR CORP VAR RT 12/01/2018 DD 02/04/13	102,221.27	102.2500	102,250.00	28.73
50,000.0000	LENNAR CORP 4.500% 04/30/2024 DD 04/28/17	50,000.00	103.3600	51,680.00	1,680.00
75,000.0000	LIONS GATE ENTERTAINMENT 144A 5.875% 11/01/2024 DD 10/27/16	75,715.74	105.2500	78,937.50	3,221.76
90,000.0000	MDC PARTNERS INC 144A 6.500% 05/01/2024 DD 03/23/16	90,000.00	99.7500	89,775.00	225.00-
50,000.0000	MGM RESORTS INTERNATIONAL 6.750% 10/01/2020 DD 04/01/13	53,756.69	110.7900	55,395.00	1,638.31
225,000.0000	MPH ACQUISITION HOLDINGS 144A 7.125% 06/01/2024 DD 06/07/16	225,813.75	106.6250	239,906.25	14,092.50
175,000.0000	MSCI INC 144A 5.750% 08/15/2025 DD 08/13/15	176,253.69	108.3120	189,546.00	13,292.31
25,000.0000	MALLINCKRODT INTERNATIONA 144A 5.500% 04/15/2025 DD 04/15/15	25,000.00	87.5000	21,875.00	3,125.00-
150,000.0000	MEDIACOM BROADBAND LLC / MEDIA 5.500% 04/15/2021 DD 03/17/14	150,000.00	102.2500	153,375.00	3,375.00
100,000.0000	MICRON TECHNOLOGY INC 144A 5.250% 01/15/2024 DD 04/30/15	100,000.00	103.5000	103,500.00	3,500.00
50,000.0000	MIDAS INTERMEDIATE HOLDCO 144A 7.875% 10/01/2022 DD 09/24/14	50,441.03	103.0000	51,500.00	1,058.97

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175,000.0000	MIDCONTINENT COMMUNICATIO 144A 6.875% 08/15/2023 DD 08/14/15	176,262.85	107.7500	188,562.50	12,299.65
65,000.0000	MOLINA HEALTHCARE INC VAR RT 11/15/2022 DD 05/15/16	65,000.00	105.8750	68,818.75	3,818.75
50,000.0000	MOLINA HEALTHCARE INC 144A 4.875% 06/15/2025 DD 06/06/17	50,000.00	100.7500	50,375.00	375.00
150,000.0000	NATURE'S BOUNTY CO/THE 144A 7.625% 05/15/2021 DD 05/05/16	150,000.00	106.2500	159,375.00	9,375.00
125,000.0000	NCR CORP 4.625% 02/15/2021 DD 02/15/13	125,188.98	102.0000	127,500.00	2,311.02
100,000.0000	NGL ENERGY PARTNERS LP / 144A 7.500% 11/01/2023 DD 10/24/16	100,000.00	98.6250	98,625.00	1,375.00-
75,000.0000	NGL ENERGY PARTNERS LP / 144A 6.125% 03/01/2025 DD 02/22/17	75,000.00	91.5000	68,625.00	6,375.00-
150,000.0000	NRG ENERGY INC 6.625% 03/15/2023 DD 03/15/13	151,520.94	102.7500	154,125.00	2,604.06
150,000.0000	NRG ENERGY INC 6.250% 07/15/2022 DD 07/15/14	153,289.77	102.6250	153,937.50	647.73
300,000.0000	NAVISTAR INTERNATIONAL CORP 8.250% 11/01/2021 DD 10/28/09	302,897.07	101.0000	303,000.00	102.93
50,000.0000	NAVIENT CORP 5.000% 10/26/2020 DD 11/06/14	50,000.00	103.7500	51,875.00	1,875.00

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75,000.0000	NAVIENT CORP 7.250% 09/25/2023 DD 09/16/16	74,912.84	107.7500	80,812.50	5,899.66
25,000.0000	NAVIENT CORP 6.500% 06/15/2022 DD 03/07/17	25,000.00	106.0000	26,500.00	1,500.00
200,000.0000	NEXSTAR BROADCASTING INC 144A 5.625% 08/01/2024 DD 07/27/16	200,000.00	101.2500	202,500.00	2,500.00
90,000.0000	NFP CORP 144A 6.875% 07/15/2025 DD 07/12/17	90,000.00	101.0000	90,900.00	900.00
100,000.0000	NIELSEN FINANCE LLC / NIELSEN 4.500% 10/01/2020 DD 04/01/13	102,140.71	101.5280	101,528.00	612.71-
50,000.0000	NIELSEN FINANCE LLC / NIE 144A 5.000% 04/15/2022 DD 04/11/14	50,501.82	103.7500	51,875.00	1,373.18
50,000.0000	NOVA CHEMICALS CORP 144A 4.875% 06/01/2024 DD 06/09/17	50,000.00	99.6250	49,812.50	187.50-
25,000.0000	NOVA CHEMICALS CORP 144A 5.250% 06/01/2027 DD 06/09/17	25,000.00	99.5000	24,875.00	125.00-
95,000.0000	NOVELIS CORP 144A 6.250% 08/15/2024 DD 08/29/16	95,000.00	105.0000	99,750.00	4,750.00
23,000.0000	NUANCE COMMUNICATIONS INC 144A 5.375% 08/15/2020 DD 08/14/12	23,416.20	101.6250	23,373.75	42.45-
50,000.0000	NUANCE COMMUNICATIONS INC 144A 5.625% 12/15/2026 DD 12/22/16	49,549.83	106.7500	53,375.00	3,825.17

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200,000.0000	SFR GROUP SA 144A 6.000% 05/15/2022 DD 05/08/14	203,679.25	104.6250	209,250.00	5,570.75
200,000.0000	OASIS PETROLEUM INC 6.500% 11/01/2021 DD 11/10/11	195,688.39	97.0000	194,000.00	1,688.39-
100,000.0000	OASIS PETROLEUM INC 6.875% 03/15/2022 DD 03/15/14	94,427.26	97.0000	97,000.00	2,572.74
50,000.0000	1011778 BC ULC / NEW RED 144A 4.250% 05/15/2024 DD 05/17/17	50,000.00	99.3690	49,684.50	315.50-
125,000.0000	ORBITAL ATK INC 5.500% 10/01/2023 DD 04/01/16	125,000.00	105.2500	131,562.50	6,562.50
25,000.0000	ORCHESTRA BORROWER LLC / 144A 6.750% 06/15/2022 DD 06/16/17	25,000.00	103.0400	25,760.00	760.00
50,000.0000	PTC INC 6.000% 05/15/2024 DD 05/12/16	50,000.00	108.2500	54,125.00	4,125.00
50,000.0000	PARK AEROSPACE HOLDINGS L 144A 5.250% 08/15/2022 DD 02/03/17	50,000.00	104.5320	52,266.00	2,266.00
25,000.0000	PARK AEROSPACE HOLDINGS L 144A 5.500% 02/15/2024 DD 02/03/17	25,000.00	104.4500	26,112.50	1,112.50
25,000.0000	PEABODY ENERGY CORP 144A 6.375% 03/31/2025 DD 02/15/17	25,000.00	98.5000	24,625.00	375.00-
150,000.0000	PENSKE AUTOMOTIVE GROUP INC 5.750% 10/01/2022 DD 04/01/13	150,481.37	103.2500	154,875.00	4,393.63

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50,000.0000	PETSMART INC 144A 5.875% 06/01/2025 DD 05/31/17	50,000.00	96.3750	48,187.50	1,812.50-
200,000.0000	PLATFORM SPECIALTY PRODUC 144A 6.500% 02/01/2022 DD 02/02/15	192,283.25	103.2500	206,500.00	14,216.75
150,000.0000	POLYONE CORP 5.250% 03/15/2023 DD 09/15/13	150,360.72	105.0000	157,500.00	7,139.28
200,000.0000	POST HOLDINGS INC 144A 6.000% 12/15/2022 DD 06/02/14	204,553.22	106.0000	212,000.00	7,446.78
25,000.0000	POST HOLDINGS INC 144A 5.750% 03/01/2027 DD 02/14/17	25,000.00	102.7500	25,687.50	687.50
80,000.0000	QUEBECOR MEDIA INC 5.750% 01/15/2023 DD 12/15/12	80,000.00	105.5000	84,400.00	4,400.00
250,000.0000	RSI HOME PRODUCTS INC 144A 6.500% 03/15/2023 DD 03/16/15	250,000.00	105.2500	263,125.00	13,125.00
75,000.0000	RADIATE HOLDCO LLC / RADI 144A 6.625% 02/15/2025 DD 02/01/17	75,140.47	100.0000	75,000.00	140.47-
100,000.0000	RANGE RESOURCES CORP 4.875% 05/15/2025 DD 11/15/15	90,428.30	95.0000	95,000.00	4,571.70
100,000.0000	RANGE RESOURCES CORP 144A 5.000% 03/15/2023 DD 09/16/16	89,548.13	97.7500	97,750.00	8,201.87
100,000.0000	REALOGY GROUP LLC / REALO 144A 4.500% 04/15/2019 DD 04/07/14	101,744.51	103.2500	103,250.00	1,505.49

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
100,000.0000	REGIONALCARE HOSPITAL PAR 144A 8.250% 05/01/2023 DD 04/29/16	103,194.05	107.2500	107,250.00	4,055.95
64,813.5500	REYNOLDS GROUP ISSUER INC / RE VAR RT 02/15/2021 DD 02/15/12	66,417.71	102.7500	66,595.92	178.21
50,000.0000	REYNOLDS GROUP ISSUER INC / RE 5.750% 10/15/2020 DD 09/28/12	51,403.63	102.3340	51,167.00	236.63-
100,000.0000	RITE AID CORP 144A 6.125% 04/01/2023 DD 04/02/15	102,722.75	98.1880	98,188.00	4,534.75-
25,000.0000	ROCKIES EXPRESS PIPELINE 144A 6.000% 01/15/2019 DD 01/17/13	26,232.69	104.2500	26,062.50	170.19-
10,000.0000	SBA COMMUNICATIONS CORP 4.875% 09/01/2024 DD 03/01/17	9,925.36	101.7500	10,175.00	249.64
175,000.0000	SESI LLC 6.375% 05/01/2019 DD 11/01/11	161,657.96	98.7500	172,812.50	11,154.54
175,000.0000	NAVIENT CORP 7.250% 01/25/2022 DD 01/27/12	178,707.78	109.2500	191,187.50	12,479.72
150,000.0000	SM ENERGY CO 6.500% 01/01/2023 DD 06/29/12	145,803.00	95.2500	142,875.00	2,928.00-
100,000.0000	SPX FLOW INC 144A 5.625% 08/15/2024 DD 08/10/16	102,317.94	103.0000	103,000.00	682.06
50,000.0000	SEAGATE HDD CAYMAN 144A 4.875% 03/01/2024 DD 02/03/17	49,680.54	101.9210	50,960.50	1,279.96

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50,000.0000	SEMGROUP CORP 144A 6.375% 03/15/2025 DD 03/15/17	49,255.63	96.7500	48,375.00	880.63-
125,000.0000	SENSATA TECHNOLOGIES BV 144A 5.000% 10/01/2025 DD 03/26/15	125,000.00	104.5800	130,725.00	5,725.00
100,000.0000	SERVICE CORP INTERNATIONAL/US 7.625% 10/01/2018 DD 10/03/06	100,329.23	106.7500	106,750.00	6,420.77
150,000.0000	SHEA HOMES LP / SHEA HOME 144A 5.875% 04/01/2023 DD 03/23/15	150,000.00	102.9500	154,425.00	4,425.00
225,000.0000	SIGNODE INDUSTRIAL GROUP 144A 6.375% 05/01/2022 DD 04/29/14	224,271.37	104.5000	235,125.00	10,853.63
250,000.0000	SIRIUS XM RADIO INC 144A 6.000% 07/15/2024 DD 05/06/14	252,489.89	106.2500	265,625.00	13,135.11
50,000.0000	SIRIUS XM RADIO INC 144A 5.000% 08/01/2027 DD 07/05/17	50,000.00	100.7500	50,375.00	375.00
45,000.0000	SIX FLAGS ENTERTAINMENT C 144A 4.875% 07/31/2024 DD 06/16/16	44,561.42	100.6120	45,275.40	713.98
25,000.0000	SONIC AUTOMOTIVE INC 144A 6.125% 03/15/2027 DD 03/10/17	25,000.00	99.5000	24,875.00	125.00-
25,000.0000	SPECTRUM BRANDS INC 6.125% 12/15/2024 DD 12/15/15	25,000.00	107.1250	26,781.25	1,781.25
100,000.0000	SPRINGLEAF FINANCE CORP 6.000% 06/01/2020 DD 12/01/13	98,308.56	105.5000	105,500.00	7,191.44

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150,000.0000	SPRINGLEAF FINANCE CORP 5.250% 12/15/2019 DD 12/03/14	146,050.44	104.0100	156,015.00	9,964.56
50,000.0000	SPRINT CAPITAL CORP 6.900% 05/01/2019 DD 05/06/99	53,533.43	106.7450	53,372.50	160.93-
25,000.0000	SPRINT COMMUNICATIONS INC 7.000% 08/15/2020 DD 08/14/12	27,087.18	110.0000	27,500.00	412.82
200,000.0000	SPRINT COMMUNICATIONS INC 6.000% 11/15/2022 DD 11/14/12	175,323.13	106.0000	212,000.00	36,676.87
100,000.0000	SPRINT CORP 7.250% 09/15/2021 DD 09/15/14	83,503.66	111.1250	111,125.00	27,621.34
100,000.0000	SPRINT CORP 7.875% 09/15/2023 DD 09/15/14	99,433.30	115.0000	115,000.00	15,566.70
150,000.0000	SPRINT CORP 7.125% 06/15/2024 DD 06/15/14	147,076.38	111.2500	166,875.00	19,798.62
35,000.0000	CALATLANTIC GROUP INC 8.375% 05/15/2018 DD 05/03/10	36,903.26	105.1250	36,793.75	109.51-
25,000.0000	STARWOOD PROPERTY TRUST I 144A 5.000% 12/15/2021 DD 12/16/16	25,000.00	104.0000	26,000.00	1,000.00
100,000.0000	STERIGENICS-NORDION TOPCO 144A 8.125% 11/01/2021 DD 11/01/16	100,000.00	102.5000	102,500.00	2,500.00
100,000.0000	SUBURBAN PROPANE PARTNERS LP/S 5.500% 06/01/2024 DD 05/27/14	100,744.16	99.5000	99,500.00	1,244.16-

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100,000.0000	SUMMIT MATERIALS LLC / SUMMIT 6.125% 07/15/2023 DD 07/08/15	99,484.27	104.7500	104,750.00	5,265.73
25,000.0000	SUMMIT MIDSTREAM HOLDINGS LLC 5.750% 04/15/2025 DD 02/15/17	25,000.00	100.5000	25,125.00	125.00
50,000.0000	SUNCOKE ENERGY PARTNERS L 144A 7.500% 06/15/2025 DD 05/24/17	49,263.67	98.7500	49,375.00	111.33
25,000.0000	SYMANTEC CORP 144A 5.000% 04/15/2025 DD 02/09/17	25,000.00	104.6560	26,164.00	1,164.00
60,000.0000	THC ESCROW CORP III 144A 4.625% 07/15/2024 DD 06/14/17	60,000.00	100.2700	60,162.00	162.00
100,000.0000	THC ESCROW CORP III 144A 5.125% 05/01/2025 DD 06/14/17	100,000.00	100.3750	100,375.00	375.00
75,000.0000	THC ESCROW CORP III 144A 7.000% 08/01/2025 DD 06/14/17	75,000.00	99.6250	74,718.75	281.25-
100,000.0000	T-MOBILE USA INC 6.125% 01/15/2022 DD 11/21/13	105,672.02	105.0940	105,094.00	578.02-
100,000.0000	T-MOBILE USA INC 6.500% 01/15/2026 DD 11/05/15	100,000.00	110.3750	110,375.00	10,375.00
25,000.0000	T-MOBILE USA INC 5.375% 04/15/2027 DD 03/16/17	25,000.00	107.2500	26,812.50	1,812.50
50,000.0000	TRI POINTE GROUP INC 5.250% 06/01/2027 DD 06/08/17	50,000.00	100.2500	50,125.00	125.00

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144,374.9990	ALLFLEX 7/13 TL	144,375.00	100.2500	144,735.94	360.94
50,000.0000	TALLGRASS ENERGY PARTNERS 144A 5.500% 09/15/2024 DD 09/01/16	50,000.00	101.2500	50,625.00	625.00
193,000.0000	TECK RESOURCES LTD 4.750% 01/15/2022 DD 07/05/11	176,917.36	103.5000	199,755.00	22,837.64
200,000.0000	TELECOM ITALIA SPA/MILANO 144A 5.303% 05/30/2024 DD 05/30/14	198,105.97	107.2500	214,500.00	16,394.03
75,000.0000	TELESAT CANADA / TELESAT 144A 8.875% 11/15/2024 DD 11/17/16	75,000.00	112.2500	84,187.50	9,187.50
50,000.0000	TEMPO ACQUISITION LLC / T 144A 6.750% 06/01/2025 DD 05/01/17	50,000.00	102.2500	51,125.00	1,125.00
100,000.0000	TENET HEALTHCARE CORP 8.125% 04/01/2022 DD 09/27/13	103,899.94	106.1250	106,125.00	2,225.06
25,000.0000	TENET HEALTHCARE CORP 144A 7.500% 01/01/2022 DD 12/01/16	25,000.00	108.4800	27,120.00	2,120.00
48,000.0000	TENET HEALTHCARE CORP 144A 4.625% 07/15/2024 DD 06/14/17	48,000.00	100.1250	48,060.00	60.00
125,000.0000	TEAM HEALTH HOLDINGS INC 144A 6.375% 02/01/2025 DD 02/01/17	121,896.86	97.0000	121,250.00	646.86-
50,000.0000	TEREX CORP 144A 5.625% 02/01/2025 DD 01/31/17	50,000.00	102.8750	51,437.50	1,437.50
150,000.0000	TESORO LOGISTICS LP / TESORO L 5.500% 10/15/2019 DD 10/15/15	149,091.75	105.5000	158,250.00	9,158.25

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
250,000.0000	TOWNSQUARE MEDIA INC 144A 6.500% 04/01/2023 DD 04/01/15	250,000.00	100.5000	251,250.00	1,250.00
150,000.0000	TRANSDIGM INC 6.000% 07/15/2022 DD 06/04/14	154,425.55	103.0000	154,500.00	74.45
50,000.0000	TRANSDIGM INC 6.500% 05/15/2025 DD 11/15/15	50,725.66	101.7500	50,875.00	149.34
50,000.0000	TRINIDAD DRILLING LTD 144A 6.625% 02/15/2025 DD 02/08/17	50,000.00	95.0000	47,500.00	2,500.00-
100,000.0000	TRONOX FINANCE LLC 6.375% 08/15/2020 DD 08/15/13	90,926.17	100.2500	100,250.00	9,323.83
25,000.0000	USG CORP 144A 4.875% 06/01/2027 DD 05/15/17	25,000.00	102.8750	25,718.75	718.75
25,000.0000	ULTRA RESOURCES INC 144A 6.875% 04/15/2022 DD 04/12/17	25,000.00	99.2500	24,812.50	187.50-
25,000.0000	ULTRA RESOURCES INC 144A 7.125% 04/15/2025 DD 04/12/17	24,634.48	98.6250	24,656.25	21.77
25,000.0000	UNITED RENTALS NORTH AMERICA I 5.875% 09/15/2026 DD 05/13/16	26,123.79	106.5000	26,625.00	501.21
50,000.0000	UNITED RENTALS NORTH AMERICA I 5.500% 05/15/2027 DD 11/07/16	50,670.39	103.0000	51,500.00	829.61
25,000.0000	UNITI GROUP INC / UNITI F 144A 7.125% 12/15/2024 DD 12/15/16	25,123.05	99.1250	24,781.25	341.80-

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180,000.0000	UNITYMEDIA HESSEN GMBH & 144A 5.500% 01/15/2023 DD 12/14/12	181,087.15	103.7500	186,750.00	5,662.85
100,000.0000	UNIVERSAL HEALTH SERVICES 144A 4.750% 08/01/2022 DD 08/07/14	101,263.37	103.3750	103,375.00	2,111.63
150,000.0000	UNIVISION COMMUNICATIONS 144A 5.125% 05/15/2023 DD 05/21/13	153,364.77	100.9680	151,452.00	1,912.77-
75,000.0000	USIS MERGER SUB INC 144A 6.875% 05/01/2025 DD 04/18/17	75,000.00	101.7500	76,312.50	1,312.50
125,000.0000	VALEANT PHARMACEUTICALS I 144A 5.375% 03/15/2020 DD 03/27/15	120,937.50	96.6250	120,781.25	156.25-
50,000.0000	VALEANT PHARMACEUTICALS I 144A 6.500% 03/15/2022 DD 03/21/17	50,000.00	104.8750	52,437.50	2,437.50
30,000.0000	VERISIGN INC 144A 4.750% 07/15/2027 DD 07/05/17	30,000.00	101.1250	30,337.50	337.50
200,000.0000	VIASAT INC 6.875% 06/15/2020 DD 06/15/12	200,901.67	101.9680	203,936.00	3,034.33
50,000.0000	VIDEOTRON LTD 5.000% 07/15/2022 DD 07/15/12	50,506.52	105.7500	52,875.00	2,368.48
150,000.0000	VIKING CRUISES LTD 144A 8.500% 10/15/2022 DD 10/19/12	142,378.71	105.0000	157,500.00	15,121.29
150,000.0000	VISTA OUTDOOR INC 5.875% 10/01/2023 DD 10/01/16	150,000.00	102.7500	154,125.00	4,125.00

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175,000.0000	VALEANT PHARMACEUTICALS I 144A 7.500% 07/15/2021 DD 07/12/13	174,281.25	96.8750	169,531.25	4,750.00-
138,000.0000	WMG ACQUISITION CORP 144A 5.625% 04/15/2022 DD 04/09/14	138,120.69	103.5000	142,830.00	4,709.31
50,000.0000	WAVEDIVISION ESCROW LLC / 144A 8.125% 09/01/2020 DD 08/21/12	51,644.23	103.5800	51,790.00	145.77
150,000.0000	WEATHERFORD INTERNATIONAL LTD 8.250% 06/15/2023 DD 06/17/16	151,669.79	100.0000	150,000.00	1,669.79-
30,000.0000	WEATHERFORD INTERNATIONAL 144A 9.875% 02/15/2024 DD 11/18/16	30,299.81	104.5000	31,350.00	1,050.19
75,000.0000	WELLCARE HEALTH PLANS INC 5.250% 04/01/2025 DD 03/22/17	75,000.00	104.7500	78,562.50	3,562.50
150,000.0000	WESCO DISTRIBUTION INC 5.375% 06/15/2024 DD 12/15/16	150,000.00	104.3750	156,562.50	6,562.50
200,000.0000	WHITING PETROLEUM CORP 5.750% 03/15/2021 DD 09/12/13	187,191.88	94.0000	188,000.00	808.12
50,000.0000	WHITING PETROLEUM CORP 6.250% 04/01/2023 DD 03/27/15	48,236.60	91.7500	45,875.00	2,361.60-
159,000.0000	WIDEOPENWEST FINANCE LLC / WID 10.250% 07/15/2019 DD 01/15/13	165,135.08	103.0000	163,770.00	1,365.08-
50,000.0000	WILDHORSE RESOURCE DEVELO 144A 6.875% 02/01/2025 DD 02/01/17	49,636.99	94.0000	47,000.00	2,636.99-

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
200,000.0000	WIND ACQUISITION FINANCE 144A 4.750% 07/15/2020 DD 07/10/14	202,778.62	101.0500	202,100.00	678.62-
200,000.0000	WPX ENERGY INC 6.000% 01/15/2022 DD 11/14/11	181,295.02	99.0000	198,000.00	16,704.98
200,000.0000	ZF NORTH AMERICA CAPITAL 144A 4.500% 04/29/2022 DD 04/29/15	192,941.03	105.0000	210,000.00	17,058.97
50,000.0000	ZAYO GROUP LLC / ZAYO CAP 144A 5.750% 01/15/2027 DD 01/27/17	50,000.00	104.6250	52,312.50	2,312.50
145,000.0000	BRAND ENERGY 6/17 TL 0.000% 06/21/2024 DD 06/01/17	143,551.70	99.7810	144,682.45	1,130.75
TOTAL INVESTMENTS FIXED INCOME SECURITIES		29,547,645.34		30,382,708.18	835,062.84
TOTAL INVESTMENT		29,986,306.18		30,821,369.02	835,062.84

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INVESTMENTS CASH EQUIVALENTS					
34.2300	BLACKROCK LIQ T FUND INSTL FUND 60	34.23	100.0000	34.23	0.00
TOTAL INVESTMENTS CASH EQUIVALENTS		34.23		34.23	0.00
INVESTMENTS EQUITY					
1,118,715.4170	PARAMETRIC TX-MGD EM MK-INST	51,431,717.21	47.7400	53,407,474.01	1,975,756.80
TOTAL INVESTMENTS EQUITY		51,431,717.21		53,407,474.01	1,975,756.80
TOTAL INVESTMENT		51,431,751.44		53,407,508.24	1,975,756.80

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INVESTMENTS CASH EQUIVALENTS					
76.4000	AUD (AUSTRALIAN DOLLARS)	58.08	0.0000	58.60	0.52 C
76.3600	NZD (NEW ZEALAND DOLLAR)	53.29	0.0000	55.91	2.62 C
56.3200	CHF (SWISS FRANC)	57.83	0.0000	58.81	0.98 C
26,401.1300	GBP (GREAT BRITISH POUNDS)	33,753.64	0.0000	34,293.75	540.11 C
23,371.8500	HKD (HONG KONG DOLLARS)	2,996.40	0.0000	2,993.92	2.48-C
9,745,194.0000	JPY (JAPANESE YEN)	86,971.48	0.0000	86,731.88	239.60-C
859.3700	SGD (SINGAPORE DOLLARS)	619.55	0.0000	624.16	4.61 C
3,432.3900	ILS (ISRAELI SHEKEL)	968.90	0.0000	983.58	14.68 C
339.5200	DKK (DANISH KRONE)	50.98	0.0000	52.08	1.10 C
9,791.7300	NOK (NORWEGIAN KRONE)	1,160.27	0.0000	1,168.93	8.66 C
440.2200	SEK (SWEDISH KRONA)	50.42	0.0000	52.19	1.77 C
30,171.7200	EUR (EURO)	34,038.08	0.0000	34,412.36	374.28 C
311,266.6200	BLACKROCK LIQ T FUND INSTL FUND 60	311,266.62	100.0000	311,266.62	0.00
TOTAL INVESTMENTS CASH EQUIVALENTS		472,045.54		472,752.79	707.25 707.25 C 0.00 I

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PARAMETRIC EAFE - PRAIRIE I 2
XCEL ENERGY NDT

SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS PREFERRED SECURITIES					
1,051.0000	HENKEL AG & CO KGAA	70,983.72	137.4362	144,445.53	73,461.81 11,414.92- C 84,876.73 I
658.0000	VOLKSWAGEN AG	71,370.04	152.0923	100,076.76	28,706.72 7,800.02- C 36,506.74 I
250.0000	BAYERISCHE MOTOREN WERKE AG	9,010.33	82.3248	20,581.22	11,570.89 3,847.20- C 15,418.09 I
375.0000	PORSCHE AUTOMOBIL HOLDING SE	20,253.15	56.1036	21,038.87	785.72 3,932.73- C 4,718.45 I
TOTAL INVESTMENTS PREFERRED SECURITIES		171,617.24		286,142.38	114,525.14 26,994.87- C 141,520.01 I
INVESTMENTS EQUITY					
28,816.0000	SCENTRE GROUP	86,863.43	3.1065	89,518.42	2,654.99 20,073.23- C 22,728.22 I
4,940.0000	AGL ENERGY LTD	58,222.97	19.5597	96,625.29	38,402.32 12,202.24- C 50,604.56 I

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PARAMETRIC EAFE - PRAIRIE I 2
XCEL ENERGY NDT

SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
44,943.0000	SOUTH32 LTD	89,140.99	2.0556	92,389.06	3,248.07 84.25 C 3,163.82 I
34,138.0000	VICINITY CENTRES	74,273.27	1.9713	67,296.87	6,976.40- 5,139.89- C 1,836.51- I
7,964.0000	TATTS GROUP LTD	17,976.43	3.2062	25,534.73	7,558.30 5,119.93- C 12,678.23 I
12,342.0000	GOODMAN GROUP	47,469.68	6.0366	74,504.75	27,035.07 1,397.35- C 28,432.42 I
4,056.0000	DEXUS	18,164.01	7.2716	29,493.75	11,329.74 5,913.75- C 17,243.49 I
1,965.0000	MACQUARIE GROUP LTD	91,217.53	67.8839	133,391.91	42,174.38 20,719.40- C 62,893.78 I
5,986.0000	CROWN RESORTS LTD	48,558.95	9.4193	56,384.37	7,825.42 2,741.64- C 10,567.06 I
2,741.0000	JAMES HARDIE INDUSTRIES PLC	18,081.23	15.7245	43,100.92	25,019.69 8,642.10- C 33,661.79 I
2,759.0000	TREASURY WINE ESTATES LTD	9,582.71	10.0943	27,850.39	18,267.68 11,426.25- C 29,693.93 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS	
6,530.0000	SYDNEY AIRPORT	30,183.30	5.4383	35,512.65	5,329.35	
					1,828.77	C
					3,500.58	I
12,410.0000	AURIZON HOLDINGS LTD	41,530.92	4.1113	51,022.33	9,491.41	
					17,374.38-	C
					26,865.79	I
806.0000	RAMSAY HEALTH CARE LTD	30,447.59	56.4548	45,502.63	15,055.04	
					11,259.23-	C
					26,314.27	I
8,262.0000	AUSTRALIA & NEW ZEALAND BANKIN	177,804.38	22.0296	182,009.18	4,204.80	
					28,952.93-	C
					33,157.73	I
4,634.0000	AMCOR LTD/AUSTRALIA	36,362.15	12.4338	57,618.60	21,256.45	
					15,671.63-	C
					36,928.08	I
10,280.0000	WESTPAC BANKING CORP	257,181.90	23.4026	240,579.71	16,602.19-	
					30,319.05-	C
					13,716.86	I
1,797.0000	BANK OF QUEENSLAND LTD	17,296.43	8.7827	15,782.55	1,513.88-	
					1,106.97-	C
					406.91-	I
11,786.0000	FORTESCUE METALS GROUP LTD	32,026.38	4.0040	47,191.16	15,164.78	
					1,159.71	C
					14,005.07	I
18,685.0000	TELSTRA CORP LTD	51,644.06	3.2983	61,629.02	9,984.96	
					12,357.14-	C
					22,342.10	I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
6,193.0000	BENDIGO & ADELAIDE BANK LTD	56,625.82	8.4989	52,633.77	3,992.05- C 2,098.89- C 1,893.16- I
739.0000	ASX LTD	23,073.95	41.1215	30,388.83	7,314.88 6,093.21- C 13,408.09 I
9,330.0000	BHP BILLITON LTD	191,740.92	17.8569	166,605.10	25,135.82- 744.55 C 25,880.37- I
13,063.0000	MIRVAC GROUP	17,571.21	1.6338	21,342.54	3,771.33 4,279.35- C 8,050.68 I
2,865.0000	CSL LTD	112,537.31	105.8759	303,334.49	190,797.18 38,648.31- C 229,445.49 I
818.0000	REA GROUP LTD	29,597.06	50.9321	41,662.47	12,065.41 7,989.77- C 20,055.18 I
9,382.0000	TRANSURBAN GROUP	53,132.17	9.0895	85,278.09	32,145.92 19,313.95- C 51,459.87 I
269.0000	COCHLEAR LTD	17,957.95	119.2379	32,075.00	14,117.05 6,431.32- C 20,548.37 I
13,135.0000	ORIGIN ENERGY LTD	66,193.76	5.2619	69,115.88	2,922.12 1,576.85 C 1,345.27 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS	
7,985.0000	COMMONWEALTH BANK OF AUSTRALIA	419,391.79	63.5194	507,202.49	87,810.70	
					98,030.43-	C
					185,841.13	I
8,135.0000	BORAL LTD	29,751.65	5.3309	43,367.66	13,616.01	
					2,320.64	C
					11,295.37	I
2,970.0000	RIO TINTO LTD	144,460.23	48.5312	144,137.82	322.41-	
					1,471.54-	C
					1,149.13	I
11,802.0000	APA GROUP	73,712.30	7.0338	83,013.48	9,301.18	
					6,220.77-	C
					15,521.95	I
3,087.0000	ARISTOCRAT LEISURE LTD	31,038.88	17.3046	53,419.45	22,380.57	
					1,427.68	C
					20,952.89	I
8,920.0000	INSURANCE AUSTRALIA GROUP LTD	32,214.91	5.2005	46,389.34	14,174.43	
					9,301.47-	C
					23,475.90	I
11,821.0000	GPT GROUP/THE	35,753.44	3.6741	43,432.36	7,678.92	
					4,341.75-	C
					12,020.67	I
5,706.0000	LENDLEASE GROUP	53,567.07	12.7713	72,873.51	19,306.44	
					3,043.15-	C
					22,349.59	I
6,838.0000	SUNCORP GROUP LTD	57,888.74	11.3676	77,732.20	19,843.46	
					12,140.58-	C
					31,984.04	I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS	
7,299.0000	NATIONAL AUSTRALIA BANK LTD	172,064.23	22.6970	165,665.47	6,398.76-	
					18,761.50-	C
					12,362.74	I
2,971.0000	NEWCREST MINING LTD	29,922.57	15.4637	45,942.74	16,020.17	
					10,092.35-	C
					26,112.52	I
14,141.0000	OIL SEARCH LTD	72,786.80	5.2312	73,975.54	1,188.74	
					2,688.80	C
					1,500.06-	I
13,382.0000	INCITEC PIVOT LTD	32,310.92	2.6156	35,002.50	2,691.58	
					2,455.04-	C
					5,146.62	I
14,234.0000	SANTOS LTD	42,383.74	2.3241	33,082.11	9,301.63-	
					906.14	C
					10,207.77-	I
3,682.0000	SONIC HEALTHCARE LTD	54,734.26	18.5779	68,404.02	13,669.76	
					3,577.20-	C
					17,246.96	I
4,063.0000	WESFARMERS LTD	120,164.02	30.7740	125,034.95	4,870.93	
					25,092.02-	C
					29,962.95	I
11,358.0000	ALUMINA LTD	18,469.39	1.4727	16,727.34	1,742.05-	
					3,353.97-	C
					1,611.92	I
1,313.0000	WOODSIDE PETROLEUM LTD	31,473.60	22.9117	30,083.17	1,390.43-	
					309.83	C
					1,700.26-	I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
1,237.0000	WOOLWORTHS LTD	23,112.64	19.5904	24,233.40	1,120.76 249.59 C 871.17 I
8,029.0000	AUCKLAND INTERNATIONAL AIRPORT	22,878.09	5.2205	41,916.08	19,037.99 4,227.69- C 23,265.68 I
4,126.0000	FLETCHER BUILDING LTD	20,022.69	5.8502	24,138.25	4,115.56 1,819.76- C 5,935.32 I
11,740.0000	SPARK NEW ZEALAND LTD	13,747.69	2.7677	32,492.99	18,745.30 1,122.77 C 17,622.53 I
1,726.0000	RAIFFEISEN BANK INTERNATIONAL	33,507.82	25.2061	43,505.82	9,998.00 2,916.15 C 7,081.85 I
1,220.0000	OMV AG	30,432.20	51.8208	63,221.48	32,789.28 5,637.32- C 38,426.60 I
1,927.0000	ERSTE GROUP BANK AG	47,056.01	38.2369	73,682.59	26,626.58 2,332.11 C 24,294.47 I
294.0000	IMMOFINANZ AG	0.00	2.2822	670.97	670.97 I
3,609.0000	ANHEUSER-BUSCH INBEV SA/NV	196,726.19	110.3025	398,082.05	201,355.86 71,530.07- C 272,885.93 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
1,405.0000	PROXIMUS SADP	40,050.27	34.9350	49,083.74	9,033.47 3,290.03 C 5,743.44 I
1,100.0000	AGEAS	38,500.91	40.2157	44,237.37	5,736.46 6,237.25- C 11,973.71 I
521.0000	UMICORE SA	18,950.42	69.4594	36,188.40	17,237.98 6,764.61- C 24,002.59 I
1,512.0000	KBC GROUP NV	80,842.10	75.7439	114,524.82	33,682.72 15,049.01- C 48,731.73 I
255.0000	SOLVAY SA	26,625.26	134.0146	34,173.73	7,548.47 6,388.01- C 13,936.48 I
433.0000	UCB SA	18,802.13	68.6953	29,745.08	10,942.95 5,560.17- C 16,503.12 I
2,272.0000	VONOVIA SE	73,257.31	39.6512	90,087.57	16,830.26 4,825.22 C 12,005.04 I
2,213.0000	QIAGEN NV	52,790.21	33.2185	73,512.59	20,722.38 5,619.53- C 26,341.91 I
1,907.0000	DEUTSCHE WOHNEN AG	37,687.83	38.1970	72,841.72	35,153.89 15,110.56- C 50,264.45 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
514.0000	LANXESS AG	29,649.72	75.6070	38,862.03	9,212.31 582.65 C 8,629.66 I
507.0000	BRENNTAG AG	19,442.18	57.8030	29,306.16	9,863.98 7,452.76- C 17,316.74 I
1,531.0000	K+S AG	35,793.74	25.5711	39,149.40	3,355.66 2,624.14 C 731.52 I
5,000.0000	COMMERZBANK AG	43,319.90	11.8959	59,479.68	16,159.78 3,121.16 C 13,038.62 I
1,199.0000	OSRAM LICHT AG	43,265.48	79.5533	95,384.48	52,119.00 10,654.05- C 62,773.05 I
1,343.0000	ADIDAS AG	79,981.67	191.3272	256,952.51	176,970.84 37,726.91- C 214,697.75 I
1,818.0000	FRESENIUS SE & CO KGAA	45,819.25	85.6096	155,638.40	109,819.15 29,093.07- C 138,912.22 I
1,176.0000	UNITED INTERNET AG	18,245.59	54.9117	64,576.25	46,330.66 12,071.03- C 58,401.69 I
362.0000	HANNOVER RUECK SE	18,317.70	119.7007	43,331.66	25,013.96 8,099.88- C 33,113.84 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS	
787.0000	GEA GROUP AG	18,771.10	40.8659	32,161.47	13,390.37	
					6,011.86-	C
					19,402.23	I
497.0000	CONTINENTAL AG	51,092.45	215.5069	107,106.94	56,014.49	
					15,159.02-	C
					71,173.51	I
4,720.0000	DEUTSCHE POST AG	94,863.15	37.4328	176,683.06	81,819.91	
					19,275.39-	C
					101,095.30	I
552.0000	MERCK KGAA	27,434.01	120.6131	66,578.47	39,144.46	
					15,659.11-	C
					54,803.57	I
3,989.0000	SAP SE	200,935.15	104.3032	416,065.85	215,130.70	
					76,326.16-	C
					291,456.86	I
1,178.0000	E.ON SE	10,737.80	9.4072	11,081.74	343.94	
					524.67	C
					180.73-	I
329.0000	HENKEL AG & CO KGAA	17,091.08	120.7842	39,738.02	22,646.94	
					7,587.54-	C
					30,234.48	I
959.0000	METRO AG	30,340.61	33.7089	32,326.89	1,986.28	
					194.15	C
					1,792.13	I
3,548.0000	BAYER AG	243,350.86	129.1102	458,083.20	214,732.34	
					85,628.29-	C
					300,360.63	I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
4,323.0000	BASF SE	281,043.77	92.4872	399,822.16	118,778.39 63,259.98- C 182,038.37 I
379.0000	BEIERSDORF AG	22,819.99	104.9762	39,785.99	16,966.00 7,437.09- C 24,403.09 I
215.0000	HOCHTIEF AG	18,569.95	182.9442	39,333.01	20,763.06 7,352.43- C 28,115.49 I
1,021.0000	HEIDELBERGCEMENT AG	63,018.73	96.5475	98,575.06	35,556.33 13,850.36- C 49,406.69 I
1,271.0000	FRESENIUS MEDICAL CARE AG & CO	76,802.94	96.0000	122,016.12	45,213.18 23,845.76- C 69,058.94 I
1,948.0000	ALLIANZ SE	248,011.82	196.6308	383,036.84	135,025.02 71,600.06- C 206,625.08 I
847.0000	MUENCHENER RUECKVERSICHERUNGS-	139,614.18	201.3641	170,555.39	30,941.21 31,881.46- C 62,822.67 I
190.0000	VOLKSWAGEN AG	18,425.63	154.8296	29,417.64	10,992.01 5,498.97- C 16,490.98 I
4,228.0000	DAIMLER AG	211,994.98	72.2766	305,585.69	93,590.71 44,637.55- C 138,228.26 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS	
184.0000	MAN SE	15,538.53	107.0634	19,699.67	4,161.14	
					3,682.43-	C
					7,843.57	I
3,777.0000	SIEMENS AG	380,751.86	137.2651	518,450.63	137,698.77	
					80,244.58-	C
					217,943.35	I
651.0000	LINDE AG	77,980.37	189.1031	123,106.18	45,125.81	
					23,011.90-	C
					68,137.71	I
3,821.0000	DEUTSCHE BANK AG	75,054.30	17.7070	67,658.60	7,395.70-	
					2,918.57	C
					10,314.27-	I
1,421.0000	BAYERISCHE MOTOREN WERKE AG	67,660.75	92.7039	131,732.25	64,071.50	
					24,624.36-	C
					88,695.86	I
14,715.0000	DEUTSCHE TELEKOM AG	204,636.73	17.9294	263,831.80	59,195.07	
					43,975.34-	C
					103,170.41	I
4,663.0000	INFINEON TECHNOLOGIES AG	32,588.98	21.0830	98,310.35	65,721.37	
					18,376.92-	C
					84,098.29	I
340.0000	FRAPORT AG FRANKFURT AIRPORT S	18,116.28	88.1645	29,975.94	11,859.66	
					5,603.33-	C
					17,462.99	I
2,462.0000	RED ELECTRICA CORP SA	36,886.70	20.8663	51,372.98	14,486.28	
					5,369.41-	C
					19,855.69	I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS	
1,534.0000	ACS ACTIVIDADES DE CONSTRUCCIO	1,267.35	0.7983	1,224.72	42.63-	
					12.78	C
					55.41-	I
5,447.0000	INDUSTRIA DE DISENO TEXTIL SA	88,340.72	38.3338	208,804.67	120,463.95	
					40,319.66-	C
					160,783.61	I
306.0000	AENA SA	30,299.72	194.8629	59,628.07	29,328.35	
					831.24	C
					28,497.11	I
2,390.0000	GRIFOLS SA	16,018.71	27.8123	66,471.43	50,452.72	
					12,425.27-	C
					62,877.99	I
1,534.0000	ACS ACTIVIDADES DE CONSTRUCCIO	48,626.91	38.5791	59,180.35	10,553.44	
					3,966.81	C
					6,586.63	I
4,617.0000	FERROVIAL SA	68,654.11	22.1665	102,343.15	33,689.04	
					932.78	C
					32,756.26	I
7,272.0000	CAIXABANK SA	20,191.38	4.7674	34,669.25	14,477.87	
					1,457.53	C
					13,020.34	I
17,260.0000	IBERDROLA SA	107,825.17	7.9074	136,482.30	28,657.13	
					4,166.92-	C
					32,824.05	I
2,403.0000	AMADEUS IT GROUP SA	69,199.82	59.7077	143,477.83	74,278.01	
					7,883.89-	C
					82,161.90	I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS	
10,778.0000	INTERNATIONAL CONSOLIDATED AIR	54,712.10	7.9256	85,423.00	30,710.90	
					744.38	C
					29,966.52	I
2,865.0000	DISTRIBUIDORA INTERNACIONAL DE	14,929.86	6.2171	17,812.11	2,882.25	
					3,851.37-	C
					6,733.62	I
2,739.0000	ABERTIS INFRAESTRUCTURAS SA	39,001.87	18.4997	50,670.74	11,668.87	
					3,396.42	C
					8,272.45	I
3,374.0000	ENDESA SA	70,057.06	23.0048	77,618.51	7,561.45	
					3,701.47	C
					3,859.98	I
2,143.0000	BANKINTER SA	11,677.31	9.1985	19,712.47	8,035.16	
					3,684.79-	C
					11,719.95	I
23,079.0000	BANCO BILBAO VIZCAYA ARGENTARI	164,871.86	8.2860	191,234.81	26,362.95	
					3,935.11	C
					22,427.84	I
3,855.0000	GAS NATURAL SDG SA	70,081.43	23.3698	90,090.85	20,009.42	
					1,204.55	C
					18,804.87	I
4,624.0000	REPSOL SA	69,665.33	15.2833	70,670.30	1,004.97	
					1,388.67	C
					383.70-	I
48,219.0000	BANCO SANTANDER SA	287,709.93	6.6060	318,537.88	30,827.95	
					8,273.47	C
					22,554.48	I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS	
18,217.0000	TELEFONICA SA	176,005.74	10.3082	187,786.14	11,780.40	
					9,317.57	C
					2,462.83	I
825.0000	ENAGAS SA	18,520.95	28.0005	23,100.41	4,579.46	
					4,318.10-	C
					8,897.56	I
1,077.0000	VALEO SA	38,162.09	67.2810	72,461.68	34,299.59	
					15,031.72-	C
					49,331.31	I
4,837.0000	ENGIE SA	58,043.03	15.0723	72,905.05	14,862.02	
					3,825.66	C
					11,036.36	I
4,648.0000	ELECTRICITE DE FRANCE SA	45,970.94	10.8146	50,266.71	4,295.77	
					2,637.74	C
					1,658.03	I
565.0000	ARKEMA SA	35,962.32	106.5615	60,207.30	24,244.98	
					5,368.54-	C
					29,613.52	I
302.0000	IMERYS SA	18,954.78	86.8528	26,229.57	7,274.79	
					4,903.03-	C
					12,177.82	I
1,267.0000	SAFRAN SA	51,231.82	91.5177	115,952.97	64,721.15	
					23,131.33-	C
					87,852.48	I
11,149.0000	NATIXIS SA	62,098.13	6.7030	74,731.88	12,633.75	
					97.03	C
					12,536.72	I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
1,444.0000	SCOR SE	42,874.47	39.5884	57,165.78	14,291.31 1,467.57- C 15,758.88 I
2,508.0000	VINCI SA	145,509.27	85.2333	213,765.12	68,255.85 35,131.72- C 103,387.57 I
1,804.0000	AIR LIQUIDE SA	173,012.64	123.4075	222,627.15	49,614.51 30,726.22- C 80,340.73 I
2,373.0000	DANONE SA	146,172.34	75.0595	178,116.42	31,944.08 32,931.93- C 64,876.01 I
1,695.0000	LEGRAND SA	79,567.49	69.8586	118,410.48	38,842.99 11,979.35- C 50,822.34 I
354.0000	EIFFAGE SA	18,751.96	90.7421	32,122.72	13,370.76 6,004.63- C 19,375.39 I
8,022.0000	TOTAL SA	442,233.77	49.3687	396,035.77	46,198.00- 42,343.62- C 3,854.38- I
224.0000	AEROPORTS DE PARIS	18,713.19	161.1597	36,099.78	17,386.59 6,748.01- C 24,134.60 I
1,372.0000	BUREAU VERITAS SA	18,650.10	22.0981	30,318.67	11,668.57 5,667.39- C 17,335.96 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS	
2,830.0000	EDENRED	57,565.89	26.0387	73,689.68	16,123.79	
					1,570.56	C
					14,553.23	I
2,457.0000	AIRBUS SE	79,751.65	82.1196	201,767.86	122,016.21	
					35,898.38-	C
					157,914.59	I
3,972.0000	VEOLIA ENVIRONNEMENT SA	71,153.01	21.1001	83,809.90	12,656.89	
					3,372.97	C
					9,283.92	I
1,027.0000	L'OREAL SA	109,846.98	208.0363	213,653.30	103,806.32	
					39,937.64-	C
					143,743.96	I
1,052.0000	LVMH MOET HENNESSY LOUIS VUITT	126,242.33	248.9820	261,929.13	135,686.80	
					48,961.72-	C
					184,648.52	I
452.0000	THALES SA	18,203.80	107.4854	48,583.42	30,379.62	
					9,081.58-	C
					39,461.20	I
988.0000	CAPGEMINI SE	61,688.64	103.1969	101,958.60	40,269.96	
					6,102.51-	C
					46,372.47	I
934.0000	CASINO GUICHARD PERRACHON SA	50,544.03	59.1489	55,245.09	4,701.06	
					2,898.97	C
					1,802.09	I
1,566.0000	PUBLICIS GROUPE SA	87,262.91	74.4893	116,650.28	29,387.37	
					2,187.38-	C
					31,574.75	I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS	
661.0000	CIE GENERALE DES ETABLISSEMENT	49,863.14	132.7600	87,754.37	37,891.23	
					16,519.81-	C
					54,411.04	I
880.0000	PERNOD RICARD SA	76,952.35	133.7294	117,681.95	40,729.60	
					20,358.19-	C
					61,087.79	I
795.0000	RENAULT SA	38,225.31	90.3885	71,858.93	33,633.62	
					13,432.39-	C
					47,066.01	I
2,544.0000	SCHNEIDER ELECTRIC SE	151,450.70	76.7247	195,187.89	43,737.19	
					25,375.58-	C
					69,112.77	I
3,765.0000	VIVENDI SA	70,097.93	22.2293	83,693.39	13,595.46	
					3,351.87	C
					10,243.59	I
3,586.0000	ORANGE SA	55,709.26	15.8422	56,810.27	1,101.01	
					2,981.10	C
					1,880.09-	I
88.0000	HERMES INTERNATIONAL	12,097.05	493.4589	43,424.39	31,327.34	
					8,117.18-	C
					39,444.52	I
616.0000	DASSAULT SYSTEMES SE	18,588.80	89.5217	55,145.41	36,556.61	
					10,308.18-	C
					46,864.79	I
461.0000	KERING	74,059.99	340.1120	156,791.64	82,731.65	
					28,262.49-	C
					110,994.14	I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
1,192.0000	CARREFOUR SA	30,326.06	25.2631	30,113.71	212.35- C 1,075.91 C 1,288.26- I
369.0000	ATOS SE	30,536.20	140.1735	51,724.06	21,187.86 10,793.31- C 31,981.17 I
4,245.0000	SANOFI	312,729.87	95.5324	405,535.33	92,805.46 72,678.49- C 165,483.95 I
1,867.0000	ACCOR SA	69,474.43	46.8138	87,401.51	17,927.08 529.35- C 18,456.43 I
1,631.0000	NOKIA OYJ	11,796.39	6.1213	9,983.90	1,812.49- 391.29 C 2,203.78- I
5,374.0000	STMICROELECTRONICS NV	56,030.34	14.3367	77,045.50	21,015.16 4,053.15- C 25,068.31 I
2,245.0000	SOCIETE GENERALE SA	94,668.32	53.7313	120,626.79	25,958.47 1,715.23- C 27,673.70 I
372.0000	EURAZEO SA	18,013.03	74.9227	27,871.26	9,858.23 5,059.24- C 14,917.47 I
404.0000	SODEXO SA	24,650.84	129.1102	52,160.55	27,509.71 9,750.23- C 37,259.94 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
587.0000	UNIBAIL-RODAMCO SE	110,510.33	251.6623	147,725.80	37,215.47 10,014.44- C 47,229.91 I
11,877.0000	AXA SA	252,588.70	27.3161	324,434.18	71,845.48 39,934.37- C 111,779.85 I
3,981.0000	PEUGEOT SA	61,562.60	19.9197	79,300.35	17,737.75 2,946.84 C 14,790.91 I
652.0000	JCDECAUX SA	18,518.33	32.7565	21,357.30	2,838.97 3,992.27- C 6,831.24 I
862.0000	ESSILOR INTERNATIONAL SA	55,719.70	127.0572	109,523.37	53,803.67 20,472.91- C 74,276.58 I
2,992.0000	CREDIT AGRICOLE SA	31,241.58	16.0646	48,065.42	16,823.84 2,275.69 C 14,548.15 I
1,405.0000	ZODIAC AEROSPACE	26,281.02	27.0880	38,058.73	11,777.71 3,532.08- C 15,309.79 I
3,505.0000	BNP PARIBAS SA	237,452.16	71.9230	252,090.41	14,638.25 23,527.12- C 38,165.37 I
492.0000	CIE DE SAINT-GOBAIN	24,076.24	53.3549	26,250.63	2,174.39 4,906.95- C 7,081.34 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS	
261.0000	WENDEL SA	19,350.98	147.8152	38,579.79	19,228.81	
					3,049.36-	C
					22,278.17	I
274.0000	GECINA SA	33,873.46	156.6545	42,923.34	9,049.88	
					6,405.29-	C
					15,455.17	I
126.0000	ILIAD SA	23,643.03	236.2079	29,762.20	6,119.17	
					1,994.94	C
					4,124.23	I
9,538.0000	CNH INDUSTRIAL NV	78,616.04	11.3085	107,860.98	29,244.94	
					4,858.78	C
					24,386.16	I
521.0000	FERRARI NV	26,125.26	85.7123	44,656.13	18,530.87	
					733.62	C
					17,797.25	I
3,982.0000	FIAT CHRYSLER AUTOMOBILES NV	30,391.92	10.5272	41,919.62	11,527.70	
					808.59	C
					10,719.11	I
11,245.0000	UNICREDIT SPA	173,080.49	18.6479	209,696.68	36,616.19	
					10,957.46	C
					25,658.73	I
727.0000	EXOR NV	29,454.72	54.0506	39,294.83	9,840.11	
					8,199.71-	C
					18,039.82	I
2,907.0000	LEONARDO SPA	30,508.39	16.5950	48,241.67	17,733.28	
					272.81	C
					17,460.47	I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
13,546.0000	TERNA RETE ELETTRICA NAZIONALE	60,064.93	5.3902	73,016.19	12,951.26 8,527.07- C 21,478.33 I
1,187.0000	PRYSMIAN SPA	29,389.44	29.3691	34,861.20	5,471.76 7,274.54- C 12,746.30 I
47,137.0000	INTESA SANPAOLO SPA	102,802.09	3.1661	149,243.60	46,441.51 3,670.58- C 50,112.09 I
4,427.0000	MEDIOBANCA SPA	35,386.90	9.8543	43,625.22	8,238.32 3,889.94- C 12,128.26 I
673.0000	LUXOTTICA GROUP SPA	18,212.35	57.7688	38,878.44	20,666.09 7,267.44- C 27,933.53 I
25,143.0000	ENEL SPA	108,617.28	5.3537	134,609.13	25,991.85 3,713.18- C 29,705.03 I
11,784.0000	ENI SPA	181,235.36	15.0096	176,873.57	4,361.79- 9,281.38 C 13,643.17- I
16,184.0000	SNAM SPA	67,861.03	4.3523	70,438.25	2,577.22 525.54 C 2,051.68 I
1,688.0000	TENARIS SA	23,832.91	15.5685	26,279.64	2,446.73 2,343.30- C 4,790.03 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS	
1,278.0000	ATLANTIA SPA	26,251.10	28.1031	35,915.83	9,664.73	
					6,713.66-	C
					16,378.39	I
8,503.0000	KONINKLIJKE AHOLD DELHAIZE NV	133,219.77	19.0928	162,346.14	29,126.37	
					26,648.99-	C
					55,775.36	I
1,093.0000	NN GROUP NV	30,000.22	35.4939	38,794.85	8,794.63	
					219.39	C
					8,575.24	I
4,121.0000	ARCELORMITTAL	81,078.59	22.6513	93,346.10	12,267.51	
					2,394.35	C
					9,873.16	I
1,849.0000	ABN AMRO GROUP NV	30,725.29	26.4721	48,947.03	18,221.74	
					1,173.73	C
					17,048.01	I
475.0000	ALTICE NV	8,582.53	23.0448	10,946.29	2,363.76	
					1,642.19-	C
					4,005.95	I
2,335.0000	ALTICE NV	40,669.75	23.0391	53,796.32	13,126.57	
					4,350.33-	C
					17,476.90	I
21,830.0000	ING GROEP NV	245,285.97	17.2223	375,962.92	130,676.95	
					57,524.40-	C
					188,201.35	I
173.0000	HEINEKEN HOLDING NV	7,721.88	91.5291	15,834.54	8,112.66	
					2,959.93-	C
					11,072.59	I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
661.0000	KONINKLIJKE DSM NV	30,260.33	72.5846	47,978.42	17,718.09 8,968.48- C 26,686.57 I
6,988.0000	UNILEVER NV	218,635.38	55.1113	385,118.30	166,482.92 71,989.15- C 238,472.07 I
1,919.0000	ASML HOLDING NV	78,935.02	130.1367	249,732.43	170,797.41 49,087.66- C 219,885.07 I
5,151.0000	RELX NV	44,121.37	20.5299	105,749.51	61,628.14 16,695.80- C 78,323.94 I
1,391.0000	AKZO NOBEL NV	82,827.83	86.7844	120,717.17	37,889.34 13,790.93- C 51,680.27 I
1,044.0000	WOLTERS KLUWER NV	22,999.06	42.2744	44,134.56	21,135.50 8,249.96- C 29,385.46 I
10,563.0000	KONINKLIJKE KPN NV	21,164.56	3.1946	33,745.41	12,580.85 5,262.03- C 17,842.88 I
1,747.0000	KONINKLIJKE PHILIPS NV	51,045.67	35.4654	61,958.06	10,912.39 1,547.38 C 9,365.01 I
1,002.0000	HEINEKEN NV	51,537.24	97.0950	97,289.21	45,751.97 18,186.03- C 63,938.00 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS	
1,956.0000	GALP ENERGIA SGPS SA	29,612.02	15.1179	29,570.79	41.23-	
					1,982.10	C
					2,023.33-	I
4,636.0000	BANCO ESPIRITO SANTO SA	12,190.60	0.0001	0.52	12,190.08-	
					0.10-	C
					12,189.98-	I
2,239.0000	CIE FINANCIERE RICHEMONT SA	89,018.46	82.4936	184,703.18	95,684.72	
					15,738.18	C
					79,946.54	I
697.0000	IDORSIA LTD	5,589.56	18.9004	13,173.60	7,584.04	
					119.27	C
					7,464.77	I
14,454.0000	UBS GROUP AG	228,714.21	16.9581	245,113.52	16,399.31	
					17,613.85	C
					1,214.54-	I
715.0000	PARGESA HOLDING SA	46,860.56	76.1760	54,465.88	7,605.32	
					2,892.00	C
					4,713.32	I
815.0000	SWISS PRIME SITE AG	63,352.56	90.9518	74,125.72	10,773.16	
					2,023.77	C
					8,749.39	I
166.0000	GEBERIT AG	30,381.52	466.9764	77,518.09	47,136.57	
					6,605.15	C
					40,531.42	I
207.0000	SCHINDLER HOLDING AG	18,695.40	211.8728	43,857.67	25,162.27	
					3,737.02	C
					21,425.25	I

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114.0000	PARTNERS GROUP HOLDING AG	29,614.44	620.7904	70,770.11	41,155.67	
					4,915.86-	C
					46,071.53	I
149.0000	KUEHNE + NAGEL INTERNATIONAL A	15,336.79	167.0756	24,894.27	9,557.48	
					2,121.21	C
					7,436.27	I
1,139.0000	JULIUS BAER GROUP LTD	44,438.34	52.6810	60,003.71	15,565.37	
					4,624.34	C
					10,941.03	I
1,935.0000	SWISS RE AG	100,377.75	91.5261	177,103.06	76,725.31	
					8,133.30	C
					68,592.01	I
18.0000	SIKA AG	53,847.01	6,432.4126	115,783.43	61,936.42	
					5,676.56-	C
					67,612.98	I
24.0000	SGS SA	33,947.33	2,424.6854	58,192.45	24,245.12	
					4,958.46	C
					19,286.66	I
101.0000	SWISSCOM AG	37,259.87	483.1619	48,799.35	11,539.48	
					4,158.09	C
					7,381.39	I
36.0000	GIVAUDAN SA	34,950.05	2,002.8194	72,101.50	37,151.45	
					5,621.56	C
					31,529.89	I
565.0000	ZURICH INSURANCE GROUP AG	134,580.23	291.4425	164,665.07	30,084.84	
					12,352.71	C
					17,732.13	I

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9,862.0000	NOVARTIS AG	541,829.54	83.3289	821,790.42	279,960.88	
					52,681.40	C
					227,279.48	I
4,884.0000	ABB LTD	99,565.13	24.7271	120,767.63	21,202.50	
					9,008.19	C
					12,194.31	I
3,014.0000	ROCHE HOLDING AG	492,574.58	254.9992	768,567.64	275,993.06	
					65,488.12	C
					210,504.94	I
527.0000	ADECCO GROUP AG	30,849.59	76.1238	40,117.27	9,267.68	
					3,418.31	C
					5,849.37	I
1,315.0000	LAFARGEHOLCIM LTD	69,988.00	57.3278	75,386.10	5,398.10	
					4,002.81	C
					1,395.29	I
14,275.0000	NESTLE SA	733,991.49	87.1403	1,243,929.15	509,937.66	
					105,992.72	C
					403,944.94	I
206.0000	BALOISE HOLDING AG	18,644.45	154.7538	31,879.29	13,234.84	
					2,716.38	C
					10,518.46	I
12,208.0000	CREDIT SUISSE GROUP AG	185,120.12	14.4729	176,685.51	8,434.61-	
					5,196.34	C
					13,630.95-	I
223.0000	LONZA GROUP AG	18,318.22	216.4673	48,272.23	29,954.01	
					4,113.18	C
					25,840.83	I

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297.0000	SWISS LIFE HOLDING AG	62,829.48	337.9105	100,359.42	37,529.94	
					6,299.36	C
					31,230.58	I
15,159.0000	NATIONAL GRID PLC	162,350.95	12.3634	187,416.87	25,065.92	
					34,723.38-	C
					59,789.30	I
6,456.0000	ROYAL MAIL PLC	37,284.15	5.4711	35,321.92	1,962.23-	
					830.74	C
					2,792.97-	I
9,039.4240	COMPASS GROUP PLC	98,260.00	21.0429	190,216.51	91,956.51	
					32,734.25-	C
					124,690.76	I
1,762.0000	INTERCONTINENTAL HOTELS GROUP	63,256.12	55.4261	97,660.96	34,404.84	
					2,647.64-	C
					37,052.48	I
1,126.0000	WOLSELEY PLC	29,829.79	61.2195	68,933.17	39,103.38	
					12,168.33-	C
					51,271.71	I
80,790.0000	VODAFONE GROUP PLC	219,964.25	2.8284	228,511.58	8,547.33	
					4,501.95-	C
					13,049.28	I
18,180.0000	STANDARD LIFE PLC	77,361.42	5.1841	94,247.11	16,885.69	
					4,262.96-	C
					21,148.65	I
5.0000	LONMIN PLC	129.90	0.8540	4.27	125.63-	
					0.91-	C
					124.72-	I

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8,168.0000	WORLDPAY GROUP PLC	29,884.85	4.0890	33,399.72	3,514.87 708.39- C 4,223.26 I
546.0000	CRODA INTERNATIONAL PLC	19,779.97	50.4642	27,553.46	7,773.49 5,239.39- C 13,012.88 I
15,155.0000	DIRECT LINE INSURANCE GROUP PL	63,743.18	4.6164	69,962.58	6,219.40 6,125.37- C 12,344.77 I
831.0000	JOHNSON MATTHEY PLC	25,302.12	37.2928	30,990.36	5,688.24 5,470.64- C 11,158.88 I
1,898.0000	LONDON STOCK EXCHANGE GROUP PL	61,463.89	47.3597	89,888.74	28,424.85 9,687.30- C 38,112.15 I
574.0000	RANDGOLD RESOURCES LTD	36,715.65	88.3935	50,737.90	14,022.25 10,257.34- C 24,279.59 I
6,071.0000	J SAINSBURY PLC	21,396.78	3.2694	19,848.88	1,547.90- 3,149.66- C 1,601.76 I
1,657.0000	BERKELEY GROUP HOLDINGS PLC	59,554.18	41.9171	69,456.66	9,902.48 1,633.54 C 8,268.94 I
17,462.0000	ROYAL DUTCH SHELL PLC A SHS	509,690.74	26.4336	461,584.09	48,106.65- 68,898.00- C 20,791.35 I

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19,825.0000	ROYAL DUTCH SHELL PLC B SHS	487,418.28	26.7908	531,128.48	43,710.20	
					74,802.95-	C
					118,513.15	I
10,532.0000	CENTRICA PLC	29,885.18	2.6004	27,388.44	2,496.74-	
					861.32	C
					3,358.06-	I
18,915.0000	COBHAM PLC	26,849.66	1.6834	31,842.25	4,992.59	
					1,250.21	C
					3,742.38	I
1,634.0000	BUNZL PLC	18,582.17	29.7199	48,562.44	29,980.27	
					8,572.62-	C
					38,552.89	I
4,261.0000	INMARSAT PLC	40,134.17	9.9954	42,590.49	2,456.32	
					1,001.68	C
					1,454.64	I
2,011.0000	MONDI PLC	39,978.22	26.1608	52,609.48	12,631.26	
					4,706.59-	C
					17,337.85	I
1,274.0000	SEVERN TRENT PLC	26,886.56	28.3430	36,109.10	9,222.54	
					6,661.56-	C
					15,884.10	I
1,457.0000	WHITBREAD PLC	47,207.41	51.5293	75,078.26	27,870.85	
					3,501.81-	C
					31,372.66	I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
3,478.0000	SMITHS GROUP PLC	58,172.47	20.7442	72,148.44	13,975.97 13,639.57- C 27,615.54 I
4,295.0000	ANGLO AMERICAN PLC	63,835.08	13.3012	57,128.86	6,706.22- 5,847.35- C 858.87- I
4,223.0000	3I GROUP PLC	19,302.93	11.7230	49,506.34	30,203.41 8,409.21- C 38,612.62 I
6,246.0000	UNILEVER PLC	197,350.95	53.9713	337,105.19	139,754.24 62,731.77- C 202,486.01 I
5,784.0000	EXPERIAN PLC	64,346.11	20.4584	118,331.75	53,985.64 21,534.04- C 75,519.68 I
5,365.0000	RELX PLC	44,925.52	21.5625	115,683.19	70,757.67 18,658.63- C 89,416.30 I
2,407.0000	SHIRE PLC	53,292.82	55.0495	132,504.15	79,211.33 23,390.60- C 102,601.93 I
1,415.0000	FRESNILLO PLC	18,875.03	19.3023	27,312.89	8,437.86 4,821.46- C 13,259.32 I
8,692.0000	CAPITA PLC	55,033.98	8.9822	78,073.62	23,039.64 2,455.30 C 20,584.34 I

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2,865.0000	RECKITT BENCKISER GROUP PLC	161,063.61	101.1102	289,680.92	128,617.31
					50,841.24- C
					179,458.55 I
2,923.0000	UNITED UTILITIES GROUP PLC	25,469.15	11.2683	32,937.51	7,468.36
					5,814.36- C
					13,282.72 I
27,635.0000	GLENCORE PLC	68,180.05	3.7305	103,094.70	34,914.65
					2,398.30- C
					37,312.95 I
8,302.0000	DIXONS CARPHONE PLC	33,177.68	3.6838	30,583.09	2,594.59-
					961.79 C
					3,556.38- I
7,366.0000	SEGRO PLC	38,931.08	6.3544	46,806.97	7,875.89
					2,728.60- C
					10,604.49 I
7,955.0000	ROLLS-ROYCE HOLDINGS PLC	74,690.75	11.5736	92,068.34	17,377.59
					16,252.58- C
					33,630.17 I
19,813.0000	OLD MUTUAL PLC	43,009.40	2.5121	49,773.61	6,764.21
					8,786.39- C
					15,550.60 I
5,199.0000	SAGE GROUP PLC/THE	20,284.02	8.9367	46,462.30	26,178.28
					8,201.86- C
					34,380.14 I
5,681.0000	MEDICLINIC INTERNATIONAL PLC	53,907.27	9.6317	54,717.78	810.51
					1,286.91 C
					476.40- I

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5,404.0000	WPP PLC	57,382.52	20.9650	113,295.15	55,912.63	
					20,068.12-	C
					75,980.75	I
1,638.0000	COCA-COLA HBC AG	34,027.96	29.3302	48,043.02	14,015.06	
					1,129.93	C
					12,885.13	I
9,441.0000	ABERDEEN ASSET MANAGEMENT PLC	30,717.49	3.9228	37,035.43	6,317.94	
					871.04	C
					5,446.90	I
2,954.0000	ANTOFAGASTA PLC	31,819.54	10.3851	30,677.60	1,141.94-	
					6,201.89-	C
					5,059.95	I
2,519.0000	ASHTEAD GROUP PLC	43,101.13	20.6403	51,992.95	8,891.82	
					8,765.90-	C
					17,657.72	I
7,402.0000	BHP BILLITON PLC	130,223.43	15.2756	113,070.38	17,153.05-	
					4,049.70	C
					21,202.75-	I
9,733.0000	BRITISH LAND CO PLC/THE	75,713.18	7.8651	76,551.44	838.26	
					3,167.00-	C
					4,005.26	I
4,889.0000	SKY PLC	46,016.87	12.9115	63,124.63	17,107.76	
					11,143.21-	C
					28,250.97	I
11,870.0000	AVIVA PLC	70,353.58	6.8324	81,101.50	10,747.92	
					14,316.62-	C
					25,064.54	I

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10,737.0000	DIAGEO PLC	185,286.07	29.4666	316,383.76	131,097.69 55,850.34- C 186,948.03 I
944.0000	SCHRODERS PLC	22,323.40	40.3194	38,061.52	15,738.12 5,215.76- C 20,953.88 I
15,189.0000	BAE SYSTEMS PLC	87,247.42	8.2288	124,987.98	37,740.56 22,063.80- C 59,804.36 I
8,565.0000	BRITISH AMERICAN TOBACCO PLC	299,885.26	67.9870	582,309.02	282,423.76 102,793.39- C 385,217.15 I
3,031.0000	HAMMERSON PLC	18,399.06	7.4624	22,618.75	4,219.69 3,992.82- C 8,212.51 I
11,556.0000	STANDARD CHARTERED PLC	106,384.22	10.0954	116,662.90	10,278.68 2,806.54- C 13,085.22 I
5,162.0000	IMPERIAL BRANDS PLC	164,751.52	44.7942	231,228.13	66,476.61 43,489.23- C 109,965.84 I
73,187.0000	HSBC HOLDINGS PLC	708,870.54	9.2446	676,586.53	32,284.01- 117,878.13- C 85,594.12 I
25,149.0000	LEGAL & GENERAL GROUP PLC	34,299.28	3.3551	84,379.62	50,080.34 14,895.30- C 64,975.64 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
9,952.0000	MEGGITT PLC	58,403.09	6.1946	61,649.58	3,246.49 2,518.86- C 5,765.35 I
24,220.0000	WM MORRISON SUPERMARKETS PLC	69,491.95	3.1330	75,882.89	6,390.94 3,630.76- C 10,021.70 I
1,312.0000	ASSOCIATED BRITISH FOODS PLC	19,799.55	38.1371	50,035.97	30,236.42 8,832.71- C 39,069.13 I
3,272.0000	PERSIMMON PLC	70,763.37	29.1224	95,288.69	24,525.32 8,169.16- C 32,694.48 I
10,909.0000	PRUDENTIAL PLC	95,841.84	22.8745	249,538.02	153,696.18 44,202.13- C 197,898.31 I
3,055.0000	RIO TINTO PLC	168,995.99	42.1119	128,652.03	40,343.96- 23,445.49- C 16,898.47- I
6,077.0000	SSE PLC	108,296.72	18.8737	114,695.74	6,399.02 10,495.49- C 16,894.51 I
67,006.0000	BP PLC	458,607.30	5.7517	385,401.80	73,205.50- 33,872.14- C 39,333.36- I
198,291.0000	LLOYDS BANKING GROUP PLC	188,656.92	0.8592	170,382.62	18,274.30- 23,351.57- C 5,077.27 I

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3,800.0000	SMITH & NEPHEW PLC	38,073.71	17.2110	65,402.13	27,328.42 11,545.27- C 38,873.69 I
16,490.0000	GLAXOSMITHKLINE PLC	318,517.98	21.2443	350,318.96	31,800.98 61,840.83- C 93,641.81 I
1,874.0000	BABCOCK INTERNATIONAL GROUP PL	21,149.32	11.4372	21,433.42	284.10 4,308.28- C 4,592.38 I
5,930.0000	ASTRAZENECA PLC	268,451.78	66.7010	395,537.42	127,085.64 69,823.13- C 196,908.77 I
10,769.0000	GKN PLC	29,649.06	4.2345	45,602.16	15,953.10 9,647.39- C 25,600.49 I
33,259.0000	BT GROUP PLC	63,783.83	3.8286	127,337.24	63,553.41 22,478.47- C 86,031.88 I
1,152.0000	CARNIVAL PLC	51,230.14	65.9866	76,016.63	24,786.49 7,301.18- C 32,087.67 I
10,148.0000	MARKS & SPENCER GROUP PLC	45,222.54	4.3294	43,934.75	1,287.79- 1,033.29 C 2,321.08- I
64,266.0000	BARCLAYS PLC	177,963.40	2.6336	169,252.30	8,711.10- 4,434.11 C 13,145.21- I

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680.0000	INTERTEK GROUP PLC	19,764.86	54.7767	37,248.17	17,483.31 7,194.73- C 24,678.04 I
1,861.0000	BURBERRY GROUP PLC	20,734.47	21.5755	40,152.12	19,417.65 7,087.93- C 26,505.58 I
5,195.0000	LAND SECURITIES GROUP PLC	60,641.91	13.1583	68,357.70	7,715.79 6,234.02- C 13,949.81 I
1,467.0000	NEXT PLC	58,469.62	50.0875	73,478.38	15,008.76 4,368.78- C 19,377.54 I
10,129.0000	KINGFISHER PLC	33,761.54	3.9059	39,563.29	5,801.75 6,984.00- C 12,785.75 I
15,062.0000	ITV PLC	31,684.10	2.3562	35,490.52	3,806.42 6,054.65- C 9,861.07 I
3,562.0000	RYANAIR HOLDINGS PLC	19,862.28	20.4842	72,965.00	53,102.72 13,639.18- C 66,741.90 I
3,583.0000	CRH PLC	91,448.43	35.3285	126,582.15	35,133.72 24,563.22- C 59,696.94 I
602.0000	KERRY GROUP PLC	19,189.59	85.9176	51,722.41	32,532.82 9,668.36- C 42,201.18 I

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12,840.0000	CHEUNG KONG PROPERTY HOLDINGS	56,400.48	7.8332	100,579.14	44,178.66 507.60- C 44,686.26 I
12,840.0000	CK HUTCHISON HOLDINGS LTD	96,994.32	12.5537	161,189.79	64,195.47 813.48- C 65,008.95 I
4,000.0000	CK INFRASTRUCTURE HOLDINGS LTD	26,166.51	8.4033	33,613.23	7,446.72 189.73- C 7,636.45 I
14,140.0000	LINK REIT	61,253.71	7.6090	107,592.57	46,338.86 479.03- C 46,817.89 I
10,000.0000	TECHTRONIC INDUSTRIES CO LTD	31,371.90	4.5987	45,987.61	14,615.71 334.67- C 14,950.38 I
60,600.0000	AIA GROUP LTD	214,993.01	7.3080	442,868.40	227,875.39 2,431.18- C 230,306.57 I
11,600.0000	SANDS CHINA LTD	19,090.29	4.5795	53,122.74	34,032.45 268.11- C 34,300.56 I
4,100.0000	SWIRE PROPERTIES LTD	9,595.32	3.2985	13,524.07	3,928.75 79.05- C 4,007.80 I
4,800.0000	BANK OF EAST ASIA LTD/THE	17,866.79	4.2977	20,629.10	2,762.31 104.10- C 2,866.41 I

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13,000.0000	CLP HOLDINGS LTD	98,825.03	10.5809	137,552.92	38,727.89 781.54- C 39,509.43 I
4,400.0000	HONG KONG EXCHANGES & CLEARING	74,950.83	25.8504	113,741.84	38,791.01 574.03- C 39,365.04 I
6,500.0000	MTR CORP LTD	24,721.83	5.6299	36,594.74	11,872.91 184.68- C 12,057.59 I
3,300.0000	HANG SENG BANK LTD	46,362.45	20.9185	69,031.38	22,668.93 348.38- C 23,017.31 I
8,169.0000	HENDERSON LAND DEVELOPMENT CO	35,839.84	5.5787	45,572.56	9,732.72 230.43- C 9,963.15 I
6,500.0000	POWER ASSETS HOLDINGS LTD	40,776.85	8.8324	57,410.86	16,634.01 302.48- C 16,936.49 I
6,000.0000	WHARF HOLDINGS LTD/THE	34,720.99	8.2880	49,728.11	15,007.12 250.96- C 15,258.08 I
36,437.0000	HONG KONG & CHINA GAS CO LTD	43,381.42	1.8804	68,519.64	25,138.22 345.82- C 25,484.04 I
8,000.0000	HYSAN DEVELOPMENT CO LTD	31,582.14	4.7716	38,173.56	6,591.42 148.74- C 6,740.16 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
13,000.0000	GALAXY ENTERTAINMENT GROUP LTD	40,096.82	6.0719	78,934.73	38,837.91 551.79- C 39,389.70 I
11,000.0000	KERRY PROPERTIES LTD	31,603.57	3.3946	37,340.92	5,737.35 239.98- C 5,977.33 I
16,000.0000	BOC HONG KONG HOLDINGS LTD	38,613.39	4.7845	76,552.08	37,938.69 386.34- C 38,325.03 I
5,500.0000	YUE YUEN INDUSTRIAL HOLDINGS L	17,773.89	4.1504	22,827.28	5,053.39 115.20- C 5,168.59 I
1,000.0000	SUN HUNG KAI PROPERTIES LTD	13,078.18	14.6929	14,692.98	1,614.80 100.62- C 1,715.42 I
12,000.0000	WHEELOCK & CO LTD	45,850.00	7.5450	90,540.51	44,690.51 533.51- C 45,224.02 I
12,900.0000	CONCORDIA FINANCIAL GROUP LTD	64,352.43	5.0427	65,051.08	698.65 3,151.70- C 3,850.35 I
5,850.0000	MEBUKI FINANCIAL GROUP INC	21,665.59	3.7201	21,763.08	97.49 2,516.32- C 2,613.81 I
3,000.0000	RECRUIT HOLDINGS CO LTD	28,805.43	17.1858	51,557.49	22,752.06 2,357.94 C 20,394.12 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS	
2,209.0000	JAPAN POST HOLDINGS CO LTD	28,136.61	12.4065	27,406.07	730.54-	
					125.04	C
					855.58-	I
2,270.0000	JAPAN POST BANK CO LTD	29,158.79	12.7981	29,051.80	106.99-	
					734.65	C
					841.64-	I
3,300.0000	SEVEN & I HOLDINGS CO LTD	81,478.41	41.1890	135,923.81	54,445.40	
					26,600.40-	C
					81,045.80	I
1,400.0000	BANDAI NAMCO HOLDINGS INC	21,386.68	34.0868	47,721.61	26,334.93	
					9,650.53-	C
					35,985.46	I
12,500.0000	MITSUBISHI CHEMICAL HOLDINGS C	76,971.30	8.2778	103,473.21	26,501.91	
					4,063.96-	C
					30,565.87	I
2,800.0000	DAIICHI SANKYO CO LTD	52,080.93	23.5582	65,962.97	13,882.04	
					12,909.01-	C
					26,791.05	I
1,600.0000	ELECTRIC POWER DEVELOPMENT CO	40,521.66	24.7241	39,558.56	963.10-	
					1,000.33	C
					1,963.43-	I
1,200.0000	SEGA SAMMY HOLDINGS INC	15,295.88	13.4567	16,148.09	852.21	
					836.35-	C
					1,688.56	I
2,400.0000	NOMURA REAL ESTATE HOLDINGS IN	40,704.49	19.6155	47,077.25	6,372.76	
					2,399.69	C
					3,973.07	I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
1,000.0000	YAMAGUCHI FINANCIAL GROUP INC	10,806.72	12.0772	12,077.25	1,270.53 2,363.54- C 3,634.07 I
15,000.0000	AOZORA BANK LTD	51,236.08	3.8091	57,137.77	5,901.69 2,999.64- C 8,901.33 I
11,000.0000	FUKUOKA FINANCIAL GROUP INC	50,675.17	4.7525	52,278.39	1,603.22 2,062.65- C 3,665.87 I
2,000.0000	INPEX CORP	22,203.12	9.6208	19,241.72	2,961.40- 880.01 C 3,841.41- I
4,700.0000	ISETAN MITSUKOSHI HOLDINGS LTD	53,286.86	10.0213	47,100.39	6,186.47- 1,780.84- C 4,405.63- I
1,500.0000	J FRONT RETAILING CO LTD	18,142.52	15.3435	23,015.31	4,872.79 4,504.12- C 9,376.91 I
2,400.0000	OTSUKA HOLDINGS CO LTD	68,677.49	42.6308	102,313.99	33,636.50 29,783.17- C 63,419.67 I
1,000.0000	MEIJI HOLDINGS CO LTD	19,510.65	81.0786	81,078.67	61,568.02 15,867.15- C 77,435.17 I
5,400.0000	DAI-ICHI LIFE HOLDINGS INC	77,538.30	18.0357	97,393.20	19,854.90 15,825.24- C 35,680.14 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
2,419.0000	SOMPO HOLDINGS INC	53,626.59	38.6169	93,414.39	39,787.80 36,167.05- C 75,954.85 I
18,362.0000	JXTG HOLDINGS INC	64,670.11	4.3672	80,190.75	15,520.64 2,602.19- C 18,122.83 I
900.0000	AISIN SEIKI CO LTD	26,686.74	51.1747	46,057.31	19,370.57 9,013.46- C 28,384.03 I
3,000.0000	AJINOMOTO CO INC	29,769.06	21.5957	64,787.29	35,018.23 12,678.94- C 47,697.17 I
3,000.0000	AMADA HOLDINGS CO LTD	25,712.53	11.5521	34,656.46	8,943.93 6,782.29- C 15,726.22 I
2,400.0000	AEON FINANCIAL SERVICE CO LTD	43,410.11	21.1641	50,793.87	7,383.76 1,284.43 C 6,099.33 I
12,600.0000	ACOM CO LTD	35,563.19	4.5656	57,527.59	21,964.40 2,932.38 C 19,032.02 I
1,700.0000	ASAHI GROUP HOLDINGS LTD	31,620.56	37.6290	63,969.38	32,348.82 12,518.86- C 44,867.68 I
6,000.0000	ASAHI KASEI CORP	32,835.39	10.7467	64,480.24	31,644.85 12,618.83- C 44,263.68 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS	
1,200.0000	ASAHI GLASS CO LTD	31,762.44	42.0968	50,516.20	18,753.76	
					2,310.34	C
					16,443.42	I
5,000.0000	HIROSHIMA BANK LTD/THE	21,187.56	4.4321	22,160.91	973.35	
					4,336.91-	C
					5,310.26	I
6,000.0000	BANK OF KYOTO LTD/THE	49,993.73	9.4339	56,603.77	6,610.04	
					2,555.05-	C
					9,165.09	I
3,000.0000	NTT DATA CORP	19,803.45	11.1249	33,374.87	13,571.42	
					6,531.49-	C
					20,102.91	I
8,400.0000	NTT DOCOMO INC	132,127.53	23.6027	198,262.72	66,135.19	
					25,626.76-	C
					91,761.95	I
2,700.0000	BRIDGESTONE CORP	45,075.20	43.0758	116,304.73	71,229.53	
					22,760.95-	C
					93,990.48	I
1,500.0000	BROTHER INDUSTRIES LTD	18,190.42	23.0776	34,616.41	16,425.99	
					6,774.45-	C
					23,200.44	I
2,000.0000	CANON INC	62,474.15	33.9622	67,924.53	5,450.38	
					1,439.54	C
					4,010.84	I
700.0000	CENTRAL JAPAN RAILWAY CO	53,139.24	162.9583	114,070.84	60,931.60	
					22,323.74-	C
					83,255.34	I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS	
9,000.0000	CHIBA BANK LTD/THE	56,091.90	7.2445	65,201.14	9,109.24	
					3,781.71-	C
					12,890.95	I
2,600.0000	CHUBU ELECTRIC POWER CO INC	32,697.13	13.2831	34,536.31	1,839.18	
					1,579.50	C
					259.68	I
2,000.0000	CHUGOKU BANK LTD/THE	27,000.83	14.9519	29,903.88	2,903.05	
					5,852.21-	C
					8,755.26	I
1,000.0000	CHUGAI PHARMACEUTICAL CO LTD	19,058.15	37.4243	37,424.35	18,366.20	
					7,323.96-	C
					25,690.16	I
3,100.0000	RAKUTEN INC	22,443.91	11.7657	36,473.83	14,029.92	
					7,137.96-	C
					21,167.88	I
7,800.0000	KDDI CORP	67,406.24	26.4773	206,523.66	139,117.42	
					40,416.83-	C
					179,534.25	I
400.0000	DAITO TRUST CONSTRUCTION CO LT	19,398.86	155.7048	62,281.95	42,883.09	
					12,188.62-	C
					55,071.71	I
1,100.0000	DAIKIN INDUSTRIES LTD	46,261.27	102.0825	112,290.85	66,029.58	
					21,975.39-	C
					88,004.97	I
2,000.0000	DAI NIPPON PRINTING CO LTD	20,170.57	11.1071	22,214.31	2,043.74	
					561.73	C
					1,482.01	I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
3,000.0000	DAIWA HOUSE INDUSTRY CO LTD	33,953.32	34.1580	102,474.19	68,520.87 20,054.25- C 88,575.12 I
9,000.0000	DAIWA SECURITIES GROUP INC	48,584.58	5.9255	53,330.36	4,745.78 8,533.53- C 13,279.31 I
200.0000	LAWSON INC	8,549.55	69.9537	13,990.74	5,441.19 2,738.01- C 8,179.20 I
5,000.0000	MITSUBISHI UFJ LEASE & FINANCE	18,046.68	5.4645	27,322.89	9,276.21 5,347.10- C 14,623.31 I
1,000.0000	DON QUIJOTE HOLDINGS CO LTD	33,841.50	37.9138	37,913.85	4,072.35 5,684.55- C 9,756.90 I
1,500.0000	EAST JAPAN RAILWAY CO	103,808.40	95.6301	143,445.17	39,636.77 28,072.35- C 67,709.12 I
1,100.0000	EISAI CO LTD	39,468.48	55.2242	60,746.70	21,278.22 11,888.18- C 33,166.40 I
300.0000	FAST RETAILING CO LTD	69,534.82	333.0366	99,911.00	30,376.18 17,272.51- C 47,648.69 I
67,500.0000	MITSUBISHI UFJ FINANCIAL GROUP	354,869.06	6.7176	453,444.27	98,575.21 70,587.64- C 169,162.85 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
4,000.0000	SUBARU CORP	20,527.45	33.6952	134,781.05	114,253.60 26,376.81- C 140,630.41 I
800.0000	FANUC CORP	86,964.82	192.7287	154,182.98	67,218.16 30,173.73- C 97,391.89 I
4,000.0000	FUJITSU LTD	21,444.29	7.3673	29,469.56	8,025.27 2,367.36- C 10,392.63 I
968.0000	NOMURA RESEARCH INSTITUTE LTD	18,227.69	39.3823	38,122.11	19,894.42 7,460.52- C 27,354.94 I
6.0000	NIPPON BUILDING FUND INC	25,552.84	5,108.5793	30,651.48	5,098.64 5,998.52- C 11,097.16 I
6.0000	JAPAN REAL ESTATE INVESTMENT C	25,137.60	4,975.0798	29,850.48	4,712.88 5,841.77- C 10,554.65 I
7,900.0000	HACHIJUNI BANK LTD/THE	47,241.99	6.3456	50,130.83	2,888.84 1,267.68 C 1,621.16 I
1,600.0000	HAMAMATSU PHOTONICS KK	29,817.38	30.7048	49,127.80	19,310.42 7,365.91- C 26,676.33 I
1,000.0000	HANKYU HANSHIN HOLDINGS INC	23,104.03	35.9558	35,955.85	12,851.82 7,036.61- C 19,888.43 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
700.0000	DENTSU INC	18,595.01	47.7928	33,454.96	14,859.95 6,547.17- C 21,407.12 I
4,200.0000	RESONA HOLDINGS INC	20,370.98	5.5046	23,119.44	2,748.46 9,088.12- C 11,836.58 I
210.0000	HIROSE ELECTRIC CO LTD	23,444.73	142.5774	29,941.26	6,496.53 5,859.53- C 12,356.06 I
20,000.0000	HITACHI LTD	78,362.03	6.1356	122,712.70	44,350.67 24,014.98- C 68,365.65 I
2,000.0000	HITACHI METALS LTD	21,102.39	13.9017	27,803.49	6,701.10 5,441.17- C 12,142.27 I
1,394.0000	SUMITOMO MITSUI TRUST HOLDINGS	52,969.04	35.7689	49,861.92	3,107.12- 1,172.40- C 1,934.72- I
4,000.0000	HONDA MOTOR CO LTD	129,592.82	27.2694	109,077.96	20,514.86- 7,491.54- C 13,023.32- I
1,800.0000	HOYA CORP	49,099.77	51.9134	93,444.28	44,344.51 18,287.13- C 62,631.64 I
10,000.0000	IHI CORP	18,206.40	3.3997	33,997.86	15,791.46 6,653.42- C 22,444.88 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
3,500.0000	ISUZU MOTORS LTD	19,079.45	12.3353	43,173.73	24,094.28 8,449.13- C 32,543.41 I
9,400.0000	ITOCHU CORP	90,386.58	14.8540	139,627.98	49,241.40 17,430.86- C 66,672.26 I
4,000.0000	JAPAN TOBACCO INC	73,890.29	35.1281	140,512.63	66,622.34 27,498.45- C 94,120.79 I
6,100.0000	AEON CO LTD	65,652.02	15.1922	92,672.66	27,020.64 5,277.82- C 32,298.46 I
8,000.0000	KAJIMA CORP	19,760.86	8.4371	67,497.33	47,736.47 13,209.28- C 60,945.75 I
3,300.0000	KANSAI ELECTRIC POWER CO INC/T	31,643.91	13.7682	45,435.21	13,791.30 2,077.95 C 11,713.35 I
3,000.0000	KAO CORP	83,734.73	59.3805	178,141.68	94,406.95 31,651.26- C 126,058.21 I
13,000.0000	KAWASAKI HEAVY INDUSTRIES LTD	37,396.08	2.9547	38,412.24	1,016.16 3,402.39- C 4,418.55 I
3,000.0000	KEIKYU CORP	24,562.66	12.0416	36,124.95	11,562.29 7,069.69- C 18,631.98 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
3,000.0000	KEIO CORP	19,995.09	8.3659	25,097.90	5,102.81 4,911.67- C 10,014.48 I
2,000.0000	KIKKOMAN CORP	23,529.90	31.9508	63,901.74	40,371.84 12,505.62- C 52,877.46 I
440.0000	KEYENCE CORP	48,358.74	439.1242	193,214.66	144,855.92 37,812.26- C 182,668.18 I
7,000.0000	KINTETSU GROUP HOLDINGS CO LTD	21,687.96	3.8536	26,975.79	5,287.83 5,279.18- C 10,567.01 I
4,100.0000	KOMATSU LTD	86,170.55	25.4049	104,160.28	17,989.73 20,384.27- C 38,374.00 I
1,000.0000	KONAMI HOLDINGS CORP	19,409.50	55.5357	55,535.78	36,126.28 10,868.38- C 46,994.66 I
1,600.0000	JTEKT CORP	19,539.40	14.6137	23,381.99	3,842.59 4,575.88- C 8,418.47 I
5,000.0000	KUBOTA CORP	46,048.34	16.7986	83,993.41	37,945.07 16,437.59- C 54,382.66 I
700.0000	KURARAY CO LTD	9,413.03	18.1381	12,696.69	3,283.66 2,484.76- C 5,768.42 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
2,500.0000	KYOCERA CORP	124,840.85	57.9031	144,757.91	19,917.06 12,647.46- C 32,564.52 I
2,000.0000	KYOWA HAKKO KIRIN CO LTD	21,017.20	18.5742	37,148.45	16,131.25 7,269.96- C 23,401.21 I
3,200.0000	TOKIO MARINE HOLDINGS INC	89,230.50	41.3937	132,459.94	43,229.44 25,922.52- C 69,151.96 I
3,300.0000	JFE HOLDINGS INC	54,332.94	17.3593	57,285.95	2,953.01 1,448.61 C 1,504.40 I
1,200.0000	MAKITA CORP	20,378.38	36.9793	44,375.22	23,996.84 8,684.25- C 32,681.09 I
6,300.0000	SUMITOMO MITSUI FINANCIAL GROU	206,866.45	38.9729	245,529.54	38,663.09 44,616.07- C 83,279.16 I
5,900.0000	MARUBENI CORP	35,020.84	6.4595	38,111.60	3,090.76 963.73 C 2,127.03 I
3,100.0000	PANASONIC CORP	30,028.31	13.5635	42,046.99	12,018.68 6,304.24- C 18,322.92 I
113,800.0000	MIZUHO FINANCIAL GROUP INC	204,154.11	1.8280	208,032.39	3,878.28 41,041.07- C 44,919.35 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
1,200.0000	CREDIT SAISON CO LTD	18,155.29	19.5265	23,431.83	5,276.54 4,585.63- C 9,862.17 I
5,000.0000	MITSUBISHI CORP	92,787.17	20.9683	104,841.58	12,054.41 14,629.64- C 26,684.05 I
1,500.0000	MITSUBISHI GAS CHEMICAL CO INC	18,270.28	21.1374	31,706.12	13,435.84 6,204.92- C 19,640.76 I
12,000.0000	MITSUBISHI ELECTRIC CORP	118,119.49	14.3778	172,534.70	54,415.21 28,151.01- C 82,566.22 I
14,000.0000	MITSUBISHI HEAVY INDUSTRIES LT	58,877.99	4.0922	57,290.85	1,587.14- 11,211.86- C 9,624.72 I
1,700.0000	MITSUBISHI MATERIALS CORP	53,395.49	30.2598	51,441.79	1,953.70- 2,467.99- C 514.29 I
2,400.0000	MITSUI & CO LTD	34,907.74	14.2888	34,293.34	614.40- 4,397.01- C 3,782.61 I
6,000.0000	MITSUI CHEMICALS INC	18,461.93	5.2954	31,772.87	13,310.94 6,217.99- C 19,528.93 I
3,000.0000	MITSUI FUDOSAN CO LTD	51,520.90	23.8563	71,569.06	20,048.16 14,006.12- C 34,054.28 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
1,100.0000	MURATA MANUFACTURING CO LTD	72,749.11	151.9223	167,114.62	94,365.51 18,467.47- C 112,832.98 I
2,200.0000	SEIKO EPSON CORP	17,415.31	22.2410	48,930.22	31,514.91 9,575.67- C 41,090.58 I
1,000.0000	NGK SPARK PLUG CO LTD	13,596.23	21.2620	21,262.01	7,665.78 4,160.99- C 11,826.77 I
700.0000	NINTENDO CO LTD	102,565.22	335.3506	234,745.45	132,180.23 5,196.71- C 137,376.94 I
2,000.0000	DENSO CORP	59,303.88	42.2036	84,407.26	25,103.38 16,518.58- C 41,621.96 I
1,200.0000	NIDEC CORP	70,048.72	102.4385	122,926.30	52,877.58 10,700.37- C 63,577.95 I
1,000.0000	NH FOODS LTD	12,882.89	30.3933	30,393.38	17,510.49 5,948.01- C 23,458.50 I
1,210.0000	NISSHIN SEIFUN GROUP INC	13,074.53	16.4204	19,868.72	6,794.19 3,888.32- C 10,682.51 I
4,400.0000	NIPPON TELEGRAPH & TELEPHONE C	92,639.67	47.2588	207,938.76	115,299.09 40,693.78- C 155,992.87 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
2,000.0000	NSK LTD	15,906.64	12.4866	24,973.30	9,066.66 4,887.29- C 13,953.95 I
1,000.0000	NISSAN CHEMICAL INDUSTRIES LTD	14,192.47	33.0188	33,018.87	18,826.40 6,461.83- C 25,288.23 I
500.0000	NISSIN FOODS HOLDINGS CO LTD	16,662.57	62.4777	31,238.87	14,576.30 6,113.47- C 20,689.77 I
700.0000	NITTO DENKO CORP	27,277.65	82.2356	57,564.97	30,287.32 11,265.50- C 41,552.82 I
4,000.0000	NIPPON EXPRESS CO LTD	17,503.69	6.2566	25,026.70	7,523.01 4,897.74- C 12,420.75 I
1,400.0000	YAMAHA CORP	18,378.87	34.5318	48,344.60	29,965.73 9,461.07- C 39,426.80 I
2,000.0000	MINEBEA MITSUMI INC	12,329.24	16.0644	32,128.87	19,799.63 6,287.63- C 26,087.26 I
1,829.0000	NIPPON STEEL & SUMITOMO METAL	35,066.68	22.5881	41,313.65	6,246.97 5,393.75- C 11,640.72 I
1,000.0000	NIPPON ELECTRIC GLASS CO LTD	28,598.11	36.3563	36,356.35	7,758.24 919.35 C 6,838.89 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
10,600.0000	NISSAN MOTOR CO LTD	91,753.83	9.9501	105,471.69	13,717.86 20,640.89- C 34,358.75 I
3,300.0000	NOMURA HOLDINGS INC	19,325.51	5.9932	19,777.68	452.17 1,008.14 C 555.97- I
400.0000	NITORI HOLDINGS CO LTD	15,118.77	133.8554	53,542.18	38,423.41 10,478.29- C 48,901.70 I
800.0000	ORIENTAL LAND CO LTD/JAPAN	13,841.12	67.7109	54,168.74	40,327.62 10,600.87- C 50,928.49 I
3,000.0000	OBAYASHI CORP	13,255.53	11.7568	35,270.56	22,015.03 6,902.48- C 28,917.51 I
1,000.0000	OLYMPUS CORP	28,433.99	36.4898	36,489.85	8,055.86 12,967.32- C 21,023.18 I
800.0000	OMRON CORP	18,457.66	43.3873	34,709.86	16,252.20 6,792.75- C 23,044.95 I
2,000.0000	ONO PHARMACEUTICAL CO LTD	17,503.69	21.8138	43,627.62	26,123.93 8,537.96- C 34,661.89 I
6,800.0000	ORIX CORP	69,385.93	15.4859	105,304.37	35,918.44 7,696.07- C 43,614.51 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
8,000.0000	OSAKA GAS CO LTD	28,363.64	4.0895	32,716.27	4,352.63 6,402.59- C 10,755.22 I
2,000.0000	JAPAN EXCHANGE GROUP INC	24,629.90	18.1114	36,222.85	11,592.95 5,559.30- C 17,152.25 I
2,400.0000	T&D HOLDINGS INC	28,363.64	15.2144	36,514.77	8,151.13 7,145.96- C 15,297.09 I
200.0000	SMC CORP/JAPAN	27,128.60	303.9337	60,786.75	33,658.15 11,896.03- C 45,554.18 I
4,300.0000	SOFTBANK GROUP CORP	123,901.34	80.9629	348,140.78	224,239.44 76,982.65- C 301,222.09 I
2,500.0000	SANTEN PHARMACEUTICAL CO LTD	15,038.90	13.5635	33,908.86	18,869.96 6,635.98- C 25,505.94 I
900.0000	SECOM CO LTD	39,670.78	75.8721	68,284.97	28,614.19 13,363.43- C 41,977.62 I
2,000.0000	SEKISUI CHEMICAL CO LTD	13,670.77	17.8978	35,795.66	22,124.89 7,005.24- C 29,130.13 I
2,000.0000	SEKISUI HOUSE LTD	19,888.62	17.6174	35,234.96	15,346.34 6,895.50- C 22,241.84 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
23,000.0000	SHARP CORP/JAPAN	48,907.55	3.7112	85,359.55	36,452.00 2,158.50 C 34,293.50 I
4,000.0000	SHIMIZU CORP	16,694.52	10.5998	42,399.43	25,704.91 8,297.60- C 34,002.51 I
2,200.0000	SHIN-ETSU CHEMICAL CO LTD	128,353.56	90.6461	199,421.49	71,067.93 36,955.53- C 108,023.46 I
1,900.0000	SHIONOGI & CO LTD	45,108.18	55.7048	105,839.26	60,731.08 4,709.80- C 65,440.88 I
400.0000	SHIMANO INC	17,801.81	158.2413	63,296.54	45,494.73 12,387.19- C 57,881.92 I
1,000.0000	SHISEIDO CO LTD	19,467.92	35.5464	35,546.46	16,078.54 16,472.29- C 32,550.83 I
6,000.0000	SHIZUOKA BANK LTD/THE	52,717.81	9.0334	54,200.78	1,482.97 2,056.41- C 3,539.38 I
5,000.0000	SONY CORP	103,784.35	38.1452	190,726.23	86,941.88 1,902.24 C 85,039.64 I
900.0000	STANLEY ELECTRIC CO LTD	17,315.24	30.1708	27,153.79	9,838.55 5,314.02- C 15,152.57 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
6,000.0000	SUMITOMO CHEMICAL CO LTD	29,385.77	5.7493	34,496.26	5,110.49 6,750.96- C 11,861.45 I
3,200.0000	SUMITOMO ELECTRIC INDUSTRIES L	39,930.56	15.3969	49,270.20	9,339.64 9,642.21- C 18,981.85 I
2,000.0000	SUMITOMO HEAVY INDUSTRIES LTD	12,095.00	6.5948	13,189.75	1,094.75 2,581.23- C 3,675.98 I
4,000.0000	SUMITOMO METAL MINING CO LTD	61,298.61	13.3543	53,417.58	7,881.03- 3,052.07- C 4,828.96- I
1,000.0000	SUMITOMO REALTY & DEVELOPMENT	19,122.04	30.8383	30,838.38	11,716.34 6,035.09- C 17,751.43 I
8,300.0000	SUMITOMO CORP	91,162.58	13.0117	107,997.50	16,834.92 9,403.26- C 26,238.18 I
2,000.0000	SURUGA BANK LTD	17,950.87	24.2257	48,451.40	30,500.53 9,481.99- C 39,982.52 I
1,500.0000	SUZUKI MOTOR CORP	33,410.34	47.4368	71,155.21	37,744.87 13,925.15- C 51,670.02 I
500.0000	TDK CORP	33,538.10	65.7707	32,885.37	652.73- 6,435.69- C 5,782.96 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
8,000.0000	TAISEI CORP	17,631.46	9.1313	73,050.90	55,419.44 14,296.14- C 69,715.58 I
2,000.0000	TAKASHIMAYA CO LTD	16,843.58	9.5140	19,028.12	2,184.54 3,723.83- C 5,908.37 I
1,300.0000	TAKEDA PHARMACEUTICAL CO LTD	57,440.64	50.8098	66,052.86	8,612.22 12,926.60- C 21,538.82 I
1,000.0000	MITSUBISHI TANABE PHARMA CORP	14,181.83	23.1043	23,104.31	8,922.48 4,521.54- C 13,444.02 I
1,000.0000	TEIJIN LTD	16,875.51	19.2328	19,232.82	2,357.31 3,763.88- C 6,121.19 I
1,400.0000	SYSMEX CORP	27,661.54	59.7187	83,606.26	55,944.72 33,995.13- C 89,939.85 I
400.0000	TERUMO CORP	10,859.96	39.3823	15,752.94	4,892.98 3,082.87- C 7,975.85 I
1,100.0000	TOHO CO LTD/TOKYO	17,579.28	30.7938	33,873.26	16,293.98 6,629.03- C 22,923.01 I
3,000.0000	TOHO GAS CO LTD	18,246.09	7.2801	21,840.51	3,594.42 8,542.05- C 12,136.47 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
7,900.0000	TOKYO ELECTRIC POWER CO HOLDIN	29,353.99	4.1206	32,553.40	3,199.41 3,194.25- C 6,393.66 I
2,000.0000	TOKYO GAS CO LTD	8,815.73	5.2002	10,400.50	1,584.77 2,035.39- C 3,620.16 I
700.0000	TOKYO ELECTRON LTD	47,475.03	134.9234	94,446.42	46,971.39 18,483.23- C 65,454.62 I
10,000.0000	TOKYU CORP	52,355.06	7.6272	76,272.69	23,917.63 1,181.31- C 25,098.94 I
10,000.0000	TORAY INDUSTRIES INC	60,866.05	8.3686	83,686.36	22,820.31 14,349.21- C 37,169.52 I
1,000.0000	LIXIL GROUP CORP	20,484.86	24.9999	25,000.00	4,515.14 4,892.52- C 9,407.66 I
700.0000	MAZDA MOTOR CORP	9,875.10	13.9551	9,768.60	106.50- 1,911.71- C 1,805.21 I
700.0000	TOYOTA INDUSTRIES CORP	19,884.36	52.5987	36,819.15	16,934.79 7,205.55- C 24,140.34 I
1,100.0000	TOYOTA TSUSHO CORP	17,462.17	29.9483	32,943.22	15,481.05 6,447.01- C 21,928.06 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
12,060.0000	TOYOTA MOTOR CORP	476,689.35	52.4474	632,516.70	155,827.35 129,906.17- C 285,733.52 I
900.0000	UNICHARM CORP	9,710.07	25.1156	22,604.13	12,894.06 4,423.62- C 17,317.68 I
1,100.0000	WEST JAPAN RAILWAY CO	43,723.37	70.6301	77,693.13	33,969.76 13,020.64- C 46,990.40 I
600.0000	YAKULT HONSHA CO LTD	15,874.70	68.0847	40,850.83	24,976.13 7,994.56- C 32,970.69 I
1,100.0000	YAMAHA MOTOR CO LTD	16,220.72	25.7920	28,371.31	12,150.59 5,552.29- C 17,702.88 I
9,500.0000	ASTELLAS PHARMA INC	69,083.15	12.2330	116,213.50	47,130.35 22,743.08- C 69,873.43 I
2,872.0000	YAMATO HOLDINGS CO LTD	42,065.90	20.2785	58,240.05	16,174.15 19,377.30- C 35,551.45 I
3,000.0000	YASKAWA ELECTRIC CORP	35,694.28	21.1908	63,572.44	27,878.16 184.59- C 28,062.75 I
9,000.0000	OVERSEA-CHINESE BANKING CORP L	57,183.03	7.8367	70,530.56	13,347.53 1,032.24 C 12,315.29 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS	
31,000.0000	SINGAPORE TELECOMMUNICATIONS L	70,835.90	2.8252	87,583.98	16,748.08	
					1,281.82	C
					15,466.26	I
11,000.0000	SEMBCORP INDUSTRIES LTD	25,196.28	2.2369	24,606.89	589.39-	
					315.79	C
					905.18-	I
19,700.0000	STARHUB LTD	41,120.42	1.9755	38,917.82	2,202.60-	
					1,292.57	C
					3,495.17-	I
9,200.0000	KEPPEL CORP LTD	40,328.71	4.5683	42,029.27	1,700.56	
					953.18	C
					747.38	I
8,600.0000	WILMAR INTERNATIONAL LTD	20,336.41	2.4330	20,924.57	588.16	
					235.91	C
					352.25	I
22,000.0000	GLOBAL LOGISTIC PROPERTIES LTD	35,174.96	2.0772	45,698.51	10,523.55	
					5,084.37-	C
					15,607.92	I
8,600.0000	DBS GROUP HOLDINGS LTD	90,941.75	15.0633	129,544.98	38,603.23	
					2,098.07	C
					36,505.16	I
1,000.0000	JARDINE CYCLE & CARRIAGE LTD	22,406.17	32.2112	32,211.21	9,805.04	
					471.43	C
					9,333.61	I
8,900.0000	CAPITALAND LTD	20,272.43	2.5420	22,624.11	2,351.68	
					255.07	C
					2,096.61	I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS	
28,000.0000	GENTING SINGAPORE PLC	17,850.45	0.7880	22,064.86	4,214.41	
					322.93	C
					3,891.48	I
14,000.0000	CAPITALAND MALL TRUST	18,031.42	1.4344	20,082.07	2,050.65	
					295.62	C
					1,755.03	I
2,800.0000	HONGKONG LAND HOLDINGS LTD	17,487.72	7.3600	20,608.00	3,120.28	I
15,000.0000	COMFORTDELGRO CORP LTD	16,761.65	1.6704	25,057.20	8,295.55	
					366.73	C
					7,928.82	I
2,600.0000	UNITED OVERSEAS BANK LTD	31,730.21	16.7919	43,659.08	11,928.87	
					921.89	C
					11,006.98	I
10,400.0000	UOL GROUP LTD	45,316.88	5.5488	57,708.54	12,391.66	
					1,916.66	C
					10,475.00	I
11,659.0000	BANK HAPOALIM BM	61,590.31	6.7455	78,646.55	17,056.24	
					5,367.71	C
					11,688.53	I
6,726.0000	BANK LEUMI LE-ISRAEL BM	27,867.13	4.8628	32,707.75	4,840.62	
					2,677.96	C
					2,162.66	I
17,743.0000	BEZEQ THE ISRAELI TELECOMMUNIC	31,931.02	1.6606	29,464.05	2,466.97-	
					2,407.09	C
					4,874.06-	I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
11,220.0000	ISRAEL CHEMICALS LTD	46,663.85	4.7196	52,953.95	6,290.10 4,335.63 C 1,954.47 I
701.0000	NICE LTD	20,040.22	80.1788	56,205.35	36,165.13 3,901.41 C 32,263.72 I
699.0000	CHECK POINT SOFTWARE TECHNOLOG	56,619.15	109.0800	76,246.92	19,627.77 I
680.0000	AERCAP HOLDINGS NV	29,355.60	46.4300	31,572.40	2,216.80 I
1,680.0000	NXP SEMICONDUCTORS NV	146,124.98	109.4500	183,876.00	37,751.02 I
9,250.0000	NOVO NORDISK A/S	147,187.48	42.7686	395,609.62	248,422.14 68,050.36- C 316,472.50 I
1,508.0000	ISS A/S	42,022.85	39.2250	59,151.32	17,128.47 5,236.41- C 22,364.88 I
1,000.0000	DONG ENERGY A/S	34,832.99	45.0849	45,084.99	10,252.00 3,028.68 C 7,223.32 I
1,000.0000	DSV A/S	18,674.67	61.3609	61,360.99	42,686.32 9,745.06- C 52,431.38 I
454.0000	PANDORA A/S	33,226.86	93.1919	42,309.17	9,082.31 8,382.36- C 17,464.67 I

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1,000.0000	NOVOZYMES A/S	26,215.68	43.7043	43,704.36	17,488.68	
					6,940.92-	C
					24,429.60	I
750.0000	COLOPLAST A/S	21,318.35	83.4509	62,588.21	41,269.86	
					10,205.24-	C
					51,475.10	I
22.0000	AP MOLLER - MAERSK A/S	34,142.91	2,008.0382	44,176.84	10,033.93	
					2,967.68	C
					7,066.25	I
17.0000	AP MOLLER - MAERSK A/S	25,166.23	1,906.7926	32,415.48	7,249.25	
					2,177.58	C
					5,071.67	I
4,923.0000	DANSKE BANK A/S	129,208.91	38.4119	189,102.17	59,893.26	
					9,092.83-	C
					68,986.09	I
169.0000	GENMAB A/S	21,770.53	213.0760	36,009.85	14,239.32	
					783.56	C
					13,455.76	I
831.0000	VESTAS WIND SYSTEMS A/S	32,325.13	92.1948	76,613.95	44,288.82	
					525.81	C
					43,763.01	I
1,035.0000	NESTE OYJ	18,307.92	39.3375	40,714.38	22,406.46	
					7,610.62-	C
					30,017.08	I
694.0000	NOKIAN RENKAAT OYJ	18,047.47	41.3335	28,685.47	10,638.00	
					5,362.11-	C
					16,000.11	I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
878.0000	KONE OYJ	18,503.75	50.8000	44,602.49	26,098.74 8,337.43- C 34,436.17 I
1,119.0000	ORION OYJ	30,466.09	63.7567	71,343.80	40,877.71 14,887.39- C 55,765.10 I
720.0000	WARTSILA OYJ ABP	18,738.23	59.0234	42,496.89	23,758.66 7,943.84- C 31,702.50 I
2,231.0000	UPM-KYMMENE OYJ	30,156.83	28.4681	63,512.39	33,355.56 11,872.22- C 45,227.78 I
2,707.0000	STORA ENSO OYJ	20,055.39	12.8996	34,919.27	14,863.88 6,527.38- C 21,391.26 I
1,803.0000	SAMPO OYJ	49,011.57	51.1764	92,271.19	43,259.62 17,248.01- C 60,507.63 I
878.0000	ELISA OYJ	28,715.42	38.6988	33,977.60	5,262.18 2,277.49 C 2,984.69 I
549.0000	METSO OYJ	14,536.88	34.6270	19,010.28	4,473.40 3,553.54- C 8,026.94 I
22,186.0000	NOKIA OYJ	99,549.13	6.1076	135,504.22	35,955.09 7,110.54 C 28,844.55 I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS	
946.0000	MARINE HARVEST ASA	16,038.67	17.0593	16,138.12	99.45	
					242.09-	C
					341.54	I
9,979.0000	NORSK HYDRO ASA	54,349.83	5.5248	55,132.79	782.96	
					12,231.49-	C
					13,014.45	I
4,100.0000	DNB ASA	52,598.77	16.9518	69,502.73	16,903.96	
					28,210.53-	C
					45,114.49	I
3,596.0000	TELENOR ASA	58,524.11	16.5340	59,456.47	932.36	
					23,213.42-	C
					24,145.78	I
2,034.0000	SCHIBSTED ASA	42,225.39	24.0669	48,952.08	6,726.69	
					221.36	C
					6,505.33	I
2,548.0000	STATOIL ASA	44,738.22	16.5221	42,098.36	2,639.86-	
					2,022.51-	C
					617.35-	I
902.0000	INTERNATIONAL PETROLEUM CORP/S	2,322.57	2.9639	2,673.53	350.96	
					161.78	C
					189.18	I
2,681.0000	KINNEVIK AB	59,606.67	30.5766	81,975.91	22,369.24	
					1,865.94	C
					20,503.30	I
2,400.0000	ESSITY AB	26,959.50	27.3280	65,587.38	38,627.88	
					11,506.66-	C
					50,134.54	I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS	
3,793.0000	ATLAS COPCO AB	69,829.49	38.2948	145,252.44	75,422.95	
					33,768.21-	C
					109,191.16	I
1,600.0000	ATLAS COPCO AB	21,656.47	34.5128	55,220.49	33,564.02	
					9,687.91-	C
					43,251.93	I
6,300.0000	SVENSKA HANDELSBANKEN AB	62,513.38	14.2983	90,079.49	27,566.11	
					15,803.59-	C
					43,369.70	I
4,200.0000	ASSA ABLOY AB	27,660.10	21.9454	92,170.89	64,510.79	
					16,170.52-	C
					80,681.31	I
728.0000	ICA GRUPPEN AB	22,081.29	37.1804	27,067.34	4,986.05	
					2,107.98	C
					2,878.07	I
1,000.0000	ELECTROLUX AB	22,922.28	32.7344	32,734.41	9,812.13	
					5,742.95-	C
					15,555.08	I
7,788.0000	VOLVO AB	84,851.79	17.0252	132,592.35	47,740.56	
					6,394.13-	C
					54,134.69	I
3,891.0000	SVENSKA CELLULOSA AB SCA	15,470.16	7.5581	29,408.95	13,938.79	
					805.77-	C
					14,744.56	I
1,900.0000	BOLIDEN AB	29,299.44	27.2569	51,788.18	22,488.74	
					13,743.32-	C
					36,232.06	I

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS	
1,015.0000	HEXAGON AB	22,810.03	47.4832	48,195.52	25,385.49	
					8,653.52-	C
					34,039.01	I
4,598.0000	TELE2 AB	36,714.28	10.4569	48,081.24	11,366.96	
					3,744.51	C
					7,622.45	I
10,111.0000	SKANDINAVISKA ENSKILDA BANKEN	73,447.96	12.0812	122,153.63	48,705.67	
					11,694.37-	C
					60,400.04	I
3,910.0000	SWEDBANK AB	50,005.25	24.3403	95,170.82	45,165.57	
					22,474.37-	C
					67,639.94	I
1,200.0000	SWEDISH MATCH AB	28,861.98	35.1767	42,212.09	13,350.11	
					7,405.71-	C
					20,755.82	I
12,800.0000	NORDEA BANK AB	131,175.63	12.7096	162,683.25	31,507.62	
					28,541.24-	C
					60,048.86	I
1,800.0000	SECURITAS AB	19,362.63	16.8355	30,303.93	10,941.30	
					5,316.54-	C
					16,257.84	I
3,043.0000	INVESTOR AB	71,722.11	48.1353	146,475.86	74,753.75	
					32,183.72-	C
					106,937.47	I
481.0000	HENNES & MAURITZ AB	13,762.94	24.8857	11,970.04	1,792.90-	
					420.45	C
					2,213.35-	I

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XCEL ENERGY NDT

SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS	
8,703.0000	TELEFONAKTIEBOLAGET LM ERICSSO	49,520.48	7.1432	62,167.60	12,647.12	
					2,523.59	C
					10,123.53	I
1,600.0000	SKANSKA AB	29,626.06	23.7001	37,920.22	8,294.16	
					6,652.75-	C
					14,946.91	I
2,708.0000	LUNDIN PETROLEUM AB	56,278.88	19.2185	52,043.89	4,234.99-	
					4,053.11	C
					8,288.10-	I
1,250.0000	ALFA LAVAL AB	18,788.18	20.4397	25,549.67	6,761.49	
					4,482.46-	C
					11,243.95	I
4,009.0000	TEVA PHARMACEUTICAL INDUSTRIES ADR	136,589.69	33.2200	133,178.98	3,410.71-	I
TOTAL INVESTMENTS EQUITY		39,256,899.54		56,855,854.11	17,598,954.57	
					6,042,671.51-	C
					23,641,626.08	I
TOTAL INVESTMENT		39,900,562.32		57,614,749.28	17,714,186.96	
					6,068,959.13-	C
					23,783,146.09	I

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PRAIRIE II-TOWNSEND RE
EXCEL ENERGY NDT

SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS REAL ESTATE					
404.1330	PRIME PROPERTY FUND LLC	3,994,102.13	22,209.2623	8,975,495.81	4,981,393.68
1,767,290.0000	FORTRESS JAPAN OPPORTUNITY DOMESTIC FUND © LP	22,852.00	0.6903	1,220,046.00	1,197,194.00
1,504,525.0000	BRAZIL REAL ESTATE OPPORTUNITIES FUND II	1,487,830.79	0.7737	1,164,101.00	323,729.79-
1,584,946.1200	BROOKFIELD REAL ESTATE FUND	0.00	0.1048	166,221.21	166,221.21
250,772.0000	EXETER INDUSTRIAL VALUE FUND II LPP	0.00	1.0291	258,080.00	258,080.00
1,594,075.4400	DIVCOWEST FUND III	0.00	0.2372	378,217.00	378,217.00
3,002,169.2300	JAMESTOWN PREMIER PROPERTY	2,298,345.39	1.7880	5,367,963.29	3,069,617.90
1,603,036.0000	BROOKFIELD FAIRFIELD MULTIFAMILY	279.00	0.3587	575,050.00	574,771.00
1,035,155.0000	CVI EUROPE REAL ESTATE PARTNER TG LLC	383,779.76	0.7410	767,116.79	383,337.03
1,222,000.0000	SAVANNA REAL ESTATE FUND IIA LP LLC	1,119,557.13	1.5961	1,950,515.13	830,958.00
6,012,458.7380	USAA EAGLE REAL ESTATE LP	5,251,069.18	1.3441	8,081,704.19	2,830,635.01
5,487,621.9100	PRISA REAL ESTATE LP	5,350,557.05	1.3897	7,626,240.00	2,275,682.95

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
993,837.0000	GREENFIELD ACQUI RTNRS VII LP	895,262.00	1.1177	1,110,836.00	215,574.00
1,136,403.3600	NORTHLIGHT REAL ESTATE OPPORTUNITY FUND	1,021,129.94	1.0774	1,224,412.50	203,282.56
1,135,061.0000	H/2 SPECIAL OPPORTUNITIES III LP	1,057,318.00	1.1144	1,264,924.00	207,606.00
309,778.0000	BRV PARTNERS FUND I LP	159,502.00	1.0121	313,533.00	154,031.00
4,498,071.0150	METLIFE CORE PROPERTY FUND L P	4,226,377.64	1.0680	4,804,375.00	577,997.36
2,662,200.0000	INLAND RETAIL PROPERTY	2,662,200.00	1.0544	2,807,095.00	144,895.00
405,000.0000	ASANA PARTNERS I	405,000.00	1.0263	415,683.00	10,683.00
2,250,000.0000	HANCOCK US REAL ESTATE	2,250,000.00	1.0000	2,250,000.00	0.00
3,881,939.1300	UBS TRUMBULL PROPERTY FUND	3,377,815.53	1.3593	5,276,978.21	1,899,162.68
1,022.7600	TTG BRPTP FUND LP	0.00	12.7879	13,079.00	13,079.00
2,115,750.0000	LION INDUSTRIAL TRUST	2,053,062.43	1.1251	2,380,500.32	327,437.89
1,670,094.9300	CITIC CAPITAL CHINA	1,318,130.05	0.8301	1,386,421.92	68,291.87
TOTAL INVESTMENTS REAL ESTATE		39,334,170.02		59,778,588.37	20,444,418.35
TOTAL INVESTMENT		39,334,170.02		59,778,588.37	20,444,418.35

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WELLINGTON-PI 2
EXCEL ENERGY-NDT

SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS FIXED INCOME SECURITIES					
2,939,649.6810	WTC-CTF JPM PAG EMERGING MARKETS DEBT	29,146,820.23	10.7200	31,513,044.58	2,366,224.35
TOTAL INVESTMENTS FIXED INCOME SECURITIES		29,146,820.23		31,513,044.58	2,366,224.35
TOTAL INVESTMENT		29,146,820.23		31,513,044.58	2,366,224.35

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STEPSTONE-PL2
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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS PRIVATE EQUITY					
50,749,915.7400	STEPSTONE XL OPP FUND LP	44,927,468.17	1.2460	63,236,932.51	18,309,464.34
TOTAL INVESTMENTS PRIVATE EQUITY		44,927,468.17		63,236,932.51	18,309,464.34
TOTAL INVESTMENT		44,927,468.17		63,236,932.51	18,309,464.34

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS CASH EQUIVALENTS					
107,155.0000	BLACKROCK LIQ T FUND INSTL FUND 60	107,155.00	100.0000	107,155.00	0.00
TOTAL INVESTMENTS CASH EQUIVALENTS		107,155.00		107,155.00	0.00
INVESTMENTS FIXED INCOME SECURITIES					
280,000.0000	AT&T INC 4.350% 06/15/2045 DD 06/15/13	266,162.91	92.8110	259,870.80	6,292.11-
180,000.0000	AT&T INC 5.150% 03/15/2042 DD 03/15/16	176,350.98	102.1190	183,814.20	7,463.22
300,000.0000	ABBVIE INC 3.200% 11/06/2022 DD 05/14/15	301,253.17	102.5660	307,698.00	6,444.83
300,000.0000	AERCAP IRELAND CAPITAL DAC / A 3.750% 05/15/2019 DD 05/15/15	303,770.92	102.7130	308,139.00	4,368.08
300,000.0000	AMAZON.COM INC 2.500% 11/29/2022 DD 11/29/12	294,911.90	100.8010	302,403.00	7,491.10
300,000.0000	AMERICAN EXPRESS CREDIT CORP VAR RT 03/03/2022 DD 03/03/17	300,000.00	100.6790	302,037.00	2,037.00
300,000.0000	AMGEN INC 2.700% 05/01/2022 DD 05/01/15	298,165.96	100.5740	301,722.00	3,556.04
500,000.0000	ANHEUSER-BUSCH INBEV FINANCE I 4.900% 02/01/2046 DD 01/25/16	573,853.71	112.8640	564,320.00	9,533.71-

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250,000.0000	APPLE INC 3.350% 02/09/2027 DD 02/09/17	248,086.30	102.2330	255,582.50	7,496.20
491,000.0000	BANK OF AMERICA CORP 5.700% 01/24/2022 DD 01/24/12	551,560.16	112.9960	554,810.36	3,250.20
250,000.0000	BANK OF AMERICA CORP 4.450% 03/03/2026 DD 03/03/16	262,615.01	104.0740	260,185.00	2,430.01-
250,000.0000	BRISTOL-MYERS SQUIBB CO 3.250% 02/27/2027 DD 02/27/17	246,117.52	100.8630	252,157.50	6,039.98
300,000.0000	BURLINGTON NORTHERN SANTA FE L 3.250% 06/15/2027 DD 03/09/17	299,261.03	102.1580	306,474.00	7,212.97
275,000.0000	CVS HEALTH CORP 4.750% 12/01/2022 DD 06/01/16	298,199.14	109.6090	301,424.75	3,225.61
300,000.0000	CHARTER COMMUNICATIONS OPERATI 4.908% 07/23/2025 DD 07/23/16	315,390.61	108.0320	324,096.00	8,705.39
500,000.0000	CITIGROUP INC 2.700% 03/30/2021 DD 03/30/16	505,490.24	100.6640	503,320.00	2,170.24-
150,000.0000	DAIMLER FINANCE NORTH AME 144A 2.850% 01/06/2022 DD 01/06/17	149,848.62	101.2080	151,812.00	1,963.38
300,000.0000	DELL INTERNATIONAL LLC / 144A 6.020% 06/15/2026 DD 06/01/16	319,836.20	110.1510	330,453.00	10,616.80
200,000.0000	DOW CHEMICAL CO/THE 8.550% 05/15/2019 DD 05/13/09	224,894.70	112.0040	224,008.00	886.70-

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SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
375,000.0000	DUKE ENERGY CORP 2.650% 09/01/2026 DD 08/12/16	357,884.94	94.9730	356,148.75	1,736.19-
0.0040	FNMA POOL #0AO7284 3.500% 07/01/2042 DD 06/01/12	0.00	103.2290	0.00	0.00
0.0100	FNMA POOL #0AQ4086 4.000% 06/01/2043 DD 06/01/13	0.01	105.9880	0.01	0.00
350,000.0000	FEDEX CORP 3.300% 03/15/2027 DD 01/06/17	353,127.30	100.2180	350,763.00	2,364.30-
400,000.0000	FORD MOTOR CREDIT CO LLC 4.250% 09/20/2022 DD 09/25/12	412,910.04	105.0530	420,212.00	7,301.96
225,000.0000	GENERAL MOTORS FINANCIAL CO IN 3.250% 05/15/2018 DD 11/15/13	227,113.81	101.1720	227,637.00	523.19
180,000.0000	GEORGIA-PACIFIC LLC 7.375% 12/01/2025 DD 12/08/95	227,045.10	127.2360	229,024.80	1,979.70
5,000.0000	GEORGIA-PACIFIC LLC 8.000% 01/15/2024 DD 12/11/03	6,263.90	128.3490	6,417.45	153.55
150,000.0000	GEORGIA-PACIFIC LLC 144A 5.400% 11/01/2020 DD 11/02/10	163,457.09	109.3970	164,095.50	638.41
500,000.0000	GOLDMAN SACHS GROUP INC/THE 5.750% 01/24/2022 DD 01/24/12	563,677.76	112.5870	562,935.00	742.76-
250,000.0000	GOLDMAN SACHS GROUP INC/THE 3.750% 02/25/2026 DD 02/25/16	259,276.17	101.8250	254,562.50	4,713.67-

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350,000.0000	HCA INC 6.500% 02/15/2020 DD 08/01/11	378,731.00	109.1250	381,937.50	3,206.50
500,000.0000	HSBC HOLDINGS PLC 4.000% 03/30/2022 DD 03/30/12	525,675.90	105.4700	527,350.00	1,674.10
360,000.0000	HONEYWELL INTERNATIONAL INC 1.850% 11/01/2021 DD 10/31/16	354,091.42	98.3980	354,232.80	141.38
266,000.0000	HYUNDAI CAPITAL AMERICA 144A 2.400% 10/30/2018 DD 10/30/15	267,875.39	100.2090	266,555.94	1,319.45-
0.0170	ILLINOIS ST HSG DEV AUTH 3.875% 12/01/2043 DD 10/01/13	0.02	102.0240	0.02	0.00
250,000.0000	INTERCONTINENTAL EXCHANGE INC 4.000% 10/15/2023 DD 10/08/13	264,249.48	107.2490	268,122.50	3,873.02
200,000.0000	JPMORGAN CHASE & CO 3.300% 04/01/2026 DD 03/23/16	203,952.07	99.3000	198,600.00	5,352.07-
300,000.0000	JOHNSON & JOHNSON 3.625% 03/03/2037 DD 03/03/17	299,246.65	104.5690	313,707.00	14,460.35
260,000.0000	KRAFT HEINZ FOODS CO 5.200% 07/15/2045 DD 07/15/16	300,620.64	108.1830	281,275.80	19,344.84-
300,000.0000	KROGER CO/THE 2.650% 10/15/2026 DD 10/03/16	279,080.57	92.2240	276,672.00	2,408.57-
250,000.0000	LOCKHEED MARTIN CORP 3.550% 01/15/2026 DD 11/23/15	251,517.62	103.6210	259,052.50	7,534.88

BNY MELLON

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FIRST PRINCIPALS CAP-PI 2
XCEL ENERGY NDT

SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
200,000.0000	MCDONALD'S CORP 4.450% 03/01/2047 DD 03/09/17	199,023.03	105.1890	210,378.00	11,354.97
300,000.0000	MICROSOFT CORP 3.300% 02/06/2027 DD 02/06/17	298,971.17	103.0070	309,021.00	10,049.83
300,000.0000	MIZUHO FINANCIAL GROUP INC 3.663% 02/28/2027 DD 02/28/17	300,000.00	103.1110	309,333.00	9,333.00
253,000.0000	MORGAN STANLEY 2.375% 07/23/2019 DD 07/23/14	255,271.11	100.6930	254,753.29	517.82-
500,000.0000	NEUBERGER BERMAN CL 23A C 144A VAR RT 10/17/2027 DD 11/29/16	500,000.00	100.0000	500,000.00	0.00
750,000.0000	NEWELL BRANDS INC 4.200% 04/01/2026 DD 03/30/16	797,848.90	106.1790	796,342.50	1,506.40-
300,000.0000	ORACLE CORP 2.800% 07/08/2021 DD 07/08/14	304,482.25	102.7020	308,106.00	3,623.75
150,000.0000	PACIFIC BELL TELEPHONE CO 7.125% 03/15/2026 DD 03/15/93	181,446.98	121.5160	182,274.00	827.02
300,000.0000	PACIFICORP 6.000% 01/15/2039 DD 01/08/09	380,617.14	129.8500	389,550.00	8,932.86
150,000.0000	PFIZER INC 2.750% 06/03/2026 DD 06/03/16	145,128.45	98.4310	147,646.50	2,518.05
400,000.0000	PRUDENTIAL FINANCIAL INC 5.750% 07/15/2033 DD 07/07/03	466,271.17	120.8010	483,204.00	16,932.83

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FIRST PRINCIPALS CAP-PI 2
XCEL ENERGY NDT

SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
200,000.0000	QUALCOMM INC 3.250% 05/20/2027 DD 05/26/17	199,480.43	100.2290	200,458.00	977.57
375,000.0000	ROCKWELL COLLINS INC 3.500% 03/15/2027 DD 04/10/17	382,188.49	101.4040	380,265.00	1,923.49-
300,000.0000	SOUTHWESTERN ELECTRIC POWER CO 3.550% 02/15/2022 DD 02/03/12	311,371.62	103.2350	309,705.00	1,666.62-
500,000.0000	SPIRIT AEROSYSTEMS INC 5.250% 03/15/2022 DD 09/15/14	520,957.41	103.7610	518,805.00	2,152.41-
1,466,248.5970	US TREAS-CPI INFLAT 3.625% 04/15/2028 DD 04/15/98	1,955,155.57	130.6350	1,915,433.85	39,721.72-
757,570.5000	US TREAS-CPI INFLAT 3.375% 04/15/2032 DD 10/15/01	1,068,654.22	137.3860	1,040,795.81	27,858.41-
893,642.7000	US TREAS-CPI INFLAT 2.125% 02/15/2040 DD 02/15/10	1,111,380.81	124.3700	1,111,423.43	42.62
427,376.7500	US TREAS-CPI INFLAT 0.750% 02/15/2042 DD 02/15/12	402,935.04	95.1440	406,623.34	3,688.30
1,907,956.1900	US TREAS-CPI INFLAT 0.750% 02/15/2045 DD 02/15/15	1,851,987.99	93.7820	1,789,319.47	62,668.52-
727,467.0500	US TREAS-CPI INFLAT 1.000% 02/15/2046 DD 02/15/16	754,184.74	99.9100	726,812.33	27,372.41-
50,000.0000	U S TREASURY BOND 3.000% 02/15/2047 DD 02/15/17	51,460.47	103.1560	51,578.00	117.53

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FIRST PRINCIPALS CAP-PI 2
XCEL ENERGY NDT

SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
300,000.0000	U S TREASURY NOTE 1.750% 11/30/2021 DD 11/30/16	298,934.03	99.7380	299,214.00	279.97
884,000.0000	U S TREASURY NOTE 2.250% 02/15/2027 DD 02/15/17	871,586.10	99.5350	879,889.40	8,303.30
360,000.0000	U S TREASURY NOTE 1.875% 03/31/2022 DD 03/31/17	360,013.39	100.0590	360,212.40	199.01
330,000.0000	U S TREASURY NOTE 1.875% 04/30/2022 DD 04/30/17	331,011.65	99.9810	329,937.30	1,074.35-
350,000.0000	UNITED TECHNOLOGIES CORP 4.500% 06/01/2042 DD 06/01/12	389,762.69	109.1950	382,182.50	7,580.19-
200,000.0000	UNITEDHEALTH GROUP INC 4.250% 04/15/2047 DD 03/13/17	210,054.83	106.6050	213,210.00	3,155.17
200,000.0000	VERIZON COMMUNICATIONS INC 5.150% 09/15/2023 DD 09/18/13	219,596.64	111.0790	222,158.00	2,561.36
250,000.0000	VERIZON COMMUNICATIONS INC 4.125% 03/16/2027 DD 03/16/17	248,399.35	103.2780	258,195.00	9,795.65
200,000.0000	WALGREEN CO 4.400% 09/15/2042 DD 09/13/12	193,376.50	100.1270	200,254.00	6,877.50
400,000.0000	WELLS FARGO & CO 4.400% 06/14/2046 DD 06/14/16	397,695.86	101.2400	404,960.00	7,264.14
1,635,000.0000	IFL L UL CPURNSA INDEX P 2.775% 2033 JUN 07	0.00	0.0000	0.00	0.00

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FIRST PRINCIPALS CAP-PI 2
XCEL ENERGY NDT

SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
1,635,000.0000	IFL L UL CPURNSA INDEX P 2.7125% 2033 JUN 10	0.00	0.0000	0.00	0.00
1,635,000.0000	IRS_R US0003M P 6.75% 2038 JUN 19	52,810.50	0.4455	7,284.00	45,526.50-
3,250,000.0000	IRS-R US0003M P 6.75% 2034 JAN 29	86,125.00	0.4845	15,748.00	70,377.00-
2,800,000.0000	IFL L_UL CPURNSA INDEX P 196BPS 2038 MAY 23	0.00	3.6622	102,542.00	102,542.00
1,400,000.0000	IFL L UL CPURNSA INDEX P 1.775% 2036 JUN 20	0.00	6.6827	93,558.00	93,558.00
1,490,000.0000	IFL L UL CPURNSA P_1.8475% 2038 JUN 28	0.00	5.8526	87,204.00	87,204.00
2,800,000.0000	INF L UL CONSUMER PRICE URBAN P 1.96% 2038 MAY 23	0.00	0.0000	0.00	0.00
4,420,000.0000	IFL L_UL CPURNSA INDEX P 2.321% 2037 APR 06	0.00	0.0000	0.00	0.00
850,000.0000	IFL_L UL CPURNSA INDEX P 2.3175% 2037 MAY 03	0.00	0.0000	0.00	0.00
TOTAL INVESTMENTS FIXED INCOME SECURITIES		27,729,749.49		27,892,005.30	162,255.81
TOTAL INVESTMENT		27,836,904.49		27,999,160.30	162,255.81

SHORT FIXED INCOME SECURITIES

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FIRST PRINCIPALS CAP-PI 2
XCEL ENERGY NDT

SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
1,635,000.0000-	IFL S UL CPURNSA INDEX P 2.775% 2033 JUN 07	0.00	18.7984	307,354.00-	307,354.00-
1,635,000.0000-	IFL S UL CPURNSA INDEX P 2.7125% 2033 JUN 10	0.00	17.2696	282,358.00-	282,358.00-
1,635,000.0000-	IRS R US0003M P 6.75% 2038 JUN 19	0.00	0.0000	0.00	0.00
3,250,000.0000-	IRS R US0003M P 6.75% 2034 JAN 27	0.00	0.0000	0.00	0.00
2,800,000.0000-	IFL S_UL CPURNSA INDEX P 196BPS 2038 MAY 23	0.00	0.0000	0.00	0.00
1,400,000.0000-	IFL S UL CPURNSA INDEX P 1.775% 2036 JUN 20	0.00	0.0000	0.00	0.00
1,490,000.0000-	IFL S UL CPURNSA P_1.8475% 2038 JUN 28	0.00	0.0000	0.00	0.00
2,800,000.0000-	INF S UL CONSUMER PRICE URBAN P 1.96% 2038 MAY 23	0.00	0.0000	0.00	0.00
4,420,000.0000-	IFL L UL_CPURNSA INDEX P 2.321% 2037 APR 06	0.00	4.3284	191,318.00-	191,318.00-
850,000.0000-	IFL_S UL CPURNSA INDEX P 2.3175% 2037 MAY 03	0.00	4.2236	35,901.00-	35,901.00-
TOTAL SHORT FIXED INCOME SECURITIES		0.00		816,931.00-	816,931.00-
TOTAL SHORT INVESTMENT		0.00		816,931.00-	816,931.00-
TOTAL NET INVESTMENT		27,836,904.49		27,182,229.30	654,675.19-

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TITAN MASTERS LP-PI 2
XCEL ENERGY NDT

SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS CASH EQUIVALENTS					
2.3300	BLACKROCK LIQ T FUND INSTL FUND 60	2.33	100.0000	2.33	0.00
TOTAL INVESTMENTS CASH EQUIVALENTS		2.33		2.33	0.00
INVESTMENTS ALTERNATIVE INVESTMENTS					
15,890,520.0280	TITAN FUND LP	15,890,520.03	1.0175	16,169,586.00	279,065.97
TOTAL INVESTMENTS ALTERNATIVE INVESTMENTS		15,890,520.03		16,169,586.00	279,065.97
TOTAL INVESTMENT		15,890,522.36		16,169,588.33	279,065.97

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MAGNITUDE-PI 2
XCEL ENERGY NDT

SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS ALTERNATIVE INVESTMENTS					
8,460.8700	MAGNITUDE US PARTNERS	8,624,657.51	1,190.8645	10,075,750.00	1,451,092.49
6,699.2500	MAGNITUDE US PARTNERS (SERIES Y)	7,258,215.88	1,206.6455	8,083,620.00	825,404.12
6,717.5900	MAGNITUDE US PARTNERS (SERIES X)	7,253,966.34	1,198.4793	8,050,893.00	796,926.66
29.6500	MAGNITUDE US PARTNERS 04/17	29,648.09	1,004.9915	29,798.00	149.91
TOTAL INVESTMENTS ALTERNATIVE INVESTMENTS		23,166,487.82		26,240,061.00	3,073,573.18
TOTAL INVESTMENT		23,166,487.82		26,240,061.00	3,073,573.18

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CORECOMMODITY-PI 2
XCEL ENERGY NDT

SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS OTHER					
31,688,000.0000	CORE COMMODITY FUND	31,688,000.00	0.7670	24,306,417.20	7,381,582.80-
TOTAL INVESTMENTS OTHER		31,688,000.00		24,306,417.20	7,381,582.80-
	TOTAL INVESTMENT	31,688,000.00		24,306,417.20	7,381,582.80-

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MARATHON EAFE-PI 2
XCEL ENERGY NDT

SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS OTHER					
15,908.6180	MARATHON EAFE	22,662,252.25	1,591.4921	25,318,441.14	2,656,188.89
TOTAL INVESTMENTS OTHER		22,662,252.25		25,318,441.14	2,656,188.89
TOTAL INVESTMENT		22,662,252.25		25,318,441.14	2,656,188.89

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GOLDMAN PI 2
XCEL ENERGY NDT

SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS FIXED INCOME SECURITIES					
224,540.0000	ISHARES IBOXX USD HIGH YIELD	19,853,622.64	88.3900	19,847,090.60	6,532.04-
TOTAL INVESTMENTS FIXED INCOME SECURITIES		19,853,622.64		19,847,090.60	6,532.04-
TOTAL INVESTMENT		19,853,622.64		19,847,090.60	6,532.04-

BNY MELLON

MONTICELLO-MINN - [redacted]

Statement of Change in Net Assets
Book Value
1/1/2017 - 6/30/2017

Report ID: GL8800
Base Currency: USD
Status: REVISED

NET ASSETS - BEGINNING OF PERIOD		504,432,968.35
RECEIPTS:		
CONTRIBUTIONS:		
COMPANY	6,696,114.00	
		6,696,114.00
INVESTMENT INCOME:		
REALIZED GAIN/LOSS	1,962.83	
		1,962.83
MASTER TRUST INVESTMENT GAIN/LOSS		
	29,923.20	
		29,923.20
MASTER TRUST ALLOCATED EXPENSES		
	-6,447,219.44	
		-6,447,219.44
MASTER TRUST CHANGE IN REALIZED G/L		
	4,959,148.24	
		4,959,148.24
MASTER TRUST INTEREST INCOME EARNED		
	1,239,376.45	
		1,239,376.45
MASTER TRUST DIVIDEND INCOME EARNED		
	3,859,210.98	
		3,859,210.98
TOTAL RECEIPTS:		10,338,516.26
DISBURSEMENTS:		
ADMINISTRATIVE EXPENSES:		
TRUSTEE/CUSTODIAN	58.88	
		58.88
TOTAL DISBURSEMENTS:		58.88
NET ASSETS - END OF PERIOD		514,771,425.73

BNY MELLON

MONTICELLO-MINN - [redacted]

Statement of Change in Net Assets
Book Value
1/1/2017 - 6/30/2017

Report ID: GL8800
Base Currency: USD
Status: REVISED

NET ASSETS - BEGINNING OF PERIOD		**9,416,018.29**
RECEIPTS:		
INVESTMENT INCOME:		
REALIZED GAIN/LOSS	45.80	
		45.80
MASTER TRUST INVESTMENT GAIN/LOSS		
	581.85	
		581.85
MASTER TRUST ALLOCATED EXPENSES		
	-124,988.86	
		-124,988.86
MASTER TRUST CHANGE IN REALIZED G/L		
	96,620.34	
		96,620.34
MASTER TRUST INTEREST INCOME EARNED		
	24,108.96	
		24,108.96
MASTER TRUST DIVIDEND INCOME EARNED		
	75,057.85	
		75,057.85
TOTAL RECEIPTS:		**71,425.94**
DISBURSEMENTS:		
ADMINISTRATIVE EXPENSES:		
TRUSTEE/CUSTODIAN	1.37	
		1.37
TOTAL DISBURSEMENTS:		**1.37**
NET ASSETS - END OF PERIOD		**9,487,442.86**

BNY MELLON

MONTICELLO-WIS - [redacted]

Statement of Change in Net Assets
Book Value
1/1/2017 - 6/30/2017

Report ID: GL8800
Base Currency: USD
Status: REVISED

NET ASSETS - BEGINNING OF PERIOD		10,004,575.11
RECEIPTS:		
INVESTMENT INCOME:		
REALIZED GAIN/LOSS	15.11	
		15.11
MASTER TRUST INVESTMENT GAIN/LOSS		
	582.80	
		582.80
MASTER TRUST ALLOCATED EXPENSES		
	-125,193.22	
		-125,193.22
MASTER TRUST CHANGE IN REALIZED G/L		
	96,766.52	
		96,766.52
MASTER TRUST INTEREST INCOME EARNED		
	24,160.32	
		24,160.32
MASTER TRUST DIVIDEND INCOME EARNED		
	75,180.61	
		75,180.61
TOTAL RECEIPTS:		71,512.14
DISBURSEMENTS:		
ADMINISTRATIVE EXPENSES:		
TRUSTEE/CUSTODIAN	0.45	
		0.45
TOTAL DISBURSEMENTS:		0.45
NET ASSETS - END OF PERIOD		10,076,086.80

BNY MELLON

PRAIRIE#1-MINN - [redacted]

Statement of Change in Net Assets
Book Value
1/1/2017 - 6/30/2017

Report ID: GL8800
Base Currency: USD
Status: REVISED

NET ASSETS - BEGINNING OF PERIOD		292,599,638.67
RECEIPTS:		
CONTRIBUTIONS:		
COMPANY	24,632.00	
		24,632.00
INVESTMENT INCOME:		
REALIZED GAIN/LOSS	1,361.88	
		1,361.88
MASTER TRUST INVESTMENT GAIN/LOSS		
	22,177.33	
		22,177.33
MASTER TRUST ALLOCATED EXPENSES		
	-2,291,178.74	
		-2,291,178.74
MASTER TRUST CHANGE IN REALIZED G/L		
	4,802,728.67	
		4,802,728.67
MASTER TRUST INTEREST INCOME EARNED		
	681,682.00	
		681,682.00
MASTER TRUST DIVIDEND INCOME EARNED		
	2,506,567.70	
		2,506,567.70
TOTAL RECEIPTS:		5,747,970.84
DISBURSEMENTS:		
ADMINISTRATIVE EXPENSES:		
TRUSTEE/CUSTODIAN	40.86	
		40.86
TOTAL DISBURSEMENTS:		40.86
NET ASSETS - END OF PERIOD		298,347,568.65

BNY MELLON

PRAIRIE#1-MINN - [redacted]

Statement of Change in Net Assets
Book Value
1/1/2017 - 6/30/2017

Report ID: GL8800
Base Currency: USD
Status: REVISED

NET ASSETS - BEGINNING OF PERIOD		7,171,931.58
RECEIPTS:		
INVESTMENT INCOME:		
REALIZED GAIN/LOSS	32.15	
		32.15
MASTER TRUST INVESTMENT GAIN/LOSS		
	559.09	
		559.09
MASTER TRUST ALLOCATED EXPENSES		
	-57,759.57	
		-57,759.57
MASTER TRUST CHANGE IN REALIZED G/L		
	121,079.57	
		121,079.57
MASTER TRUST INTEREST INCOME EARNED		
	17,185.20	
		17,185.20
MASTER TRUST DIVIDEND INCOME EARNED		
	63,191.43	
		63,191.43
TOTAL RECEIPTS:		144,287.87
DISBURSEMENTS:		
ADMINISTRATIVE EXPENSES:		
TRUSTEE/CUSTODIAN	0.97	
		0.97
TOTAL DISBURSEMENTS:		0.97
NET ASSETS - END OF PERIOD		7,316,218.48

BNY MELLON

PRAIRIE#1 WIS - [redacted]

Statement of Change in Net Assets
Book Value
1/1/2017 - 6/30/2017

Report ID: GL8800
Base Currency: USD
Status: REVISED

NET ASSETS - BEGINNING OF PERIOD		5,836,629.84
RECEIPTS:		
INVESTMENT INCOME:		
REALIZED GAIN/LOSS	7.21	
		7.21
MASTER TRUST INVESTMENT GAIN/LOSS		
	344.64	
		344.64
MASTER TRUST ALLOCATED EXPENSES		
	-35,604.49	
		-35,604.49
MASTER TRUST CHANGE IN REALIZED G/L		
	74,623.73	
		74,623.73
MASTER TRUST INTEREST INCOME EARNED		
	10,606.33	
		10,606.33
MASTER TRUST DIVIDEND INCOME EARNED		
	38,952.85	
		38,952.85
TOTAL RECEIPTS:		88,930.27
DISBURSEMENTS:		
ADMINISTRATIVE EXPENSES:		
TRUSTEE/CUSTODIAN	0.22	
		0.22
TOTAL DISBURSEMENTS:		0.22
NET ASSETS - END OF PERIOD		5,925,559.89

BNY MELLON

PRAIRIE#2 MINN - [redacted]

Statement of Change in Net Assets
Book Value
1/1/2017 - 6/30/2017

Report ID: GL8800
Base Currency: USD
Status: REVISED

NET ASSETS - BEGINNING OF PERIOD		331,992,382.37
RECEIPTS:		
CONTRIBUTIONS:		
COMPANY	294,670.00	
		294,670.00
INVESTMENT INCOME:		
REALIZED GAIN/LOSS	1,383.21	
		1,383.21
MASTER TRUST INVESTMENT GAIN/LOSS		
	22,187.90	
		22,187.90
MASTER TRUST ALLOCATED EXPENSES		
	-3,247,237.18	
		-3,247,237.18
MASTER TRUST CHANGE IN REALIZED G/L		
	4,887,571.56	
		4,887,571.56
MASTER TRUST INTEREST INCOME EARNED		
	778,995.10	
		778,995.10
MASTER TRUST DIVIDEND INCOME EARNED		
	2,722,866.36	
		2,722,866.36
TOTAL RECEIPTS:		5,460,436.95
DISBURSEMENTS:		
ADMINISTRATIVE EXPENSES:		
TRUSTEE/CUSTODIAN	41.50	
		41.50
TOTAL DISBURSEMENTS:		41.50
NET ASSETS - END OF PERIOD		337,452,777.82

BNY MELLON

PRAIRIE#2 MINN - [redacted]

Statement of Change in Net Assets
Book Value
1/1/2017 - 6/30/2017

Report ID: GL8800
Base Currency: USD
Status: REVISED

NET ASSETS - BEGINNING OF PERIOD		6,804,931.54
RECEIPTS:		
INVESTMENT INCOME:		
REALIZED GAIN/LOSS	21.96	
		21.96
MASTER TRUST INVESTMENT GAIN/LOSS		
	455.44	
		455.44
MASTER TRUST ALLOCATED EXPENSES		
	-66,636.99	
		-66,636.99
MASTER TRUST CHANGE IN REALIZED G/L		
	100,337.80	
		100,337.80
MASTER TRUST INTEREST INCOME EARNED		
	15,986.14	
		15,986.14
MASTER TRUST DIVIDEND INCOME EARNED		
	55,891.63	
		55,891.63
TOTAL RECEIPTS:		106,055.98
DISBURSEMENTS:		
ADMINISTRATIVE EXPENSES:		
TRUSTEE/CUSTODIAN	0.66	
		0.66
TOTAL DISBURSEMENTS:		0.66
NET ASSETS - END OF PERIOD		6,910,986.86

BNY MELLON

PRAIRIE#2 WIS - [redacted]

Statement of Change in Net Assets
Book Value
1/1/2017 - 6/30/2017

Report ID: GL8800
Base Currency: USD
Status: REVISED

NET ASSETS - BEGINNING OF PERIOD		5,489,199.02
RECEIPTS:		
INVESTMENT INCOME:		
REALIZED GAIN/LOSS	9.74	
		9.74
MASTER TRUST INVESTMENT GAIN/LOSS		
	359.83	
		359.83
MASTER TRUST ALLOCATED EXPENSES		
	-52,645.72	
		-52,645.72
MASTER TRUST CHANGE IN REALIZED G/L		
	79,256.15	
		79,256.15
MASTER TRUST INTEREST INCOME EARNED		
	12,644.15	
		12,644.15
MASTER TRUST DIVIDEND INCOME EARNED		
	44,156.50	
		44,156.50
TOTAL RECEIPTS:		83,780.65
DISBURSEMENTS:		
ADMINISTRATIVE EXPENSES:		
TRUSTEE/CUSTODIAN	0.30	
		0.30
TOTAL DISBURSEMENTS:		0.30
NET ASSETS - END OF PERIOD		5,572,979.37

BNY MELLON

MONTICELLO-MINN - [redacted]

Statement of Change in Net Assets
Market Value
1/1/2017 - 6/30/2017

Report ID: GL8800
Base Currency: USD
Status: REVISED

NET ASSETS - BEGINNING OF PERIOD		598,834,561.85
RECEIPTS:		
CONTRIBUTIONS:		
COMPANY	6,696,114.00	
		6,696,114.00
INVESTMENT INCOME:		
REALIZED GAIN/LOSS	1,962.83	
UNREALIZED GAIN/LOSS-INVESTMENT	32,711,208.79	
		32,713,171.62
MASTER TRUST INVESTMENT GAIN/LOSS		
	29,923.20	
		29,923.20
MASTER TRUST ALLOCATED EXPENSES		
	-6,447,219.44	
		-6,447,219.44
MASTER TRUST CHANGE IN REALIZED G/L		
	4,959,148.24	
		4,959,148.24
MASTER TRUST INTEREST INCOME EARNED		
	1,239,376.45	
		1,239,376.45
MASTER TRUST DIVIDEND INCOME EARNED		
	3,859,210.98	
		3,859,210.98
TOTAL RECEIPTS:		43,049,725.05
DISBURSEMENTS:		
ADMINISTRATIVE EXPENSES:		
TRUSTEE/CUSTODIAN	58.88	
		58.88
TOTAL DISBURSEMENTS:		58.88
NET ASSETS - END OF PERIOD		641,884,228.02

BNY MELLON

MONTICELLO-MINN - [redacted]

Statement of Change in Net Assets
Market Value
1/1/2017 - 6/30/2017

Report ID: GL8800
Base Currency: USD
Status: REVISED

NET ASSETS - BEGINNING OF PERIOD		**11,702,136.01**
RECEIPTS:		
INVESTMENT INCOME:		
REALIZED GAIN/LOSS	45.80	
UNREALIZED GAIN/LOSS-INVESTMENT	637,356.02	
		637,401.82
MASTER TRUST INVESTMENT GAIN/LOSS		
	581.85	
		581.85
MASTER TRUST ALLOCATED EXPENSES		
	-124,988.86	
		-124,988.86
MASTER TRUST CHANGE IN REALIZED G/L		
	96,620.34	
		96,620.34
MASTER TRUST INTEREST INCOME EARNED		
	24,108.96	
		24,108.96
MASTER TRUST DIVIDEND INCOME EARNED		
	75,057.85	
		75,057.85
TOTAL RECEIPTS:		**708,781.96**
DISBURSEMENTS:		
ADMINISTRATIVE EXPENSES:		
TRUSTEE/CUSTODIAN	1.37	
		1.37
TOTAL DISBURSEMENTS:		**1.37**
NET ASSETS - END OF PERIOD		**12,410,916.60**

BNY MELLON

MONTICELLO-WIS - [redacted]

Statement of Change in Net Assets
Market Value
1/1/2017 - 6/30/2017

Report ID: GL8800
Base Currency: USD
Status: REVISED

NET ASSETS - BEGINNING OF PERIOD		**11,721,296.14**
RECEIPTS:		
INVESTMENT INCOME:		
REALIZED GAIN/LOSS	15.11	
UNREALIZED GAIN/LOSS-INVESTMENT	638,398.32	
		638,413.43
MASTER TRUST INVESTMENT GAIN/LOSS		
	582.80	
		582.80
MASTER TRUST ALLOCATED EXPENSES		
	-125,193.22	
		-125,193.22
MASTER TRUST CHANGE IN REALIZED G/L		
	96,766.52	
		96,766.52
MASTER TRUST INTEREST INCOME EARNED		
	24,160.32	
		24,160.32
MASTER TRUST DIVIDEND INCOME EARNED		
	75,180.61	
		75,180.61
TOTAL RECEIPTS:		**709,910.46**
DISBURSEMENTS:		
ADMINISTRATIVE EXPENSES:		
TRUSTEE/CUSTODIAN	0.45	
		0.45
TOTAL DISBURSEMENTS:		**0.45**
NET ASSETS - END OF PERIOD		**12,431,206.15**

BNY MELLON

PRAIRIE#1-MINN - [redacted]

Statement of Change in Net Assets
Market Value
1/1/2017 - 6/30/2017

Report ID: GL8800
Base Currency: USD
Status: REVISED

NET ASSETS - BEGINNING OF PERIOD		**364,752,198.60**
RECEIPTS:		
CONTRIBUTIONS:		
COMPANY	24,632.00	
		24,632.00
INVESTMENT INCOME:		
REALIZED GAIN/LOSS	1,361.88	
UNREALIZED GAIN/LOSS-INVESTMENT	17,813,134.78	
		17,814,496.66
MASTER TRUST INVESTMENT GAIN/LOSS		
	22,177.33	
		22,177.33
MASTER TRUST ALLOCATED EXPENSES		
	-2,291,178.74	
		-2,291,178.74
MASTER TRUST CHANGE IN REALIZED G/L		
	4,802,728.67	
		4,802,728.67
MASTER TRUST INTEREST INCOME EARNED		
	681,682.00	
		681,682.00
MASTER TRUST DIVIDEND INCOME EARNED		
	2,506,567.70	
		2,506,567.70
TOTAL RECEIPTS:		**23,561,105.62**
DISBURSEMENTS:		
ADMINISTRATIVE EXPENSES:		
TRUSTEE/CUSTODIAN	40.86	
		40.86
TOTAL DISBURSEMENTS:		**40.86**
NET ASSETS - END OF PERIOD		**388,313,263.36**

BNY MELLON

PRAIRIE#1-MINN - [redacted]

Statement of Change in Net Assets
Market Value
1/1/2017 - 6/30/2017

Report ID: GL8800
Base Currency: USD
Status: REVISED

NET ASSETS - BEGINNING OF PERIOD		**9,195,799.02**
RECEIPTS:		
INVESTMENT INCOME:		
REALIZED GAIN/LOSS	32.15	
UNREALIZED GAIN/LOSS-INVESTMENT	449,080.68	
		449,112.83
MASTER TRUST INVESTMENT GAIN/LOSS		
	559.09	
		559.09
MASTER TRUST ALLOCATED EXPENSES		
	-57,759.57	
		-57,759.57
MASTER TRUST CHANGE IN REALIZED G/L		
	121,079.57	
		121,079.57
MASTER TRUST INTEREST INCOME EARNED		
	17,185.20	
		17,185.20
MASTER TRUST DIVIDEND INCOME EARNED		
	63,191.43	
		63,191.43
TOTAL RECEIPTS:		**593,368.55**
DISBURSEMENTS:		
ADMINISTRATIVE EXPENSES:		
TRUSTEE/CUSTODIAN	0.97	
		0.97
TOTAL DISBURSEMENTS:		**0.97**
NET ASSETS - END OF PERIOD		**9,789,166.60**

BNY MELLON

PRAIRIE#1 WIS - [redacted]

Statement of Change in Net Assets
Market Value
1/1/2017 - 6/30/2017

Report ID: GL8800
Base Currency: USD
Status: REVISED

NET ASSETS - BEGINNING OF PERIOD		**5,668,539.54**
RECEIPTS:		
INVESTMENT INCOME:		
REALIZED GAIN/LOSS	7.21	
UNREALIZED GAIN/LOSS-INVESTMENT	276,825.00	
		276,832.21
MASTER TRUST INVESTMENT GAIN/LOSS		
	344.64	
		344.64
MASTER TRUST ALLOCATED EXPENSES		
	-35,604.49	
		-35,604.49
MASTER TRUST CHANGE IN REALIZED G/L		
	74,623.73	
		74,623.73
MASTER TRUST INTEREST INCOME EARNED		
	10,606.33	
		10,606.33
MASTER TRUST DIVIDEND INCOME EARNED		
	38,952.85	
		38,952.85
TOTAL RECEIPTS:		**365,755.27**
DISBURSEMENTS:		
ADMINISTRATIVE EXPENSES:		
TRUSTEE/CUSTODIAN	0.22	
		0.22
TOTAL DISBURSEMENTS:		**0.22**
NET ASSETS - END OF PERIOD		**6,034,294.59**

BNY MELLON

PRAIRIE#2 MINN - [redacted]

Statement of Change in Net Assets
Market Value
1/1/2017 - 6/30/2017

Report ID: GL8800
Base Currency: USD
Status: REVISED

NET ASSETS - BEGINNING OF PERIOD		**410,699,887.21**
RECEIPTS:		
CONTRIBUTIONS:		
COMPANY	294,670.00	
		294,670.00
INVESTMENT INCOME:		
REALIZED GAIN/LOSS	1,383.21	
UNREALIZED GAIN/LOSS-INVESTMENT	20,646,839.69	
		20,648,222.90
MASTER TRUST INVESTMENT GAIN/LOSS		
	22,187.90	
		22,187.90
MASTER TRUST ALLOCATED EXPENSES		
	-3,247,237.18	
		-3,247,237.18
MASTER TRUST CHANGE IN REALIZED G/L		
	4,887,571.56	
		4,887,571.56
MASTER TRUST INTEREST INCOME EARNED		
	778,995.10	
		778,995.10
MASTER TRUST DIVIDEND INCOME EARNED		
	2,722,866.36	
		2,722,866.36
TOTAL RECEIPTS:		**26,107,276.64**
DISBURSEMENTS:		
ADMINISTRATIVE EXPENSES:		
TRUSTEE/CUSTODIAN	41.50	
		41.50
TOTAL DISBURSEMENTS:		**41.50**
NET ASSETS - END OF PERIOD		**436,807,122.35**

BNY MELLON

PRAIRIE#2 MINN - [redacted]

Statement of Change in Net Assets
Market Value
1/1/2017 - 6/30/2017

Report ID: GL8800
Base Currency: USD
Status: REVISED

NET ASSETS - BEGINNING OF PERIOD		8,432,962.84
RECEIPTS:		
INVESTMENT INCOME:		
REALIZED GAIN/LOSS	21.96	
UNREALIZED GAIN/LOSS-INVESTMENT	423,865.80	
		423,887.76
MASTER TRUST INVESTMENT GAIN/LOSS		
	455.44	
		455.44
MASTER TRUST ALLOCATED EXPENSES		
	-66,636.99	
		-66,636.99
MASTER TRUST CHANGE IN REALIZED G/L		
	100,337.80	
		100,337.80
MASTER TRUST INTEREST INCOME EARNED		
	15,986.14	
		15,986.14
MASTER TRUST DIVIDEND INCOME EARNED		
	55,891.63	
		55,891.63
TOTAL RECEIPTS:		529,921.78
DISBURSEMENTS:		
ADMINISTRATIVE EXPENSES:		
TRUSTEE/CUSTODIAN	0.66	
		0.66
TOTAL DISBURSEMENTS:		0.66
NET ASSETS - END OF PERIOD		8,962,883.96

BNY MELLON

PRAIRIE#2 WIS - [redacted]

Statement of Change in Net Assets
Market Value
1/1/2017 - 6/30/2017

Report ID: GL8800
Base Currency: USD
Status: REVISED

NET ASSETS - BEGINNING OF PERIOD		6,662,363.26
RECEIPTS:		
INVESTMENT INCOME:		
REALIZED GAIN/LOSS	9.74	
UNREALIZED GAIN/LOSS-INVESTMENT	334,869.90	
		334,879.64
MASTER TRUST INVESTMENT GAIN/LOSS		
	359.83	
		359.83
MASTER TRUST ALLOCATED EXPENSES		
	-52,645.72	
		-52,645.72
MASTER TRUST CHANGE IN REALIZED G/L		
	79,256.15	
		79,256.15
MASTER TRUST INTEREST INCOME EARNED		
	12,644.15	
		12,644.15
MASTER TRUST DIVIDEND INCOME EARNED		
	44,156.50	
		44,156.50
TOTAL RECEIPTS:		418,650.55
DISBURSEMENTS:		
ADMINISTRATIVE EXPENSES:		
TRUSTEE/CUSTODIAN	0.30	
		0.30
TOTAL DISBURSEMENTS:		0.30
NET ASSETS - END OF PERIOD		7,081,013.51

Schedule F contains the calculations for the various annual accruals based on the input data. We have presented 20 accrual calculations based on varying inputs such as different radiological methods, fuel storage scenarios, license termination, and start of the new accrual. Each accrual calculation has four worksheets each and these worksheets are described below.

Accrual Comparison Worksheet

This worksheet shows the results of the annual accrual calculation using the new parameters and then comparing the results to the $14,030,831 that was approved in the 2014 Filing. The comparison is shown for each nuclear unit.

MN Retail Summary Worksheet

This worksheet presents the resulting annual accrual by nuclear unit as well as showing many of the input data that was used in the accrual calculation. Many of the inputs shown on this worksheet are constant throughout every calculation and those that vary depending on the different radiological methods chosen, the length of the fuel storage, and the current license termination or some other operational date. Below is a brief description of the input data shown in this worksheet.

- Remaining Life is based on the current license shutdown date of each respective plant. A key assumption in determining the decommissioning accrual is the recovery period. Currently, the Company calculates the required accrual with the assumption that contributions to the Qualified Trust will cease at shutdown of each unit. The remaining recovery periods for decommissioning as of January 1, 2017 are 13.75 years for Monticello, 16.67 years for Prairie Island Unit 1, and 17.83 for Prairie Island Unit 2. Most accrual calculations use the current license shutdown. However, there are two accrual calculations that assume an early shutdown of five years before current license and two accrual calculations that assume a 20-year license extension.

- The Operational Earnings Rates and the Post-Shutdown Earnings Rates were determined by analysis completed by GSAM and are discussed in Schedule D, *External Fund Analysis / Investment Strategy*. They also are used to calculate the assumed interest on the External Fund Calculation

worksheet. The rates vary depending on the fuel storage scenario, radiological method and start of the new accrual.

- The Tax Rate for tax-effect adjustment of 27.84 percent. Since state taxes are deductible on the federal return, the Tax Rate is a composite of the Minnesota state rate of 9.80 percent and the federal Qualified Trust rate of 20 percent. The composite is calculated by taking one minus the 9.80 percent, then taking that result by 20 percent to get the federal effect with a state tax deduction, or 18.04 percent. Adding the state tax rate of 9.80 percent to the 18.04 percent results in the composite Tax Rate of 27.84 percent. This rate is constant throughout all the accrual calculations.

- The Market Value Balance is the total market fund balance as of June 30, 2017 which is equal to the Book Value plus Unrealized Gain or Loss. The Tax Effect Adjustment is a calculation of the Unrealized Gain or Loss times the Tax Rate for tax-effect adjustment. The Tax Adjusted Fund Balance is the Market Value Balance less Tax-Effect Adjustment. These balances are consistent throughout all the accrual calculations.

- The Escalation Rate (Labor) of 4.05 percent and Escalation Rate (Non-Labor) of 2.85percent were determined using long-range inflation and escalation assumptions provided by GSAM and were discussed in Schedule C, Escalation Analysis. The Escalation Rate (PIIC) is 0.00 percent since the PIIC Payment is based on a fixed settlement that will not change with inflation. These rates are the escalation factors used to calculate the future value of the TLG cost estimate. These rates are constant throughout all the accrual calculations.

- The Jurisdictional Factor of 73.4886 percent is the 2017 Minnesota Jurisdictional percent from the 2016 Electric Rate case Docket No. E,002/GR-15-826. This factor is constant throughout all the accrual calculations.

Amount to Recover Calculation

The Amount to Recover worksheet shows the jurisdictional future cost of the TLG cost estimates. This is calculated by taking the TLG Cost Estimate and separating the costs into three categories, Labor, Non-Labor and the PIIC Payment. Those amounts are then multiplied by the Jurisdiction Factor to arrive at the Minnesota Jurisdictional cost. Those amounts are then escalated

to the future cost using the escalation factor for that category. Those amounts are then added together to get the Total Jurisdictional Cost in Future dollars.

External Fund Calculation

The External Fund Calculation worksheet shows the annual roll forward of the Qualified Trust beginning with June 30, 2017 and continuing through the last year of decommissioning. The Beginning Balance equals the Tax-Adjusted Fund Balance as of June 30, 2017 shown on the MN Retail Summary worksheet. The Assumed Interest is calculated by taking the Beginning Balance plus one-half of the annuity times the earnings rate for the period. The earnings rates are shown on the MN Retail Summary, where the Operational Earning Rate is used during the years the unit is in operations and the Post-Shutdown Earnings Rate is used for the years after the unit ceases operations. The Decommissioning Payment is the Total Jurisdictional Cost in Future Dollars as calculated in the Amount to Recover worksheet, shown as a negative because these payments reduce the overall balance. It was assumed that the Decommissioning Payments occur at the end of each year. The Ending Balance is calculated by adding the Assumed Interest and the Annuity and subtracting the Decommissioning Payment to the Beginning Balance.

The current annuity as approved in the 2014 Triennial Nuclear Decommissioning Accrual Docket No. E,002/M-14-761. This approved annuity is continued until the year the new annuity calculation begins, either 2019 or 2021. The Annuity beginning in either 2019 or 2021 was calculated using the Goal Seek function in Excel such that the Ending Balance would be zero at the end of the decommissioning period. In some of the annuity calculations calculated annuity was less than zero, we are showing a solution that is below zero, however this is to demonstrate over-funding only. We would only be able to stop at zero for future contributions because of the NRC regulations on the trust funds.

Decommissioning Accruals and Supporting Schedules

2019 Accrual Calculations

F.1 Annual Accrual 32-Year DECON

F.2 Annual Accrual 60-Year DECON

F.3 Annual Accrual 60-year DECON 5-year early shutdown

F.4 Annual Accrual 60-year DECON 20-year life extension

F.5 Annual Accrual 60-year DECON with Recasking

F.6 Annual Accrual 100-year DECON

F.7 Annual Accrual 200-year DECON

F.8 Annual Accrual 60-year SAFSTOR

F.9 Annual Accrual 60-year SAFSTOR 5-year early shutdown

F.10 Annual Accrual 60-year SAFSTOR 20-year life extension

2021 Accrual Calculations

F.11 Annual Accrual 32-year DECON

F.12 Annual Accrual 60-year DECON

F.13 Annual Accrual 60-year DECON 5-year early shutdown

F.14 Annual Accrual 60-year DECON 20-year life extension

F.15 Annual Accrual 60-year DECON with recasking

F.16 Annual Accrual 100-year DECON

F.17 Annual Accrual 200-year DECON

F.18 Annual Accrual 60-year SAFSTOR

F.19 Annual Accrual 60-year SAFSTOR 5-year early shutdown

F.20 Annual Accrual 60-year SAFSTOR 20-year life extension

Other Information

F.21 Accrual Summary of Previous Dockets

Xcel Energy
Nuclear Decommissioning Accrual
32-Year Decommissioning Period
DECON Method - No Recasking

Docket No. E002/M-17-828
Schedule F.1
Page 1 of 8

Proposed

2019 ACCRUAL COMPARISON

	Present	Proposed	Difference
Monticello	$13,392,226	$10,116,959	($3,275,267)
Prairie Island Unit 1	49,264	12,043,664	11,994,400
Prairie Island Unit 2	589,341	6,323,109	5,733,768
TOTAL	$14,030,831	$28,483,732	$14,452,901

Xcel Energy
Nuclear Decommissioning Accrual
32-Year Decommissioning Period
DECON Method - No Recasking

Docket No. E002/M-17-828
Schedule F.1
Page 2 of 8

Proposed

2019 MN RETAIL SUMMARY

	Remaining Life (yrs)	Operational Earnings Rate	Post-Shutdown Earnings Rate	Market Value Balance 6/30/2017	Book Value 6/30/2017	Unrealized Gain/Loss 6/30/2017	Tax-Effect Adjustment	Tax-Adjusted Fund Balance 6/30/2017	2019-2021 Decommissioning Accrual
Monticello	13.75	4.99%	3.90%	$660,140,345	$529,148,381	$130,991,964	$36,468,163	$623,672,182	**10,116,959**
Prairie Island Unit 1	16.67	4.98%	3.85%	399,941,696	308,078,761	91,862,935	25,574,641	374,367,055	**12,043,664**
Prairie Island Unit 2	17.83	5.03%	3.76%	448,597,551	346,627,064	101,970,487	28,388,583	420,208,967	**6,323,109**
TOTAL DECOMMISSIONING ACCRUAL				**$1,508,679,592**	**$1,183,854,206**	**$324,825,386**	**$90,431,387**	**$1,418,248,204**	**$28,483,732**

INPUT DATA

Escalation Rate (Labor)	4.05%
Escalation Rate (Non-Labor)	2.85%
Escalation Rate (PIIC)	0.00%
Jurisdictional Factor	73.4886%
Tax Rate for tax-effect adjustment	27.84%

Xcel Energy
Nuclear Decommissioning Accrual
32-Year Decommissioning Period
DECON Method - No Recasking

Docket No. E002/M-17-828
Schedule F.1
Page 3 of 8

Proposed

AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
Monticello															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2030	$22,828,619	$16,776,422	1.6755	$28,108,895	$14,110,561	$10,369,648	1.4410	$14,942,662	$0	$0	1.0000	$0	$36,939,181	$27,146,070	$43,051,557
2031	72,399,645	53,205,452	1.7434	92,758,385	42,911,573	31,535,094	1.4820	46,735,010	0	0	1.0000	0	115,311,218	84,740,546	139,493,395
2032	78,459,767	57,658,948	1.8140	104,593,332	102,213,410	75,115,157	1.5243	114,498,034	0	0	1.0000	0	180,673,177	132,774,105	219,091,366
2033	78,071,622	57,373,706	1.8874	108,287,132	98,380,888	72,298,692	1.5677	113,342,659	0	0	1.0000	0	176,452,509	129,672,397	221,629,791
2034	66,363,782	48,769,784	1.9639	95,778,979	38,844,898	28,546,554	1.6124	46,028,463	0	0	1.0000	0	105,208,680	77,316,338	141,807,442
2035	86,863,179	63,834,494	2.0434	130,439,405	113,097,318	83,113,583	1.6584	137,835,567	0	0	1.0000	0	199,960,497	146,948,077	268,274,971
2036	50,290,909	36,958,062	2.1262	78,580,231	20,638,561	15,166,980	1.7056	25,868,801	0	0	1.0000	0	70,929,470	52,125,042	104,449,032
2037	34,606,532	25,431,840	2.2123	56,262,860	14,147,109	10,396,506	1.7542	18,237,551	0	0	1.0000	0	48,753,642	35,828,346	74,500,411
2038	29,564,886	21,726,807	2.3019	50,012,937	15,064,303	11,070,538	1.8042	19,973,465	0	0	1.0000	0	44,629,189	32,797,345	69,986,402
2039	5,908,428	4,342,018	2.3951	10,399,568	2,334,187	1,715,360	1.8556	3,183,022	0	0	1.0000	0	8,242,615	6,057,378	13,582,590
2040	5,924,615	4,353,914	2.4921	10,850,389	2,340,582	1,720,060	1.9085	3,282,734	0	0	1.0000	0	8,265,197	6,073,973	14,133,123
2041	5,908,428	4,342,018	2.5930	11,258,853	2,334,187	1,715,360	1.9629	3,367,080	0	0	1.0000	0	8,242,615	6,057,378	14,625,934
2042	6,004,114	4,412,337	2.6981	11,904,925	2,621,246	1,926,316	2.0189	3,889,038	0	0	1.0000	0	8,625,360	6,338,652	15,793,964
2043	6,195,487	4,552,974	2.8073	12,781,563	3,195,364	2,348,227	2.0764	4,875,858	0	0	1.0000	0	9,390,851	6,901,200	17,657,421
2044	6,115,988	4,494,551	2.9210	13,128,584	2,914,700	2,141,971	2.1356	4,574,392	0	0	1.0000	0	9,030,688	6,636,522	17,702,976
2045	6,099,800	4,482,655	3.0393	13,624,133	2,908,305	2,137,271	2.1964	4,694,302	0	0	1.0000	0	9,008,105	6,619,926	18,318,435
2046	6,482,546	4,763,929	3.1624	15,065,450	4,056,542	2,981,094	2.2590	6,734,291	0	0	1.0000	0	10,539,088	7,745,023	21,799,741
2047	6,386,860	4,693,611	3.2905	15,444,327	3,769,483	2,770,138	2.3234	6,436,139	0	0	1.0000	0	10,156,343	7,463,749	21,880,466
2048	7,066,692	5,193,210	3.4238	17,780,512	5,766,812	4,237,946	2.3896	10,126,997	0	0	1.0000	0	12,833,504	9,431,156	27,907,509
2049	6,386,860	4,693,611	3.5624	16,720,520	3,769,483	2,770,138	2.4577	6,808,169	0	0	1.0000	0	10,156,343	7,463,749	23,528,689
2050	6,195,487	4,552,974	3.7067	16,876,508	3,195,364	2,348,227	2.5278	5,935,847	0	0	1.0000	0	9,390,851	6,901,200	22,812,355
2051	6,099,800	4,482,655	3.8568	17,288,703	2,908,305	2,137,271	2.5998	5,556,477	0	0	1.0000	0	9,008,105	6,619,926	22,845,180
2052	6,211,674	4,564,869	4.0130	18,318,821	3,201,759	2,352,926	2.6739	6,291,489	0	0	1.0000	0	9,413,433	6,917,796	24,610,310
2053	6,099,800	4,482,655	4.1756	18,717,773	2,908,305	2,137,271	2.7501	5,877,709	0	0	1.0000	0	9,008,105	6,619,926	24,595,482
2054	6,099,800	4,482,655	4.3447	19,475,790	2,908,305	2,137,271	2.8285	6,045,271	0	0	1.0000	0	9,008,105	6,619,926	25,521,061
2055	6,195,487	4,552,974	4.5206	20,582,173	3,195,364	2,348,227	2.9091	6,831,226	0	0	1.0000	0	9,390,851	6,901,200	27,413,399
2056	6,115,988	4,494,551	4.7037	21,141,020	2,914,700	2,141,971	2.9920	6,408,776	0	0	1.0000	0	9,030,688	6,636,522	27,549,796
2057	6,099,800	4,482,655	4.8942	21,939,009	2,908,305	2,137,271	3.0773	6,577,024	0	0	1.0000	0	9,008,105	6,619,926	28,516,033
2058	6,195,487	4,552,974	5.0924	23,185,564	3,195,364	2,348,227	3.1650	7,432,137	0	0	1.0000	0	9,390,851	6,901,200	30,617,701
2059	6,291,173	4,623,292	5.2987	24,497,438	3,482,424	2,559,183	3.2552	8,330,652	0	0	1.0000	0	9,773,597	7,182,475	32,828,089
2060	6,115,988	4,494,551	5.5133	24,779,809	2,914,700	2,141,971	3.3480	7,171,318	0	0	1.0000	0	9,030,688	6,636,522	31,951,126
2061	6,291,173	4,623,292	5.7366	26,521,977	3,482,424	2,559,183	3.4434	8,812,290	0	0	1.0000	0	9,773,597	7,182,475	35,334,267
2062	6,291,173	4,623,292	5.9689	27,595,968	3,482,424	2,559,183	3.5415	9,063,346	0	0	1.0000	0	9,773,597	7,182,475	36,659,314
2063	2,248,102	1,652,098	6.2106	10,260,519	24,955,221	18,339,231	3.6425	66,800,650	0	0	1.0000	0	27,203,324	19,991,329	77,061,169
	$670,479,691	$492,725,829		$1,184,962,052	$561,072,469	$412,324,043		$752,568,447	$0	$0		$0	$1,231,552,159	$905,049,872	$1,937,530,499

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	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
Prairie Island Unit 1															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2033	$22,324,352	$16,405,843	1.8874	$30,964,388	$9,448,311	$6,943,427	1.5677	$10,885,211	$1,250,000	$918,607	1.0000	$918,607	$33,022,663	$24,267,877	$42,768,206
2034	63,582,249	46,725,675	1.9639	91,764,553	32,971,807	24,230,504	1.6124	39,069,265	1,250,000	918,607	1.0000	918,607	97,804,055	71,874,786	131,752,425
2035	66,068,657	48,552,900	2.0434	99,212,997	81,814,054	60,123,965	1.6584	99,709,584	1,250,000	918,607	1.0000	918,607	149,132,711	109,595,473	199,841,188
2036	57,950,689	42,587,123	2.1262	90,548,742	66,169,136	48,626,741	1.7056	82,937,770	1,250,000	918,607	1.0000	918,607	125,369,825	92,132,471	174,405,118
2037	38,254,474	28,112,660	2.2123	62,193,638	37,320,257	27,426,117	1.7542	48,110,895	1,250,000	918,607	1.0000	918,607	76,824,731	56,457,384	111,223,139
2038	10,524,282	7,734,143	2.3019	17,803,224	10,943,807	8,042,445	1.8042	14,510,180	1,250,000	918,607	1.0000	918,607	22,718,089	16,695,195	33,232,010
2039	35,901,875	26,383,769	2.3951	63,191,765	76,077,529	55,908,276	1.8556	103,743,397	1,250,000	918,607	1.0000	918,607	113,229,405	83,210,652	167,853,770
2040	32,068,444	23,566,636	2.4921	58,730,414	13,813,311	10,151,203	1.9085	19,373,570	1,250,000	918,607	1.0000	918,607	47,131,756	34,636,446	79,022,591
2041	19,800,405	14,551,031	2.5930	37,730,823	10,002,203	7,350,474	1.9629	14,428,246	1,250,000	918,607	1.0000	918,607	31,052,607	22,820,112	53,077,676
2042	14,925,482	10,968,521	2.6981	29,594,165	12,099,028	8,891,401	2.0189	17,950,849	1,250,000	918,607	1.0000	918,607	28,274,510	20,778,529	48,463,622
2043	8,672,291	6,373,141	2.8073	17,891,320	6,853,529	5,036,559	2.0764	10,457,912	1,250,000	918,607	1.0000	918,607	16,775,820	12,328,308	29,267,838
2044	3,150,484	2,315,245	2.9210	6,762,831	2,315,654	1,701,741	2.1356	3,634,237	1,250,000	918,607	1.0000	918,607	6,716,138	4,935,593	11,315,675
2045	3,142,137	2,309,111	3.0393	7,018,081	2,306,696	1,695,158	2.1964	3,723,244	1,250,000	918,607	1.0000	918,607	6,698,833	4,922,875	11,659,932
2046	3,046,451	2,238,793	3.1624	7,079,958	2,019,637	1,484,202	2.2590	3,352,812	1,250,000	918,607	1.0000	918,607	6,316,088	4,641,602	11,351,378
2047	3,046,451	2,238,793	3.2905	7,366,748	2,019,637	1,484,202	2.3234	3,448,395	1,250,000	918,607	1.0000	918,607	6,316,088	4,641,602	11,733,750
2048	3,054,797	2,244,926	3.4238	7,686,178	2,028,595	1,490,785	2.3896	3,562,380	1,250,000	918,607	1.0000	918,607	6,333,392	4,654,318	12,167,165
2049	3,046,451	2,238,793	3.5624	7,975,475	2,019,637	1,484,202	2.4577	3,647,723	1,250,000	918,607	1.0000	918,607	6,316,088	4,641,602	12,541,806
2050	3,142,137	2,309,111	3.7067	8,559,182	2,306,696	1,695,158	2.5278	4,285,019	1,250,000	918,607	1.0000	918,607	6,698,833	4,922,875	13,762,808
2051	3,142,137	2,309,111	3.8568	8,905,779	2,306,696	1,695,158	2.5998	4,407,071	1,250,000	918,607	1.0000	918,607	6,698,833	4,922,875	14,231,457
2052	3,150,484	2,315,245	4.0130	9,291,079	2,315,654	1,701,741	2.6739	4,550,284	1,250,000	918,607	1.0000	918,607	6,716,138	4,935,593	14,759,970
2053	3,142,137	2,309,111	4.1756	9,641,924	2,306,696	1,695,158	2.7501	4,661,853	1,250,000	918,607	1.0000	918,607	6,698,833	4,922,875	15,222,384
2054	3,142,137	2,309,111	4.3447	10,032,395	2,306,696	1,695,158	2.8285	4,794,753	1,250,000	918,607	1.0000	918,607	6,698,833	4,922,875	15,745,755
2055	3,142,137	2,309,111	4.5206	10,438,567	2,306,696	1,695,158	2.9091	4,931,383	1,250,000	918,607	1.0000	918,607	6,698,833	4,922,875	16,288,557
2056	3,150,484	2,315,245	4.7037	10,890,219	2,315,654	1,701,741	2.9920	5,091,608	1,250,000	918,607	1.0000	918,607	6,716,138	4,935,593	16,900,433
2057	3,142,137	2,309,111	4.8942	11,301,251	2,306,696	1,695,158	3.0773	5,216,508	1,250,000	918,607	1.0000	918,607	6,698,833	4,922,875	17,436,366
2058	3,142,137	2,309,111	5.0924	11,758,917	2,306,696	1,695,158	3.1650	5,365,174	1,250,000	918,607	1.0000	918,607	6,698,833	4,922,875	18,042,698
2059	3,142,137	2,309,111	5.2987	12,235,287	2,306,696	1,695,158	3.2552	5,518,077	1,250,000	918,607	1.0000	918,607	6,698,833	4,922,875	18,671,970
2060	3,150,484	2,315,245	5.5133	12,764,641	2,315,654	1,701,741	3.3480	5,697,427	1,250,000	918,607	1.0000	918,607	6,716,138	4,935,593	19,380,675
2061	3,142,137	2,309,111	5.7366	13,246,446	2,306,696	1,695,158	3.4434	5,837,105	1,250,000	918,607	1.0000	918,607	6,698,833	4,922,875	20,002,159
2062	3,142,137	2,309,111	5.9689	13,782,853	2,306,696	1,695,158	3.5415	6,003,400	1,250,000	918,607	1.0000	918,607	6,698,833	4,922,875	20,704,860
2063	3,142,137	2,309,111	6.2106	14,340,965	2,306,696	1,695,158	3.6425	6,174,611	1,250,000	918,607	1.0000	918,607	6,698,833	4,922,875	21,434,183
2064	3,146,606	2,312,395	6.4622	14,943,162	13,948,599	10,250,624	3.7463	38,401,913	1,250,000	918,607	1.0000	918,607	18,345,206	13,481,626	54,263,681
2065	795,605	584,679	6.7239	3,931,322	4,510,695	3,314,844	3.8531	12,772,427	0	0	1.0000	0	5,306,300	3,899,523	16,703,749
	$436,517,141	$320,790,135		$819,579,289	$421,002,740	$309,388,826		$606,254,283	$40,000,000	$29,395,422		$29,395,422	$897,519,882	$659,574,382	$1,455,228,994

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	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
Prairie Island Unit 2															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2034	$7,760,266	$5,702,908	1.9639	$11,199,940	$4,479,535	$3,291,946	1.6124	$5,307,933	$1,250,000	$918,607	1.0000	$918,607	$13,489,801	$9,913,460	$17,426,480
2035	47,102,812	34,615,176	2.0434	70,732,650	36,175,458	26,584,821	1.6584	44,088,268	1,250,000	918,607	1.0000	918,607	84,528,271	62,118,604	115,739,524
2036	67,705,423	49,755,737	2.1262	105,790,647	86,872,951	63,841,675	1.7056	108,888,362	1,250,000	918,607	1.0000	918,607	155,828,374	114,516,019	215,597,616
2037	71,039,578	52,205,958	2.2123	115,495,242	70,988,753	52,168,608	1.7542	91,514,172	1,250,000	918,607	1.0000	918,607	143,278,331	105,293,173	207,928,021
2038	43,919,901	32,276,100	2.3019	74,296,356	34,731,268	25,523,507	1.8042	46,049,511	1,250,000	918,607	1.0000	918,607	79,901,170	58,718,214	121,264,473
2039	40,527,011	29,782,714	2.3951	71,332,578	77,052,498	56,624,767	1.8556	105,072,917	1,250,000	918,607	1.0000	918,607	118,829,509	87,326,087	177,324,102
2040	37,548,754	27,594,036	2.4921	68,767,098	14,641,371	10,759,732	1.9085	20,534,948	1,250,000	918,607	1.0000	918,607	53,440,125	39,272,375	90,220,653
2041	23,571,483	17,322,342	2.5930	44,916,834	13,611,612	10,002,977	1.9629	19,634,844	1,250,000	918,607	1.0000	918,607	38,433,096	28,243,926	65,470,284
2042	16,800,451	12,346,409	2.6981	33,311,845	17,608,969	12,940,577	2.0189	26,125,730	1,250,000	918,607	1.0000	918,607	35,659,420	26,205,592	60,356,182
2043	9,555,838	7,022,447	2.8073	19,714,117	9,449,994	6,944,664	2.0764	14,419,900	1,250,000	918,607	1.0000	918,607	20,255,832	14,885,718	35,052,624
2044	3,150,484	2,315,245	2.9210	6,762,831	2,315,654	1,701,741	2.1356	3,634,237	1,250,000	918,607	1.0000	918,607	6,716,138	4,935,593	11,315,675
2045	3,142,137	2,309,111	3.0393	7,018,081	2,306,696	1,695,158	2.1964	3,723,244	1,250,000	918,607	1.0000	918,607	6,698,833	4,922,875	11,659,932
2046	3,046,451	2,238,793	3.1624	7,079,958	2,019,637	1,484,202	2.2590	3,352,812	1,250,000	918,607	1.0000	918,607	6,316,088	4,641,602	11,351,378
2047	3,046,451	2,238,793	3.2905	7,366,748	2,019,637	1,484,202	2.3234	3,448,395	1,250,000	918,607	1.0000	918,607	6,316,088	4,641,602	11,733,750
2048	3,054,797	2,244,926	3.4238	7,686,178	2,028,595	1,490,785	2.3896	3,562,380	1,250,000	918,607	1.0000	918,607	6,333,392	4,654,318	12,167,165
2049	3,046,451	2,238,793	3.5624	7,975,475	2,019,637	1,484,202	2.4577	3,647,723	1,250,000	918,607	1.0000	918,607	6,316,088	4,641,602	12,541,806
2050	3,142,137	2,309,111	3.7067	8,559,182	2,306,696	1,695,158	2.5278	4,285,019	1,250,000	918,607	1.0000	918,607	6,698,833	4,922,875	13,762,808
2051	3,142,137	2,309,111	3.8568	8,905,779	2,306,696	1,695,158	2.5998	4,407,071	1,250,000	918,607	1.0000	918,607	6,698,833	4,922,875	14,231,457
2052	3,150,484	2,315,245	4.0130	9,291,079	2,315,654	1,701,741	2.6739	4,550,284	1,250,000	918,607	1.0000	918,607	6,716,138	4,935,593	14,759,970
2053	3,142,137	2,309,111	4.1756	9,641,924	2,306,696	1,695,158	2.7501	4,661,853	1,250,000	918,607	1.0000	918,607	6,698,833	4,922,875	15,222,384
2054	3,142,137	2,309,111	4.3447	10,032,395	2,306,696	1,695,158	2.8285	4,794,753	1,250,000	918,607	1.0000	918,607	6,698,833	4,922,875	15,745,755
2055	3,142,137	2,309,111	4.5206	10,438,567	2,306,696	1,695,158	2.9091	4,931,383	1,250,000	918,607	1.0000	918,607	6,698,833	4,922,875	16,288,557
2056	3,150,484	2,315,245	4.7037	10,890,219	2,315,654	1,701,741	2.9920	5,091,608	1,250,000	918,607	1.0000	918,607	6,716,138	4,935,593	16,900,433
2057	3,142,137	2,309,111	4.8942	11,301,251	2,306,696	1,695,158	3.0773	5,216,508	1,250,000	918,607	1.0000	918,607	6,698,833	4,922,875	17,436,366
2058	3,142,137	2,309,111	5.0924	11,758,917	2,306,696	1,695,158	3.1650	5,365,174	1,250,000	918,607	1.0000	918,607	6,698,833	4,922,875	18,042,698
2059	3,142,137	2,309,111	5.2987	12,235,287	2,306,696	1,695,158	3.2552	5,518,077	1,250,000	918,607	1.0000	918,607	6,698,833	4,922,875	18,671,970
2060	3,150,484	2,315,245	5.5133	12,764,641	2,315,654	1,701,741	3.3480	5,697,427	1,250,000	918,607	1.0000	918,607	6,716,138	4,935,593	19,380,675
2061	3,142,137	2,309,111	5.7366	13,246,446	2,306,696	1,695,158	3.4434	5,837,105	1,250,000	918,607	1.0000	918,607	6,698,833	4,922,875	20,002,159
2062	3,142,137	2,309,111	5.9689	13,782,853	2,306,696	1,695,158	3.5415	6,003,400	1,250,000	918,607	1.0000	918,607	6,698,833	4,922,875	20,704,860
2063	3,142,137	2,309,111	6.2106	14,340,965	2,306,696	1,695,158	3.6425	6,174,611	1,250,000	918,607	1.0000	918,607	6,698,833	4,922,875	21,434,183
2064	3,146,606	2,312,395	6.4622	14,943,162	13,948,599	10,250,624	3.7463	38,401,913	1,250,000	918,607	1.0000	918,607	18,345,206	13,481,626	54,263,681
2065	795,605	584,679	6.7239	3,931,322	4,510,695	3,314,844	3.8531	12,772,427	0	-	1.0000	-	5,306,300	3,899,523	16,703,749
	$431,975,460	$317,452,519		$835,510,566	$429,102,177	$315,340,985		$626,713,989	$38,750,000	$28,476,815		$28,476,815	$899,827,638	$661,270,318	$1,490,701,369
	$1,538,972,292	$1,130,968,482		$2,840,051,907	$1,411,177,386	$1,037,053,854		$1,985,536,718	$78,750,000	$57,872,236		$57,872,236	$3,028,899,678	$2,225,894,572	$4,883,460,862

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EXTERNAL FUND CALCULATION

Monticello

External Levelized

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	623,672,182	15,644,155	-	6,696,113	646,012,450
2018	646,012,450	32,570,157	-	13,392,226	691,974,833
2019	691,974,833	34,781,962	-	10,116,959	736,873,755
2020	736,873,755	37,022,419	-	10,116,959	784,013,133
2021	784,013,133	39,374,673	-	10,116,959	833,504,765
2022	833,504,765	41,844,306	-	10,116,959	885,466,031
2023	885,466,031	44,437,173	-	10,116,959	940,020,163
2024	940,020,163	47,159,424	-	10,116,959	997,296,547
2025	997,296,547	50,017,516	-	10,116,959	1,057,431,022
2026	1,057,431,022	53,018,226	-	10,116,959	1,120,566,207
2027	1,120,566,207	56,168,672	-	10,116,959	1,186,851,838
2028	1,186,851,838	59,476,325	-	10,116,959	1,256,445,122
2029	1,256,445,122	62,949,030	-	10,116,959	1,329,511,111
2030	1,329,511,111	51,998,894	(43,051,557)	7,587,719	1,346,046,167
2031	1,346,046,167	52,495,801	(139,493,395)	-	1,259,048,573
2032	1,259,048,573	49,102,894	(219,091,366)	-	1,089,060,101
2033	1,089,060,101	42,473,344	(221,629,791)	-	909,903,654
2034	909,903,654	35,486,243	(141,807,442)	-	803,582,455
2035	803,582,455	31,339,716	(268,274,971)	-	566,647,199
2036	566,647,199	22,099,241	(104,449,032)	-	484,297,407
2037	484,297,407	18,887,599	(74,500,411)	-	428,684,596
2038	428,684,596	16,718,699	(69,986,402)	-	375,416,892
2039	375,416,892	14,641,259	(13,582,590)	-	376,475,561
2040	376,475,561	14,682,547	(14,133,123)	-	377,024,986
2041	377,024,986	14,703,974	(14,625,934)	-	377,103,026
2042	377,103,026	14,707,018	(15,793,964)	-	376,016,081
2043	376,016,081	14,664,627	(17,657,421)	-	373,023,287
2044	373,023,287	14,547,908	(17,702,976)	-	369,868,219
2045	369,868,219	14,424,861	(18,318,435)	-	365,974,645
2046	365,974,645	14,273,011	(21,799,741)	-	358,447,915
2047	358,447,915	13,979,469	(21,880,466)	-	350,546,917
2048	350,546,917	13,671,330	(27,907,509)	-	336,310,738
2049	336,310,738	13,116,119	(23,528,689)	-	325,898,168
2050	325,898,168	12,710,029	(22,812,355)	-	315,795,842
2051	315,795,842	12,316,038	(22,845,180)	-	305,266,700
2052	305,266,700	11,905,401	(24,610,310)	-	292,561,791
2053	292,561,791	11,409,910	(24,595,482)	-	279,376,218
2054	279,376,218	10,895,673	(25,521,061)	-	264,750,829
2055	264,750,829	10,325,282	(27,413,399)	-	247,662,713
2056	247,662,713	9,658,846	(27,549,796)	-	229,771,762
2057	229,771,762	8,961,099	(28,516,033)	-	210,216,827
2058	210,216,827	8,198,456	(30,617,701)	-	187,797,583
2059	187,797,583	7,324,106	(32,828,089)	-	162,293,599
2060	162,293,599	6,329,450	(31,951,126)	-	136,671,923
2061	136,671,923	5,330,205	(35,334,267)	-	106,667,861
2062	106,667,861	4,160,047	(36,659,314)	-	74,168,594
2063	74,168,594	2,892,575	(77,061,169)	-	0

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EXTERNAL FUND CALCULATION

Prairie Island Unit 1

External Levelized

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	374,367,055	9,322,046	-	24,632	383,713,733
2018	383,713,733	19,110,171	-	49,264	402,873,168
2019	402,873,168	20,362,971	-	12,043,664	435,279,804
2020	435,279,804	21,976,821	-	12,043,664	469,300,289
2021	469,300,289	23,671,042	-	12,043,664	505,014,995
2022	505,014,995	25,449,634	-	12,043,664	542,508,294
2023	542,508,294	27,316,800	-	12,043,664	581,868,758
2024	581,868,758	29,276,951	-	12,043,664	623,189,374
2025	623,189,374	31,334,718	-	12,043,664	666,567,756
2026	666,567,756	33,494,961	-	12,043,664	712,106,382
2027	712,106,382	35,762,785	-	12,043,664	759,912,831
2028	759,912,831	38,143,546	-	12,043,664	810,100,042
2029	810,100,042	40,642,869	-	12,043,664	862,786,575
2030	862,786,575	43,266,659	-	12,043,664	918,096,898
2031	918,096,898	46,021,113	-	12,043,664	976,161,675
2032	976,161,675	48,912,739	-	12,043,664	1,037,118,078
2033	1,037,118,078	40,084,379	(42,768,206)	8,069,255	1,042,503,507
2034	1,042,503,507	40,136,385	(131,752,425)	-	950,887,467
2035	950,887,467	36,609,167	(199,841,188)	-	787,655,446
2036	787,655,446	30,324,735	(174,405,118)	-	643,575,063
2037	643,575,063	24,777,640	(111,223,139)	-	557,129,563
2038	557,129,563	21,449,488	(33,232,010)	-	545,347,041
2039	545,347,041	20,995,861	(167,853,770)	-	398,489,132
2040	398,489,132	15,341,832	(79,022,591)	-	334,808,373
2041	334,808,373	12,890,122	(53,077,676)	-	294,620,819
2042	294,620,819	11,342,902	(48,463,622)	-	257,500,099
2043	257,500,099	9,913,754	(29,267,838)	-	238,146,014
2044	238,146,014	9,168,622	(11,315,675)	-	235,998,961
2045	235,998,961	9,085,960	(11,659,932)	-	233,424,989
2046	233,424,989	8,986,862	(11,351,378)	-	231,060,473
2047	231,060,473	8,895,828	(11,733,750)	-	228,222,552
2048	228,222,552	8,786,568	(12,167,165)	-	224,841,955
2049	224,841,955	8,656,415	(12,541,806)	-	220,956,565
2050	220,956,565	8,506,828	(13,762,808)	-	215,700,585
2051	215,700,585	8,304,473	(14,231,457)	-	209,773,600
2052	209,773,600	8,076,284	(14,759,970)	-	203,089,914
2053	203,089,914	7,818,962	(15,222,384)	-	195,686,492
2054	195,686,492	7,533,930	(15,745,755)	-	187,474,667
2055	187,474,667	7,217,775	(16,288,557)	-	178,403,885
2056	178,403,885	6,868,550	(16,900,433)	-	168,372,001
2057	168,372,001	6,482,322	(17,436,366)	-	157,417,957
2058	157,417,957	6,060,591	(18,042,698)	-	145,435,851
2059	145,435,851	5,599,280	(18,671,970)	-	132,363,161
2060	132,363,161	5,095,982	(19,380,675)	-	118,078,467
2061	118,078,467	4,546,021	(20,002,159)	-	102,622,329
2062	102,622,329	3,950,960	(20,704,860)	-	85,868,429
2063	85,868,429	3,305,935	(21,434,183)	-	67,740,180
2064	67,740,180	2,607,997	(54,263,681)	-	16,084,496
2065	16,084,496	619,253	(16,703,749)	-	0

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EXTERNAL FUND CALCULATION

Prairie Island Unit 2

External Levelized

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	420,208,967	10,571,961	-	294,670	431,075,599
2018	431,075,599	21,697,925	-	589,341	453,362,864
2019	453,362,864	22,963,178	-	6,323,109	482,649,151
2020	482,649,151	24,436,278	-	6,323,109	513,408,538
2021	513,408,538	25,983,476	-	6,323,109	545,715,122
2022	545,715,122	27,608,497	-	6,323,109	579,646,728
2023	579,646,728	29,315,257	-	6,323,109	615,285,093
2024	615,285,093	31,107,866	-	6,323,109	652,716,068
2025	652,716,068	32,990,644	-	6,323,109	692,029,821
2026	692,029,821	34,968,126	-	6,323,109	733,321,056
2027	733,321,056	37,045,075	-	6,323,109	776,689,240
2028	776,689,240	39,226,495	-	6,323,109	822,238,844
2029	822,238,844	41,517,640	-	6,323,109	870,079,592
2030	870,079,592	43,924,030	-	6,323,109	920,326,731
2031	920,326,731	46,451,461	-	6,323,109	973,101,300
2032	973,101,300	49,106,022	-	6,323,109	1,028,530,430
2033	1,028,530,430	51,894,107	-	6,323,109	1,086,747,646
2034	1,086,747,646	40,960,377	(17,426,480)	5,248,180	1,115,529,723
2035	1,115,529,723	41,943,918	(115,739,524)	-	1,041,734,116
2036	1,041,734,116	39,169,203	(215,597,616)	-	865,305,704
2037	865,305,704	32,535,494	(207,928,021)	-	689,913,177
2038	689,913,177	25,940,735	(121,264,473)	-	594,589,439
2039	594,589,439	22,356,563	(177,324,102)	-	439,621,900
2040	439,621,900	16,529,783	(90,220,653)	-	365,931,031
2041	365,931,031	13,759,007	(65,470,284)	-	314,219,753
2042	314,219,753	11,814,663	(60,356,182)	-	265,678,234
2043	265,678,234	9,989,502	(35,052,624)	-	240,615,112
2044	240,615,112	9,047,128	(11,315,675)	-	238,346,565
2045	238,346,565	8,961,831	(11,659,932)	-	235,648,464
2046	235,648,464	8,860,382	(11,351,378)	-	233,157,468
2047	233,157,468	8,766,721	(11,733,750)	-	230,190,439
2048	230,190,439	8,655,161	(12,167,165)	-	226,678,435
2049	226,678,435	8,523,109	(12,541,806)	-	222,659,739
2050	222,659,739	8,372,006	(13,762,808)	-	217,268,937
2051	217,268,937	8,169,312	(14,231,457)	-	211,206,792
2052	211,206,792	7,941,375	(14,759,970)	-	204,388,197
2053	204,388,197	7,684,996	(15,222,384)	-	196,850,810
2054	196,850,810	7,401,590	(15,745,755)	-	188,506,646
2055	188,506,646	7,087,850	(16,288,557)	-	179,305,938
2056	179,305,938	6,741,903	(16,900,433)	-	169,147,409
2057	169,147,409	6,359,943	(17,436,366)	-	158,070,985
2058	158,070,985	5,943,469	(18,042,698)	-	145,971,756
2059	145,971,756	5,488,538	(18,671,970)	-	132,788,324
2060	132,788,324	4,992,841	(19,380,675)	-	118,400,489
2061	118,400,489	4,451,858	(20,002,159)	-	102,850,189
2062	102,850,189	3,867,167	(20,704,860)	-	86,012,496
2063	86,012,496	3,234,070	(21,434,183)	-	67,812,383
2064	67,812,383	2,549,746	(54,263,681)	-	16,098,447
2065	16,098,447	605,302	(16,703,749)	-	(0)

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2019 ACCRUAL COMPARISON

	Present	Proposed	Difference
Monticello	$13,392,226	$21,406,585	$8,014,359
Prairie Island Unit 1	49,264	15,064,498	15,015,234
Prairie Island Unit 2	589,341	9,122,323	8,532,982
TOTAL	$14,030,831	$45,593,406	$31,562,574

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2019 MN RETAIL SUMMARY

	Remaining Life (yrs)	Operational Earnings Rate	Post-Shutdown Earnings Rate	Market Value Balance 6/30/2017	Book Value 6/30/2017	Unrealized Gain/Loss 6/30/2017	Tax-Effect Adjustment	Tax-Adjusted Fund Balance 6/30/2017	2019-2021 Decommissioning Accrual
Monticello	13.75	5.01%	4.43%	$660,140,345	$529,148,381	$130,991,964	$36,468,163	$623,672,182	**21,406,585**
Prairie Island Unit 1	16.67	4.99%	4.15%	399,941,696	308,078,761	91,862,935	25,574,641	374,367,055	**15,064,498**
Prairie Island Unit 2	17.83	5.04%	4.09%	448,597,551	346,627,064	101,970,487	28,388,583	420,208,967	**9,122,323**
TOTAL DECOMMISSIONING ACCRUAL				**$1,508,679,592**	**$1,183,854,206**	**$324,825,386**	**$90,431,387**	**$1,418,248,204**	**$45,593,406**

INPUT DATA

Escalation Rate (Labor)	4.05%
Escalation Rate (Non-Labor)	2.85%
Escalation Rate (PIIC)	0.00%
Jurisdictional Factor	73.4886%
Tax Rate for tax-effect adjustment	27.84%

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AMOUNT TO RECOVER

	LABOR				NON-LABOR				PHC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
Monticello															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2030	$21,103,620	$15,508,745	1.6755	$25,984,903	$8,935,561	$6,566,615	1.4410	$9,462,492	$0	$0	1.0000	$0	$30,039,182	$22,075,360	$35,447,395
2031	72,416,242	53,217,649	1.7434	92,779,649	42,961,353	31,571,677	1.4820	46,789,225	0	0	1.0000	0	115,377,595	84,789,326	139,568,874
2032	78,476,357	57,671,140	1.8140	104,615,448	102,263,189	75,151,739	1.5243	114,553,795	0	0	1.0000	0	180,739,546	132,822,879	219,169,243
2033	78,663,227	57,808,468	1.8874	109,107,702	100,155,666	73,602,950	1.5677	115,387,345	0	0	1.0000	0	178,818,892	131,411,418	224,495,047
2034	66,380,423	48,782,013	1.9639	95,802,994	38,894,671	28,583,132	1.6124	46,087,441	0	0	1.0000	0	105,275,094	77,365,144	141,890,436
2035	86,879,803	63,846,711	2.0434	130,464,369	113,147,091	83,150,161	1.6584	137,896,227	0	0	1.0000	0	200,026,894	146,996,872	268,360,596
2036	50,307,504	36,970,257	2.1262	78,606,161	20,688,337	15,203,559	1.7056	25,931,191	0	0	1.0000	0	70,995,841	52,173,817	104,537,352
2037	34,623,126	25,444,035	2.2123	56,289,838	14,196,883	10,433,084	1.7542	18,301,716	0	0	1.0000	0	48,820,010	35,877,119	74,591,555
2038	29,581,478	21,739,000	2.3019	50,041,005	15,098,979	11,096,021	1.8042	20,019,442	0	0	1.0000	0	44,680,457	32,835,022	70,060,446
2039	5,925,016	4,354,209	2.3951	10,428,765	2,187,162	1,607,314	1.8556	2,982,532	0	0	1.0000	0	8,112,178	5,961,523	13,411,297
2040	5,941,203	4,366,104	2.4921	10,880,768	2,193,018	1,611,617	1.9085	3,075,772	0	0	1.0000	0	8,134,221	5,977,722	13,956,540
2041	5,925,016	4,354,209	2.5930	11,290,463	2,187,162	1,607,314	1.9629	3,154,997	0	0	1.0000	0	8,112,178	5,961,523	14,445,460
2042	5,925,016	4,354,209	2.6981	11,748,090	2,187,162	1,607,314	2.0189	3,245,006	0	0	1.0000	0	8,112,178	5,961,523	14,993,096
2043	5,925,016	4,354,209	2.8073	12,223,570	2,187,162	1,607,314	2.0764	3,337,427	0	0	1.0000	0	8,112,178	5,961,523	15,560,997
2044	5,941,203	4,366,104	2.9210	12,753,390	2,193,018	1,611,617	2.1356	3,441,770	0	0	1.0000	0	8,134,221	5,977,722	16,195,160
2045	5,925,016	4,354,209	3.0393	13,233,746	2,187,162	1,607,314	2.1964	3,530,305	0	0	1.0000	0	8,112,178	5,961,523	16,764,051
2046	5,925,016	4,354,209	3.1624	13,769,749	2,187,162	1,607,314	2.2590	3,630,922	0	0	1.0000	0	8,112,178	5,961,523	17,400,672
2047	5,925,016	4,354,209	3.2905	14,327,523	2,187,162	1,607,314	2.3234	3,734,433	0	0	1.0000	0	8,112,178	5,961,523	18,061,957
2048	6,604,848	4,853,807	3.4238	16,618,465	4,183,953	3,074,727	2.3896	7,347,367	0	0	1.0000	0	10,788,801	7,928,534	23,965,832
2049	5,925,016	4,354,209	3.5624	15,511,433	2,187,162	1,607,314	2.4577	3,950,296	0	0	1.0000	0	8,112,178	5,961,523	19,461,728
2050	7,418,217	5,451,540	3.7067	20,207,225	6,666,766	4,899,310	2.5278	12,384,476	0	0	1.0000	0	14,084,983	10,350,851	32,591,701
2051	7,418,217	5,451,540	3.8568	21,025,501	6,666,766	4,899,310	2.5998	12,737,227	0	0	1.0000	0	14,084,983	10,350,851	33,762,728
2052	8,296,904	6,097,275	4.0130	24,468,364	9,260,122	6,805,130	2.6739	18,196,237	0	0	1.0000	0	17,557,026	12,902,405	42,664,601
2053	8,927,592	6,560,758	4.1756	27,395,102	11,194,891	8,226,964	2.7501	22,624,973	0	0	1.0000	0	20,122,483	14,787,722	50,020,075
2054	7,633,842	5,610,000	4.3447	24,373,767	7,313,641	5,374,689	2.8285	15,202,309	0	0	1.0000	0	14,947,483	10,984,689	39,576,076
2055	8,711,967	6,402,299	4.5206	28,942,231	10,548,016	7,751,585	2.9091	22,550,135	0	0	1.0000	0	19,259,983	14,153,883	51,492,366
2056	9,159,404	6,731,114	4.7037	31,661,139	11,847,622	8,706,646	2.9920	26,050,286	0	0	1.0000	0	21,007,026	15,437,760	57,711,424
2057	5,908,425	4,342,016	4.8942	21,250,695	2,137,389	1,570,737	3.0773	4,833,628	0	0	1.0000	0	8,045,814	5,912,753	26,084,323
2058	5,908,425	4,342,016	5.0924	22,111,283	2,137,389	1,570,737	3.1650	4,971,381	0	0	1.0000	0	8,045,814	5,912,753	27,082,664
2059	5,908,425	4,342,016	5.2987	23,007,041	2,137,389	1,570,737	3.2552	5,113,062	0	0	1.0000	0	8,045,814	5,912,753	28,120,102
2060	5,924,612	4,353,912	5.5133	24,004,421	2,143,245	1,575,040	3.3480	5,273,234	0	0	1.0000	0	8,067,857	5,928,952	29,277,655
2061	5,908,425	4,342,016	5.7366	24,908,410	2,137,389	1,570,737	3.4434	5,408,674	0	0	1.0000	0	8,045,814	5,912,753	30,317,084
2062	5,908,425	4,342,016	5.9689	25,917,060	2,137,389	1,570,737	3.5415	5,562,764	0	0	1.0000	0	8,045,814	5,912,753	31,479,823
2063	5,908,425	4,342,016	6.2106	26,966,525	2,137,389	1,570,737	3.6425	5,721,408	0	0	1.0000	0	8,045,814	5,912,753	32,687,933
2064	5,924,612	4,353,912	6.4622	28,135,848	2,143,245	1,575,040	3.7463	5,900,572	0	0	1.0000	0	8,067,857	5,928,952	34,036,420
2065	5,908,425	4,342,016	6.7239	29,195,282	2,137,389	1,570,737	3.8531	6,052,205	0	0	1.0000	0	8,045,814	5,912,753	35,247,487
2066	5,908,425	4,342,016	6.9962	30,377,613	2,137,389	1,570,737	3.9629	6,224,672	0	0	1.0000	0	8,045,814	5,912,753	36,602,285
2067	5,908,425	4,342,016	7.2795	31,607,706	2,137,389	1,570,737	4.0758	6,402,008	0	0	1.0000	0	8,045,814	5,912,753	38,009,714
2068	5,924,612	4,353,912	7.5744	32,978,269	2,143,245	1,575,040	4.1920	6,602,568	0	0	1.0000	0	8,067,857	5,928,952	39,580,836
2069	5,908,425	4,342,016	7.8811	34,219,863	2,137,389	1,570,737	4.3115	6,772,231	0	0	1.0000	0	8,045,814	5,912,753	40,992,094
2070	5,908,425	4,342,016	8.2003	35,605,835	2,137,389	1,570,737	4.4343	6,965,117	0	0	1.0000	0	8,045,814	5,912,753	42,570,952
2071	5,908,425	4,342,016	8.5324	37,047,818	2,137,389	1,570,737	4.5607	7,163,658	0	0	1.0000	0	8,045,814	5,912,753	44,211,476
2072	5,924,612	4,353,912	8.8780	38,654,028	2,143,245	1,575,040	4.6907	7,388,040	0	0	1.0000	0	8,067,857	5,928,952	46,042,068
2073	5,908,425	4,342,016	9.2375	40,109,374	2,137,389	1,570,737	4.8244	7,577,862	0	0	1.0000	0	8,045,814	5,912,753	47,687,235
2074	5,908,425	4,342,016	9.6117	41,734,156	2,137,389	1,570,737	4.9619	7,793,838	0	0	1.0000	0	8,045,814	5,912,753	49,527,994
2075	5,908,425	4,342,016	10.0009	43,424,069	2,137,389	1,570,737	5.1033	8,015,940	0	0	1.0000	0	8,045,814	5,912,753	51,440,009
2076	5,924,612	4,353,912	10.4060	45,306,805	2,143,245	1,575,040	5.2487	8,266,912	0	0	1.0000	0	8,067,857	5,928,952	53,573,717
2077	5,908,425	4,342,016	10.8274	47,012,745	2,137,389	1,570,737	5.3983	8,479,307	0	0	1.0000	0	8,045,814	5,912,753	55,492,052
2078	6,386,857	4,693,609	11.2659	52,877,728	3,557,353	2,614,247	5.5522	14,514,823	0	0	1.0000	0	9,944,210	7,307,856	67,392,551
2079	6,482,543	4,763,927	11.7222	55,843,706	3,844,412	2,825,203	5.7104	16,133,037	0	0	1.0000	0	10,326,955	7,589,130	71,976,743
2080	6,403,045	4,705,505	12.1970	57,393,047	3,563,167	2,618,520	5.8731	15,378,828	0	0	1.0000	0	9,966,212	7,324,025	72,771,874
2081	6,386,857	4,693,609	12.6909	59,566,121	3,557,353	2,614,247	6.0405	15,791,360	0	0	1.0000	0	9,944,210	7,307,856	75,357,480
2082	6,386,857	4,693,609	13.2049	61,978,635	3,557,353	2,614,247	6.2127	16,241,533	0	0	1.0000	0	9,944,210	7,307,856	78,220,169
2083	6,482,543	4,763,927	13.7397	65,454,929	3,844,412	2,825,203	6.3897	18,052,197	0	0	1.0000	0	10,326,955	7,589,130	83,507,127
2084	6,403,045	4,705,505	14.2962	67,270,843	3,563,167	2,618,520	6.5719	17,208,649	0	0	1.0000	0	9,966,212	7,324,025	84,479,492

Xcel Energy
Nuclear Decommissioning Accrual
60-Year Decommissioning Period
DECON Method - No Recasking

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AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
2085	6,386,857	4,693,609	14.8752	69,818,370	3,557,353	2,614,247	6.7592	17,670,219	0	0	1.0000	0	9,944,210	7,307,856	87,488,590
2086	6,386,857	4,693,609	15.4776	72,645,800	3,557,353	2,614,247	6.9518	18,173,723	0	0	1.0000	0	9,944,210	7,307,856	90,819,524
2087	6,482,543	4,763,927	16.1045	76,720,664	3,844,412	2,825,203	7.1499	20,199,916	0	0	1.0000	0	10,326,955	7,589,130	96,920,580
2088	7,066,689	5,193,208	16.7567	87,021,021	5,554,101	4,081,628	7.3537	30,015,070	0	0	1.0000	0	12,620,790	9,274,836	117,036,091
2089	6,386,857	4,693,609	17.4353	81,834,478	3,557,353	2,614,247	7.5633	19,772,335	0	0	1.0000	0	9,944,210	7,307,856	101,606,814
2090	6,099,798	4,482,653	18.1415	81,322,056	2,696,175	1,981,380	7.7788	15,412,758	0	0	1.0000	0	8,795,973	6,464,033	96,734,813
2091	2,034,890	1,495,411	18.8762	28,227,679	24,955,010	18,339,076	8.0005	146,721,776	0	0	1.0000	0	26,989,900	19,834,487	174,949,455
	$851,819,402	$625,989,760		$2,666,101,282	$664,030,274	$487,986,246		$1,223,380,650	$0	$0		$0	$1,515,849,676	$1,113,976,006	$3,889,481,932

Xcel Energy
Nuclear Decommissioning Accrual
60-Year Decommissioning Period
DECON Method - No Recasking

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AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
Prairie Island Unit 1															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2033	$22,324,352	$16,405,843	1.8874	$30,964,388	$9,728,959	$7,149,672	1.5677	$11,208,540	$1,250,000	$918,607	1.0000	$918,607	$33,303,311	$24,474,122	$43,091,536
2034	63,582,247	46,725,674	1.9639	91,764,550	33,397,619	24,543,427	1.6124	39,573,822	1,250,000	918,607	1.0000	918,607	98,229,866	72,187,708	132,256,979
2035	65,877,290	48,412,268	2.0434	98,925,629	81,239,936	59,702,054	1.6584	99,009,886	1,250,000	918,607	1.0000	918,607	148,367,226	109,032,929	198,854,122
2036	57,759,315	42,446,486	2.1262	90,249,718	65,595,019	48,204,831	1.7056	82,218,159	1,250,000	918,607	1.0000	918,607	124,604,334	91,569,923	173,386,484
2037	38,110,947	28,007,184	2.2123	61,960,292	36,889,671	27,109,686	1.7542	47,555,811	1,250,000	918,607	1.0000	918,607	76,250,618	56,035,476	110,434,710
2038	13,207,914	9,706,305	2.3019	22,342,944	18,994,691	13,958,924	1.8042	25,184,690	1,250,000	918,607	1.0000	918,607	33,452,605	24,583,836	48,446,241
2039	36,035,855	26,482,229	2.3951	63,427,586	76,476,728	56,201,641	1.8556	104,287,765	1,250,000	918,607	1.0000	918,607	113,762,582	83,602,477	168,633,958
2040	31,919,556	23,457,220	2.4921	58,457,738	13,365,606	9,822,190	1.9085	18,745,650	1,250,000	918,607	1.0000	918,607	46,535,162	34,198,017	78,121,996
2041	19,571,318	14,382,679	2.5930	37,294,286	9,445,873	6,941,635	1.9629	13,625,736	1,250,000	918,607	1.0000	918,607	30,267,191	22,242,921	51,838,628
2042	14,781,952	10,863,043	2.6981	29,309,575	11,668,700	8,575,159	2.0189	17,312,388	1,250,000	918,607	1.0000	918,607	27,700,652	20,356,808	47,540,570
2043	8,544,452	6,279,195	2.8073	17,627,583	6,492,672	4,771,371	2.0764	9,907,275	1,250,000	918,607	1.0000	918,607	16,287,125	11,969,172	28,453,465
2044	3,054,798	2,244,927	2.9210	6,557,431	1,939,011	1,424,951	2.1356	3,043,125	1,250,000	918,607	1.0000	918,607	6,243,809	4,588,485	10,519,163
2045	3,046,451	2,238,793	3.0393	6,804,363	1,930,298	1,418,548	2.1964	3,115,698	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	10,838,668
2046	3,046,451	2,238,793	3.1624	7,079,958	1,930,298	1,418,548	2.2590	3,204,499	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	11,203,065
2047	3,046,451	2,238,793	3.2905	7,366,748	1,930,298	1,418,548	2.3234	3,295,854	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	11,581,208
2048	3,054,798	2,244,927	3.4238	7,686,181	1,939,011	1,424,951	2.3896	3,405,063	1,250,000	918,607	1.0000	918,607	6,243,809	4,588,485	12,009,850
2049	3,046,451	2,238,793	3.5624	7,975,475	1,930,298	1,418,548	2.4577	3,486,365	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	12,380,447
2050	3,046,451	2,238,793	3.7067	8,298,533	1,930,298	1,418,548	2.5278	3,585,805	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	12,802,945
2051	3,046,451	2,238,793	3.8568	8,634,576	1,930,298	1,418,548	2.5998	3,687,940	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	13,241,123
2052	3,054,798	2,244,927	4.0130	9,008,892	1,939,011	1,424,951	2.6739	3,810,176	1,250,000	918,607	1.0000	918,607	6,243,809	4,588,485	13,737,675
2053	3,142,138	2,309,112	4.1756	9,641,927	2,217,357	1,629,503	2.7501	4,481,297	1,250,000	918,607	1.0000	918,607	6,609,495	4,857,222	15,041,831
2054	3,237,824	2,379,430	4.3447	10,337,910	2,504,416	1,840,459	2.8285	5,205,738	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	16,462,254
2055	3,237,824	2,379,430	4.5206	10,756,451	2,504,416	1,840,459	2.9091	5,354,079	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	17,029,137
2056	3,294,014	2,420,723	4.7037	11,386,356	2,656,659	1,952,340	2.9920	5,841,401	1,250,000	918,607	1.0000	918,607	7,200,673	5,291,670	18,146,364
2057	3,189,981	2,344,271	4.8942	11,473,331	2,360,887	1,734,981	3.0773	5,339,058	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	17,730,996
2058	3,333,510	2,449,748	5.0924	12,475,098	2,791,475	2,051,414	3.1650	6,492,726	1,250,000	918,607	1.0000	918,607	7,374,985	5,419,769	19,886,431
2059	3,189,981	2,344,271	5.2987	12,421,588	2,360,887	1,734,981	3.2552	5,647,711	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	18,987,907
2060	3,150,484	2,315,245	5.5133	12,764,641	2,226,070	1,635,906	3.3480	5,477,015	1,250,000	918,607	1.0000	918,607	6,626,554	4,869,758	19,160,263
2061	3,237,824	2,379,430	5.7366	13,649,838	2,504,416	1,840,459	3.4434	6,337,436	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	20,905,881
2062	3,237,824	2,379,430	5.9689	14,202,580	2,504,416	1,840,459	3.5415	6,517,985	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	21,639,172
2063	3,189,981	2,344,271	6.2106	14,559,329	2,360,887	1,734,981	3.6425	6,319,670	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	21,797,605
2064	3,246,170	2,385,563	6.4622	15,415,988	2,513,129	1,846,862	3.7463	6,918,899	1,250,000	918,607	1.0000	918,607	7,009,299	5,151,032	23,253,493
2065	3,237,824	2,379,430	6.7239	15,999,050	2,504,416	1,840,459	3.8531	7,091,472	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	24,009,128
2066	3,189,981	2,344,271	6.9962	16,400,988	2,360,887	1,734,981	3.9629	6,875,558	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	24,195,153
2067	3,237,824	2,379,430	7.2795	17,321,061	2,504,416	1,840,459	4.0758	7,501,342	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	25,741,010
2068	3,246,170	2,385,563	7.5744	18,069,211	2,513,129	1,846,862	4.1920	7,742,045	1,250,000	918,607	1.0000	918,607	7,009,299	5,151,032	26,729,863
2069	3,189,981	2,344,271	7.8811	18,475,433	2,360,887	1,734,981	4.3115	7,480,372	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	26,874,413
2070	3,237,824	2,379,430	8.2003	19,512,040	2,504,416	1,840,459	4.4343	8,161,146	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	28,591,793
2071	3,237,824	2,379,430	8.5324	20,302,249	2,504,416	1,840,459	4.5607	8,393,780	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	29,614,636
2072	3,246,170	2,385,563	8.8780	21,179,032	2,513,129	1,846,862	4.6907	8,663,075	1,250,000	918,607	1.0000	918,607	7,009,299	5,151,032	30,760,714
2073	3,237,824	2,379,430	9.2375	21,979,985	2,504,416	1,840,459	4.8244	8,879,109	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	31,777,701
2074	3,237,824	2,379,430	9.6117	22,870,368	2,504,416	1,840,459	4.9619	9,132,172	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	32,921,147
2075	3,569,646	2,623,281	10.0009	26,235,173	3,499,884	2,572,014	5.1033	13,125,758	1,250,000	918,607	1.0000	918,607	8,319,530	6,113,902	40,279,538
2076	3,246,170	2,385,563	10.4060	24,824,173	2,513,129	1,846,862	5.2487	9,693,624	1,250,000	918,607	1.0000	918,607	7,009,299	5,151,032	35,436,404
2077	3,237,974	2,379,540	10.8274	25,764,234	14,152,775	10,400,669	5.3983	56,145,933	1,250,000	918,607	1.0000	918,607	18,640,749	13,698,817	82,828,774
2078	832,743	611,971	11.2659	6,894,405	4,620,063	3,395,217	5.5522	18,850,925	0	0	1.0000	0	5,452,806	4,007,188	25,745,329
	$481,031,633	$353,503,191		$1,096,648,885	$459,759,673	$337,870,735		$746,933,573	$56,250,000	$41,337,312		$41,337,312	$997,041,305	$732,711,237	$1,884,919,770

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AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
Prairie Island Unit 2															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2034	$7,760,265	$5,702,906	1.9639	$11,199,938	$4,479,535	$3,291,946	1.6124	$5,307,933	$1,250,000	$918,607	1.0000	$918,607	$13,489,800	$9,913,459	$17,426,478
2035	46,911,429	34,474,531	2.0434	70,445,256	35,601,339	26,162,909	1.6584	43,388,568	1,250,000	918,607	1.0000	918,607	83,762,768	61,556,047	114,752,431
2036	67,514,044	49,615,094	2.1262	105,491,613	86,298,832	63,419,763	1.7056	108,168,748	1,250,000	918,607	1.0000	918,607	155,062,875	113,953,465	214,578,969
2037	70,896,041	52,100,475	2.2123	115,261,881	70,558,163	51,852,174	1.7542	90,959,083	1,250,000	918,607	1.0000	918,607	142,704,204	104,871,256	207,139,571
2038	46,603,528	34,248,259	2.3019	78,836,068	42,782,149	31,439,982	1.8042	56,724,016	1,250,000	918,607	1.0000	918,607	90,635,677	66,606,848	136,478,691
2039	40,663,625	29,883,110	2.3951	71,573,036	77,452,618	56,918,809	1.8556	105,618,542	1,250,000	918,607	1.0000	918,607	119,366,242	87,720,525	178,110,184
2040	37,417,177	27,497,343	2.4921	68,526,127	14,193,501	10,430,599	1.9085	19,906,798	1,250,000	918,607	1.0000	918,607	52,860,679	38,846,548	89,351,532
2041	23,327,583	17,143,103	2.5930	44,452,067	13,070,130	9,605,049	1.9629	18,853,752	1,250,000	918,607	1.0000	918,607	37,647,713	27,666,760	64,224,426
2042	16,656,921	12,240,930	2.6981	33,027,253	17,178,640	12,624,334	2.0189	25,487,268	1,250,000	918,607	1.0000	918,607	35,085,561	25,783,871	59,433,129
2043	9,422,862	6,924,725	2.8073	19,439,782	9,074,042	6,668,382	2.0764	13,846,228	1,250,000	918,607	1.0000	918,607	19,746,904	14,511,714	34,204,617
2044	3,054,798	2,244,927	2.9210	6,557,431	1,939,011	1,424,951	2.1356	3,043,125	1,250,000	918,607	1.0000	918,607	6,243,809	4,588,485	10,519,163
2045	3,046,451	2,238,793	3.0393	6,804,363	1,930,298	1,418,548	2.1964	3,115,698	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	10,838,668
2046	3,046,451	2,238,793	3.1624	7,079,958	1,930,298	1,418,548	2.2590	3,204,499	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	11,203,065
2047	3,046,451	2,238,793	3.2905	7,366,748	1,930,298	1,418,548	2.3234	3,295,854	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	11,581,208
2048	3,054,798	2,244,927	3.4238	7,686,181	1,939,011	1,424,951	2.3896	3,405,063	1,250,000	918,607	1.0000	918,607	6,243,809	4,588,485	12,009,850
2049	3,046,451	2,238,793	3.5624	7,975,475	1,930,298	1,418,548	2.4577	3,486,365	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	12,380,447
2050	3,046,451	2,238,793	3.7067	8,298,533	1,930,298	1,418,548	2.5278	3,585,805	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	12,802,945
2051	3,046,451	2,238,793	3.8568	8,634,576	1,930,298	1,418,548	2.5998	3,687,940	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	13,241,123
2052	3,054,798	2,244,927	4.0130	9,008,892	1,939,011	1,424,951	2.6739	3,810,176	1,250,000	918,607	1.0000	918,607	6,243,809	4,588,485	13,737,675
2053	3,142,138	2,309,112	4.1756	9,641,927	2,217,358	1,629,504	2.7501	4,481,299	1,250,000	918,607	1.0000	918,607	6,609,496	4,857,223	15,041,833
2054	3,237,824	2,379,430	4.3447	10,337,910	2,504,416	1,840,459	2.8285	5,205,738	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	16,462,254
2055	3,237,824	2,379,430	4.5206	10,756,451	2,504,416	1,840,459	2.9091	5,354,079	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	17,029,137
2056	3,294,014	2,420,723	4.7037	11,386,356	2,656,659	1,952,340	2.9920	5,841,401	1,250,000	918,607	1.0000	918,607	7,200,673	5,291,670	18,146,364
2057	3,189,981	2,344,271	4.8942	11,473,331	2,360,887	1,734,981	3.0773	5,339,058	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	17,730,996
2058	3,333,510	2,449,748	5.0924	12,475,098	2,791,475	2,051,414	3.1650	6,492,726	1,250,000	918,607	1.0000	918,607	7,374,985	5,419,769	19,886,431
2059	3,189,981	2,344,271	5.2987	12,421,588	2,360,887	1,734,981	3.2552	5,647,711	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	18,987,907
2060	3,150,484	2,315,245	5.5133	12,764,641	2,226,070	1,635,906	3.3480	5,477,015	1,250,000	918,607	1.0000	918,607	6,626,554	4,869,758	19,160,263
2061	3,237,824	2,379,430	5.7366	13,649,838	2,504,416	1,840,459	3.4434	6,337,436	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	20,905,881
2062	3,237,824	2,379,430	5.9689	14,202,580	2,504,416	1,840,459	3.5415	6,517,985	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	21,639,172
2063	3,189,981	2,344,271	6.2106	14,559,329	2,360,887	1,734,981	3.6425	6,319,670	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	21,797,605
2064	3,246,170	2,385,563	6.4622	15,415,988	2,513,129	1,846,862	3.7463	6,918,899	1,250,000	918,607	1.0000	918,607	7,009,299	5,151,032	23,253,493
2065	3,237,824	2,379,430	6.7239	15,999,050	2,504,416	1,840,459	3.8531	7,091,472	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	24,009,128
2066	3,189,981	2,344,271	6.9962	16,400,988	2,360,887	1,734,981	3.9629	6,875,558	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	24,195,153
2067	3,237,824	2,379,430	7.2795	17,321,061	2,504,416	1,840,459	4.0758	7,501,342	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	25,741,010
2068	3,246,170	2,385,563	7.5744	18,069,211	2,513,129	1,846,862	4.1920	7,742,045	1,250,000	918,607	1.0000	918,607	7,009,299	5,151,032	26,729,863
2069	3,189,981	2,344,271	7.8811	18,475,433	2,360,887	1,734,981	4.3115	7,480,372	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	26,874,413
2070	3,237,824	2,379,430	8.2003	19,512,040	2,504,416	1,840,459	4.4343	8,161,146	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	28,591,793
2071	3,237,824	2,379,430	8.5324	20,302,249	2,504,416	1,840,459	4.5607	8,393,780	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	29,614,636
2072	3,246,170	2,385,563	8.8780	21,179,032	2,513,129	1,846,862	4.6907	8,663,075	1,250,000	918,607	1.0000	918,607	7,009,299	5,151,032	30,760,714
2073	3,237,824	2,379,430	9.2375	21,979,985	2,504,416	1,840,459	4.8244	8,879,109	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	31,777,701
2074	3,237,824	2,379,430	9.6117	22,870,368	2,504,416	1,840,459	4.9619	9,132,172	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	32,921,147
2075	3,569,646	2,623,281	10.0009	26,235,173	3,499,884	2,572,014	5.1033	13,125,758	1,250,000	918,607	1.0000	918,607	8,319,530	6,113,902	40,279,538
2076	3,246,170	2,385,563	10.4060	24,824,173	2,513,129	1,846,862	5.2487	9,693,624	1,250,000	918,607	1.0000	918,607	7,009,299	5,151,032	35,436,404
2077	3,237,824	2,379,430	10.8274	25,763,042	14,152,675	10,400,596	5.3983	56,145,536	1,250,000	918,607	1.0000	918,607	18,640,499	13,698,633	82,827,186
2078	832,743	611,971	11.2659	6,894,405	4,620,063	3,395,217	5.5522	18,850,925	0	-	1.0000	-	5,452,806	4,007,188	25,745,329
	$476,489,759	$350,165,433		$1,112,576,425	$467,153,049	$343,304,020		$766,564,392	$55,000,000	$40,418,705		$40,418,705	$998,642,807	$733,888,158	$1,919,559,522
	$1,809,340,794	$1,329,658,384		$4,875,326,592	$1,590,942,995	$1,169,161,000		$2,736,878,615	$111,250,000	$81,756,016		$81,756,016	$3,511,533,789	$2,580,575,401	$7,693,961,224

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60-Year Decommissioning Period
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EXTERNAL FUND CALCULATION

Monticello

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	623,672,182	15,706,857	-	6,696,113	646,075,152
2018	646,075,152	32,703,840	-	13,392,226	692,171,218
2019	692,171,218	35,214,013	-	21,406,585	748,791,816
2020	748,791,816	38,050,705	-	21,406,585	808,249,105
2021	808,249,105	41,029,515	-	21,406,585	870,685,205
2022	870,685,205	44,157,564	-	21,406,585	936,249,353
2023	936,249,353	47,442,328	-	21,406,585	1,005,098,265
2024	1,005,098,265	50,891,658	-	21,406,585	1,077,396,508
2025	1,077,396,508	54,513,800	-	21,406,585	1,153,316,892
2026	1,153,316,892	58,317,411	-	21,406,585	1,233,040,888
2027	1,233,040,888	62,311,583	-	21,406,585	1,316,759,056
2028	1,316,759,056	66,505,864	-	21,406,585	1,404,671,504
2029	1,404,671,504	70,910,277	-	21,406,585	1,496,988,366
2030	1,496,988,366	66,672,202	(35,447,395)	16,054,938	1,544,268,112
2031	1,544,268,112	68,411,077	(139,568,874)	-	1,473,110,315
2032	1,473,110,315	65,258,787	(219,169,243)	-	1,319,199,858
2033	1,319,199,858	58,440,554	(224,495,047)	-	1,153,145,365
2034	1,153,145,365	51,084,340	(141,890,436)	-	1,062,339,269
2035	1,062,339,269	47,061,630	(268,360,596)	-	841,040,302
2036	841,040,302	37,258,085	(104,537,352)	-	773,761,036
2037	773,761,036	34,277,614	(74,591,555)	-	733,447,095
2038	733,447,095	32,491,706	(70,060,446)	-	695,878,355
2039	695,878,355	30,827,411	(13,411,297)	-	713,294,470
2040	713,294,470	31,598,945	(13,956,540)	-	730,936,875
2041	730,936,875	32,380,504	(14,445,460)	-	748,871,919
2042	748,871,919	33,175,026	(14,993,096)	-	767,053,848
2043	767,053,848	33,980,485	(15,560,997)	-	785,473,337
2044	785,473,337	34,796,469	(16,195,160)	-	804,074,645
2045	804,074,645	35,620,507	(16,764,051)	-	822,931,101
2046	822,931,101	36,455,848	(17,400,672)	-	841,986,278
2047	841,986,278	37,299,992	(18,061,957)	-	861,224,313
2048	861,224,313	38,152,237	(23,965,832)	-	875,410,718
2049	875,410,718	38,780,695	(19,461,728)	-	894,729,684
2050	894,729,684	39,636,525	(32,591,701)	-	901,774,508
2051	901,774,508	39,948,611	(33,762,728)	-	907,960,391
2052	907,960,391	40,222,645	(42,664,601)	-	905,518,436
2053	905,518,436	40,114,467	(50,020,075)	-	895,612,827
2054	895,612,827	39,675,648	(39,576,076)	-	895,712,399

External Levelized

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EXTERNAL FUND CALCULATION

2055	895,712,399	39,680,059	(51,492,366)	-	883,900,092
2056	883,900,092	39,156,774	(57,711,424)	-	865,345,442
2057	865,345,442	38,334,803	(26,084,323)	-	877,595,922
2058	877,595,922	38,877,499	(27,082,664)	-	889,390,758
2059	889,390,758	39,400,011	(28,120,102)	-	900,670,666
2060	900,670,666	39,899,710	(29,277,655)	-	911,292,721
2061	911,292,721	40,370,268	(30,317,084)	-	921,345,905
2062	921,345,905	40,815,624	(31,479,823)	-	930,681,705
2063	930,681,705	41,229,200	(32,687,933)	-	939,222,972
2064	939,222,972	41,607,578	(34,036,420)	-	946,794,129
2065	946,794,129	41,942,980	(35,247,487)	-	953,489,622
2066	953,489,622	42,239,590	(36,602,285)	-	959,126,927
2067	959,126,927	42,489,323	(38,009,714)	-	963,606,536
2068	963,606,536	42,687,770	(39,580,836)	-	966,713,469
2069	966,713,469	42,825,407	(40,992,094)	-	968,546,782
2070	968,546,782	42,906,622	(42,570,952)	-	968,882,453
2071	968,882,453	42,921,493	(44,211,476)	-	967,592,469
2072	967,592,469	42,864,346	(46,042,068)	-	964,414,747
2073	964,414,747	42,723,573	(47,687,235)	-	959,451,086
2074	959,451,086	42,503,683	(49,527,994)	-	952,426,775
2075	952,426,775	42,192,506	(51,440,009)	-	943,179,272
2076	943,179,272	41,782,842	(53,573,717)	-	931,388,397
2077	931,388,397	41,260,506	(55,492,052)	-	917,156,851
2078	917,156,851	40,630,048	(67,392,551)	-	890,394,348
2079	890,394,348	39,444,470	(71,976,743)	-	857,862,074
2080	857,862,074	38,003,290	(72,771,874)	-	823,093,490
2081	823,093,490	36,463,042	(75,357,480)	-	784,199,051
2082	784,199,051	34,740,018	(78,220,169)	-	740,718,900
2083	740,718,900	32,813,847	(83,507,127)	-	690,025,621
2084	690,025,621	30,568,135	(84,479,492)	-	636,114,264
2085	636,114,264	28,179,862	(87,488,590)	-	576,805,536
2086	576,805,536	25,552,485	(90,819,524)	-	511,538,498
2087	511,538,498	22,661,155	(96,920,580)	-	437,279,073
2088	437,279,073	19,371,463	(117,036,091)	-	339,614,445
2089	339,614,445	15,044,920	(101,606,814)	-	253,052,551
2090	253,052,551	11,210,228	(96,734,813)	-	167,527,966
2091	167,527,966	7,421,489	(174,949,455)	-	(0)

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Prairie Island Unit 1

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	374,367,055	9,340,765	-	24,632	383,732,452
2018	383,732,452	19,149,479	-	49,264	402,931,195
2019	402,931,195	20,482,126	-	15,064,498	438,477,820
2020	438,477,820	22,255,902	-	15,064,498	475,798,220
2021	475,798,220	24,118,190	-	15,064,498	514,980,909
2022	514,980,909	26,073,407	-	15,064,498	556,118,814
2023	556,118,814	28,126,188	-	15,064,498	599,309,501
2024	599,309,501	30,281,403	-	15,064,498	644,655,402
2025	644,655,402	32,544,164	-	15,064,498	692,264,064
2026	692,264,064	34,919,836	-	15,064,498	742,248,399
2027	742,248,399	37,414,054	-	15,064,498	794,726,952
2028	794,726,952	40,032,734	-	15,064,498	849,824,184
2029	849,824,184	42,782,086	-	15,064,498	907,670,768
2030	907,670,768	45,668,631	-	15,064,498	968,403,897
2031	968,403,897	48,699,214	-	15,064,498	1,032,167,610
2032	1,032,167,610	51,881,023	-	15,064,498	1,099,113,131
2033	1,099,113,131	45,822,629	(43,091,536)	10,093,214	1,111,937,438
2034	1,111,937,438	46,145,404	(132,256,979)	-	1,025,825,863
2035	1,025,825,863	42,571,773	(198,854,122)	-	869,543,514
2036	869,543,514	36,086,056	(173,386,484)	-	732,243,086
2037	732,243,086	30,388,088	(110,434,710)	-	652,196,464
2038	652,196,464	27,066,153	(48,446,241)	-	630,816,377
2039	630,816,377	26,178,880	(168,633,958)	-	488,361,298
2040	488,361,298	20,266,994	(78,121,996)	-	430,506,296
2041	430,506,296	17,866,011	(51,838,628)	-	396,533,679
2042	396,533,679	16,456,148	(47,540,570)	-	365,449,257
2043	365,449,257	15,166,144	(28,453,465)	-	352,161,936
2044	352,161,936	14,614,720	(10,519,163)	-	356,257,493
2045	356,257,493	14,784,686	(10,838,668)	-	360,203,511
2046	360,203,511	14,948,446	(11,203,065)	-	363,948,892
2047	363,948,892	15,103,879	(11,581,208)	-	367,471,563
2048	367,471,563	15,250,070	(12,009,850)	-	370,711,783
2049	370,711,783	15,384,539	(12,380,447)	-	373,715,875
2050	373,715,875	15,509,209	(12,802,945)	-	376,422,138
2051	376,422,138	15,621,519	(13,241,123)	-	378,802,534
2052	378,802,534	15,720,305	(13,737,675)	-	380,785,164
2053	380,785,164	15,802,584	(15,041,831)	-	381,545,917
2054	381,545,917	15,834,156	(16,462,254)	-	380,917,819
2055	380,917,819	15,808,089	(17,029,137)	-	379,696,771

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2056	379,696,771	15,757,416	(18,146,364)	-	377,307,823
2057	377,307,823	15,658,275	(17,730,996)	-	375,235,102
2058	375,235,102	15,572,257	(19,886,431)	-	370,920,928
2059	370,920,928	15,393,218	(18,987,907)	-	367,326,240
2060	367,326,240	15,244,039	(19,160,263)	-	363,410,016
2061	363,410,016	15,081,516	(20,905,881)	-	357,585,651
2062	357,585,651	14,839,805	(21,639,172)	-	350,786,284
2063	350,786,284	14,557,631	(21,797,605)	-	343,546,309
2064	343,546,309	14,257,172	(23,253,493)	-	334,549,987
2065	334,549,987	13,883,824	(24,009,128)	-	324,424,684
2066	324,424,684	13,463,624	(24,195,153)	-	313,693,155
2067	313,693,155	13,018,266	(25,741,010)	-	300,970,412
2068	300,970,412	12,490,272	(26,729,863)	-	286,730,820
2069	286,730,820	11,899,329	(26,874,413)	-	271,755,737
2070	271,755,737	11,277,863	(28,591,793)	-	254,441,807
2071	254,441,807	10,559,335	(29,614,636)	-	235,386,506
2072	235,386,506	9,768,540	(30,760,714)	-	214,394,332
2073	214,394,332	8,897,365	(31,777,701)	-	191,513,995
2074	191,513,995	7,947,831	(32,921,147)	-	166,540,679
2075	166,540,679	6,911,438	(40,279,538)	-	133,172,579
2076	133,172,579	5,526,662	(35,436,404)	-	103,262,838
2077	103,262,838	4,285,408	(82,828,774)	-	24,719,471
2078	24,719,471	1,025,858	(25,745,329)	-	(0)

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EXTERNAL FUND CALCULATION

Prairie Island Unit 2

External Levelized

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	420,208,967	10,592,979	-	294,670	431,096,616
2018	431,096,616	21,742,121	-	589,341	453,428,078
2019	453,428,078	23,082,658	-	9,122,323	485,633,058
2020	485,633,058	24,705,789	-	9,122,323	519,461,170
2021	519,461,170	26,410,725	-	9,122,323	554,994,218
2022	554,994,218	28,201,591	-	9,122,323	592,318,132
2023	592,318,132	30,082,716	-	9,122,323	631,523,171
2024	631,523,171	32,058,650	-	9,122,323	672,704,144
2025	672,704,144	34,134,171	-	9,122,323	715,960,638
2026	715,960,638	36,314,299	-	9,122,323	761,397,259
2027	761,397,259	38,604,304	-	9,122,323	809,123,886
2028	809,123,886	41,009,726	-	9,122,323	859,255,935
2029	859,255,935	43,536,382	-	9,122,323	911,914,639
2030	911,914,639	46,190,380	-	9,122,323	967,227,342
2031	967,227,342	48,978,141	-	9,122,323	1,025,327,805
2032	1,025,327,805	51,906,404	-	9,122,323	1,086,356,532
2033	1,086,356,532	54,982,252	-	9,122,323	1,150,461,106
2034	1,150,461,106	47,208,697	(17,426,478)	7,571,528	1,187,814,854
2035	1,187,814,854	48,581,628	(114,752,431)	-	1,121,644,050
2036	1,121,644,050	45,875,242	(214,578,969)	-	952,940,323
2037	952,940,323	38,975,259	(207,139,571)	-	784,776,011
2038	784,776,011	32,097,339	(136,478,691)	-	680,394,659
2039	680,394,659	27,828,142	(178,110,184)	-	530,112,616
2040	530,112,616	21,681,606	(89,351,532)	-	462,442,690
2041	462,442,690	18,913,906	(64,224,426)	-	417,132,170
2042	417,132,170	17,060,706	(59,433,129)	-	374,759,747
2043	374,759,747	15,327,674	(34,204,617)	-	355,882,804
2044	355,882,804	14,555,607	(10,519,163)	-	359,919,247
2045	359,919,247	14,720,697	(10,838,668)	-	363,801,277
2046	363,801,277	14,879,472	(11,203,065)	-	367,477,684
2047	367,477,684	15,029,837	(11,581,208)	-	370,926,313
2048	370,926,313	15,170,886	(12,009,850)	-	374,087,349
2049	374,087,349	15,300,173	(12,380,447)	-	377,007,075
2050	377,007,075	15,419,589	(12,802,945)	-	379,623,719
2051	379,623,719	15,526,610	(13,241,123)	-	381,909,206
2052	381,909,206	15,620,087	(13,737,675)	-	383,791,617
2053	383,791,617	15,697,077	(15,041,833)	-	384,446,862
2054	384,446,862	15,723,877	(16,462,254)	-	383,708,484

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2055	383,708,484	15,693,677	(17,029,137)	-	382,373,024
2056	382,373,024	15,639,057	(18,146,364)	-	379,865,717
2057	379,865,717	15,536,508	(17,730,996)	-	377,671,229
2058	377,671,229	15,446,753	(19,886,431)	-	373,231,551
2059	373,231,551	15,265,170	(18,987,907)	-	369,508,815
2060	369,508,815	15,112,911	(19,160,263)	-	365,461,463
2061	365,461,463	14,947,374	(20,905,881)	-	359,502,955
2062	359,502,955	14,703,671	(21,639,172)	-	352,567,455
2063	352,567,455	14,420,009	(21,797,605)	-	345,189,858
2064	345,189,858	14,118,265	(23,253,493)	-	336,054,630
2065	336,054,630	13,744,634	(24,009,128)	-	325,790,136
2066	325,790,136	13,324,817	(24,195,153)	-	314,919,800
2067	314,919,800	12,880,220	(25,741,010)	-	302,059,010
2068	302,059,010	12,354,214	(26,729,863)	-	287,683,360
2069	287,683,360	11,766,249	(26,874,413)	-	272,575,197
2070	272,575,197	11,148,326	(28,591,793)	-	255,131,730
2071	255,131,730	10,434,888	(29,614,636)	-	235,951,981
2072	235,951,981	9,650,436	(30,760,714)	-	214,841,703
2073	214,841,703	8,787,026	(31,777,701)	-	191,851,028
2074	191,851,028	7,846,707	(32,921,147)	-	166,776,588
2075	166,776,588	6,821,162	(40,279,538)	-	133,318,213
2076	133,318,213	5,452,715	(35,436,404)	-	103,334,524
2077	103,334,524	4,226,382	(82,827,186)	-	24,733,720
2078	24,733,720	1,011,609	(25,745,329)	-	0

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Proposed

2019 ACCRUAL COMPARISON

	Present	Proposed	Difference
Monticello	$13,392,226	$44,081,384	$30,689,158
Prairie Island Unit 1	49,264	25,969,989	25,920,725
Prairie Island Unit 2	589,341	17,105,727	16,516,386
TOTAL	$14,030,831	$87,157,100	$73,126,269

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Proposed

2019 MN RETAIL SUMMARY

	Remaining Life (yrs)	Operational Earnings Rate	Post-Shutdown Earnings Rate	Market Value Balance 6/30/2017	Book Value 6/30/2017	Unrealized Gain/Loss 6/30/2017	Tax-Effect Adjustment	Tax-Adjusted Fund Balance 6/30/2017	2019-2021 Decommissioning Accrual
Monticello	8.75	5.01%	4.43%	$660,140,345	$529,148,381	$130,991,964	$36,468,163	$623,672,182	**44,081,384**
Prairie Island Unit 1	11.67	4.99%	4.15%	399,941,696	308,078,761	91,862,935	25,574,641	374,367,055	**25,969,989**
Prairie Island Unit 2	12.83	5.04%	4.09%	448,597,551	346,627,064	101,970,487	28,388,583	420,208,967	**17,105,727**
TOTAL DECOMMISSIONING ACCRUAL				**$1,508,679,592**	**$1,183,854,206**	**$324,825,386**	**$90,431,387**	**$1,418,248,204**	**$87,157,100**

INPUT DATA

Escalation Rate (Labor)	4.05%
Escalation Rate (Non-Labor)	2.85%
Escalation Rate (PIIC)	0.00%
Jurisdictional Factor	73.4886%
Tax Rate for tax-effect adjustment	27.84%

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Proposed

AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
Monticello															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2025	$21,103,620	$15,508,745	1.3738	$21,305,914	$8,935,561	$6,566,615	1.2521	$8,222,059	$0	$0	1.0000	$0	$30,039,182	$22,075,360	$29,527,973
2026	72,416,242	53,217,649	1.4295	76,074,629	42,961,353	31,571,677	1.2878	40,658,006	0	0	1.0000	0	115,377,595	84,789,326	116,732,635
2027	78,476,357	57,671,140	1.4874	85,780,054	102,263,189	75,151,739	1.3245	99,538,478	0	0	1.0000	0	180,739,546	132,822,879	185,318,532
2028	78,663,227	57,808,468	1.5476	89,464,385	100,155,666	73,602,950	1.3622	100,261,939	0	0	1.0000	0	178,818,892	131,411,418	189,726,324
2029	66,380,423	48,782,013	1.6103	78,553,675	38,894,671	28,583,132	1.4010	40,044,967	0	0	1.0000	0	105,275,094	77,365,144	118,598,642
2030	86,879,803	63,846,711	1.6755	106,975,164	113,147,091	83,150,161	1.4410	119,819,382	0	0	1.0000	0	200,026,894	146,996,872	226,794,546
2031	50,307,504	36,970,257	1.7434	64,453,946	20,688,337	15,203,559	1.4820	22,531,675	0	0	1.0000	0	70,995,841	52,173,817	86,985,621
2032	34,623,126	25,444,035	1.8140	46,155,479	14,196,883	10,433,084	1.5243	15,903,150	0	0	1.0000	0	48,820,010	35,877,119	62,058,629
2033	29,581,478	21,739,000	1.8874	41,030,189	15,098,979	11,096,021	1.5677	17,395,233	0	0	1.0000	0	44,680,457	32,835,022	58,425,422
2034	5,925,016	4,354,209	1.9639	8,551,230	2,187,162	1,607,314	1.6124	2,591,633	0	0	1.0000	0	8,112,178	5,961,523	11,142,863
2035	5,941,203	4,366,104	2.0434	8,921,697	2,193,018	1,611,617	1.6584	2,672,706	0	0	1.0000	0	8,134,221	5,977,722	11,594,404
2036	5,925,016	4,354,209	2.1262	9,257,918	2,187,162	1,607,314	1.7056	2,741,435	0	0	1.0000	0	8,112,178	5,961,523	11,999,353
2037	5,925,016	4,354,209	2.2123	9,632,816	2,187,162	1,607,314	1.7542	2,819,550	0	0	1.0000	0	8,112,178	5,961,523	12,452,366
2038	5,925,016	4,354,209	2.3019	10,022,953	2,187,162	1,607,314	1.8042	2,899,916	0	0	1.0000	0	8,112,178	5,961,523	12,922,869
2039	5,941,203	4,366,104	2.3951	10,457,256	2,193,018	1,611,617	1.8556	2,990,517	0	0	1.0000	0	8,134,221	5,977,722	13,447,773
2040	5,925,016	4,354,209	2.4921	10,851,123	2,187,162	1,607,314	1.9085	3,067,559	0	0	1.0000	0	8,112,178	5,961,523	13,918,682
2041	5,925,016	4,354,209	2.5930	11,290,463	2,187,162	1,607,314	1.9629	3,154,997	0	0	1.0000	0	8,112,178	5,961,523	14,445,460
2042	5,925,016	4,354,209	2.6981	11,748,090	2,187,162	1,607,314	2.0189	3,245,006	0	0	1.0000	0	8,112,178	5,961,523	14,993,096
2043	6,604,848	4,853,807	2.8073	13,626,093	4,183,953	3,074,727	2.0764	6,384,363	0	0	1.0000	0	10,788,801	7,928,534	20,010,456
2044	5,925,016	4,354,209	2.9210	12,718,643	2,187,162	1,607,314	2.1356	3,432,580	0	0	1.0000	0	8,112,178	5,961,523	16,151,223
2045	7,418,217	5,451,540	3.0393	16,568,867	6,666,766	4,899,310	2.1964	10,760,845	0	0	1.0000	0	14,084,983	10,350,851	27,329,712
2046	7,418,217	5,451,540	3.1624	17,239,951	6,666,766	4,899,310	2.2590	11,067,542	0	0	1.0000	0	14,084,983	10,350,851	28,307,493
2047	8,296,904	6,097,275	3.2905	20,063,083	9,260,122	6,805,130	2.3234	15,811,039	0	0	1.0000	0	17,557,026	12,902,405	35,874,122
2048	8,927,592	6,560,758	3.4238	22,462,724	11,194,891	8,226,964	2.3896	19,659,153	0	0	1.0000	0	20,122,483	14,787,722	42,121,877
2049	7,633,842	5,610,000	3.5624	19,985,064	7,313,641	5,374,689	2.4577	13,209,374	0	0	1.0000	0	14,947,483	10,984,689	33,194,438
2050	8,711,967	6,402,299	3.7067	23,731,400	10,548,016	7,751,585	2.5278	19,594,456	0	0	1.0000	0	19,259,983	14,153,883	43,325,856
2051	9,159,404	6,731,114	3.8568	25,960,559	11,847,622	8,706,646	2.5998	22,635,539	0	0	1.0000	0	21,007,026	15,437,760	48,596,098
2052	5,908,425	4,342,016	4.0130	17,424,511	2,137,389	1,570,737	2.6739	4,199,993	0	0	1.0000	0	8,045,814	5,912,753	21,624,503
2053	5,908,425	4,342,016	4.1756	18,130,522	2,137,389	1,570,737	2.7501	4,319,683	0	0	1.0000	0	8,045,814	5,912,753	22,450,205
2054	5,908,425	4,342,016	4.3447	18,864,757	2,137,389	1,570,737	2.8285	4,442,828	0	0	1.0000	0	8,045,814	5,912,753	23,307,586
2055	5,924,612	4,353,912	4.5206	19,682,293	2,143,245	1,575,040	2.9091	4,581,949	0	0	1.0000	0	8,067,857	5,928,952	24,264,242
2056	5,908,425	4,342,016	4.7037	20,423,541	2,137,389	1,570,737	2.9920	4,699,644	0	0	1.0000	0	8,045,814	5,912,753	25,123,185
2057	5,908,425	4,342,016	4.8942	21,250,695	2,137,389	1,570,737	3.0773	4,833,628	0	0	1.0000	0	8,045,814	5,912,753	26,084,323
2058	5,908,425	4,342,016	5.0924	22,111,283	2,137,389	1,570,737	3.1650	4,971,381	0	0	1.0000	0	8,045,814	5,912,753	27,082,664
2059	5,924,612	4,353,912	5.2987	23,070,072	2,143,245	1,575,040	3.2552	5,127,070	0	0	1.0000	0	8,067,857	5,928,952	28,197,142
2060	5,908,425	4,342,016	5.5133	23,938,837	2,137,389	1,570,737	3.3480	5,258,826	0	0	1.0000	0	8,045,814	5,912,753	29,197,663
2061	5,908,425	4,342,016	5.7366	24,908,410	2,137,389	1,570,737	3.4434	5,408,674	0	0	1.0000	0	8,045,814	5,912,753	30,317,084
2062	5,908,425	4,342,016	5.9689	25,917,060	2,137,389	1,570,737	3.5415	5,562,764	0	0	1.0000	0	8,045,814	5,912,753	31,479,823
2063	5,924,612	4,353,912	6.2106	27,040,404	2,143,245	1,575,040	3.6425	5,737,083	0	0	1.0000	0	8,067,857	5,928,952	32,777,487
2064	5,908,425	4,342,016	6.4622	28,058,976	2,137,389	1,570,737	3.7463	5,884,450	0	0	1.0000	0	8,045,814	5,912,753	33,943,427
2065	5,908,425	4,342,016	6.7239	29,195,282	2,137,389	1,570,737	3.8531	6,052,205	0	0	1.0000	0	8,045,814	5,912,753	35,247,487
2066	5,908,425	4,342,016	6.9962	30,377,613	2,137,389	1,570,737	3.9629	6,224,672	0	0	1.0000	0	8,045,814	5,912,753	36,602,285
2067	5,924,612	4,353,912	7.2795	31,694,300	2,143,245	1,575,040	4.0758	6,419,548	0	0	1.0000	0	8,067,857	5,928,952	38,113,848
2068	5,908,425	4,342,016	7.5744	32,888,167	2,137,389	1,570,737	4.1920	6,584,528	0	0	1.0000	0	8,045,814	5,912,753	39,472,694
2069	5,908,425	4,342,016	7.8811	34,219,863	2,137,389	1,570,737	4.3115	6,772,231	0	0	1.0000	0	8,045,814	5,912,753	40,992,094
2070	5,908,425	4,342,016	8.2003	35,605,835	2,137,389	1,570,737	4.4343	6,965,117	0	0	1.0000	0	8,045,814	5,912,753	42,570,952
2071	5,924,612	4,353,912	8.5324	37,149,316	2,143,245	1,575,040	4.5607	7,183,285	0	0	1.0000	0	8,067,857	5,928,952	44,332,601
2072	5,908,425	4,342,016	8.8780	38,548,419	2,137,389	1,570,737	4.6907	7,367,854	0	0	1.0000	0	8,045,814	5,912,753	45,916,273
2073	6,386,857	4,693,609	9.2375	43,357,212	3,557,353	2,614,247	4.8244	12,612,174	0	0	1.0000	0	9,944,210	7,307,856	55,969,386
2074	6,482,543	4,763,927	9.6117	45,789,438	3,844,412	2,825,203	4.9619	14,018,373	0	0	1.0000	0	10,326,955	7,589,130	59,807,811
2075	6,403,045	4,705,505	10.0009	47,059,287	3,563,167	2,618,520	5.1033	13,363,091	0	0	1.0000	0	9,966,212	7,324,025	60,422,378
2076	6,386,857	4,693,609	10.4060	48,841,694	3,557,353	2,614,247	5.2487	13,721,399	0	0	1.0000	0	9,944,210	7,307,856	62,563,093
2077	6,386,857	4,693,609	10.8274	50,819,580	3,557,353	2,614,247	5.3983	14,112,490	0	0	1.0000	0	9,944,210	7,307,856	64,932,071
2078	6,482,543	4,763,927	11.2659	53,669,926	3,844,412	2,825,203	5.5522	15,686,090	0	0	1.0000	0	10,326,955	7,589,130	69,356,016
2079	6,403,045	4,705,505	11.7222	55,158,873	3,563,167	2,618,520	5.7104	14,952,795	0	0	1.0000	0	9,966,212	7,324,025	70,111,667

Xcel Energy
Nuclear Decommissioning Accrual
60-Year Decommissioning Period
DECON Method - No Recasking
5-Year Early Shutdown

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AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
2080	6,386,857	4,693,609	12.1970	57,247,947	3,557,353	2,614,247	5.8731	15,353,735	0	0	1.0000	0	9,944,210	7,307,856	72,601,682
2081	6,386,857	4,693,609	12.6909	59,566,121	3,557,353	2,614,247	6.0405	15,791,360	0	0	1.0000	0	9,944,210	7,307,856	75,357,480
2082	6,482,543	4,763,927	13.2049	62,907,181	3,844,412	2,825,203	6.2127	17,552,136	0	0	1.0000	0	10,326,955	7,589,130	80,459,317
2083	7,066,689	5,193,208	13.7397	71,353,114	5,554,101	4,081,628	6.3897	26,080,380	0	0	1.0000	0	12,620,790	9,274,836	97,433,494
2084	6,386,857	4,693,609	14.2962	67,100,771	3,557,353	2,614,247	6.5719	17,180,571	0	0	1.0000	0	9,944,210	7,307,856	84,281,342
2085	6,099,798	4,482,653	14.8752	66,680,365	2,696,175	1,981,380	6.7592	13,392,543	0	0	1.0000	0	8,795,973	6,464,033	80,072,908
2086	2,034,890	1,495,411	15.4776	23,145,375	24,955,010	18,339,076	6.9518	127,489,587	0	0	1.0000	0	26,989,900	19,834,487	150,634,962
	$851,819,402	$625,989,760		$2,186,080,404	$664,030,274	$487,986,246		$1,063,017,234	$0	$0		$0	$1,515,849,676	$1,113,976,006	$3,249,097,637

Xcel Energy
Nuclear Decommissioning Accrual
60-Year Decommissioning Period
DECON Method - No Recasking
5-Year Early Shutdown

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AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
Prairie Island Unit 1															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2028	$22,324,352	$16,405,843	1.5476	$25,389,683	$9,728,959	$7,149,672	1.3622	$9,739,283	$1,250,000	$918,607	1.0000	$918,607	$33,303,311	$24,474,122	$36,047,572
2029	63,582,247	46,725,674	1.6103	75,242,352	33,397,619	24,543,427	1.4010	34,385,342	1,250,000	918,607	1.0000	918,607	98,229,866	72,187,708	110,546,301
2030	65,877,290	48,412,268	1.6755	81,114,755	81,239,936	59,702,054	1.4410	86,030,660	1,250,000	918,607	1.0000	918,607	148,367,226	109,032,929	168,064,022
2031	57,759,315	42,446,486	1.7434	74,001,203	65,595,019	48,204,831	1.4820	71,439,559	1,250,000	918,607	1.0000	918,607	124,604,334	91,569,923	146,359,369
2032	38,110,947	28,007,184	1.8140	50,805,031	36,889,671	27,109,686	1.5243	41,323,294	1,250,000	918,607	1.0000	918,607	76,250,618	56,035,476	93,046,932
2033	13,207,914	9,706,305	1.8874	18,319,680	18,994,691	13,958,924	1.5677	21,883,405	1,250,000	918,607	1.0000	918,607	33,452,605	24,583,836	41,121,692
2034	36,035,855	26,482,229	1.9639	52,008,449	76,476,728	56,201,641	1.6124	90,619,526	1,250,000	918,607	1.0000	918,607	113,762,582	83,602,477	143,546,582
2035	31,919,556	23,457,220	2.0434	47,932,484	13,365,606	9,822,190	1.6584	16,289,120	1,250,000	918,607	1.0000	918,607	46,535,162	34,198,017	65,140,211
2036	19,571,318	14,382,679	2.1262	30,580,451	9,445,873	6,941,635	1.7056	11,839,653	1,250,000	918,607	1.0000	918,607	30,267,191	22,242,921	43,338,711
2037	14,781,952	10,863,043	2.2123	24,032,309	11,668,700	8,575,159	1.7542	15,042,543	1,250,000	918,607	1.0000	918,607	27,700,652	20,356,808	39,993,460
2038	8,544,452	6,279,195	2.3019	14,454,078	6,492,672	4,771,371	1.8042	8,608,507	1,250,000	918,607	1.0000	918,607	16,287,125	11,969,172	23,981,192
2039	3,054,798	2,244,927	2.3951	5,376,824	1,939,011	1,424,951	1.8556	2,644,139	1,250,000	918,607	1.0000	918,607	6,243,809	4,588,485	8,939,570
2040	3,046,451	2,238,793	2.4921	5,579,295	1,930,298	1,418,548	1.9085	2,707,298	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	9,205,201
2041	3,046,451	2,238,793	2.5930	5,805,190	1,930,298	1,418,548	1.9629	2,784,467	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	9,508,264
2042	3,046,451	2,238,793	2.6981	6,040,487	1,930,298	1,418,548	2.0189	2,863,906	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	9,823,000
2043	3,054,798	2,244,927	2.8073	6,302,183	1,939,011	1,424,951	2.0764	2,958,768	1,250,000	918,607	1.0000	918,607	6,243,809	4,588,485	10,179,558
2044	3,046,451	2,238,793	2.9210	6,539,514	1,930,298	1,418,548	2.1356	3,029,451	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	10,487,571
2045	3,046,451	2,238,793	3.0393	6,804,363	1,930,298	1,418,548	2.1964	3,115,698	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	10,838,668
2046	3,046,451	2,238,793	3.1624	7,079,958	1,930,298	1,418,548	2.2590	3,204,499	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	11,203,065
2047	3,054,798	2,244,927	3.2905	7,386,932	1,939,011	1,424,951	2.3234	3,310,731	1,250,000	918,607	1.0000	918,607	6,243,809	4,588,485	11,616,270
2048	3,142,138	2,309,112	3.4238	7,905,937	2,217,357	1,629,503	2.3896	3,893,861	1,250,000	918,607	1.0000	918,607	6,609,495	4,857,222	12,718,405
2049	3,237,824	2,379,430	3.5624	8,476,482	2,504,416	1,840,459	2.4577	4,523,295	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	13,918,384
2050	3,237,824	2,379,430	3.7067	8,819,833	2,504,416	1,840,459	2.5278	4,652,312	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	14,390,752
2051	3,294,014	2,420,723	3.8568	9,336,245	2,656,659	1,952,340	2.5998	5,075,694	1,250,000	918,607	1.0000	918,607	7,200,673	5,291,670	15,330,546
2052	3,189,981	2,344,271	4.0130	9,407,559	2,360,887	1,734,981	2.6739	4,639,167	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	14,965,333
2053	3,333,510	2,449,748	4.1756	10,229,169	2,791,475	2,051,414	2.7501	5,641,594	1,250,000	918,607	1.0000	918,607	7,374,985	5,419,769	16,789,370
2054	3,189,981	2,344,271	4.3447	10,185,154	2,360,887	1,734,981	2.8285	4,907,395	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	16,011,156
2055	3,150,484	2,315,245	4.5206	10,466,297	2,226,070	1,635,906	2.9091	4,759,015	1,250,000	918,607	1.0000	918,607	6,626,554	4,869,758	16,143,919
2056	3,237,824	2,379,430	4.7037	11,192,125	2,504,416	1,840,459	2.9920	5,506,653	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	17,617,385
2057	3,237,824	2,379,430	4.8942	11,645,406	2,504,416	1,840,459	3.0773	5,663,644	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	18,227,657
2058	3,189,981	2,344,271	5.0924	11,937,965	2,360,887	1,734,981	3.1650	5,491,216	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	18,347,788
2059	3,246,170	2,385,563	5.2987	12,640,385	2,513,129	1,846,862	3.2552	6,011,905	1,250,000	918,607	1.0000	918,607	7,009,299	5,151,032	19,570,897
2060	3,237,824	2,379,430	5.5133	13,118,512	2,504,416	1,840,459	3.3480	6,161,856	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	20,198,974
2061	3,189,981	2,344,271	5.7366	13,448,144	2,360,887	1,734,981	3.4434	5,974,235	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	20,340,986
2062	3,237,824	2,379,430	5.9689	14,202,580	2,504,416	1,840,459	3.5415	6,517,985	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	21,639,172
2063	3,246,170	2,385,563	6.2106	14,815,780	2,513,129	1,846,862	3.6425	6,727,195	1,250,000	918,607	1.0000	918,607	7,009,299	5,151,032	22,461,581
2064	3,189,981	2,344,271	6.4622	15,149,147	2,360,887	1,734,981	3.7463	6,499,761	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	22,567,515
2065	3,237,824	2,379,430	6.7239	15,999,050	2,504,416	1,840,459	3.8531	7,091,472	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	24,009,128
2066	3,237,824	2,379,430	6.9962	16,646,968	2,504,416	1,840,459	3.9629	7,293,554	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	24,859,129
2067	3,246,170	2,385,563	7.2795	17,365,709	2,513,129	1,846,862	4.0758	7,527,440	1,250,000	918,607	1.0000	918,607	7,009,299	5,151,032	25,811,755
2068	3,237,824	2,379,430	7.5744	18,022,755	2,504,416	1,840,459	4.1920	7,715,203	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	26,656,565
2069	3,237,824	2,379,430	7.8811	18,752,526	2,504,416	1,840,459	4.3115	7,935,138	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	27,606,271
2070	3,569,646	2,623,281	8.2003	21,511,693	3,499,884	2,572,014	4.4343	11,405,081	1,250,000	918,607	1.0000	918,607	8,319,530	6,113,902	33,835,381
2071	3,246,170	2,385,563	8.5324	20,354,581	2,513,129	1,846,862	4.5607	8,422,983	1,250,000	918,607	1.0000	918,607	7,009,299	5,151,032	29,696,171
2072	3,237,974	2,379,540	8.8780	21,125,558	14,152,775	10,400,669	4.6907	48,786,420	1,250,000	918,607	1.0000	918,607	18,640,749	13,698,817	70,830,585
2073	832,743	611,971	9.2375	5,653,083	4,620,063	3,395,217	4.8244	16,379,886	0	0	1.0000	0	5,452,806	4,007,188	22,032,968
	$481,031,633	$353,503,191		$899,203,866	$459,759,673	$337,870,735		$649,023,806	$56,250,000	$41,337,312		$41,337,312	$997,041,305	$732,711,237	$1,589,564,984

Xcel Energy
Nuclear Decommissioning Accrual
60-Year Decommissioning Period
DECON Method - No Recasking
5-Year Early Shutdown

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AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
Prairie Island Unit 2															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2029	$7,760,265	$5,702,906	1.6103	$9,183,390	$4,479,535	$3,291,946	1.4010	$4,612,016	$1,250,000	$918,607	1.0000	$918,607	$13,489,800	$9,913,459	$14,714,013
2030	46,911,429	34,474,531	1.6755	57,762,076	35,601,339	26,162,909	1.4410	37,700,752	1,250,000	918,607	1.0000	918,607	83,762,768	61,556,047	96,381,435
2031	67,514,044	49,615,094	1.7434	86,498,955	86,298,832	63,419,763	1.4820	93,988,089	1,250,000	918,607	1.0000	918,607	155,062,875	113,953,465	181,405,652
2032	70,896,041	52,100,475	1.8140	94,510,262	70,558,163	51,852,174	1.5243	79,038,268	1,250,000	918,607	1.0000	918,607	142,704,204	104,871,256	174,467,137
2033	46,603,528	34,248,259	1.8874	64,640,164	42,782,149	31,439,982	1.5677	49,288,460	1,250,000	918,607	1.0000	918,607	90,635,677	66,606,848	114,847,231
2034	40,663,625	29,883,110	1.9639	58,687,439	77,452,618	56,918,809	1.6124	91,775,887	1,250,000	918,607	1.0000	918,607	119,366,242	87,720,525	151,381,933
2035	37,417,177	27,497,343	2.0434	56,188,070	14,193,501	10,430,599	1.6584	17,298,105	1,250,000	918,607	1.0000	918,607	52,860,679	38,846,548	74,404,782
2036	23,327,583	17,143,103	2.1262	36,449,666	13,070,130	9,605,049	1.7056	16,382,372	1,250,000	918,607	1.0000	918,607	37,647,713	27,666,760	53,750,646
2037	16,656,921	12,240,930	2.2123	27,080,609	17,178,640	12,624,334	1.7542	22,145,607	1,250,000	918,607	1.0000	918,607	35,085,561	25,783,871	50,144,824
2038	9,422,862	6,924,725	2.3019	15,940,025	9,074,042	6,668,382	1.8042	12,031,095	1,250,000	918,607	1.0000	918,607	19,746,904	14,511,714	28,889,727
2039	3,054,798	2,244,927	2.3951	5,376,824	1,939,011	1,424,951	1.8556	2,644,139	1,250,000	918,607	1.0000	918,607	6,243,809	4,588,485	8,939,570
2040	3,046,451	2,238,793	2.4921	5,579,295	1,930,298	1,418,548	1.9085	2,707,298	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	9,205,201
2041	3,046,451	2,238,793	2.5930	5,805,190	1,930,298	1,418,548	1.9629	2,784,467	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	9,508,264
2042	3,046,451	2,238,793	2.6981	6,040,487	1,930,298	1,418,548	2.0189	2,863,906	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	9,823,000
2043	3,054,798	2,244,927	2.8073	6,302,183	1,939,011	1,424,951	2.0764	2,958,768	1,250,000	918,607	1.0000	918,607	6,243,809	4,588,485	10,179,558
2044	3,046,451	2,238,793	2.9210	6,539,514	1,930,298	1,418,548	2.1356	3,029,451	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	10,487,571
2045	3,046,451	2,238,793	3.0393	6,804,363	1,930,298	1,418,548	2.1964	3,115,698	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	10,838,668
2046	3,046,451	2,238,793	3.1624	7,079,958	1,930,298	1,418,548	2.2590	3,204,499	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	11,203,065
2047	3,054,798	2,244,927	3.2905	7,386,932	1,939,011	1,424,951	2.3234	3,310,731	1,250,000	918,607	1.0000	918,607	6,243,809	4,588,485	11,616,270
2048	3,142,138	2,309,112	3.4238	7,905,937	2,217,358	1,629,504	2.3896	3,893,863	1,250,000	918,607	1.0000	918,607	6,609,496	4,857,223	12,718,407
2049	3,237,824	2,379,430	3.5624	8,476,482	2,504,416	1,840,459	2.4577	4,523,295	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	13,918,384
2050	3,237,824	2,379,430	3.7067	8,819,833	2,504,416	1,840,459	2.5278	4,652,312	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	14,390,752
2051	3,294,014	2,420,723	3.8568	9,336,245	2,656,659	1,952,340	2.5998	5,075,694	1,250,000	918,607	1.0000	918,607	7,200,673	5,291,670	15,330,546
2052	3,189,981	2,344,271	4.0130	9,407,559	2,360,887	1,734,981	2.6739	4,639,167	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	14,965,333
2053	3,333,510	2,449,748	4.1756	10,229,169	2,791,475	2,051,414	2.7501	5,641,594	1,250,000	918,607	1.0000	918,607	7,374,985	5,419,769	16,789,370
2054	3,189,981	2,344,271	4.3447	10,185,154	2,360,887	1,734,981	2.8285	4,907,395	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	16,011,156
2055	3,150,484	2,315,245	4.5206	10,466,297	2,226,070	1,635,906	2.9091	4,759,015	1,250,000	918,607	1.0000	918,607	6,626,554	4,869,758	16,143,919
2056	3,237,824	2,379,430	4.7037	11,192,125	2,504,416	1,840,459	2.9920	5,506,653	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	17,617,385
2057	3,237,824	2,379,430	4.8942	11,645,406	2,504,416	1,840,459	3.0773	5,663,644	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	18,227,657
2058	3,189,981	2,344,271	5.0924	11,937,965	2,360,887	1,734,981	3.1650	5,491,216	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	18,347,788
2059	3,246,170	2,385,563	5.2987	12,640,385	2,513,129	1,846,862	3.2552	6,011,905	1,250,000	918,607	1.0000	918,607	7,009,299	5,151,032	19,570,897
2060	3,237,824	2,379,430	5.5133	13,118,512	2,504,416	1,840,459	3.3480	6,161,856	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	20,198,974
2061	3,189,981	2,344,271	5.7366	13,448,144	2,360,887	1,734,981	3.4434	5,974,235	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	20,340,986
2062	3,237,824	2,379,430	5.9689	14,202,580	2,504,416	1,840,459	3.5415	6,517,985	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	21,639,172
2063	3,246,170	2,385,563	6.2106	14,815,780	2,513,129	1,846,862	3.6425	6,727,195	1,250,000	918,607	1.0000	918,607	7,009,299	5,151,032	22,461,581
2064	3,189,981	2,344,271	6.4622	15,149,147	2,360,887	1,734,981	3.7463	6,499,761	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	22,567,515
2065	3,237,824	2,379,430	6.7239	15,999,050	2,504,416	1,840,459	3.8531	7,091,472	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	24,009,128
2066	3,237,824	2,379,430	6.9962	16,646,968	2,504,416	1,840,459	3.9629	7,293,554	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	24,859,129
2067	3,246,170	2,385,563	7.2795	17,365,709	2,513,129	1,846,862	4.0758	7,527,440	1,250,000	918,607	1.0000	918,607	7,009,299	5,151,032	25,811,755
2068	3,237,824	2,379,430	7.5744	18,022,755	2,504,416	1,840,459	4.1920	7,715,203	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	26,656,565
2069	3,237,824	2,379,430	7.8811	18,752,526	2,504,416	1,840,459	4.3115	7,935,138	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	27,606,271
2070	3,569,646	2,623,281	8.2003	21,511,693	3,499,884	2,572,014	4.4343	11,405,081	1,250,000	918,607	1.0000	918,607	8,319,530	6,113,902	33,835,381
2071	3,246,170	2,385,563	8.5324	20,354,581	2,513,129	1,846,862	4.5607	8,422,983	1,250,000	918,607	1.0000	918,607	7,009,299	5,151,032	29,696,171
2072	3,237,824	2,379,430	8.8780	21,124,581	14,152,675	10,400,596	4.6907	48,786,075	1,250,000	918,607	1.0000	918,607	18,640,499	13,698,633	70,829,263
2073	832,743	611,971	9.2375	5,653,083	4,620,063	3,395,217	4.8244	16,379,886	0	-	1.0000	-	5,452,806	4,007,188	22,032,968
	$476,489,759	$350,165,433		$912,263,071	$467,153,049	$343,304,020		$666,083,223	$55,000,000	$40,418,705		$40,418,705	$998,642,807	$733,888,158	$1,618,764,999
	$1,809,340,794	$1,329,658,384		$3,997,547,341	$1,590,942,995	$1,169,161,000		$2,378,124,263	$111,250,000	$81,756,016		$81,756,016	$3,511,533,789	$2,580,575,401	$6,457,427,620

Xcel Energy
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60-Year Decommissioning Period
DECON Method - No Recasking
5-Year Early Shutdown

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EXTERNAL FUND CALCULATION

Monticello

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	623,672,182	15,706,857	-	6,696,113	646,075,152
2018	646,075,152	32,703,840	-	13,392,226	692,171,218
2019	692,171,218	35,782,017	-	44,081,384	772,034,619
2020	772,034,619	39,783,173	-	44,081,384	855,899,176
2021	855,899,176	43,984,787	-	44,081,384	943,965,347
2022	943,965,347	48,396,903	-	44,081,384	1,036,443,633
2023	1,036,443,633	53,030,065	-	44,081,384	1,133,555,082
2024	1,133,555,082	57,895,348	-	44,081,384	1,235,531,814
2025	1,235,531,814	55,466,361	(29,527,973)	33,061,038	1,294,531,240
2026	1,294,531,240	57,347,734	(116,732,635)	-	1,235,146,340
2027	1,235,146,340	54,716,983	(185,318,532)	-	1,104,544,791
2028	1,104,544,791	48,931,334	(189,726,324)	-	963,749,802
2029	963,749,802	42,694,116	(118,598,642)	-	887,845,276
2030	887,845,276	39,331,546	(226,794,546)	-	700,382,276
2031	700,382,276	31,026,935	(86,985,621)	-	644,423,589
2032	644,423,589	28,547,965	(62,058,629)	-	610,912,925
2033	610,912,925	27,063,443	(58,425,422)	-	579,550,945
2034	579,550,945	25,674,107	(11,142,863)	-	594,082,189
2035	594,082,189	26,317,841	(11,594,404)	-	608,805,626
2036	608,805,626	26,970,089	(11,999,353)	-	623,776,362
2037	623,776,362	27,633,293	(12,452,366)	-	638,957,289
2038	638,957,289	28,305,808	(12,922,869)	-	654,340,229
2039	654,340,229	28,987,272	(13,447,773)	-	669,879,727
2040	669,879,727	29,675,672	(13,918,682)	-	685,636,717
2041	685,636,717	30,373,707	(14,445,460)	-	701,564,964
2042	701,564,964	31,079,328	(14,993,096)	-	717,651,196
2043	717,651,196	31,791,948	(20,010,456)	-	729,432,688
2044	729,432,688	32,313,868	(16,151,223)	-	745,595,333
2045	745,595,333	33,029,873	(27,329,712)	-	751,295,494
2046	751,295,494	33,282,390	(28,307,493)	-	756,270,391
2047	756,270,391	33,502,778	(35,874,122)	-	753,899,048
2048	753,899,048	33,397,728	(42,121,877)	-	745,174,899
2049	745,174,899	33,011,248	(33,194,438)	-	744,991,709
2050	744,991,709	33,003,133	(43,325,856)	-	734,668,986
2051	734,668,986	32,545,836	(48,596,098)	-	718,618,724
2052	718,618,724	31,834,809	(21,624,503)	-	728,829,031
2053	728,829,031	32,287,126	(22,450,205)	-	738,665,952
2054	738,665,952	32,722,902	(23,307,586)	-	748,081,267

External Levelized

Xcel Energy
Nuclear Decommissioning Accrual
60-Year Decommissioning Period
DECON Method - No Recasking
5-Year Early Shutdown

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Proposed

EXTERNAL FUND CALCULATION

2055	748,081,267	33,140,000	(24,264,242)	-	756,957,026
2056	756,957,026	33,533,196	(25,123,185)	-	765,367,037
2057	765,367,037	33,905,760	(26,084,323)	-	773,188,474
2058	773,188,474	34,252,249	(27,082,664)	-	780,358,059
2059	780,358,059	34,569,862	(28,197,142)	-	786,730,780
2060	786,730,780	34,852,174	(29,197,663)	-	792,385,290
2061	792,385,290	35,102,668	(30,317,084)	-	797,170,874
2062	797,170,874	35,314,670	(31,479,823)	-	801,005,721
2063	801,005,721	35,484,553	(32,777,487)	-	803,712,787
2064	803,712,787	35,604,476	(33,943,427)	-	805,373,837
2065	805,373,837	35,678,061	(35,247,487)	-	805,804,411
2066	805,804,411	35,697,135	(36,602,285)	-	804,899,261
2067	804,899,261	35,657,037	(38,113,848)	-	802,442,450
2068	802,442,450	35,548,201	(39,472,694)	-	798,517,956
2069	798,517,956	35,374,345	(40,992,094)	-	792,900,208
2070	792,900,208	35,125,479	(42,570,952)	-	785,454,736
2071	785,454,736	34,795,645	(44,332,601)	-	775,917,780
2072	775,917,780	34,373,158	(45,916,273)	-	764,374,664
2073	764,374,664	33,861,798	(55,969,386)	-	742,267,076
2074	742,267,076	32,882,431	(59,807,811)	-	715,341,697
2075	715,341,697	31,689,637	(60,422,378)	-	686,608,956
2076	686,608,956	30,416,777	(62,563,093)	-	654,462,640
2077	654,462,640	28,992,695	(64,932,071)	-	618,523,264
2078	618,523,264	27,400,581	(69,356,016)	-	576,567,828
2079	576,567,828	25,541,955	(70,111,667)	-	531,998,116
2080	531,998,116	23,567,517	(72,601,682)	-	482,963,950
2081	482,963,950	21,395,303	(75,357,480)	-	429,001,773
2082	429,001,773	19,004,779	(80,459,317)	-	367,547,234
2083	367,547,234	16,282,342	(97,433,494)	-	286,396,083
2084	286,396,083	12,687,346	(84,281,342)	-	214,802,088
2085	214,802,088	9,515,732	(80,072,908)	-	144,244,912
2086	144,244,912	6,390,050	(150,634,962)	-	(0)

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60-Year Decommissioning Period **Page 9 of 12**
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5-Year Early Shutdown **Proposed**

EXTERNAL FUND CALCULATION

Prairie Island Unit 1

External Levelized

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	374,367,055	9,340,765	-	24,632	383,732,452
2018	383,732,452	19,149,479	-	49,264	402,931,195
2019	402,931,195	20,754,218	-	25,969,989	449,655,402
2020	449,655,402	23,085,756	-	25,969,989	498,711,148
2021	498,711,148	25,533,637	-	25,969,989	550,214,774
2022	550,214,774	28,103,668	-	25,969,989	604,288,432
2023	604,288,432	30,801,944	-	25,969,989	661,060,366
2024	661,060,366	33,634,863	-	25,969,989	720,665,218
2025	720,665,218	36,609,146	-	25,969,989	783,244,353
2026	783,244,353	39,731,844	-	25,969,989	848,946,187
2027	848,946,187	43,010,366	-	25,969,989	917,926,542
2028	917,926,542	38,454,999	(36,047,572)	17,399,893	937,733,862
2029	937,733,862	38,915,955	(110,546,301)	-	866,103,517
2030	866,103,517	35,943,296	(168,064,022)	-	733,982,791
2031	733,982,791	30,460,286	(146,359,369)	-	618,083,707
2032	618,083,707	25,650,474	(93,046,932)	-	550,687,249
2033	550,687,249	22,853,521	(41,121,692)	-	532,419,078
2034	532,419,078	22,095,392	(143,546,582)	-	410,967,888
2035	410,967,888	17,055,167	(65,140,211)	-	362,882,844
2036	362,882,844	15,059,638	(43,338,711)	-	334,603,771
2037	334,603,771	13,886,057	(39,993,460)	-	308,496,368
2038	308,496,368	12,802,599	(23,981,192)	-	297,317,775
2039	297,317,775	12,338,688	(8,939,570)	-	300,716,892
2040	300,716,892	12,479,751	(9,205,201)	-	303,991,443
2041	303,991,443	12,615,645	(9,508,264)	-	307,098,823
2042	307,098,823	12,744,601	(9,823,000)	-	310,020,425
2043	310,020,425	12,865,848	(10,179,558)	-	312,706,714
2044	312,706,714	12,977,329	(10,487,571)	-	315,196,472
2045	315,196,472	13,080,654	(10,838,668)	-	317,438,457
2046	317,438,457	13,173,696	(11,203,065)	-	319,409,089
2047	319,409,089	13,255,477	(11,616,270)	-	321,048,296
2048	321,048,296	13,323,504	(12,718,405)	-	321,653,396
2049	321,653,396	13,348,616	(13,918,384)	-	321,083,628
2050	321,083,628	13,324,971	(14,390,752)	-	320,017,846
2051	320,017,846	13,280,741	(15,330,546)	-	317,968,041
2052	317,968,041	13,195,674	(14,965,333)	-	316,198,382
2053	316,198,382	13,122,233	(16,789,370)	-	312,531,245
2054	312,531,245	12,970,047	(16,011,156)	-	309,490,136
2055	309,490,136	12,843,841	(16,143,919)	-	306,190,057

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EXTERNAL FUND CALCULATION

2056	306,190,057	12,706,887	(17,617,385)	-	301,279,560
2057	301,279,560	12,503,102	(18,227,657)	-	295,555,004
2058	295,555,004	12,265,533	(18,347,788)	-	289,472,749
2059	289,472,749	12,013,119	(19,570,897)	-	281,914,971
2060	281,914,971	11,699,471	(20,198,974)	-	273,415,468
2061	273,415,468	11,346,742	(20,340,986)	-	264,421,224
2062	264,421,224	10,973,481	(21,639,172)	-	253,755,533
2063	253,755,533	10,530,855	(22,461,581)	-	241,824,806
2064	241,824,806	10,035,729	(22,567,515)	-	229,293,021
2065	229,293,021	9,515,660	(24,009,128)	-	214,799,553
2066	214,799,553	8,914,181	(24,859,129)	-	198,854,605
2067	198,854,605	8,252,466	(25,811,755)	-	181,295,316
2068	181,295,316	7,523,756	(26,656,565)	-	162,162,507
2069	162,162,507	6,729,744	(27,606,271)	-	141,285,980
2070	141,285,980	5,863,368	(33,835,381)	-	113,313,967
2071	113,313,967	4,702,530	(29,696,171)	-	88,320,326
2072	88,320,326	3,665,294	(70,830,585)	-	21,155,034
2073	21,155,034	877,934	(22,032,968)	-	(0)

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EXTERNAL FUND CALCULATION

Prairie Island Unit 2

External Levelized

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	420,208,967	10,592,979	-	294,670	431,096,616
2018	431,096,616	21,742,121	-	589,341	453,428,078
2019	453,428,078	23,283,839	-	17,105,727	493,817,644
2020	493,817,644	25,319,474	-	17,105,727	536,242,845
2021	536,242,845	27,457,704	-	17,105,727	580,806,275
2022	580,806,275	29,703,701	-	17,105,727	627,615,703
2023	627,615,703	32,062,896	-	17,105,727	676,784,325
2024	676,784,325	34,540,994	-	17,105,727	728,431,047
2025	728,431,047	37,143,989	-	17,105,727	782,680,763
2026	782,680,763	39,878,175	-	17,105,727	839,664,664
2027	839,664,664	42,750,163	-	17,105,727	899,520,554
2028	899,520,554	45,766,900	-	17,105,727	962,393,181
2029	962,393,181	39,652,225	(14,714,013)	14,197,753	1,001,529,147
2030	1,001,529,147	40,962,542	(96,381,435)	-	946,110,254
2031	946,110,254	38,695,909	(181,405,652)	-	803,400,512
2032	803,400,512	32,859,081	(174,467,137)	-	661,792,456
2033	661,792,456	27,067,311	(114,847,231)	-	574,012,536
2034	574,012,536	23,477,113	(151,381,933)	-	446,107,716
2035	446,107,716	18,245,806	(74,404,782)	-	389,948,739
2036	389,948,739	15,948,903	(53,750,646)	-	352,146,997
2037	352,146,997	14,402,812	(50,144,824)	-	316,404,985
2038	316,404,985	12,940,964	(28,889,727)	-	300,456,222
2039	300,456,222	12,288,659	(8,939,570)	-	303,805,312
2040	303,805,312	12,425,637	(9,205,201)	-	307,025,748
2041	307,025,748	12,557,353	(9,508,264)	-	310,074,837
2042	310,074,837	12,682,061	(9,823,000)	-	312,933,898
2043	312,933,898	12,798,996	(10,179,558)	-	315,553,337
2044	315,553,337	12,906,131	(10,487,571)	-	317,971,897
2045	317,971,897	13,005,051	(10,838,668)	-	320,138,279
2046	320,138,279	13,093,656	(11,203,065)	-	322,028,870
2047	322,028,870	13,170,981	(11,616,270)	-	323,583,582
2048	323,583,582	13,234,568	(12,718,407)	-	324,099,744
2049	324,099,744	13,255,680	(13,918,384)	-	323,437,039
2050	323,437,039	13,228,575	(14,390,752)	-	322,274,862
2051	322,274,862	13,181,042	(15,330,546)	-	320,125,358
2052	320,125,358	13,093,127	(14,965,333)	-	318,253,152
2053	318,253,152	13,016,554	(16,789,370)	-	314,480,336
2054	314,480,336	12,862,246	(16,011,156)	-	311,331,426

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EXTERNAL FUND CALCULATION

2055	311,331,426	12,733,455	(16,143,919)	-	307,920,962
2056	307,920,962	12,593,967	(17,617,385)	-	302,897,545
2057	302,897,545	12,388,510	(18,227,657)	-	297,058,397
2058	297,058,397	12,149,688	(18,347,788)	-	290,860,298
2059	290,860,298	11,896,186	(19,570,897)	-	283,185,587
2060	283,185,587	11,582,291	(20,198,974)	-	274,568,904
2061	274,568,904	11,229,868	(20,340,986)	-	265,457,785
2062	265,457,785	10,857,223	(21,639,172)	-	254,675,837
2063	254,675,837	10,416,242	(22,461,581)	-	242,630,498
2064	242,630,498	9,923,587	(22,567,515)	-	229,986,570
2065	229,986,570	9,406,451	(24,009,128)	-	215,383,892
2066	215,383,892	8,809,201	(24,859,129)	-	199,333,964
2067	199,333,964	8,152,759	(25,811,755)	-	181,674,968
2068	181,674,968	7,430,506	(26,656,565)	-	162,448,909
2069	162,448,909	6,644,160	(27,606,271)	-	141,486,799
2070	141,486,799	5,786,810	(33,835,381)	-	113,438,228
2071	113,438,228	4,639,624	(29,696,171)	-	88,381,681
2072	88,381,681	3,614,811	(70,829,263)	-	21,167,228
2073	21,167,228	865,740	(22,032,968)	-	0

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2019 ACCRUAL COMPARISON

	Present	Proposed	Difference
Monticello	$13,392,226	($838,566)	($14,230,792)
Prairie Island Unit 1	49,264	1,282,107	1,232,843
Prairie Island Unit 2	589,341	(2,292,979)	(2,882,320)
TOTAL	$14,030,831	($1,849,439)	($15,880,270)

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2019 MN RETAIL SUMMARY

	Remaining Life (yrs)	Operational Earnings Rate	Post-Shutdown Earnings Rate	Market Value Balance 6/30/2017	Book Value 6/30/2017	Unrealized Gain/Loss 6/30/2017	Tax-Effect Adjustment	Tax-Adjusted Fund Balance 6/30/2017	2019-2021 Decommissioning Accrual
Monticello	33.75	5.01%	4.43%	$660,140,345	$529,148,381	$130,991,964	$36,468,163	$623,672,182	**(838,566)**
Prairie Island Unit 1	36.67	4.99%	4.15%	399,941,696	308,078,761	91,862,935	25,574,641	374,367,055	**1,282,107**
Prairie Island Unit 2	37.83	5.04%	4.09%	448,597,551	346,627,064	101,970,487	28,388,583	420,208,967	**(2,292,979)**
TOTAL DECOMMISSIONING ACCRUAL				**$1,508,679,592**	**$1,183,854,206**	**$324,825,386**	**$90,431,387**	**$1,418,248,204**	**($1,849,439)**

INPUT DATA

Escalation Rate (Labor)	4.05%
Escalation Rate (Non-Labor)	2.85%
Escalation Rate (PIIC)	0.00%
Jurisdictional Factor	73.4886%
Tax Rate for tax-effect adjustment	27.84%

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AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
Monticello															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2050	$21,103,620	$15,508,745	3.7067	$57,486,266	$8,935,561	$6,566,615	2.5278	$16,599,089	$0	$0	1.0000	$0	$30,039,182	$22,075,360	$74,085,355
2051	72,416,242	53,217,649	3.8568	205,249,828	42,961,353	31,571,677	2.5998	82,080,046	0	0	1.0000	0	115,377,595	84,789,326	287,329,874
2052	78,476,357	57,671,140	4.0130	231,434,285	102,263,189	75,151,739	2.6739	200,948,234	0	0	1.0000	0	180,739,546	132,822,879	432,382,519
2053	78,663,227	57,808,468	4.1756	241,385,038	100,155,666	73,602,950	2.7501	202,415,473	0	0	1.0000	0	178,818,892	131,411,418	443,800,512
2054	66,380,423	48,782,013	4.3447	211,943,210	38,894,671	28,583,132	2.8285	80,847,388	0	0	1.0000	0	105,275,094	77,365,144	292,790,598
2055	86,879,803	63,846,711	4.5206	288,625,441	113,147,091	83,150,161	2.9091	241,892,133	0	0	1.0000	0	200,026,894	146,996,872	530,517,574
2056	50,307,504	36,970,257	4.7037	173,896,999	20,688,337	15,203,559	2.9920	45,489,050	0	0	1.0000	0	70,995,841	52,173,817	219,386,048
2057	34,623,126	25,444,035	4.8942	124,528,195	14,196,883	10,433,084	3.0773	32,105,730	0	0	1.0000	0	48,820,010	35,877,119	156,633,925
2058	29,581,478	21,739,000	5.0924	110,703,685	15,098,979	11,096,021	3.1650	35,118,908	0	0	1.0000	0	44,680,457	32,835,022	145,822,593
2059	5,925,016	4,354,209	5.2987	23,071,645	2,187,162	1,607,314	3.2552	5,232,129	0	0	1.0000	0	8,112,178	5,961,523	28,303,774
2060	5,941,203	4,366,104	5.5133	24,071,642	2,193,018	1,611,617	3.3480	5,395,695	0	0	1.0000	0	8,134,221	5,977,722	29,467,337
2061	5,925,016	4,354,209	5.7366	24,978,353	2,187,162	1,607,314	3.4434	5,534,625	0	0	1.0000	0	8,112,178	5,961,523	30,512,978
2062	5,925,016	4,354,209	5.9689	25,989,836	2,187,162	1,607,314	3.5415	5,692,303	0	0	1.0000	0	8,112,178	5,961,523	31,682,138
2063	5,925,016	4,354,209	6.2106	27,042,248	2,187,162	1,607,314	3.6425	5,854,641	0	0	1.0000	0	8,112,178	5,961,523	32,896,889
2064	5,941,203	4,366,104	6.4622	28,214,638	2,193,018	1,611,617	3.7463	6,037,602	0	0	1.0000	0	8,134,221	5,977,722	34,252,241
2065	5,925,016	4,354,209	6.7239	29,277,263	2,187,162	1,607,314	3.8531	6,193,142	0	0	1.0000	0	8,112,178	5,961,523	35,470,405
2066	5,925,016	4,354,209	6.9962	30,462,914	2,187,162	1,607,314	3.9629	6,369,625	0	0	1.0000	0	8,112,178	5,961,523	36,832,539
2067	5,925,016	4,354,209	7.2795	31,696,461	2,187,162	1,607,314	4.0758	6,551,091	0	0	1.0000	0	8,112,178	5,961,523	38,247,552
2068	6,604,848	4,853,807	7.5744	36,764,678	4,183,953	3,074,727	4.1920	12,889,255	0	0	1.0000	0	10,788,801	7,928,534	49,653,932
2069	5,925,016	4,354,209	7.8811	34,315,953	2,187,162	1,607,314	4.3115	6,929,934	0	0	1.0000	0	8,112,178	5,961,523	41,245,888
2070	7,418,217	5,451,540	8.2003	44,704,267	6,666,766	4,899,310	4.4343	21,725,011	0	0	1.0000	0	14,084,983	10,350,851	66,429,278
2071	7,418,217	5,451,540	8.5324	46,514,723	6,666,766	4,899,310	4.5607	22,344,284	0	0	1.0000	0	14,084,983	10,350,851	68,859,007
2072	8,296,904	6,097,275	8.8780	54,131,605	9,260,122	6,805,130	4.6907	31,920,823	0	0	1.0000	0	17,557,026	12,902,405	86,052,428
2073	8,927,592	6,560,758	9.2375	60,605,004	11,194,891	8,226,964	4.8244	39,690,164	0	0	1.0000	0	20,122,483	14,787,722	100,295,169
2074	7,633,842	5,610,000	9.6117	53,921,638	7,313,641	5,374,689	4.9619	26,668,671	0	0	1.0000	0	14,947,483	10,984,689	80,590,309
2075	8,711,967	6,402,299	10.0009	64,028,748	10,548,016	7,751,585	5.1033	39,558,662	0	0	1.0000	0	19,259,983	14,153,883	103,587,410
2076	9,159,404	6,731,114	10.4060	70,043,968	11,847,622	8,706,646	5.2487	45,698,574	0	0	1.0000	0	21,007,026	15,437,760	115,742,542
2077	5,908,425	4,342,016	10.8274	47,012,745	2,137,389	1,570,737	5.3983	8,479,307	0	0	1.0000	0	8,045,814	5,912,753	55,492,052
2078	5,908,425	4,342,016	11.2659	48,916,719	2,137,389	1,570,737	5.5522	8,721,044	0	0	1.0000	0	8,045,814	5,912,753	57,637,763
2079	5,908,425	4,342,016	11.7222	50,897,981	2,137,389	1,570,737	5.7104	8,969,534	0	0	1.0000	0	8,045,814	5,912,753	59,867,515
2080	5,924,612	4,353,912	12.1970	53,104,661	2,143,245	1,575,040	5.8731	9,250,367	0	0	1.0000	0	8,067,857	5,928,952	62,355,028
2081	5,908,425	4,342,016	12.6909	55,104,092	2,137,389	1,570,737	6.0405	9,488,034	0	0	1.0000	0	8,045,814	5,912,753	64,592,126
2082	5,908,425	4,342,016	13.2049	57,335,888	2,137,389	1,570,737	6.2127	9,758,515	0	0	1.0000	0	8,045,814	5,912,753	67,094,403
2083	5,908,425	4,342,016	13.7397	59,657,998	2,137,389	1,570,737	6.3897	10,036,535	0	0	1.0000	0	8,045,814	5,912,753	69,694,534
2084	5,924,612	4,353,912	14.2962	62,244,392	2,143,245	1,575,040	6.5719	10,351,005	0	0	1.0000	0	8,067,857	5,928,952	72,595,397
2085	5,908,425	4,342,016	14.8752	64,588,358	2,137,389	1,570,737	6.7592	10,616,923	0	0	1.0000	0	8,045,814	5,912,753	75,205,280
2086	5,908,425	4,342,016	15.4776	67,203,988	2,137,389	1,570,737	6.9518	10,919,447	0	0	1.0000	0	8,045,814	5,912,753	78,123,435
2087	5,908,425	4,342,016	16.1045	69,925,998	2,137,389	1,570,737	7.1499	11,230,609	0	0	1.0000	0	8,045,814	5,912,753	81,156,608
2088	5,924,612	4,353,912	16.7567	72,957,192	2,143,245	1,575,040	7.3537	11,582,371	0	0	1.0000	0	8,067,857	5,928,952	84,539,563
2089	5,908,425	4,342,016	17.4353	75,704,353	2,137,389	1,570,737	7.5633	11,879,952	0	0	1.0000	0	8,045,814	5,912,753	87,584,305
2090	5,908,425	4,342,016	18.1415	78,770,685	2,137,389	1,570,737	7.7788	12,218,446	0	0	1.0000	0	8,045,814	5,912,753	90,989,131
2091	5,908,425	4,342,016	18.8762	81,960,764	2,137,389	1,570,737	8.0005	12,566,678	0	0	1.0000	0	8,045,814	5,912,753	94,527,442
2092	5,924,612	4,353,912	19.6407	85,513,873	2,143,245	1,575,040	8.2285	12,960,216	0	0	1.0000	0	8,067,857	5,928,952	98,474,090
2093	5,908,425	4,342,016	20.4361	88,733,875	2,137,389	1,570,737	8.4630	13,293,144	0	0	1.0000	0	8,045,814	5,912,753	102,027,019
2094	5,908,425	4,342,016	21.2638	92,327,762	2,137,389	1,570,737	8.7042	13,672,005	0	0	1.0000	0	8,045,814	5,912,753	105,999,767
2095	5,908,425	4,342,016	22.1250	96,067,106	2,137,389	1,570,737	8.9523	14,061,705	0	0	1.0000	0	8,045,814	5,912,753	110,128,811
2096	5,924,612	4,353,912	23.0210	100,231,401	2,143,245	1,575,040	9.2075	14,502,180	0	0	1.0000	0	8,067,857	5,928,952	114,733,581
2097	5,908,425	4,342,016	23.9534	104,006,048	2,137,389	1,570,737	9.4699	14,874,718	0	0	1.0000	0	8,045,814	5,912,753	118,880,766
2098	6,386,857	4,693,609	24.9235	116,981,160	3,557,353	2,614,247	9.7398	25,462,244	0	0	1.0000	0	9,944,210	7,307,856	142,443,404
2099	6,482,543	4,763,927	25.9329	123,542,445	3,844,412	2,825,203	10.0173	28,300,902	0	0	1.0000	0	10,326,955	7,589,130	151,843,348
2100	6,403,045	4,705,505	26.9832	126,969,587	3,563,167	2,618,520	10.3028	26,978,084	0	0	1.0000	0	9,966,212	7,324,025	153,947,671
2101	6,386,857	4,693,609	28.0760	131,777,762	3,557,353	2,614,247	10.5965	27,701,870	0	0	1.0000	0	9,944,210	7,307,856	159,479,632
2102	6,386,857	4,693,609	29.2131	137,114,865	3,557,353	2,614,247	10.8985	28,491,372	0	0	1.0000	0	9,944,210	7,307,856	165,606,237
2103	6,482,543	4,763,927	30.3962	144,805,281	3,844,412	2,825,203	11.2091	31,667,979	0	0	1.0000	0	10,326,955	7,589,130	176,473,260
2104	6,403,045	4,705,505	31.6272	148,821,953	3,563,167	2,618,520	11.5285	30,187,604	0	0	1.0000	0	9,966,212	7,324,025	179,009,557

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60-Year Decommissioning Period
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AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
2105	6,386,857	4,693,609	32.9081	154,457,749	3,557,353	2,614,247	11.8571	30,997,390	0	0	1.0000	0	9,944,210	7,307,856	185,455,139
2106	6,386,857	4,693,609	34.2409	160,713,391	3,557,353	2,614,247	12.1950	31,880,744	0	0	1.0000	0	9,944,210	7,307,856	192,594,135
2107	6,482,543	4,763,927	35.6277	169,727,766	3,844,412	2,825,203	12.5426	35,435,387	0	0	1.0000	0	10,326,955	7,589,130	205,163,152
2108	7,066,689	5,193,208	37.0706	192,515,320	5,554,101	4,081,628	12.9000	52,653,004	0	0	1.0000	0	12,620,790	9,274,836	245,168,324
2109	6,386,857	4,693,609	38.5720	181,041,880	3,557,353	2,614,247	13.2677	34,685,047	0	0	1.0000	0	9,944,210	7,307,856	215,726,927
2110	6,099,798	4,482,653	40.1341	179,907,257	2,696,175	1,981,380	13.6458	27,037,513	0	0	1.0000	0	8,795,973	6,464,033	206,944,771
2111	2,034,890	1,495,411	41.7596	62,447,769	24,955,010	18,339,076	14.0347	257,383,427	0	0	1.0000	0	26,989,900	19,834,487	319,831,196
	$851,819,402	$625,989,760		$5,898,178,598	$664,030,274	$487,986,246		$2,146,077,587	$0	$0		$0	$1,515,849,676	$1,113,976,006	$8,044,256,184

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	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
Prairie Island Unit 1															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2053	$22,324,352	$16,405,843	4.1756	$68,504,239	$9,728,959	$7,149,672	2.7501	$19,662,312	$1,250,000	$918,607	1.0000	$918,607	$33,303,311	$24,474,122	$89,085,158
2054	63,582,247	46,725,674	4.3447	203,009,034	33,397,619	24,543,427	2.8285	69,421,084	1,250,000	918,607	1.0000	918,607	98,229,866	72,187,708	273,348,725
2055	65,877,290	48,412,268	4.5206	218,852,499	81,239,936	59,702,054	2.9091	173,679,245	1,250,000	918,607	1.0000	918,607	148,367,226	109,032,929	393,450,351
2056	57,759,315	42,446,486	4.7037	199,655,534	65,595,019	48,204,831	2.9920	144,228,854	1,250,000	918,607	1.0000	918,607	124,604,334	91,569,923	344,802,995
2057	38,110,947	28,007,184	4.8942	137,072,758	36,889,671	27,109,686	3.0773	83,424,636	1,250,000	918,607	1.0000	918,607	76,250,618	56,035,476	221,416,001
2058	13,207,914	9,706,305	5.0924	49,428,388	18,994,691	13,958,924	3.1650	44,179,994	1,250,000	918,607	1.0000	918,607	33,452,605	24,583,836	94,526,988
2059	36,035,855	26,482,229	5.2987	140,321,385	76,476,728	56,201,641	3.2552	182,947,582	1,250,000	918,607	1.0000	918,607	113,762,582	83,602,477	324,187,574
2060	31,919,556	23,457,220	5.5133	129,326,692	13,365,606	9,822,190	3.3480	32,884,693	1,250,000	918,607	1.0000	918,607	46,535,162	34,198,017	163,129,992
2061	19,571,318	14,382,679	5.7366	82,507,674	9,445,873	6,941,635	3.4434	23,902,826	1,250,000	918,607	1.0000	918,607	30,267,191	22,242,921	107,329,108
2062	14,781,952	10,863,043	5.9689	64,840,415	11,668,700	8,575,159	3.5415	30,368,925	1,250,000	918,607	1.0000	918,607	27,700,652	20,356,808	96,127,947
2063	8,544,452	6,279,195	6.2106	38,997,566	6,492,672	4,771,371	3.6425	17,379,719	1,250,000	918,607	1.0000	918,607	16,287,125	11,969,172	57,295,891
2064	3,054,798	2,244,927	6.4622	14,507,166	1,939,011	1,424,951	3.7463	5,338,294	1,250,000	918,607	1.0000	918,607	6,243,809	4,588,485	20,764,067
2065	3,046,451	2,238,793	6.7239	15,053,419	1,930,298	1,418,548	3.8531	5,465,806	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	21,437,832
2066	3,046,451	2,238,793	6.9962	15,663,042	1,930,298	1,418,548	3.9629	5,621,563	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	22,203,212
2067	3,046,451	2,238,793	7.2795	16,297,292	1,930,298	1,418,548	4.0758	5,781,717	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	22,997,616
2068	3,054,798	2,244,927	7.5744	17,003,974	1,939,011	1,424,951	4.1920	5,973,394	1,250,000	918,607	1.0000	918,607	6,243,809	4,588,485	23,895,975
2069	3,046,451	2,238,793	7.8811	17,644,150	1,930,298	1,418,548	4.3115	6,116,069	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	24,678,825
2070	3,046,451	2,238,793	8.2003	18,358,772	1,930,298	1,418,548	4.4343	6,290,266	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	25,567,646
2071	3,046,451	2,238,793	8.5324	19,102,276	1,930,298	1,418,548	4.5607	6,469,571	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	26,490,453
2072	3,054,798	2,244,927	8.8780	19,930,461	1,939,011	1,424,951	4.6907	6,684,017	1,250,000	918,607	1.0000	918,607	6,243,809	4,588,485	27,533,085
2073	3,142,138	2,309,112	9.2375	21,330,420	2,217,357	1,629,503	4.8244	7,861,375	1,250,000	918,607	1.0000	918,607	6,609,495	4,857,222	30,110,402
2074	3,237,824	2,379,430	9.6117	22,870,368	2,504,416	1,840,459	4.9619	9,132,172	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	32,921,147
2075	3,237,824	2,379,430	10.0009	23,796,442	2,504,416	1,840,459	5.1033	9,392,413	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	34,107,462
2076	3,294,014	2,420,723	10.4060	25,190,046	2,656,659	1,952,340	5.2487	10,247,247	1,250,000	918,607	1.0000	918,607	7,200,673	5,291,670	36,355,900
2077	3,189,981	2,344,271	10.8274	25,382,359	2,360,887	1,734,981	5.3983	9,365,950	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	35,666,916
2078	3,333,510	2,449,748	11.2659	27,598,619	2,791,475	2,051,414	5.5522	11,389,862	1,250,000	918,607	1.0000	918,607	7,374,985	5,419,769	39,907,088
2079	3,189,981	2,344,271	11.7222	27,480,012	2,360,887	1,734,981	5.7104	9,907,438	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	38,306,057
2080	3,150,484	2,315,245	12.1970	28,239,045	2,226,070	1,635,906	5.8731	9,607,842	1,250,000	918,607	1.0000	918,607	6,626,554	4,869,758	38,765,494
2081	3,237,824	2,379,430	12.6909	30,197,109	2,504,416	1,840,459	6.0405	11,117,291	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	42,233,007
2082	3,237,824	2,379,430	13.2049	31,420,136	2,504,416	1,840,459	6.2127	11,434,218	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	43,772,961
2083	3,189,981	2,344,271	13.7397	32,209,579	2,360,887	1,734,981	6.3897	11,086,010	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	44,214,196
2084	3,246,170	2,385,563	14.2962	34,104,491	2,513,129	1,846,862	6.5719	12,137,392	1,250,000	918,607	1.0000	918,607	7,009,299	5,151,032	47,160,490
2085	3,237,824	2,379,430	14.8752	35,394,498	2,504,416	1,840,459	6.7592	12,440,029	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	48,753,133
2086	3,189,981	2,344,271	15.4776	36,283,687	2,360,887	1,734,981	6.9518	12,061,243	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	49,263,538
2087	3,237,824	2,379,430	16.1045	38,319,531	2,504,416	1,840,459	7.1499	13,159,096	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	52,397,234
2088	3,246,170	2,385,563	16.7567	39,974,170	2,513,129	1,846,862	7.3537	13,581,268	1,250,000	918,607	1.0000	918,607	7,009,299	5,151,032	54,474,045
2089	3,189,981	2,344,271	17.4353	40,873,067	2,360,887	1,734,981	7.5633	13,122,185	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	54,913,858
2090	3,237,824	2,379,430	18.1415	43,166,430	2,504,416	1,840,459	7.7788	14,316,561	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	58,401,597
2091	3,237,824	2,379,430	18.8762	44,914,597	2,504,416	1,840,459	8.0005	14,724,590	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	60,557,794
2092	3,246,170	2,385,563	19.6407	46,854,135	2,513,129	1,846,862	8.2285	15,196,903	1,250,000	918,607	1.0000	918,607	7,009,299	5,151,032	62,969,645
2093	3,237,824	2,379,430	20.4361	48,626,270	2,504,416	1,840,459	8.4630	15,575,802	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	65,120,679
2094	3,237,824	2,379,430	21.2638	50,595,724	2,504,416	1,840,459	8.7042	16,019,721	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	67,534,052
2095	3,569,646	2,623,281	22.1250	58,040,097	3,499,884	2,572,014	8.9523	23,025,439	1,250,000	918,607	1.0000	918,607	8,319,530	6,113,902	81,984,143
2096	3,246,170	2,385,563	23.0210	54,918,055	2,513,129	1,846,862	9.2075	17,004,981	1,250,000	918,607	1.0000	918,607	7,009,299	5,151,032	72,841,643
2097	3,237,974	2,379,540	23.9534	56,998,080	14,152,775	10,400,669	9.4699	98,493,298	1,250,000	918,607	1.0000	918,607	18,640,749	13,698,817	156,409,985
2098	832,743	611,971	24.9235	15,252,461	4,620,063	3,395,217	9.7398	33,068,736	0	0	1.0000	0	5,452,806	4,007,188	48,321,196
	$481,031,633	$353,503,191		$2,426,106,164	$459,759,673	$337,870,735		$1,310,289,630	$56,250,000	$41,337,312		$41,337,312	$997,041,305	$732,711,237	$3,777,733,106

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	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
Prairie Island Unit 2															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2054	$7,760,265	$5,702,906	4.3447	$24,777,417	$4,479,535	$3,291,946	2.8285	$9,311,268	$1,250,000	$918,607	1.0000	$918,607	$13,489,800	$9,913,459	$35,007,292
2055	46,911,429	34,474,531	4.5206	155,845,564	35,601,339	26,162,909	2.9091	76,110,519	1,250,000	918,607	1.0000	918,607	83,762,768	61,556,047	232,874,689
2056	67,514,044	49,615,094	4.7037	233,374,519	86,298,832	63,419,763	2.9920	189,751,932	1,250,000	918,607	1.0000	918,607	155,062,875	113,953,465	424,045,058
2057	70,896,041	52,100,475	4.8942	254,990,145	70,558,163	51,852,174	3.0773	159,564,694	1,250,000	918,607	1.0000	918,607	142,704,204	104,871,256	415,473,446
2058	46,603,528	34,248,259	5.0924	174,405,835	42,782,149	31,439,982	3.1650	99,507,544	1,250,000	918,607	1.0000	918,607	90,635,677	66,606,848	274,831,986
2059	40,663,625	29,883,110	5.2987	158,341,633	77,452,618	56,918,809	3.2552	185,282,106	1,250,000	918,607	1.0000	918,607	119,366,242	87,720,525	344,542,346
2060	37,417,177	27,497,343	5.5133	151,601,099	14,193,501	10,430,599	3.3480	34,921,645	1,250,000	918,607	1.0000	918,607	52,860,679	38,846,548	187,441,351
2061	23,327,583	17,143,103	5.7366	98,343,127	13,070,130	9,605,049	3.4434	33,074,027	1,250,000	918,607	1.0000	918,607	37,647,713	27,666,760	132,335,761
2062	16,656,921	12,240,930	5.9689	73,064,887	17,178,640	12,624,334	3.5415	44,709,080	1,250,000	918,607	1.0000	918,607	35,085,561	25,783,871	118,692,574
2063	9,422,862	6,924,725	6.2106	43,006,699	9,074,042	6,668,382	3.6425	24,289,581	1,250,000	918,607	1.0000	918,607	19,746,904	14,511,714	68,214,888
2064	3,054,798	2,244,927	6.4622	14,507,166	1,939,011	1,424,951	3.7463	5,338,294	1,250,000	918,607	1.0000	918,607	6,243,809	4,588,485	20,764,067
2065	3,046,451	2,238,793	6.7239	15,053,419	1,930,298	1,418,548	3.8531	5,465,806	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	21,437,832
2066	3,046,451	2,238,793	6.9962	15,663,042	1,930,298	1,418,548	3.9629	5,621,563	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	22,203,212
2067	3,046,451	2,238,793	7.2795	16,297,292	1,930,298	1,418,548	4.0758	5,781,717	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	22,997,616
2068	3,054,798	2,244,927	7.5744	17,003,974	1,939,011	1,424,951	4.1920	5,973,394	1,250,000	918,607	1.0000	918,607	6,243,809	4,588,485	23,895,975
2069	3,046,451	2,238,793	7.8811	17,644,150	1,930,298	1,418,548	4.3115	6,116,069	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	24,678,825
2070	3,046,451	2,238,793	8.2003	18,358,772	1,930,298	1,418,548	4.4343	6,290,266	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	25,567,646
2071	3,046,451	2,238,793	8.5324	19,102,276	1,930,298	1,418,548	4.5607	6,469,571	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	26,490,453
2072	3,054,798	2,244,927	8.8780	19,930,461	1,939,011	1,424,951	4.6907	6,684,017	1,250,000	918,607	1.0000	918,607	6,243,809	4,588,485	27,533,085
2073	3,142,138	2,309,112	9.2375	21,330,420	2,217,358	1,629,504	4.8244	7,861,379	1,250,000	918,607	1.0000	918,607	6,609,496	4,857,223	30,110,406
2074	3,237,824	2,379,430	9.6117	22,870,368	2,504,416	1,840,459	4.9619	9,132,172	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	32,921,147
2075	3,237,824	2,379,430	10.0009	23,796,442	2,504,416	1,840,459	5.1033	9,392,413	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	34,107,462
2076	3,294,014	2,420,723	10.4060	25,190,046	2,656,659	1,952,340	5.2487	10,247,247	1,250,000	918,607	1.0000	918,607	7,200,673	5,291,670	36,355,900
2077	3,189,981	2,344,271	10.8274	25,382,359	2,360,887	1,734,981	5.3983	9,365,950	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	35,666,916
2078	3,333,510	2,449,748	11.2659	27,598,619	2,791,475	2,051,414	5.5522	11,389,862	1,250,000	918,607	1.0000	918,607	7,374,985	5,419,769	39,907,088
2079	3,189,981	2,344,271	11.7222	27,480,012	2,360,887	1,734,981	5.7104	9,907,438	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	38,306,057
2080	3,150,484	2,315,245	12.1970	28,239,045	2,226,070	1,635,906	5.8731	9,607,842	1,250,000	918,607	1.0000	918,607	6,626,554	4,869,758	38,765,494
2081	3,237,824	2,379,430	12.6909	30,197,109	2,504,416	1,840,459	6.0405	11,117,291	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	42,233,007
2082	3,237,824	2,379,430	13.2049	31,420,136	2,504,416	1,840,459	6.2127	11,434,218	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	43,772,961
2083	3,189,981	2,344,271	13.7397	32,209,579	2,360,887	1,734,981	6.3897	11,086,010	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	44,214,196
2084	3,246,170	2,385,563	14.2962	34,104,491	2,513,129	1,846,862	6.5719	12,137,392	1,250,000	918,607	1.0000	918,607	7,009,299	5,151,032	47,160,490
2085	3,237,824	2,379,430	14.8752	35,394,498	2,504,416	1,840,459	6.7592	12,440,029	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	48,753,133
2086	3,189,981	2,344,271	15.4776	36,283,687	2,360,887	1,734,981	6.9518	12,061,243	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	49,263,538
2087	3,237,824	2,379,430	16.1045	38,319,531	2,504,416	1,840,459	7.1499	13,159,096	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	52,397,234
2088	3,246,170	2,385,563	16.7567	39,974,170	2,513,129	1,846,862	7.3537	13,581,268	1,250,000	918,607	1.0000	918,607	7,009,299	5,151,032	54,474,045
2089	3,189,981	2,344,271	17.4353	40,873,067	2,360,887	1,734,981	7.5633	13,122,185	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	54,913,858
2090	3,237,824	2,379,430	18.1415	43,166,430	2,504,416	1,840,459	7.7788	14,316,561	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	58,401,597
2091	3,237,824	2,379,430	18.8762	44,914,597	2,504,416	1,840,459	8.0005	14,724,590	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	60,557,794
2092	3,246,170	2,385,563	19.6407	46,854,135	2,513,129	1,846,862	8.2285	15,196,903	1,250,000	918,607	1.0000	918,607	7,009,299	5,151,032	62,969,645
2093	3,237,824	2,379,430	20.4361	48,626,270	2,504,416	1,840,459	8.4630	15,575,802	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	65,120,679
2094	3,237,824	2,379,430	21.2638	50,595,724	2,504,416	1,840,459	8.7042	16,019,721	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	67,534,052
2095	3,569,646	2,623,281	22.1250	58,040,097	3,499,884	2,572,014	8.9523	23,025,439	1,250,000	918,607	1.0000	918,607	8,319,530	6,113,902	81,984,143
2096	3,246,170	2,385,563	23.0210	54,918,055	2,513,129	1,846,862	9.2075	17,004,981	1,250,000	918,607	1.0000	918,607	7,009,299	5,151,032	72,841,643
2097	3,237,824	2,379,430	23.9534	56,995,443	14,152,675	10,400,596	9.4699	98,492,602	1,250,000	918,607	1.0000	918,607	18,640,499	13,698,633	156,406,652
2098	832,743	611,971	24.9235	15,252,461	4,620,063	3,395,217	9.7398	33,068,736	0	-	1.0000	-	5,452,806	4,007,188	48,321,196
	$476,489,759	$350,165,433		$2,461,338,267	$467,153,049	$343,304,020		$1,344,731,465	$55,000,000	$40,418,705		$40,418,705	$998,642,807	$733,888,158	$3,846,488,437
	$1,809,340,794	$1,329,658,384		$10,785,623,029	$1,590,942,995	$1,169,161,000		$4,801,098,682	$111,250,000	$81,756,016		$81,756,016	$3,511,533,789	$2,580,575,401	$15,668,477,727

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Proposed

EXTERNAL FUND CALCULATION

Monticello

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	623,672,182	15,706,857	-	6,696,113	646,075,152
2018	646,075,152	32,703,840	-	13,392,226	692,171,218
2019	692,171,218	34,656,772	-	(838,566)	725,989,424
2020	725,989,424	36,351,064	-	(838,566)	761,501,922
2021	761,501,922	38,130,240	-	(838,566)	798,793,597
2022	798,793,597	39,998,553	-	(838,566)	837,953,584
2023	837,953,584	41,960,468	-	(838,566)	879,075,486
2024	879,075,486	44,020,676	-	(838,566)	922,257,596
2025	922,257,596	46,184,099	-	(838,566)	967,603,129
2026	967,603,129	48,455,911	-	(838,566)	1,015,220,474
2027	1,015,220,474	50,841,540	-	(838,566)	1,065,223,447
2028	1,065,223,447	53,346,689	-	(838,566)	1,117,731,570
2029	1,117,731,570	55,977,346	-	(838,566)	1,172,870,350
2030	1,172,870,350	58,739,798	-	(838,566)	1,230,771,582
2031	1,230,771,582	61,640,650	-	(838,566)	1,291,573,666
2032	1,291,573,666	64,686,835	-	(838,566)	1,355,421,935
2033	1,355,421,935	67,885,633	-	(838,566)	1,422,469,002
2034	1,422,469,002	71,244,691	-	(838,566)	1,492,875,126
2035	1,492,875,126	74,772,038	-	(838,566)	1,566,808,598
2036	1,566,808,598	78,476,105	-	(838,566)	1,644,446,137
2037	1,644,446,137	82,365,745	-	(838,566)	1,725,973,316
2038	1,725,973,316	86,450,257	-	(838,566)	1,811,585,007
2039	1,811,585,007	90,739,403	-	(838,566)	1,901,485,844
2040	1,901,485,844	95,243,435	-	(838,566)	1,995,890,712
2041	1,995,890,712	99,973,119	-	(838,566)	2,095,025,265
2042	2,095,025,265	104,939,760	-	(838,566)	2,199,126,459
2043	2,199,126,459	110,155,229	-	(838,566)	2,308,443,122
2044	2,308,443,122	115,631,994	-	(838,566)	2,423,236,550
2045	2,423,236,550	121,383,145	-	(838,566)	2,543,781,129
2046	2,543,781,129	127,422,429	-	(838,566)	2,670,364,992
2047	2,670,364,992	133,764,280	-	(838,566)	2,803,290,706
2048	2,803,290,706	140,423,858	-	(838,566)	2,942,875,998
2049	2,942,875,998	147,417,081	-	(838,566)	3,089,454,513
2050	3,089,454,513	136,848,904	(74,085,355)	(628,925)	3,151,589,138
2051	3,151,589,138	139,615,399	(287,329,874)	-	3,003,874,664
2052	3,003,874,664	133,071,648	(432,382,519)	-	2,704,563,792
2053	2,704,563,792	119,812,176	(443,800,512)	-	2,380,575,456
2054	2,380,575,456	105,459,493	(292,790,598)	-	2,193,244,352

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EXTERNAL FUND CALCULATION

External Levelized	2055	2,193,244,352	97,160,725	(530,517,574)	-	1,759,887,502
	2056	1,759,887,502	77,963,016	(219,386,048)	-	1,618,464,470
	2057	1,618,464,470	71,697,976	(156,633,925)	-	1,533,528,521
	2058	1,533,528,521	67,935,313	(145,822,593)	-	1,455,641,241
	2059	1,455,641,241	64,484,907	(28,303,774)	-	1,491,822,375
	2060	1,491,822,375	66,087,731	(29,467,337)	-	1,528,442,769
	2061	1,528,442,769	67,710,015	(30,512,978)	-	1,565,639,805
	2062	1,565,639,805	69,357,843	(31,682,138)	-	1,603,315,511
	2063	1,603,315,511	71,026,877	(32,896,889)	-	1,641,445,499
	2064	1,641,445,499	72,716,036	(34,252,241)	-	1,679,909,293
	2065	1,679,909,293	74,419,982	(35,470,405)	-	1,718,858,870
	2066	1,718,858,870	76,145,448	(36,832,539)	-	1,758,171,780
	2067	1,758,171,780	77,887,010	(38,247,552)	-	1,797,811,238
	2068	1,797,811,238	79,643,038	(49,653,932)	-	1,827,800,343
	2069	1,827,800,343	80,971,555	(41,245,888)	-	1,867,526,010
	2070	1,867,526,010	82,731,402	(66,429,278)	-	1,883,828,135
	2071	1,883,828,135	83,453,586	(68,859,007)	-	1,898,422,713
	2072	1,898,422,713	84,100,126	(86,052,428)	-	1,896,470,411
	2073	1,896,470,411	84,013,639	(100,295,169)	-	1,880,188,882
	2074	1,880,188,882	83,292,367	(80,590,309)	-	1,882,890,941
	2075	1,882,890,941	83,412,069	(103,587,410)	-	1,862,715,599
	2076	1,862,715,599	82,518,301	(115,742,542)	-	1,829,491,358
	2077	1,829,491,358	81,046,467	(55,492,052)	-	1,855,045,773
	2078	1,855,045,773	82,178,528	(57,637,763)	-	1,879,586,538
	2079	1,879,586,538	83,265,684	(59,867,515)	-	1,902,984,707
	2080	1,902,984,707	84,302,223	(62,355,028)	-	1,924,931,901
	2081	1,924,931,901	85,274,483	(64,592,126)	-	1,945,614,258
	2082	1,945,614,258	86,190,712	(67,094,403)	-	1,964,710,567
	2083	1,964,710,567	87,036,678	(69,694,534)	-	1,982,052,711
	2084	1,982,052,711	87,804,935	(72,595,397)	-	1,997,262,248
	2085	1,997,262,248	88,478,718	(75,205,280)	-	2,010,535,686
	2086	2,010,535,686	89,066,731	(78,123,435)	-	2,021,478,982
	2087	2,021,478,982	89,551,519	(81,156,608)	-	2,029,873,893
	2088	2,029,873,893	89,923,413	(84,539,563)	-	2,035,257,743
	2089	2,035,257,743	90,161,918	(87,584,305)	-	2,037,835,356
	2090	2,037,835,356	90,276,106	(90,989,131)	-	2,037,122,332
	2091	2,037,122,332	90,244,519	(94,527,442)	-	2,032,839,409
	2092	2,032,839,409	90,054,786	(98,474,090)	-	2,024,420,106
	2093	2,024,420,106	89,681,811	(102,027,019)	-	2,012,074,898
	2094	2,012,074,898	89,134,918	(105,999,767)	-	1,995,210,049
	2095	1,995,210,049	88,387,805	(110,128,811)	-	1,973,469,043
	2096	1,973,469,043	87,424,679	(114,733,581)	-	1,946,160,140
	2097	1,946,160,140	86,214,894	(118,880,766)	-	1,913,494,268
	2098	1,913,494,268	84,767,796	(142,443,404)	-	1,855,818,659
	2099	1,855,818,659	82,212,767	(151,843,348)	-	1,786,188,078

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EXTERNAL FUND CALCULATION

2100	1,786,188,078	79,128,132	(153,947,671)	-	1,711,368,539
2101	1,711,368,539	75,813,626	(159,479,632)	-	1,627,702,533
2102	1,627,702,533	72,107,222	(165,606,237)	-	1,534,203,519
2103	1,534,203,519	67,965,216	(176,473,260)	-	1,425,695,474
2104	1,425,695,474	63,158,310	(179,009,557)	-	1,309,844,227
2105	1,309,844,227	58,026,099	(185,455,139)	-	1,182,415,187
2106	1,182,415,187	52,380,993	(192,594,135)	-	1,042,202,045
2107	1,042,202,045	46,169,551	(205,163,152)	-	883,208,443
2108	883,208,443	39,126,134	(245,168,324)	-	677,166,253
2109	677,166,253	29,998,465	(215,726,927)	-	491,437,791
2110	491,437,791	21,770,694	(206,944,771)	-	306,263,714
2111	306,263,714	13,567,483	(319,831,196)	-	0

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EXTERNAL FUND CALCULATION

Prairie Island Unit 1

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	374,367,055	9,340,765	-	24,632	383,732,452
2018	383,732,452	19,149,479	-	49,264	402,931,195
2019	402,931,195	20,138,255	-	1,282,107	424,351,557
2020	424,351,557	21,207,131	-	1,282,107	446,840,796
2021	446,840,796	22,329,344	-	1,282,107	470,452,247
2022	470,452,247	23,507,556	-	1,282,107	495,241,910
2023	495,241,910	24,744,560	-	1,282,107	521,268,577
2024	521,268,577	26,043,291	-	1,282,107	548,593,974
2025	548,593,974	27,406,828	-	1,282,107	577,282,909
2026	577,282,909	28,838,406	-	1,282,107	607,403,422
2027	607,403,422	30,341,419	-	1,282,107	639,026,948
2028	639,026,948	31,919,433	-	1,282,107	672,228,488
2029	672,228,488	33,576,190	-	1,282,107	707,086,786
2030	707,086,786	35,315,619	-	1,282,107	743,684,512
2031	743,684,512	37,141,846	-	1,282,107	782,108,465
2032	782,108,465	39,059,201	-	1,282,107	822,449,773
2033	822,449,773	41,072,232	-	1,282,107	864,804,112
2034	864,804,112	43,185,714	-	1,282,107	909,271,933
2035	909,271,933	45,404,658	-	1,282,107	955,958,698
2036	955,958,698	47,734,328	-	1,282,107	1,004,975,132
2037	1,004,975,132	50,180,248	-	1,282,107	1,056,437,487
2038	1,056,437,487	52,748,219	-	1,282,107	1,110,467,813
2039	1,110,467,813	55,444,332	-	1,282,107	1,167,194,252
2040	1,167,194,252	58,274,982	-	1,282,107	1,226,751,341
2041	1,226,751,341	61,246,880	-	1,282,107	1,289,280,329
2042	1,289,280,329	64,367,077	-	1,282,107	1,354,929,513
2043	1,354,929,513	67,642,971	-	1,282,107	1,423,854,591
2044	1,423,854,591	71,082,333	-	1,282,107	1,496,219,031
2045	1,496,219,031	74,693,318	-	1,282,107	1,572,194,456
2046	1,572,194,456	78,484,492	-	1,282,107	1,651,961,055
2047	1,651,961,055	82,464,845	-	1,282,107	1,735,708,007
2048	1,735,708,007	86,643,818	-	1,282,107	1,823,633,932
2049	1,823,633,932	91,031,322	-	1,282,107	1,915,947,361
2050	1,915,947,361	95,637,762	-	1,282,107	2,012,867,230
2051	2,012,867,230	100,474,063	-	1,282,107	2,114,623,400
2052	2,114,623,400	105,551,696	-	1,282,107	2,221,457,203
2053	2,221,457,203	92,208,298	(89,085,158)	859,012	2,225,439,356
2054	2,225,439,356	92,355,733	(273,348,725)	-	2,044,446,364
2055	2,044,446,364	84,844,524	(393,450,351)	-	1,735,840,537

External Levelized

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EXTERNAL FUND CALCULATION

2056	1,735,840,537	72,037,382	(344,802,995)	-	1,463,074,925
2057	1,463,074,925	60,717,609	(221,416,001)	-	1,302,376,533
2058	1,302,376,533	54,048,626	(94,526,988)	-	1,261,898,170
2059	1,261,898,170	52,368,774	(324,187,574)	-	990,079,371
2060	990,079,371	41,088,294	(163,129,992)	-	868,037,672
2061	868,037,672	36,023,563	(107,329,108)	-	796,732,128
2062	796,732,128	33,064,383	(96,127,947)	-	733,668,564
2063	733,668,564	30,447,245	(57,295,891)	-	706,819,918
2064	706,819,918	29,333,027	(20,764,067)	-	715,388,878
2065	715,388,878	29,688,638	(21,437,832)	-	723,639,684
2066	723,639,684	30,031,047	(22,203,212)	-	731,467,519
2067	731,467,519	30,355,902	(22,997,616)	-	738,825,805
2068	738,825,805	30,661,271	(23,895,975)	-	745,591,101
2069	745,591,101	30,942,031	(24,678,825)	-	751,854,306
2070	751,854,306	31,201,954	(25,567,646)	-	757,488,615
2071	757,488,615	31,435,778	(26,490,453)	-	762,433,939
2072	762,433,939	31,641,008	(27,533,085)	-	766,541,863
2073	766,541,863	31,811,487	(30,110,402)	-	768,242,947
2074	768,242,947	31,882,082	(32,921,147)	-	767,203,883
2075	767,203,883	31,838,961	(34,107,462)	-	764,935,382
2076	764,935,382	31,744,818	(36,355,900)	-	760,324,300
2077	760,324,300	31,553,458	(35,666,916)	-	756,210,843
2078	756,210,843	31,382,750	(39,907,088)	-	747,686,505
2079	747,686,505	31,028,990	(38,306,057)	-	740,409,438
2080	740,409,438	30,726,992	(38,765,494)	-	732,370,935
2081	732,370,935	30,393,394	(42,233,007)	-	720,531,323
2082	720,531,323	29,902,050	(43,772,961)	-	706,660,412
2083	706,660,412	29,326,407	(44,214,196)	-	691,772,623
2084	691,772,623	28,708,564	(47,160,490)	-	673,320,696
2085	673,320,696	27,942,809	(48,753,133)	-	652,510,372
2086	652,510,372	27,079,180	(49,263,538)	-	630,326,015
2087	630,326,015	26,158,530	(52,397,234)	-	604,087,310
2088	604,087,310	25,069,623	(54,474,045)	-	574,682,888
2089	574,682,888	23,849,340	(54,913,858)	-	543,618,370
2090	543,618,370	22,560,162	(58,401,597)	-	507,776,935
2091	507,776,935	21,072,743	(60,557,794)	-	468,291,883
2092	468,291,883	19,434,113	(62,969,645)	-	424,756,351
2093	424,756,351	17,627,389	(65,120,679)	-	377,263,061
2094	377,263,061	15,656,417	(67,534,052)	-	325,385,425
2095	325,385,425	13,503,495	(81,984,143)	-	256,904,777
2096	256,904,777	10,661,548	(72,841,643)	-	194,724,683
2097	194,724,683	8,081,074	(156,409,985)	-	46,395,772
2098	46,395,772	1,925,425	(48,321,196)	-	(0)

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EXTERNAL FUND CALCULATION

Prairie Island Unit 2

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	420,208,967	10,592,979	-	294,670	431,096,616
2018	431,096,616	21,742,121	-	589,341	453,428,078
2019	453,428,078	22,794,992	-	(2,292,979)	473,930,091
2020	473,930,091	23,828,293	-	(2,292,979)	495,465,405
2021	495,465,405	24,913,673	-	(2,292,979)	518,086,099
2022	518,086,099	26,053,756	-	(2,292,979)	541,846,875
2023	541,846,875	27,251,299	-	(2,292,979)	566,805,195
2024	566,805,195	28,509,199	-	(2,292,979)	593,021,415
2025	593,021,415	29,830,496	-	(2,292,979)	620,558,931
2026	620,558,931	31,218,387	-	(2,292,979)	649,484,339
2027	649,484,339	32,676,228	-	(2,292,979)	679,867,587
2028	679,867,587	34,207,543	-	(2,292,979)	711,782,151
2029	711,782,151	35,816,037	-	(2,292,979)	745,305,209
2030	745,305,209	37,505,599	-	(2,292,979)	780,517,829
2031	780,517,829	39,280,315	-	(2,292,979)	817,505,165
2032	817,505,165	41,144,477	-	(2,292,979)	856,356,662
2033	856,356,662	43,102,593	-	(2,292,979)	897,166,275
2034	897,166,275	45,159,397	-	(2,292,979)	940,032,693
2035	940,032,693	47,319,865	-	(2,292,979)	985,059,578
2036	985,059,578	49,589,220	-	(2,292,979)	1,032,355,818
2037	1,032,355,818	51,972,950	-	(2,292,979)	1,082,035,789
2038	1,082,035,789	54,476,821	-	(2,292,979)	1,134,219,630
2039	1,134,219,630	57,106,886	-	(2,292,979)	1,189,033,537
2040	1,189,033,537	59,869,507	-	(2,292,979)	1,246,610,065
2041	1,246,610,065	62,771,364	-	(2,292,979)	1,307,088,450
2042	1,307,088,450	65,819,475	-	(2,292,979)	1,370,614,945
2043	1,370,614,945	69,021,210	-	(2,292,979)	1,437,343,175
2044	1,437,343,175	72,384,313	-	(2,292,979)	1,507,434,509
2045	1,507,434,509	75,916,916	-	(2,292,979)	1,581,058,446
2046	1,581,058,446	79,627,563	-	(2,292,979)	1,658,393,029
2047	1,658,393,029	83,525,226	-	(2,292,979)	1,739,625,275
2048	1,739,625,275	87,619,331	-	(2,292,979)	1,824,951,626
2049	1,824,951,626	91,919,779	-	(2,292,979)	1,914,578,425
2050	1,914,578,425	96,436,970	-	(2,292,979)	2,008,722,416
2051	2,008,722,416	101,181,827	-	(2,292,979)	2,107,611,263
2052	2,107,611,263	106,165,825	-	(2,292,979)	2,211,484,108
2053	2,211,484,108	111,401,016	-	(2,292,979)	2,320,592,144
2054	2,320,592,144	94,873,299	(35,007,292)	(1,903,173)	2,378,554,978

External Levelized

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2055	2,378,554,978	97,282,899	(232,874,689)	-	2,242,963,188
2056	2,242,963,188	91,737,194	(424,045,058)	-	1,910,655,324
2057	1,910,655,324	78,145,803	(415,473,446)	-	1,573,327,681
2058	1,573,327,681	64,349,102	(274,831,986)	-	1,362,844,797
2059	1,362,844,797	55,740,352	(344,542,346)	-	1,074,042,803
2060	1,074,042,803	43,928,351	(187,441,351)	-	930,529,803
2061	930,529,803	38,058,669	(132,335,761)	-	836,252,711
2062	836,252,711	34,202,736	(118,692,574)	-	751,762,873
2063	751,762,873	30,747,101	(68,214,888)	-	714,295,087
2064	714,295,087	29,214,669	(20,764,067)	-	722,745,689
2065	722,745,689	29,560,299	(21,437,832)	-	730,868,155
2066	730,868,155	29,892,508	(22,203,212)	-	738,557,451
2067	738,557,451	30,207,000	(22,997,616)	-	745,766,835
2068	745,766,835	30,501,864	(23,895,975)	-	752,372,723
2069	752,372,723	30,772,044	(24,678,825)	-	758,465,942
2070	758,465,942	31,021,257	(25,567,646)	-	763,919,554
2071	763,919,554	31,244,310	(26,490,453)	-	768,673,410
2072	768,673,410	31,438,742	(27,533,085)	-	772,579,068
2073	772,579,068	31,598,484	(30,110,406)	-	774,067,146
2074	774,067,146	31,659,346	(32,921,147)	-	772,805,345
2075	772,805,345	31,607,739	(34,107,462)	-	770,305,622
2076	770,305,622	31,505,500	(36,355,900)	-	765,455,222
2077	765,455,222	31,307,119	(35,666,916)	-	761,095,425
2078	761,095,425	31,128,803	(39,907,088)	-	752,317,139
2079	752,317,139	30,769,771	(38,306,057)	-	744,780,853
2080	744,780,853	30,461,537	(38,765,494)	-	736,476,896
2081	736,476,896	30,121,905	(42,233,007)	-	724,365,795
2082	724,365,795	29,626,561	(43,772,961)	-	710,219,395
2083	710,219,395	29,047,973	(44,214,196)	-	695,053,172
2084	695,053,172	28,427,675	(47,160,490)	-	676,320,357
2085	676,320,357	27,661,503	(48,753,133)	-	655,228,726
2086	655,228,726	26,798,855	(49,263,538)	-	632,764,043
2087	632,764,043	25,880,049	(52,397,234)	-	606,246,858
2088	606,246,858	24,795,497	(54,474,045)	-	576,568,309
2089	576,568,309	23,581,644	(54,913,858)	-	545,236,095
2090	545,236,095	22,300,156	(58,401,597)	-	509,134,654
2091	509,134,654	20,823,607	(60,557,794)	-	469,400,467
2092	469,400,467	19,198,479	(62,969,645)	-	425,629,301
2093	425,629,301	17,408,238	(65,120,679)	-	377,916,860
2094	377,916,860	15,456,800	(67,534,052)	-	325,839,607
2095	325,839,607	13,326,840	(81,984,143)	-	257,182,304
2096	257,182,304	10,518,756	(72,841,643)	-	194,859,418
2097	194,859,418	7,969,750	(156,406,652)	-	46,422,516
2098	46,422,516	1,898,681	(48,321,196)	-	(0)

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2019 ACCRUAL COMPARISON

	Present	Proposed	Difference
Monticello	$13,392,226	$25,304,645	$11,912,419
Prairie Island Unit 1	49,264	18,867,378	18,818,114
Prairie Island Unit 2	589,341	12,760,253	12,170,912
TOTAL	$14,030,831	$56,932,276	$42,901,445

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2019 MN RETAIL SUMMARY

	Remaining Life (yrs)	Operational Earnings Rate	Post-Shutdown Earnings Rate	Market Value Balance 6/30/2017	Book Value 6/30/2017	Unrealized Gain/Loss 6/30/2017	Tax-Effect Adjustment	Tax-Adjusted Fund Balance 6/30/2017	2019-2021 Decommissioning Accrual
Monticello	13.75	5.01%	4.46%	$660,140,345	$529,148,381	$130,991,964	$36,468,163	$623,672,182	**25,304,645**
Prairie Island Unit 1	16.67	5.00%	4.19%	399,941,696	308,078,761	91,862,935	25,574,641	374,367,055	**18,867,378**
Prairie Island Unit 2	17.83	5.05%	4.13%	448,597,551	346,627,064	101,970,487	28,388,583	420,208,967	**12,760,253**
TOTAL DECOMMISSIONING ACCRUAL				**$1,508,679,592**	**$1,183,854,206**	**$324,825,386**	**$90,431,387**	**$1,418,248,204**	**$56,932,276**

INPUT DATA

Escalation Rate (Labor)	4.05%
Escalation Rate (Non-Labor)	2.85%
Escalation Rate (PIIC)	0.00%
Jurisdictional Factor	73.4886%
Tax Rate for tax-effect adjustment	27.84%

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AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
Monticello															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2030	$21,103,620	$15,508,745	1.6755	$25,984,903	$8,935,561	$6,566,615	1.4410	$9,462,492	$0	$0	1.0000	$0	$30,039,182	$22,075,360	$35,447,395
2031	72,416,235	53,217,644	1.7434	92,779,641	42,961,344	31,571,670	1.4820	46,789,215	0	0	1.0000	0	115,377,579	84,789,314	139,568,856
2032	81,871,153	60,165,927	1.8140	109,140,991	112,447,587	82,636,106	1.5243	125,962,216	0	0	1.0000	0	194,318,741	142,802,033	235,103,207
2033	78,663,227	57,808,468	1.8874	109,107,702	100,155,666	73,602,950	1.5677	115,387,345	0	0	1.0000	0	178,818,892	131,411,418	224,495,047
2034	66,380,423	48,782,013	1.9639	95,802,994	38,894,671	28,583,132	1.6124	46,087,441	0	0	1.0000	0	105,275,094	77,365,144	141,890,436
2035	86,879,803	63,846,711	2.0434	130,464,369	113,147,091	83,150,161	1.6584	137,896,227	0	0	1.0000	0	200,026,894	146,996,872	268,360,596
2036	50,307,504	36,970,257	2.1262	78,606,161	20,688,337	15,203,559	1.7056	25,931,191	0	0	1.0000	0	70,995,841	52,173,817	104,537,352
2037	34,623,126	25,444,035	2.2123	56,289,838	14,196,883	10,433,084	1.7542	18,301,716	0	0	1.0000	0	48,820,010	35,877,119	74,591,555
2038	29,581,478	21,739,000	2.3019	50,041,005	15,098,979	11,096,021	1.8042	20,019,442	0	0	1.0000	0	44,680,457	32,835,022	70,060,446
2039	5,925,017	4,354,209	2.3951	10,428,767	2,187,162	1,607,314	1.8556	2,982,532	0	0	1.0000	0	8,112,179	5,961,523	13,411,299
2040	5,941,204	4,366,105	2.4921	10,880,770	2,193,018	1,611,617	1.9085	3,075,772	0	0	1.0000	0	8,134,222	5,977,722	13,956,542
2041	5,925,017	4,354,209	2.5930	11,290,465	2,187,162	1,607,314	1.9629	3,154,997	0	0	1.0000	0	8,112,179	5,961,523	14,445,461
2042	5,925,017	4,354,209	2.6981	11,748,092	2,187,162	1,607,314	2.0189	3,245,006	0	0	1.0000	0	8,112,179	5,961,523	14,993,098
2043	5,925,017	4,354,209	2.8073	12,223,572	2,187,162	1,607,314	2.0764	3,337,427	0	0	1.0000	0	8,112,179	5,961,523	15,560,999
2044	5,941,204	4,366,105	2.9210	12,753,392	2,193,018	1,611,617	2.1356	3,441,770	0	0	1.0000	0	8,134,222	5,977,722	16,195,163
2045	5,925,017	4,354,209	3.0393	13,233,748	2,187,162	1,607,314	2.1964	3,530,305	0	0	1.0000	0	8,112,179	5,961,523	16,764,053
2046	5,925,017	4,354,209	3.1624	13,769,752	2,187,162	1,607,314	2.2590	3,630,922	0	0	1.0000	0	8,112,179	5,961,523	17,400,674
2047	5,925,017	4,354,209	3.2905	14,327,526	2,187,162	1,607,314	2.3234	3,734,433	0	0	1.0000	0	8,112,179	5,961,523	18,061,959
2048	6,604,849	4,853,808	3.4238	16,618,468	4,183,955	3,074,728	2.3896	7,347,371	0	0	1.0000	0	10,788,804	7,928,536	23,965,838
2049	5,925,017	4,354,209	3.5624	15,511,435	2,187,159	1,607,312	2.4577	3,950,290	0	0	1.0000	0	8,112,176	5,961,521	19,461,726
2050	7,418,218	5,451,541	3.7067	20,207,228	6,666,765	4,899,309	2.5278	12,384,475	0	0	1.0000	0	14,084,983	10,350,851	32,591,702
2051	7,418,218	5,451,541	3.8568	21,025,504	6,666,765	4,899,309	2.5998	12,737,225	0	0	1.0000	0	14,084,983	10,350,851	33,762,729
2052	8,296,905	6,097,276	4.0130	24,468,367	9,260,121	6,805,129	2.6739	18,196,235	0	0	1.0000	0	17,557,026	12,902,405	42,664,602
2053	8,927,593	6,560,759	4.1756	27,395,105	11,194,890	8,226,963	2.7501	22,624,971	0	0	1.0000	0	20,122,483	14,787,722	50,020,076
2054	7,633,843	5,610,001	4.3447	24,373,771	7,313,640	5,374,689	2.8285	15,202,307	0	0	1.0000	0	14,947,483	10,984,689	39,576,077
2055	8,711,968	6,402,299	4.5206	28,942,234	10,548,015	7,751,584	2.9091	22,550,133	0	0	1.0000	0	19,259,983	14,153,883	51,492,367
2056	9,159,405	6,731,114	4.7037	31,661,142	11,847,621	8,706,646	2.9920	26,050,283	0	0	1.0000	0	21,007,026	15,437,760	57,711,426
2057	5,908,426	4,342,017	4.8942	21,250,699	2,137,389	1,570,737	3.0773	4,833,628	0	0	1.0000	0	8,045,815	5,912,753	26,084,326
2058	12,004,811	8,822,162	5.0924	44,925,978	20,426,543	15,011,171	3.1650	47,510,357	0	0	1.0000	0	32,431,354	23,833,333	92,436,335
2059	5,908,426	4,342,017	5.2987	23,007,045	2,137,389	1,570,737	3.2552	5,113,062	0	0	1.0000	0	8,045,815	5,912,753	28,120,106
2060	5,924,613	4,353,912	5.5133	24,004,425	2,143,245	1,575,040	3.3480	5,273,234	0	0	1.0000	0	8,067,858	5,928,952	29,277,659
2061	5,908,426	4,342,017	5.7366	24,908,414	2,137,389	1,570,737	3.4434	5,408,674	0	0	1.0000	0	8,045,815	5,912,753	30,317,088
2062	5,908,426	4,342,017	5.9689	25,917,064	2,137,389	1,570,737	3.5415	5,562,764	0	0	1.0000	0	8,045,815	5,912,753	31,479,828
2063	5,908,426	4,342,017	6.2106	26,966,530	2,137,389	1,570,737	3.6425	5,721,408	0	0	1.0000	0	8,045,815	5,912,753	32,687,938
2064	5,924,613	4,353,912	6.4622	28,135,853	2,143,245	1,575,040	3.7463	5,900,572	0	0	1.0000	0	8,067,858	5,928,952	34,036,425
2065	5,908,426	4,342,017	6.7239	29,195,287	2,137,389	1,570,737	3.8531	6,052,205	0	0	1.0000	0	8,045,815	5,912,753	35,247,492
2066	9,566,257	7,030,104	6.9962	49,184,013	13,110,882	9,634,998	3.9629	38,182,533	0	0	1.0000	0	22,677,139	16,665,102	87,366,546
2067	5,908,426	4,342,017	7.2795	31,607,711	2,137,389	1,570,737	4.0758	6,402,008	0	0	1.0000	0	8,045,815	5,912,753	38,009,720
2068	14,459,552	10,626,116	7.5744	80,486,450	27,748,061	20,391,649	4.1920	85,481,792	0	0	1.0000	0	42,207,613	31,017,765	165,968,243
2069	5,908,426	4,342,017	7.8811	34,219,869	2,137,389	1,570,737	4.3115	6,772,231	0	0	1.0000	0	8,045,815	5,912,753	40,992,100
2070	5,908,426	4,342,017	8.2003	35,605,841	2,137,389	1,570,737	4.4343	6,965,117	0	0	1.0000	0	8,045,815	5,912,753	42,570,958
2071	5,908,426	4,342,017	8.5324	37,047,824	2,137,389	1,570,737	4.5607	7,163,658	0	0	1.0000	0	8,045,815	5,912,753	44,211,483
2072	5,924,613	4,353,912	8.8780	38,654,034	2,143,245	1,575,040	4.6907	7,388,040	0	0	1.0000	0	8,067,858	5,928,952	46,042,074
2073	5,908,426	4,342,017	9.2375	40,109,380	2,137,389	1,570,737	4.8244	7,577,862	0	0	1.0000	0	8,045,815	5,912,753	47,687,242
2074	5,908,426	4,342,017	9.6117	41,734,163	2,137,389	1,570,737	4.9619	7,793,838	0	0	1.0000	0	8,045,815	5,912,753	49,528,001
2075	5,908,426	4,342,017	10.0009	43,424,076	2,137,389	1,570,737	5.1033	8,015,940	0	0	1.0000	0	8,045,815	5,912,753	51,440,016
2076	5,924,613	4,353,912	10.4060	45,306,813	2,143,245	1,575,040	5.2487	8,266,912	0	0	1.0000	0	8,067,858	5,928,952	53,573,725
2077	5,908,426	4,342,017	10.8274	47,012,753	2,137,389	1,570,737	5.3983	8,479,307	0	0	1.0000	0	8,045,815	5,912,753	55,492,060
2078	6,386,857	4,693,609	11.2659	52,877,728	3,557,353	2,614,247	5.5522	14,514,823	0	0	1.0000	0	9,944,210	7,307,856	67,392,551
2079	6,482,543	4,763,927	11.7222	55,843,706	3,844,412	2,825,203	5.7104	16,133,037	0	0	1.0000	0	10,326,955	7,589,130	71,976,743
2080	6,403,045	4,705,505	12.1970	57,393,047	3,563,167	2,618,520	5.8731	15,378,828	0	0	1.0000	0	9,966,212	7,324,025	72,771,874
2081	6,386,857	4,693,609	12.6909	59,566,121	3,557,353	2,614,247	6.0405	15,791,360	0	0	1.0000	0	9,944,210	7,307,856	75,357,480
2082	6,386,857	4,693,609	13.2049	61,978,635	3,557,353	2,614,247	6.2127	16,241,533	0	0	1.0000	0	9,944,210	7,307,856	78,220,169
2083	6,482,543	4,763,927	13.7397	65,454,929	3,844,412	2,825,203	6.3897	18,052,197	0	0	1.0000	0	10,326,955	7,589,130	83,507,127
2084	6,403,045	4,705,505	14.2962	67,270,843	3,563,167	2,618,520	6.5719	17,208,649	0	0	1.0000	0	9,966,212	7,324,025	84,479,492

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	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
2085	6,386,857	4,693,609	14.8752	69,818,370	3,557,353	2,614,247	6.7592	17,670,219	0	0	1.0000	0	9,944,210	7,307,856	87,488,590
2086	6,386,857	4,693,609	15.4776	72,645,800	3,557,353	2,614,247	6.9518	18,173,723	0	0	1.0000	0	9,944,210	7,307,856	90,819,524
2087	6,482,543	4,763,927	16.1045	76,720,664	3,844,412	2,825,203	7.1499	20,199,916	0	0	1.0000	0	10,326,955	7,589,130	96,920,580
2088	7,066,689	5,193,208	16.7567	87,021,021	5,554,101	4,081,628	7.3537	30,015,070	0	0	1.0000	0	12,620,790	9,274,836	117,036,091
2089	6,386,857	4,693,609	17.4353	81,834,478	3,557,353	2,614,247	7.5633	19,772,335	0	0	1.0000	0	9,944,210	7,307,856	101,606,814
2090	6,099,798	4,482,653	18.1415	81,322,056	11,895,081	8,741,523	7.7788	67,998,558	0	0	1.0000	0	17,994,879	13,224,176	149,320,614
2091	2,067,326	1,519,248	18.8762	28,677,630	15,798,591	11,610,156	8.0005	92,887,054	0	0	1.0000	0	17,865,917	13,129,404	121,564,684
	$873,535,822	$641,948,844		$2,760,206,192	$729,124,605	$535,823,128		$1,386,916,184	$0	$0		$0	$1,602,660,427	$1,177,771,972	$4,147,122,376

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	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
Prairie Island Unit 1															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2033	$22,324,352	$16,405,843	1.8874	$30,964,388	$9,448,311	$6,943,427	1.5677	$10,885,211	$1,250,000	$918,607	1.0000	$918,607	$33,022,663	$24,267,877	$42,768,206
2034	63,582,247	46,725,674	1.9639	91,764,550	32,971,808	24,230,505	1.6124	39,069,266	1,250,000	918,607	1.0000	918,607	97,804,054	71,874,785	131,752,423
2035	65,877,290	48,412,268	2.0434	98,925,629	81,239,936	59,702,054	1.6584	99,009,886	1,250,000	918,607	1.0000	918,607	148,367,226	109,032,929	198,854,122
2036	57,759,315	42,446,486	2.1262	90,249,718	65,595,018	48,204,830	1.7056	82,218,158	1,250,000	918,607	1.0000	918,607	124,604,333	91,569,923	173,386,483
2037	39,808,345	29,254,577	2.2123	64,719,901	41,981,871	30,851,870	1.7542	54,120,350	1,250,000	918,607	1.0000	918,607	83,040,216	61,025,054	119,758,858
2038	13,207,909	9,706,302	2.3019	22,342,936	18,994,691	13,958,923	1.8042	25,184,690	1,250,000	918,607	1.0000	918,607	33,452,600	24,583,832	48,446,232
2039	36,035,851	26,482,226	2.3951	63,427,579	76,476,727	56,201,641	1.8556	104,287,765	1,250,000	918,607	1.0000	918,607	113,762,578	83,602,474	168,633,951
2040	31,919,556	23,457,220	2.4921	58,457,738	13,365,606	9,822,190	1.9085	18,745,650	1,250,000	918,607	1.0000	918,607	46,535,162	34,198,017	78,121,996
2041	19,571,318	14,382,679	2.5930	37,294,286	9,445,873	6,941,635	1.9629	13,625,736	1,250,000	918,607	1.0000	918,607	30,267,191	22,242,921	51,838,628
2042	14,781,952	10,863,043	2.6981	29,309,575	11,668,700	8,575,159	2.0189	17,312,388	1,250,000	918,607	1.0000	918,607	27,700,652	20,356,808	47,540,570
2043	8,544,452	6,279,195	2.8073	17,627,583	6,492,672	4,771,371	2.0764	9,907,275	1,250,000	918,607	1.0000	918,607	16,287,125	11,969,172	28,453,465
2044	3,054,798	2,244,927	2.9210	6,557,431	1,939,011	1,424,951	2.1356	3,043,125	1,250,000	918,607	1.0000	918,607	6,243,809	4,588,485	10,519,163
2045	5,353,318	3,934,076	3.0393	11,956,837	8,850,896	6,504,395	2.1964	14,286,253	1,250,000	918,607	1.0000	918,607	15,454,214	11,357,078	27,161,698
2046	4,584,362	3,368,981	3.1624	10,654,067	6,544,030	4,809,113	2.2590	10,863,786	1,250,000	918,607	1.0000	918,607	12,378,392	9,096,701	22,436,459
2047	4,584,362	3,368,981	3.2905	11,085,633	6,544,030	4,809,113	2.3234	11,173,492	1,250,000	918,607	1.0000	918,607	12,378,392	9,096,701	23,177,732
2048	3,054,798	2,244,927	3.4238	7,686,181	1,939,011	1,424,951	2.3896	3,405,063	1,250,000	918,607	1.0000	918,607	6,243,809	4,588,485	12,009,850
2049	4,584,362	3,368,981	3.5624	12,001,659	6,544,030	4,809,113	2.4577	11,819,356	1,250,000	918,607	1.0000	918,607	12,378,392	9,096,701	24,739,622
2050	5,353,318	3,934,076	3.7067	14,582,439	8,850,896	6,504,395	2.5278	16,441,810	1,250,000	918,607	1.0000	918,607	15,454,214	11,357,078	31,942,856
2051	5,159,362	3,791,541	3.8568	14,623,213	8,269,028	6,076,789	2.5998	15,798,435	1,250,000	918,607	1.0000	918,607	14,678,390	10,786,936	31,340,256
2052	5,361,664	3,940,209	4.0130	15,812,060	8,859,611	6,510,800	2.6739	17,409,227	1,250,000	918,607	1.0000	918,607	15,471,275	11,369,616	34,139,894
2053	3,142,138	2,309,112	4.1756	9,641,927	2,217,357	1,629,503	2.7501	4,481,297	1,250,000	918,607	1.0000	918,607	6,609,495	4,857,222	15,041,831
2054	3,237,824	2,379,430	4.3447	10,337,910	2,504,416	1,840,459	2.8285	5,205,738	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	16,462,254
2055	5,544,690	4,074,712	4.5206	18,420,145	9,425,014	6,926,306	2.9091	20,149,317	1,250,000	918,607	1.0000	918,607	16,219,704	11,919,626	39,488,069
2056	4,831,925	3,550,912	4.7037	16,702,424	7,270,391	5,342,905	2.9920	15,985,972	1,250,000	918,607	1.0000	918,607	13,352,316	9,812,424	33,607,002
2057	5,302,892	3,897,019	4.8942	19,072,789	8,699,619	6,393,224	3.0773	19,673,868	1,250,000	918,607	1.0000	918,607	15,252,511	11,208,849	39,665,263
2058	3,333,511	2,449,749	5.0924	12,475,102	2,791,475	2,051,414	3.1650	6,492,726	1,250,000	918,607	1.0000	918,607	7,374,986	5,419,770	19,886,435
2059	3,189,981	2,344,271	5.2987	12,421,588	2,360,887	1,734,981	3.2552	5,647,711	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	18,987,907
2060	3,150,484	2,315,245	5.5133	12,764,641	2,226,070	1,635,906	3.3480	5,477,015	1,250,000	918,607	1.0000	918,607	6,626,554	4,869,758	19,160,263
2061	3,237,824	2,379,430	5.7366	13,649,838	2,504,416	1,840,459	3.4434	6,337,436	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	20,905,881
2062	3,237,824	2,379,430	5.9689	14,202,580	2,504,416	1,840,459	3.5415	6,517,985	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	21,639,172
2063	3,189,981	2,344,271	6.2106	14,559,329	2,360,887	1,734,981	3.6425	6,319,670	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	21,797,605
2064	3,246,171	2,385,564	6.4622	15,415,992	2,513,129	1,846,862	3.7463	6,918,899	1,250,000	918,607	1.0000	918,607	7,009,300	5,151,033	23,253,498
2065	3,237,824	2,379,430	6.7239	15,999,050	2,504,416	1,840,459	3.8531	7,091,472	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	24,009,128
2066	3,189,981	2,344,271	6.9962	16,400,988	2,360,887	1,734,981	3.9629	6,875,558	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	24,195,153
2067	3,237,824	2,379,430	7.2795	17,321,061	2,504,416	1,840,459	4.0758	7,501,342	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	25,741,010
2068	3,246,171	2,385,564	7.5744	18,069,217	2,513,129	1,846,862	4.1920	7,742,045	1,250,000	918,607	1.0000	918,607	7,009,300	5,151,033	26,729,869
2069	3,189,981	2,344,271	7.8811	18,475,433	2,360,887	1,734,981	4.3115	7,480,372	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	26,874,413
2070	3,237,824	2,379,430	8.2003	19,512,040	2,504,416	1,840,459	4.4343	8,161,146	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	28,591,793
2071	3,237,824	2,379,430	8.5324	20,302,249	2,504,416	1,840,459	4.5607	8,393,780	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	29,614,636
2072	3,246,171	2,385,564	8.8780	21,179,038	2,513,129	1,846,862	4.6907	8,663,075	1,250,000	918,607	1.0000	918,607	7,009,300	5,151,033	30,760,720
2073	3,237,824	2,379,430	9.2375	21,979,985	2,504,416	1,840,459	4.8244	8,879,109	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	31,777,701
2074	3,237,824	2,379,430	9.6117	22,870,368	2,504,416	1,840,459	4.9619	9,132,172	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	32,921,147
2075	3,569,647	2,623,282	10.0009	26,235,181	3,499,884	2,572,014	5.1033	13,125,758	1,250,000	918,607	1.0000	918,607	8,319,531	6,113,903	40,279,545
2076	3,246,171	2,385,564	10.4060	24,824,180	2,513,129	1,846,862	5.2487	9,693,624	1,250,000	918,607	1.0000	918,607	7,009,300	5,151,033	35,436,411
2077	3,237,824	2,379,430	10.8274	25,763,042	14,152,682	10,400,601	5.3983	56,145,565	1,250,000	918,607	1.0000	918,607	18,640,506	13,698,638	82,827,215
2078	982,878	722,303	11.2659	8,137,390	5,148,901	3,783,853	5.5522	21,008,709	0	0	1.0000	0	6,131,779	4,506,156	29,146,099
	$502,483,945	$369,268,185		$1,156,776,892	$523,488,941	$384,704,452		$867,708,282	$56,250,000	$41,337,312		$41,337,312	$1,082,222,886	$795,309,949	$2,065,822,485

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	LABOR				NON-LABOR				PIIC Payment						
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Prairie Island Unit 2															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2034	$7,760,265	$5,702,906	1.9639	$11,199,938	$4,479,535	$3,291,946	1.6124	$5,307,933	$1,250,000	$918,607	1.0000	$918,607	$13,489,800	$9,913,459	$17,426,478
2035	46,911,429	34,474,531	2.0434	70,445,256	35,601,339	26,162,909	1.6584	43,388,568	1,250,000	918,607	1.0000	918,607	83,762,768	61,556,047	114,752,431
2036	67,514,013	49,615,071	2.1262	105,491,565	86,298,834	63,419,765	1.7056	108,168,751	1,250,000	918,607	1.0000	918,607	155,062,846	113,953,443	214,578,923
2037	72,593,441	53,347,870	2.2123	118,021,492	75,650,366	55,594,360	1.7542	97,523,626	1,250,000	918,607	1.0000	918,607	149,493,807	109,860,837	216,463,726
2038	46,603,527	34,248,258	2.3019	78,836,066	42,782,151	31,439,984	1.8042	56,724,019	1,250,000	918,607	1.0000	918,607	90,635,678	66,606,849	136,478,692
2039	40,663,625	29,883,110	2.3951	71,573,036	77,452,618	56,918,809	1.8556	105,618,542	1,250,000	918,607	1.0000	918,607	119,366,242	87,720,525	178,110,184
2040	37,417,177	27,497,343	2.4921	68,526,127	14,193,501	10,430,599	1.9085	19,906,798	1,250,000	918,607	1.0000	918,607	52,860,679	38,846,548	89,351,532
2041	23,327,583	17,143,103	2.5930	44,452,067	13,070,130	9,605,049	1.9629	18,853,752	1,250,000	918,607	1.0000	918,607	37,647,713	27,666,760	64,224,426
2042	16,656,921	12,240,930	2.6981	33,027,253	17,178,640	12,624,334	2.0189	25,487,268	1,250,000	918,607	1.0000	918,607	35,085,561	25,783,871	59,433,129
2043	9,422,862	6,924,725	2.8073	19,439,782	9,074,042	6,668,382	2.0764	13,846,228	1,250,000	918,607	1.0000	918,607	19,746,904	14,511,714	34,204,617
2044	3,054,798	2,244,927	2.9210	6,557,431	1,939,011	1,424,951	2.1356	3,043,125	1,250,000	918,607	1.0000	918,607	6,243,809	4,588,485	10,519,163
2045	5,353,318	3,934,076	3.0393	11,956,837	8,850,896	6,504,395	2.1964	14,286,253	1,250,000	918,607	1.0000	918,607	15,454,214	11,357,078	27,161,698
2046	4,584,362	3,368,981	3.1624	10,654,067	6,544,030	4,809,113	2.2590	10,863,786	1,250,000	918,607	1.0000	918,607	12,378,392	9,096,701	22,436,459
2047	4,584,362	3,368,981	3.2905	11,085,633	6,544,030	4,809,113	2.3234	11,173,492	1,250,000	918,607	1.0000	918,607	12,378,392	9,096,701	23,177,732
2048	3,054,798	2,244,927	3.4238	7,686,181	1,939,011	1,424,951	2.3896	3,405,063	1,250,000	918,607	1.0000	918,607	6,243,809	4,588,485	12,009,850
2049	4,584,362	3,368,981	3.5624	12,001,659	6,544,030	4,809,113	2.4577	11,819,356	1,250,000	918,607	1.0000	918,607	12,378,392	9,096,701	24,739,622
2050	5,353,318	3,934,076	3.7067	14,582,439	8,850,896	6,504,395	2.5278	16,441,810	1,250,000	918,607	1.0000	918,607	15,454,214	11,357,078	31,942,856
2051	5,159,362	3,791,541	3.8568	14,623,213	8,269,030	6,076,790	2.5998	15,798,439	1,250,000	918,607	1.0000	918,607	14,678,392	10,786,938	31,340,260
2052	5,361,664	3,940,209	4.0130	15,812,060	8,859,609	6,510,798	2.6739	17,409,224	1,250,000	918,607	1.0000	918,607	15,471,273	11,369,615	34,139,891
2053	3,142,138	2,309,112	4.1756	9,641,927	2,217,357	1,629,503	2.7501	4,481,297	1,250,000	918,607	1.0000	918,607	6,609,495	4,857,222	15,041,831
2054	3,237,824	2,379,430	4.3447	10,337,910	2,504,416	1,840,459	2.8285	5,205,738	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	16,462,254
2055	5,544,690	4,074,712	4.5206	18,420,145	9,425,014	6,926,306	2.9091	20,149,317	1,250,000	918,607	1.0000	918,607	16,219,704	11,919,626	39,488,069
2056	4,831,925	3,550,912	4.7037	16,702,424	7,270,391	5,342,905	2.9920	15,985,972	1,250,000	918,607	1.0000	918,607	13,352,316	9,812,424	33,607,002
2057	5,302,892	3,897,019	4.8942	19,072,789	8,699,619	6,393,224	3.0773	19,673,868	1,250,000	918,607	1.0000	918,607	15,252,511	11,208,849	39,665,263
2058	3,333,511	2,449,749	5.0924	12,475,102	2,791,475	2,051,414	3.1650	6,492,726	1,250,000	918,607	1.0000	918,607	7,374,986	5,419,770	19,886,435
2059	3,189,981	2,344,271	5.2987	12,421,588	2,360,887	1,734,981	3.2552	5,647,711	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	18,987,907
2060	3,150,484	2,315,245	5.5133	12,764,641	2,226,070	1,635,906	3.3480	5,477,015	1,250,000	918,607	1.0000	918,607	6,626,554	4,869,758	19,160,263
2061	3,237,824	2,379,430	5.7366	13,649,838	2,504,416	1,840,459	3.4434	6,337,436	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	20,905,881
2062	3,237,824	2,379,430	5.9689	14,202,580	2,504,416	1,840,459	3.5415	6,517,985	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	21,639,172
2063	3,189,981	2,344,271	6.2106	14,559,329	2,360,887	1,734,981	3.6425	6,319,670	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	21,797,605
2064	3,246,171	2,385,564	6.4622	15,415,992	2,513,129	1,846,862	3.7463	6,918,899	1,250,000	918,607	1.0000	918,607	7,009,300	5,151,033	23,253,498
2065	3,237,824	2,379,430	6.7239	15,999,050	2,504,416	1,840,459	3.8531	7,091,472	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	24,009,128
2066	3,189,981	2,344,271	6.9962	16,400,988	2,360,887	1,734,981	3.9629	6,875,558	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	24,195,153
2067	3,237,824	2,379,430	7.2795	17,321,061	2,504,416	1,840,459	4.0758	7,501,342	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	25,741,010
2068	3,246,171	2,385,564	7.5744	18,069,217	2,513,129	1,846,862	4.1920	7,742,045	1,250,000	918,607	1.0000	918,607	7,009,300	5,151,033	26,729,869
2069	3,189,981	2,344,271	7.8811	18,475,433	2,360,887	1,734,981	4.3115	7,480,372	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	26,874,413
2070	3,237,824	2,379,430	8.2003	19,512,040	2,504,416	1,840,459	4.4343	8,161,146	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	28,591,793
2071	3,237,824	2,379,430	8.5324	20,302,249	2,504,416	1,840,459	4.5607	8,393,780	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	29,614,636
2072	3,246,171	2,385,564	8.8780	21,179,038	2,513,129	1,846,862	4.6907	8,663,075	1,250,000	918,607	1.0000	918,607	7,009,300	5,151,033	30,760,720
2073	3,237,824	2,379,430	9.2375	21,979,985	2,504,416	1,840,459	4.8244	8,879,109	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	31,777,701
2074	3,237,824	2,379,430	9.6117	22,870,368	2,504,416	1,840,459	4.9619	9,132,172	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	32,921,147
2075	3,569,647	2,623,282	10.0009	26,235,181	3,499,884	2,572,014	5.1033	13,125,758	1,250,000	918,607	1.0000	918,607	8,319,531	6,113,903	40,279,545
2076	3,246,171	2,385,564	10.4060	24,824,180	2,513,129	1,846,862	5.2487	9,693,624	1,250,000	918,607	1.0000	918,607	7,009,300	5,151,033	35,436,411
2077	3,237,824	2,379,430	10.8274	25,763,042	14,152,682	10,400,601	5.3983	56,145,565	1,250,000	918,607	1.0000	918,607	18,640,506	13,698,638	82,827,215
2078	982,878	722,303	11.2659	8,137,389	5,148,901	3,783,853	5.5522	21,008,709	0	-	1.0000	-	6,131,779	4,506,156	29,146,099
	$497,942,199	$365,930,521		$1,172,705,590	$531,588,885	$390,656,984		$888,167,393	$55,000,000	$40,418,705		$40,418,705	$1,084,531,084	$797,006,210	$2,101,291,688
	$1,873,961,967	$1,377,147,550		$5,089,688,674	$1,784,202,430	$1,311,184,564		$3,142,791,860	$111,250,000	$81,756,016		$81,756,016	$3,769,414,397	$2,770,088,131	$8,314,236,550

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Monticello

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	623,672,182	15,706,857	-	6,696,113	646,075,152
2018	646,075,152	32,703,840	-	13,392,226	692,171,218
2019	692,171,218	35,311,659	-	25,304,645	752,787,523
2020	752,787,523	38,348,536	-	25,304,645	816,440,704
2021	816,440,704	41,537,561	-	25,304,645	883,282,909
2022	883,282,909	44,886,355	-	25,304,645	953,473,909
2023	953,473,909	48,402,924	-	25,304,645	1,027,181,478
2024	1,027,181,478	52,095,673	-	25,304,645	1,104,581,796
2025	1,104,581,796	55,973,429	-	25,304,645	1,185,859,871
2026	1,185,859,871	60,045,461	-	25,304,645	1,271,209,976
2027	1,271,209,976	64,321,501	-	25,304,645	1,360,836,122
2028	1,360,836,122	68,811,771	-	25,304,645	1,454,952,538
2029	1,454,952,538	73,527,004	-	25,304,645	1,553,784,186
2030	1,553,784,186	69,721,995	(35,447,395)	18,978,484	1,607,037,270
2031	1,607,037,270	71,673,862	(139,568,856)	-	1,539,142,277
2032	1,539,142,277	68,645,746	(235,103,207)	-	1,372,684,815
2033	1,372,684,815	61,221,743	(224,495,047)	-	1,209,411,511
2034	1,209,411,511	53,939,753	(141,890,436)	-	1,121,460,828
2035	1,121,460,828	50,017,153	(268,360,596)	-	903,117,385
2036	903,117,385	40,279,035	(104,537,352)	-	838,859,069
2037	838,859,069	37,413,114	(74,591,555)	-	801,680,629
2038	801,680,629	35,754,956	(70,060,446)	-	767,375,138
2039	767,375,138	34,224,931	(13,411,299)	-	788,188,771
2040	788,188,771	35,153,219	(13,956,542)	-	809,385,448
2041	809,385,448	36,098,591	(14,445,461)	-	831,038,578
2042	831,038,578	37,064,321	(14,993,098)	-	853,109,800
2043	853,109,800	38,048,697	(15,560,999)	-	875,597,498
2044	875,597,498	39,051,648	(16,195,163)	-	898,453,984
2045	898,453,984	40,071,048	(16,764,053)	-	921,760,979
2046	921,760,979	41,110,540	(17,400,674)	-	945,470,845
2047	945,470,845	42,168,000	(18,061,959)	-	969,576,885
2048	969,576,885	43,243,129	(23,965,838)	-	988,854,176
2049	988,854,176	44,102,896	(19,461,726)	-	1,013,495,347
2050	1,013,495,347	45,201,892	(32,591,702)	-	1,026,105,537
2051	1,026,105,537	45,764,307	(33,762,729)	-	1,038,107,115
2052	1,038,107,115	46,299,577	(42,664,602)	-	1,041,742,091
2053	1,041,742,091	46,461,697	(50,020,076)	-	1,038,183,712
2054	1,038,183,712	46,302,994	(39,576,077)	-	1,044,910,628

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2055	1,044,910,628	46,603,014	(51,492,367)	-	1,040,021,275
2056	1,040,021,275	46,384,949	(57,711,426)	-	1,028,694,798
2057	1,028,694,798	45,879,788	(26,084,326)	-	1,048,490,260
2058	1,048,490,260	46,762,666	(92,436,335)	-	1,002,816,590
2059	1,002,816,590	44,725,620	(28,120,106)	-	1,019,422,104
2060	1,019,422,104	45,466,226	(29,277,659)	-	1,035,610,671
2061	1,035,610,671	46,188,236	(30,317,088)	-	1,051,481,818
2062	1,051,481,818	46,896,089	(31,479,828)	-	1,066,898,080
2063	1,066,898,080	47,583,654	(32,687,938)	-	1,081,793,796
2064	1,081,793,796	48,248,003	(34,036,425)	-	1,096,005,375
2065	1,096,005,375	48,881,840	(35,247,492)	-	1,109,639,722
2066	1,109,639,722	49,489,932	(87,366,546)	-	1,071,763,108
2067	1,071,763,108	47,800,635	(38,009,720)	-	1,081,554,023
2068	1,081,554,023	48,237,309	(165,968,243)	-	963,823,089
2069	963,823,089	42,986,510	(40,992,100)	-	965,817,499
2070	965,817,499	43,075,460	(42,570,958)	-	966,322,002
2071	966,322,002	43,097,961	(44,211,483)	-	965,208,481
2072	965,208,481	43,048,298	(46,042,074)	-	962,214,705
2073	962,214,705	42,914,776	(47,687,242)	-	957,442,239
2074	957,442,239	42,701,924	(49,528,001)	-	950,616,161
2075	950,616,161	42,397,481	(51,440,016)	-	941,573,626
2076	941,573,626	41,994,184	(53,573,725)	-	929,994,085
2077	929,994,085	41,477,736	(55,492,060)	-	915,979,761
2078	915,979,761	40,852,697	(67,392,551)	-	889,439,908
2079	889,439,908	39,669,020	(71,976,743)	-	857,132,184
2080	857,132,184	38,228,095	(72,771,874)	-	822,588,405
2081	822,588,405	36,687,443	(75,357,480)	-	783,918,367
2082	783,918,367	34,962,759	(78,220,169)	-	740,660,958
2083	740,660,958	33,033,479	(83,507,127)	-	690,187,310
2084	690,187,310	30,782,354	(84,479,492)	-	636,490,172
2085	636,490,172	28,387,462	(87,488,590)	-	577,389,044
2086	577,389,044	25,751,551	(90,819,524)	-	512,321,072
2087	512,321,072	22,849,520	(96,920,580)	-	438,250,011
2088	438,250,011	19,545,951	(117,036,091)	-	340,759,871
2089	340,759,871	15,197,890	(101,606,814)	-	254,350,948
2090	254,350,948	11,344,052	(149,320,614)	-	116,374,386
2091	116,374,386	5,190,298	(121,564,684)	-	(0)

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Prairie Island Unit 1

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	374,367,055	9,359,484	-	24,632	383,751,171
2018	383,751,171	19,188,790	-	49,264	402,989,226
2019	402,989,226	20,621,146	-	18,867,378	442,477,750
2020	442,477,750	22,595,572	-	18,867,378	483,940,700
2021	483,940,700	24,668,719	-	18,867,378	527,476,798
2022	527,476,798	26,845,524	-	18,867,378	573,189,701
2023	573,189,701	29,131,170	-	18,867,378	621,188,249
2024	621,188,249	31,531,097	-	18,867,378	671,586,724
2025	671,586,724	34,051,021	-	18,867,378	724,505,123
2026	724,505,123	36,696,941	-	18,867,378	780,069,442
2027	780,069,442	39,475,157	-	18,867,378	838,411,977
2028	838,411,977	42,392,283	-	18,867,378	899,671,639
2029	899,671,639	45,455,266	-	18,867,378	963,994,284
2030	963,994,284	48,671,399	-	18,867,378	1,031,533,061
2031	1,031,533,061	52,048,338	-	18,867,378	1,102,448,777
2032	1,102,448,777	55,594,123	-	18,867,378	1,176,910,279
2033	1,176,910,279	49,577,373	(42,768,206)	12,641,144	1,196,360,589
2034	1,196,360,589	50,127,509	(131,752,423)	-	1,114,735,675
2035	1,114,735,675	46,707,425	(198,854,122)	-	962,588,978
2036	962,588,978	40,332,478	(173,386,483)	-	829,534,973
2037	829,534,973	34,757,515	(119,758,858)	-	744,533,631
2038	744,533,631	31,195,959	(48,446,232)	-	727,283,357
2039	727,283,357	30,473,173	(168,633,951)	-	589,122,579
2040	589,122,579	24,684,236	(78,121,996)	-	535,684,820
2041	535,684,820	22,445,194	(51,838,628)	-	506,291,385
2042	506,291,385	21,213,609	(47,540,570)	-	479,964,424
2043	479,964,424	20,110,509	(28,453,465)	-	471,621,469
2044	471,621,469	19,760,940	(10,519,163)	-	480,863,245
2045	480,863,245	20,148,170	(27,161,698)	-	473,849,717
2046	473,849,717	19,854,303	(22,436,459)	-	471,267,562
2047	471,267,562	19,746,111	(23,177,732)	-	467,835,940
2048	467,835,940	19,602,326	(12,009,850)	-	475,428,416
2049	475,428,416	19,920,451	(24,739,622)	-	470,609,244
2050	470,609,244	19,718,527	(31,942,856)	-	458,384,915
2051	458,384,915	19,206,328	(31,340,256)	-	446,250,987
2052	446,250,987	18,697,916	(34,139,894)	-	430,809,009
2053	430,809,009	18,050,897	(15,041,831)	-	433,818,076
2054	433,818,076	18,176,977	(16,462,254)	-	435,532,799
2055	435,532,799	18,248,824	(39,488,069)	-	414,293,554

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2056	414,293,554	17,358,900	(33,607,002)	-	398,045,451
2057	398,045,451	16,678,104	(39,665,263)	-	375,058,292
2058	375,058,292	15,714,942	(19,886,435)	-	370,886,800
2059	370,886,800	15,540,157	(18,987,907)	-	367,439,050
2060	367,439,050	15,395,696	(19,160,263)	-	363,674,484
2061	363,674,484	15,237,961	(20,905,881)	-	358,006,564
2062	358,006,564	15,000,475	(21,639,172)	-	351,367,867
2063	351,367,867	14,722,314	(21,797,605)	-	344,292,575
2064	344,292,575	14,425,859	(23,253,498)	-	335,464,936
2065	335,464,936	14,055,981	(24,009,128)	-	325,511,789
2066	325,511,789	13,638,944	(24,195,153)	-	314,955,580
2067	314,955,580	13,196,639	(25,741,010)	-	302,411,209
2068	302,411,209	12,671,030	(26,729,869)	-	288,352,370
2069	288,352,370	12,081,964	(26,874,413)	-	273,559,921
2070	273,559,921	11,462,161	(28,591,793)	-	256,430,289
2071	256,430,289	10,744,429	(29,614,636)	-	237,560,082
2072	237,560,082	9,953,767	(30,760,720)	-	216,753,129
2073	216,753,129	9,081,956	(31,777,701)	-	194,057,384
2074	194,057,384	8,131,004	(32,921,147)	-	169,267,242
2075	169,267,242	7,092,297	(40,279,545)	-	136,079,994
2076	136,079,994	5,701,752	(35,436,411)	-	106,345,334
2077	106,345,334	4,455,869	(82,827,215)	-	27,973,989
2078	27,973,989	1,172,110	(29,146,099)	-	0

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EXTERNAL FUND CALCULATION

Prairie Island Unit 2

External Levelized

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	420,208,967	10,613,997	-	294,670	431,117,634
2018	431,117,634	21,786,321	-	589,341	453,493,297
2019	453,493,297	23,223,608	-	12,760,253	489,477,157
2020	489,477,157	25,040,793	-	12,760,253	527,278,202
2021	527,278,202	26,949,746	-	12,760,253	566,988,200
2022	566,988,200	28,955,100	-	12,760,253	608,703,553
2023	608,703,553	31,061,726	-	12,760,253	652,525,532
2024	652,525,532	33,274,736	-	12,760,253	698,560,520
2025	698,560,520	35,599,503	-	12,760,253	746,920,275
2026	746,920,275	38,041,670	-	12,760,253	797,722,198
2027	797,722,198	40,607,167	-	12,760,253	851,089,618
2028	851,089,618	43,302,222	-	12,760,253	907,152,092
2029	907,152,092	46,133,377	-	12,760,253	966,045,722
2030	966,045,722	49,107,505	-	12,760,253	1,027,913,480
2031	1,027,913,480	52,231,827	-	12,760,253	1,092,905,559
2032	1,092,905,559	55,513,927	-	12,760,253	1,161,179,739
2033	1,161,179,739	58,961,773	-	12,760,253	1,232,901,765
2034	1,232,901,765	51,137,547	(17,426,478)	10,591,010	1,277,203,844
2035	1,277,203,844	52,748,519	(114,752,431)	-	1,215,199,931
2036	1,215,199,931	50,187,757	(214,578,923)	-	1,050,808,766
2037	1,050,808,766	43,398,402	(216,463,726)	-	877,743,442
2038	877,743,442	36,250,804	(136,478,692)	-	777,515,555
2039	777,515,555	32,111,392	(178,110,184)	-	631,516,763
2040	631,516,763	26,081,642	(89,351,532)	-	568,246,873
2041	568,246,873	23,468,596	(64,224,426)	-	527,491,043
2042	527,491,043	21,785,380	(59,433,129)	-	489,843,294
2043	489,843,294	20,230,528	(34,204,617)	-	475,869,206
2044	475,869,206	19,653,398	(10,519,163)	-	485,003,440
2045	485,003,440	20,030,642	(27,161,698)	-	477,872,385
2046	477,872,385	19,736,129	(22,436,459)	-	475,172,055
2047	475,172,055	19,624,606	(23,177,732)	-	471,618,929
2048	471,618,929	19,477,862	(12,009,850)	-	479,086,941
2049	479,086,941	19,786,291	(24,739,622)	-	474,133,609
2050	474,133,609	19,581,718	(31,942,856)	-	461,772,471
2051	461,772,471	19,071,203	(31,340,260)	-	449,503,414
2052	449,503,414	18,564,491	(34,139,891)	-	433,928,014
2053	433,928,014	17,921,227	(15,041,831)	-	436,807,411
2054	436,807,411	18,040,146	(16,462,254)	-	438,385,302

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2055	438,385,302	18,105,313	(39,488,069)	-	417,002,546
2056	417,002,546	17,222,205	(33,607,002)	-	400,617,749
2057	400,617,749	16,545,513	(39,665,263)	-	377,497,998
2058	377,497,998	15,590,667	(19,886,435)	-	373,202,231
2059	373,202,231	15,413,252	(18,987,907)	-	369,627,576
2060	369,627,576	15,265,619	(19,160,263)	-	365,732,933
2061	365,732,933	15,104,770	(20,905,881)	-	359,931,822
2062	359,931,822	14,865,184	(21,639,172)	-	353,157,835
2063	353,157,835	14,585,419	(21,797,605)	-	345,945,648
2064	345,945,648	14,287,555	(23,253,498)	-	336,979,705
2065	336,979,705	13,917,262	(24,009,128)	-	326,887,838
2066	326,887,838	13,500,468	(24,195,153)	-	316,193,153
2067	316,193,153	13,058,777	(25,741,010)	-	303,510,921
2068	303,510,921	12,535,001	(26,729,869)	-	289,316,053
2069	289,316,053	11,948,753	(26,874,413)	-	274,390,394
2070	274,390,394	11,332,323	(28,591,793)	-	257,130,923
2071	257,130,923	10,619,507	(29,614,636)	-	238,135,795
2072	238,135,795	9,835,008	(30,760,720)	-	217,210,083
2073	217,210,083	8,970,776	(31,777,701)	-	194,403,158
2074	194,403,158	8,028,850	(32,921,147)	-	169,510,861
2075	169,510,861	7,000,799	(40,279,545)	-	136,232,115
2076	136,232,115	5,626,386	(35,436,411)	-	106,422,090
2077	106,422,090	4,395,232	(82,827,215)	-	27,990,107
2078	27,990,107	1,155,991	(29,146,099)	-	(0)

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2019 ACCRUAL COMPARISON

	Present	Proposed	Difference
Monticello	$13,392,226	$48,876,564	$35,484,338
Prairie Island Unit 1	49,264	32,632,158	32,582,894
Prairie Island Unit 2	589,341	25,930,172	25,340,831
TOTAL	$14,030,831	$107,438,894	$93,408,063

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2019 MN RETAIL SUMMARY

	Remaining Life (yrs)	Operational Earnings Rate	Post-Shutdown Earnings Rate	Market Value Balance 6/30/2017	Book Value 6/30/2017	Unrealized Gain/Loss 6/30/2017	Tax-Effect Adjustment	Tax-Adjusted Fund Balance 6/30/2017	2019-2021 Decommissioning Accrual
Monticello	13.75	5.03%	4.79%	$660,140,345	$529,148,381	$130,991,964	$36,468,163	$623,672,182	**48,876,564**
Prairie Island Unit 1	16.67	5.04%	4.71%	399,941,696	308,078,761	91,862,935	25,574,641	374,367,055	**32,632,158**
Prairie Island Unit 2	17.83	5.07%	4.69%	448,597,551	346,627,064	101,970,487	28,388,583	420,208,967	**25,930,172**
TOTAL DECOMMISSIONING ACCRUAL				**$1,508,679,592**	**$1,183,854,206**	**$324,825,386**	**$90,431,387**	**$1,418,248,204**	**$107,438,894**

INPUT DATA

Escalation Rate (Labor)	4.05%
Escalation Rate (Non-Labor)	2.85%
Escalation Rate (PIIC)	0.00%
Jurisdictional Factor	73.4886%
Tax Rate for tax-effect adjustment	27.84%

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	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
Monticello															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2030	$21,103,620	$15,508,745	1.6755	$25,984,903	$8,935,561	$6,566,615	1.4410	$9,462,492	$0	$0	1.0000	$0	$30,039,182	$22,075,360	$35,447,395
2031	72,416,235	53,217,644	1.7434	92,779,641	42,961,344	31,571,670	1.4820	46,789,215	0	0	1.0000	0	115,377,579	84,789,314	139,568,856
2032	81,871,153	60,165,927	1.8140	109,140,991	112,447,587	82,636,106	1.5243	125,962,216	0	0	1.0000	0	194,318,741	142,802,033	235,103,207
2033	78,663,227	57,808,468	1.8874	109,107,702	100,155,666	73,602,950	1.5677	115,387,345	0	0	1.0000	0	178,818,892	131,411,418	224,495,047
2034	66,380,423	48,782,013	1.9639	95,802,994	38,894,671	28,583,132	1.6124	46,087,441	0	0	1.0000	0	105,275,094	77,365,144	141,890,436
2035	86,879,803	63,846,711	2.0434	130,464,369	113,147,091	83,150,161	1.6584	137,896,227	0	0	1.0000	0	200,026,894	146,996,872	268,360,596
2036	50,307,504	36,970,257	2.1262	78,606,161	20,688,337	15,203,559	1.7056	25,931,191	0	0	1.0000	0	70,995,841	52,173,817	104,537,352
2037	34,755,723	25,541,478	2.2123	56,505,412	14,196,883	10,433,084	1.7542	18,301,716	0	0	1.0000	0	48,952,606	35,974,562	74,807,128
2038	29,827,529	21,919,820	2.3019	50,457,233	15,094,222	11,092,525	1.8042	20,013,134	0	0	1.0000	0	44,921,751	33,012,345	70,470,367
2039	7,164,563	5,265,134	2.3951	12,610,522	2,125,149	1,561,742	1.8556	2,897,968	0	0	1.0000	0	9,289,712	6,826,875	15,508,490
2040	7,184,147	5,279,526	2.4921	13,157,106	2,130,835	1,565,920	1.9085	2,988,559	0	0	1.0000	0	9,314,982	6,845,446	16,145,665
2041	7,164,563	5,265,134	2.5930	13,652,492	2,125,149	1,561,742	1.9629	3,065,543	0	0	1.0000	0	9,289,712	6,826,875	16,718,034
2042	7,164,563	5,265,134	2.6981	14,205,857	2,125,149	1,561,742	2.0189	3,153,000	0	0	1.0000	0	9,289,712	6,826,875	17,358,857
2043	7,164,563	5,265,134	2.8073	14,780,810	2,125,149	1,561,742	2.0764	3,242,800	0	0	1.0000	0	9,289,712	6,826,875	18,023,610
2044	7,184,147	5,279,526	2.9210	15,421,495	2,130,835	1,565,920	2.1356	3,344,179	0	0	1.0000	0	9,314,982	6,845,446	18,765,674
2045	7,164,563	5,265,134	3.0393	16,002,321	2,125,149	1,561,742	2.1964	3,430,209	0	0	1.0000	0	9,289,712	6,826,875	19,432,530
2046	7,164,563	5,265,134	3.1624	16,650,459	2,125,149	1,561,742	2.2590	3,527,974	0	0	1.0000	0	9,289,712	6,826,875	20,178,433
2047	7,164,563	5,265,134	3.2905	17,324,923	2,125,149	1,561,742	2.3234	3,628,550	0	0	1.0000	0	9,289,712	6,826,875	20,953,473
2048	7,847,792	5,767,229	3.4238	19,745,838	4,121,769	3,029,029	2.3896	7,238,167	0	0	1.0000	0	11,969,561	8,796,258	26,984,005
2049	7,164,563	5,265,134	3.5624	18,756,512	2,125,149	1,561,742	2.4577	3,838,292	0	0	1.0000	0	9,289,712	6,826,875	22,594,805
2050	8,657,764	6,362,466	3.7067	23,583,751	6,604,752	4,853,737	2.5278	12,269,277	0	0	1.0000	0	15,262,516	11,216,203	35,853,028
2051	8,657,764	6,362,466	3.8568	24,538,757	6,604,752	4,853,737	2.5998	12,618,746	0	0	1.0000	0	15,262,516	11,216,203	37,157,503
2052	8,677,348	6,376,858	4.0130	25,590,329	6,610,438	4,857,916	2.6739	12,989,580	0	0	1.0000	0	15,287,786	11,234,773	38,579,910
2053	8,657,764	6,362,466	4.1756	26,567,111	6,604,752	4,853,737	2.7501	13,348,262	0	0	1.0000	0	15,262,516	11,216,203	39,915,373
2054	8,657,764	6,362,466	4.3447	27,643,004	6,604,752	4,853,737	2.8285	13,728,795	0	0	1.0000	0	15,262,516	11,216,203	41,371,799
2055	8,657,764	6,362,466	4.5206	28,762,162	6,604,752	4,853,737	2.9091	14,120,006	0	0	1.0000	0	15,262,516	11,216,203	42,882,168
2056	8,677,348	6,376,858	4.7037	29,994,825	6,610,438	4,857,916	2.9920	14,534,883	0	0	1.0000	0	15,287,786	11,234,773	44,529,708
2057	8,657,764	6,362,466	4.8942	31,139,179	6,604,752	4,853,737	3.0773	14,936,405	0	0	1.0000	0	15,262,516	11,216,203	46,075,584
2058	14,754,149	10,842,611	5.0924	55,214,911	24,893,906	18,294,172	3.1650	57,901,054	0	0	1.0000	0	39,648,055	29,136,783	113,115,965
2059	8,657,764	6,362,466	5.2987	33,712,796	6,604,752	4,853,737	3.2552	15,799,885	0	0	1.0000	0	15,262,516	11,216,203	49,512,681
2060	8,677,348	6,376,858	5.5133	35,157,529	6,610,438	4,857,916	3.3480	16,264,301	0	0	1.0000	0	15,287,786	11,234,773	51,421,830
2061	8,657,764	6,362,466	5.7366	36,498,920	6,604,752	4,853,737	3.4434	16,713,358	0	0	1.0000	0	15,262,516	11,216,203	53,212,278
2062	8,657,764	6,362,466	5.9689	37,976,921	6,604,752	4,853,737	3.5415	17,189,510	0	0	1.0000	0	15,262,516	11,216,203	55,166,430
2063	8,657,764	6,362,466	6.2106	39,514,729	6,604,752	4,853,737	3.6425	17,679,737	0	0	1.0000	0	15,262,516	11,216,203	57,194,466
2064	8,677,348	6,376,858	6.4622	41,208,529	6,610,438	4,857,916	3.7463	18,199,209	0	0	1.0000	0	15,287,786	11,234,773	59,407,738
2065	8,657,764	6,362,466	6.7239	42,780,582	6,604,752	4,853,737	3.8531	18,701,934	0	0	1.0000	0	15,262,516	11,216,203	61,482,516
2066	12,315,595	9,050,553	6.9962	63,319,477	17,578,245	12,917,998	3.9629	51,192,736	0	0	1.0000	0	29,893,840	21,968,551	114,512,212
2067	8,657,764	6,362,466	7.2795	46,315,568	6,604,752	4,853,737	4.0758	19,782,861	0	0	1.0000	0	15,262,516	11,216,203	66,098,430
2068	17,212,287	12,649,061	7.5744	95,809,046	32,215,254	23,674,525	4.1920	99,243,607	0	0	1.0000	0	49,427,541	36,323,585	195,052,653
2069	8,657,764	6,362,466	7.8811	50,143,227	6,604,752	4,853,737	4.3115	20,926,887	0	0	1.0000	0	15,262,516	11,216,203	71,070,115
2070	8,657,764	6,362,466	8.2003	52,174,126	6,604,752	4,853,737	4.4343	21,522,926	0	0	1.0000	0	15,262,516	11,216,203	73,697,053
2071	8,657,764	6,362,466	8.5324	54,287,101	6,604,752	4,853,737	4.5607	22,136,439	0	0	1.0000	0	15,262,516	11,216,203	76,423,540
2072	8,677,348	6,376,858	8.8780	56,613,741	6,610,438	4,857,916	4.6907	22,787,025	0	0	1.0000	0	15,287,786	11,234,773	79,400,766
2073	8,657,764	6,362,466	9.2375	58,773,276	6,604,752	4,853,737	4.8244	23,416,369	0	0	1.0000	0	15,262,516	11,216,203	82,189,645
2074	8,657,764	6,362,466	9.6117	61,154,110	6,604,752	4,853,737	4.9619	24,083,758	0	0	1.0000	0	15,262,516	11,216,203	85,237,868
2075	8,657,764	6,362,466	10.0009	63,630,382	6,604,752	4,853,737	5.1033	24,770,076	0	0	1.0000	0	15,262,516	11,216,203	88,400,458
2076	8,677,348	6,376,858	10.4060	66,357,580	6,610,438	4,857,916	5.2487	25,497,742	0	0	1.0000	0	15,287,786	11,234,773	91,855,321
2077	8,657,764	6,362,466	10.8274	68,888,960	6,604,752	4,853,737	5.3983	26,201,929	0	0	1.0000	0	15,262,516	11,216,203	95,090,888
2078	8,657,764	6,362,466	11.2659	71,678,901	6,604,752	4,853,737	5.5522	26,948,919	0	0	1.0000	0	15,262,516	11,216,203	98,627,820
2079	8,657,764	6,362,466	11.7222	74,582,094	6,604,752	4,853,737	5.7104	27,716,780	0	0	1.0000	0	15,262,516	11,216,203	102,298,874
2080	8,677,348	6,376,858	12.1970	77,778,532	6,610,438	4,857,916	5.8731	28,531,024	0	0	1.0000	0	15,287,786	11,234,773	106,309,556
2081	8,657,764	6,362,466	12.6909	80,745,414	6,604,752	4,853,737	6.0405	29,318,999	0	0	1.0000	0	15,262,516	11,216,203	110,064,413
2082	8,657,764	6,362,466	13.2049	84,015,722	6,604,752	4,853,737	6.2127	30,154,812	0	0	1.0000	0	15,262,516	11,216,203	114,170,534
2083	8,657,764	6,362,466	13.7397	87,418,368	6,604,752	4,853,737	6.3897	31,013,924	0	0	1.0000	0	15,262,516	11,216,203	118,432,292
2084	8,677,348	6,376,858	14.2962	91,164,831	6,610,438	4,857,916	6.5719	31,925,735	0	0	1.0000	0	15,287,786	11,234,773	123,090,567

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AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
2085	8,657,764	6,362,466	14.8752	94,642,948	6,604,752	4,853,737	6.7592	32,807,380	0	0	1.0000	0	15,262,516	11,216,203	127,450,327
2086	8,657,764	6,362,466	15.4776	98,475,697	6,604,752	4,853,737	6.9518	33,742,209	0	0	1.0000	0	15,262,516	11,216,203	132,217,906
2087	8,657,764	6,362,466	16.1045	102,464,327	6,604,752	4,853,737	7.1499	34,703,735	0	0	1.0000	0	15,262,516	11,216,203	137,168,061
2088	9,340,993	6,864,561	16.7567	115,027,384	8,601,373	6,321,025	7.3537	46,482,921	0	0	1.0000	0	17,942,366	13,185,586	161,510,305
2089	8,657,764	6,362,466	17.4353	110,931,496	6,604,752	4,853,737	7.5633	36,710,269	0	0	1.0000	0	15,262,516	11,216,203	147,641,765
2090	8,657,764	6,362,466	18.1415	115,424,669	6,604,752	4,853,737	7.7788	37,756,250	0	0	1.0000	0	15,262,516	11,216,203	153,180,919
2091	8,657,764	6,362,466	18.8762	120,099,172	6,604,752	4,853,737	8.0005	38,832,323	0	0	1.0000	0	15,262,516	11,216,203	158,931,496
2092	9,539,848	7,010,696	19.6407	137,694,984	9,197,938	6,759,432	8.2285	55,619,986	0	0	1.0000	0	18,737,786	13,770,128	193,314,969
2093	10,167,139	7,471,683	20.4361	152,692,070	11,132,877	8,181,391	8.4630	69,239,109	0	0	1.0000	0	21,300,016	15,653,074	221,931,179
2094	8,873,389	6,520,925	21.2638	138,659,650	7,251,627	5,329,116	8.7042	46,385,693	0	0	1.0000	0	16,125,016	11,850,041	185,045,343
2095	31,288,861	22,993,731	22.1250	508,736,309	83,569,860	61,414,281	8.9523	549,799,071	0	0	1.0000	0	114,858,721	84,408,013	1,058,535,380
2096	10,402,348	7,644,535	23.0210	175,984,843	11,785,438	8,660,948	9.2075	79,745,681	0	0	1.0000	0	22,187,786	16,305,483	255,730,524
2097	7,147,972	5,252,941	23.9534	125,825,803	2,075,375	1,525,163	9.4699	14,443,145	0	0	1.0000	0	9,223,347	6,778,105	140,268,948
2098	7,147,972	5,252,941	24.9235	130,921,681	2,075,375	1,525,163	9.7398	14,854,786	0	0	1.0000	0	9,223,347	6,778,105	145,776,468
2099	7,147,972	5,252,941	25.9329	136,224,000	2,075,375	1,525,163	10.0173	15,278,019	0	0	1.0000	0	9,223,347	6,778,105	151,502,020
2100	7,147,972	5,252,941	26.9832	141,741,164	2,075,375	1,525,163	10.3028	15,713,453	0	0	1.0000	0	9,223,347	6,778,105	157,454,618
2101	7,147,972	5,252,941	28.0760	147,481,579	2,075,375	1,525,163	10.5965	16,161,394	0	0	1.0000	0	9,223,347	6,778,105	163,642,973
2102	7,147,972	5,252,941	29.2131	153,454,698	2,075,375	1,525,163	10.8985	16,621,993	0	0	1.0000	0	9,223,347	6,778,105	170,076,691
2103	7,147,972	5,252,941	30.3962	159,669,453	2,075,375	1,525,163	11.2091	17,095,709	0	0	1.0000	0	9,223,347	6,778,105	176,765,162
2104	7,167,556	5,267,333	31.6272	166,591,002	2,081,061	1,529,342	11.5285	17,631,018	0	0	1.0000	0	9,248,617	6,796,675	184,222,021
2105	7,147,972	5,252,941	32.9081	172,864,316	2,075,375	1,525,163	11.8571	18,084,015	0	0	1.0000	0	9,223,347	6,778,105	190,948,331
2106	7,147,972	5,252,941	34.2409	179,865,436	2,075,375	1,525,163	12.1950	18,599,368	0	0	1.0000	0	9,223,347	6,778,105	198,464,804
2107	7,147,972	5,252,941	35.6277	187,150,215	2,075,375	1,525,163	12.5426	19,129,514	0	0	1.0000	0	9,223,347	6,778,105	206,279,730
2108	13,263,941	9,747,478	37.0706	361,344,874	20,370,216	14,969,777	12.9000	193,110,129	0	0	1.0000	0	33,634,157	24,717,256	554,455,003
2109	7,147,972	5,252,941	38.5720	202,616,450	2,075,375	1,525,163	13.2677	20,235,410	0	0	1.0000	0	9,223,347	6,778,105	222,851,861
2110	7,147,972	5,252,941	40.1341	210,822,070	2,075,375	1,525,163	13.6458	20,812,075	0	0	1.0000	0	9,223,347	6,778,105	231,634,144
2111	7,147,972	5,252,941	41.7596	219,360,726	2,075,375	1,525,163	14.0347	21,405,211	0	0	1.0000	0	9,223,347	6,778,105	240,765,936
2112	7,167,556	5,267,333	43.4508	228,869,844	2,081,061	1,529,342	14.4347	22,075,592	0	0	1.0000	0	9,248,617	6,796,675	250,945,436
2113	7,147,972	5,252,941	45.2106	237,488,626	11,274,281	8,285,306	14.8461	123,004,487	0	0	1.0000	0	18,422,253	13,538,248	360,493,113
2114	7,147,972	5,252,941	47.0416	247,106,761	2,075,375	1,525,163	15.2692	23,288,025	0	0	1.0000	0	9,223,347	6,778,105	270,394,786
2115	7,147,972	5,252,941	48.9468	257,114,665	2,075,375	1,525,163	15.7044	23,951,776	0	0	1.0000	0	9,223,347	6,778,105	281,066,441
2116	10,825,387	7,955,420	50.9291	405,162,399	13,054,554	9,593,603	16.1520	154,955,880	0	0	1.0000	0	23,879,941	17,549,024	560,118,279
2117	7,147,972	5,252,941	52.9918	278,362,812	2,075,375	1,525,163	16.6123	25,336,472	0	0	1.0000	0	9,223,347	6,778,105	303,699,284
2118	14,921,796	10,965,812	55.1379	604,631,851	29,162,169	21,430,856	17.0857	366,161,179	0	0	1.0000	0	44,083,965	32,396,668	970,793,029
2119	6,482,543	4,763,927	57.3710	273,311,262	3,844,412	2,825,203	17.5727	49,646,438	0	0	1.0000	0	10,326,955	7,589,130	322,957,700
2120	6,403,045	4,705,505	59.6946	280,893,249	3,563,167	2,618,520	18.0735	47,325,815	0	0	1.0000	0	9,966,212	7,324,025	328,219,064
2121	6,386,857	4,693,609	62.1122	291,530,372	3,557,353	2,614,247	18.5886	48,595,194	0	0	1.0000	0	9,944,210	7,307,856	340,125,566
2122	6,386,857	4,693,609	64.6277	303,337,145	3,557,353	2,614,247	19.1184	49,980,222	0	0	1.0000	0	9,944,210	7,307,856	353,317,367
2123	6,482,543	4,763,927	67.2451	320,350,755	3,844,412	2,825,203	19.6633	55,552,807	0	0	1.0000	0	10,326,955	7,589,130	375,903,562
2124	6,403,045	4,705,505	69.9686	329,237,609	3,563,167	2,618,520	20.2237	52,956,156	0	0	1.0000	0	9,966,212	7,324,025	382,193,765
2125	6,386,857	4,693,609	72.8023	341,705,519	3,557,353	2,614,247	20.8000	54,376,340	0	0	1.0000	0	9,944,210	7,307,856	396,081,860
2126	6,386,857	4,693,609	75.7508	355,544,625	3,557,353	2,614,247	21.3928	55,926,066	0	0	1.0000	0	9,944,210	7,307,856	411,470,691
2127	6,482,543	4,763,927	78.8187	375,486,541	3,844,412	2,825,203	22.0025	62,161,521	0	0	1.0000	0	10,326,955	7,589,130	437,648,062
2128	7,066,689	5,193,208	82.0109	425,899,625	5,554,101	4,081,628	22.6296	92,365,615	0	0	1.0000	0	12,620,790	9,274,836	518,265,240
2129	6,386,857	4,693,609	85.3323	400,516,438	3,557,353	2,614,247	23.2745	60,845,295	0	0	1.0000	0	9,944,210	7,307,856	461,361,733
2130	6,099,798	4,482,653	88.7883	398,007,170	2,696,175	1,981,380	23.9379	47,430,073	0	0	1.0000	0	8,795,973	6,464,033	445,437,243
2131	2,028,079	1,490,406	92.3842	137,689,966	5,022,573	3,691,016	24.6201	90,873,191	0	0	1.0000	0	7,050,652	5,181,422	228,563,157
	$1,309,028,449	$961,986,078		$13,824,906,481	$1,110,107,131	$815,801,677		$4,468,161,723	$0	$0		$0	$2,419,135,581	$1,777,787,755	$18,293,068,204

Xcel Energy
Nuclear Decommissioning Accrual
100-Year Decommissioning Period
DECON Method

Docket No. E002/M-17-828
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Proposed

AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
Prairie Island Unit 1															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2033	$22,324,352	$16,405,843	1.8874	$30,964,388	$9,448,311	$6,943,427	1.5677	$10,885,211	$1,250,000	$918,607	1.0000	$918,607	$33,022,663	$24,267,877	$42,768,206
2034	63,582,247	46,725,674	1.9639	91,764,550	32,971,808	24,230,505	1.6124	39,069,266	1,250,000	918,607	1.0000	918,607	97,804,054	71,874,785	131,752,423
2035	65,877,290	48,412,268	2.0434	98,925,629	81,239,936	59,702,054	1.6584	99,009,886	1,250,000	918,607	1.0000	918,607	148,367,226	109,032,929	198,854,122
2036	57,759,315	42,446,486	2.1262	90,249,718	65,595,018	48,204,830	1.7056	82,218,158	1,250,000	918,607	1.0000	918,607	124,604,333	91,569,923	173,386,483
2037	39,808,345	29,254,577	2.2123	64,719,901	41,981,870	30,851,869	1.7542	54,120,349	1,250,000	918,607	1.0000	918,607	83,040,216	61,025,054	119,758,858
2038	13,207,909	9,706,302	2.3019	22,342,936	18,994,690	13,958,923	1.8042	25,184,688	1,250,000	918,607	1.0000	918,607	33,452,599	24,583,831	48,446,231
2039	35,713,289	26,245,180	2.3951	62,859,831	75,509,036	55,490,499	1.8556	102,968,170	1,250,000	918,607	1.0000	918,607	112,472,326	82,654,286	166,746,607
2040	31,919,562	23,457,225	2.4921	58,457,750	13,365,605	9,822,190	1.9085	18,745,649	1,250,000	918,607	1.0000	918,607	46,535,167	34,198,022	78,122,006
2041	19,624,628	14,421,855	2.5930	37,395,870	9,445,873	6,941,635	1.9629	13,625,736	1,250,000	918,607	1.0000	918,607	30,320,500	22,282,097	51,940,213
2042	14,863,703	10,923,120	2.6981	29,471,671	11,668,700	8,575,159	2.0189	17,312,388	1,250,000	918,607	1.0000	918,607	27,782,403	20,416,886	47,702,666
2043	8,912,167	6,549,423	2.8073	18,386,194	6,470,357	4,754,972	2.0764	9,873,223	1,250,000	918,607	1.0000	918,607	16,632,524	12,223,001	29,178,024
2044	3,676,270	2,701,638	2.9210	7,891,484	1,896,910	1,394,012	2.1356	2,977,052	1,250,000	918,607	1.0000	918,607	6,823,180	5,014,256	11,787,142
2045	5,973,091	4,389,538	3.0393	13,341,123	8,808,910	6,473,541	2.1964	14,218,485	1,250,000	918,607	1.0000	918,607	16,032,001	11,781,686	28,478,215
2046	5,204,136	3,824,444	3.1624	12,094,423	6,502,044	4,778,258	2.2590	10,794,085	1,250,000	918,607	1.0000	918,607	12,956,180	9,521,309	23,807,115
2047	5,204,136	3,824,444	3.2905	12,584,334	6,502,044	4,778,258	2.3234	11,101,805	1,250,000	918,607	1.0000	918,607	12,956,180	9,521,309	24,604,746
2048	3,676,270	2,701,638	3.4238	9,249,867	1,896,910	1,394,012	2.3896	3,331,131	1,250,000	918,607	1.0000	918,607	6,823,180	5,014,256	13,499,605
2049	5,204,136	3,824,444	3.5624	13,624,200	6,502,044	4,778,258	2.4577	11,743,525	1,250,000	918,607	1.0000	918,607	12,956,180	9,521,309	26,286,332
2050	5,973,091	4,389,538	3.7067	16,270,701	8,808,910	6,473,541	2.5278	16,363,816	1,250,000	918,607	1.0000	918,607	16,032,001	11,781,686	33,553,124
2051	5,779,136	4,247,003	3.8568	16,379,843	8,227,044	6,045,936	2.5998	15,718,224	1,250,000	918,607	1.0000	918,607	15,256,180	11,211,546	33,016,674
2052	5,983,136	4,396,920	4.0130	17,644,840	8,817,508	6,479,859	2.6739	17,326,496	1,250,000	918,607	1.0000	918,607	16,050,644	11,795,386	35,889,943
2053	3,666,225	2,694,256	4.1756	11,250,134	1,888,312	1,387,693	2.7501	3,816,295	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	15,985,036
2054	3,666,225	2,694,256	4.3447	11,705,733	1,888,312	1,387,693	2.8285	3,925,090	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	16,549,430
2055	5,973,091	4,389,538	4.5206	19,843,346	8,808,910	6,473,541	2.9091	18,832,177	1,250,000	918,607	1.0000	918,607	16,032,001	11,781,686	39,594,130
2056	5,214,180	3,831,825	4.7037	18,023,758	6,510,642	4,784,577	2.9920	14,315,454	1,250,000	918,607	1.0000	918,607	12,974,822	9,535,009	33,257,818
2057	5,204,136	3,824,444	4.8942	18,717,595	6,502,044	4,778,258	3.0773	14,704,134	1,250,000	918,607	1.0000	918,607	12,956,180	9,521,309	34,340,336
2058	3,666,225	2,694,256	5.0924	13,720,228	1,888,312	1,387,693	3.1650	4,392,049	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	19,030,884
2059	5,010,180	3,681,909	5.2987	19,509,330	5,920,178	4,350,653	3.2552	14,162,246	1,250,000	918,607	1.0000	918,607	12,180,358	8,951,169	34,590,184
2060	5,214,180	3,831,825	5.5133	21,126,003	6,510,642	4,784,577	3.3480	16,018,763	1,250,000	918,607	1.0000	918,607	12,974,822	9,535,009	38,063,373
2061	5,204,136	3,824,444	5.7366	21,939,307	6,502,044	4,778,258	3.4434	16,453,454	1,250,000	918,607	1.0000	918,607	12,956,180	9,521,309	39,311,368
2062	3,666,225	2,694,256	5.9689	16,081,743	1,888,312	1,387,693	3.5415	4,914,516	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	21,914,866
2063	8,279,957	6,084,821	6.2106	37,790,387	15,729,508	11,559,388	3.6425	42,105,071	1,250,000	918,607	1.0000	918,607	25,259,465	18,562,816	80,814,065
2064	6,558,136	4,819,479	6.4622	31,144,439	10,542,508	7,747,537	3.7463	29,024,597	1,250,000	918,607	1.0000	918,607	18,350,644	13,485,623	61,087,643
2065	5,204,136	3,824,444	6.7239	25,715,181	6,502,044	4,778,258	3.8531	18,411,107	1,250,000	918,607	1.0000	918,607	12,956,180	9,521,309	45,044,894
2066	3,666,225	2,694,256	6.9962	18,849,552	1,888,312	1,387,693	3.9629	5,499,289	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	25,267,448
2067	3,666,225	2,694,256	7.2795	19,612,835	1,888,312	1,387,693	4.0758	5,655,960	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	26,187,402
2068	6,752,091	4,962,014	7.5744	37,584,279	11,124,374	8,175,142	4.1920	34,270,194	1,250,000	918,607	1.0000	918,607	19,126,465	14,055,763	72,773,080
2069	5,973,091	4,389,538	7.8811	34,594,389	8,808,910	6,473,541	4.3115	27,910,670	1,250,000	918,607	1.0000	918,607	16,032,001	11,781,686	63,423,667
2070	3,666,225	2,694,256	8.2003	22,093,705	1,888,312	1,387,693	4.4343	6,153,448	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	29,165,760
2071	3,666,225	2,694,256	8.5324	22,988,468	1,888,312	1,387,693	4.5607	6,328,853	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	30,235,927
2072	7,327,091	5,384,573	8.8780	47,804,241	12,849,374	9,442,819	4.6907	44,293,432	1,250,000	918,607	1.0000	918,607	21,426,465	15,745,999	93,016,280
2073	3,666,225	2,694,256	9.2375	24,888,187	1,888,312	1,387,693	4.8244	6,694,787	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	32,501,581
2074	3,666,225	2,694,256	9.6117	25,896,378	1,888,312	1,387,693	4.9619	6,885,595	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	33,700,580
2075	7,842,824	5,763,578	10.0009	57,640,967	14,418,110	10,595,661	5.1033	54,072,835	1,250,000	918,607	1.0000	918,607	23,510,934	17,277,845	112,632,408
2076	3,676,270	2,701,638	10.4060	28,113,241	1,896,910	1,394,012	5.2487	7,316,750	1,250,000	918,607	1.0000	918,607	6,823,180	5,014,256	36,348,598
2077	3,666,225	2,694,256	10.8274	29,171,785	1,888,312	1,387,693	5.3983	7,491,184	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	37,581,576
2078	7,511,002	5,519,727	11.2659	62,184,690	13,422,642	9,864,106	5.5522	54,767,487	1,250,000	918,607	1.0000	918,607	22,183,644	16,302,439	117,870,783
2079	3,666,225	2,694,256	11.7222	31,582,605	1,888,312	1,387,693	5.7104	7,924,283	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	40,425,495
2080	3,676,270	2,701,638	12.1970	32,951,875	1,896,910	1,394,012	5.8731	8,187,171	1,250,000	918,607	1.0000	918,607	6,823,180	5,014,256	42,057,653
2081	3,666,225	2,694,256	12.6909	34,192,530	1,888,312	1,387,693	6.0405	8,382,361	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	43,493,498
2082	7,123,091	5,234,657	13.2049	69,123,117	12,258,910	9,008,896	6.2127	55,969,566	1,250,000	918,607	1.0000	918,607	20,632,001	15,162,159	126,011,290
2083	3,666,225	2,694,256	13.7397	37,018,266	1,888,312	1,387,693	6.3897	8,866,943	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	46,803,816
2084	3,676,270	2,701,638	14.2962	38,623,152	1,896,910	1,394,012	6.5719	9,161,307	1,250,000	918,607	1.0000	918,607	6,823,180	5,014,256	48,703,066
2085	3,666,225	2,694,256	14.8752	40,077,593	1,888,312	1,387,693	6.7592	9,379,696	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	50,375,896
2086	3,666,225	2,694,256	15.4776	41,700,613	1,888,312	1,387,693	6.9518	9,646,966	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	52,266,185
2087	3,666,225	2,694,256	16.1045	43,389,641	1,888,312	1,387,693	7.1499	9,921,868	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	54,230,116

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	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
2088	3,676,270	2,701,638	16.7567	45,270,532	1,896,910	1,394,012	7.3537	10,251,145	1,250,000	918,607	1.0000	918,607	6,823,180	5,014,256	56,440,284
2089	26,815,724	19,706,488	17.4353	343,588,526	73,271,240	53,845,975	7.5633	407,253,263	1,250,000	918,607	1.0000	918,607	101,336,964	74,471,070	751,760,396
2090	3,666,225	2,694,256	18.1415	48,877,840	1,888,312	1,387,693	7.7788	10,794,588	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	60,591,035
2091	3,666,225	2,694,256	18.8762	50,857,310	1,888,312	1,387,693	8.0005	11,102,240	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	62,878,157
2092	3,676,270	2,701,638	19.6407	53,062,055	1,896,910	1,394,012	8.2285	11,470,627	1,250,000	918,607	1.0000	918,607	6,823,180	5,014,256	65,451,288
2093	3,050,095	2,241,471	20.4361	45,806,920	1,970,565	1,448,140	8.4630	12,255,605	1,250,000	918,607	1.0000	918,607	6,270,660	4,608,217	58,981,132
2094	3,145,781	2,311,789	21.2638	49,157,418	2,257,624	1,659,095	8.7042	14,441,095	1,250,000	918,607	1.0000	918,607	6,653,405	4,889,491	64,517,121
2095	5,452,647	4,007,071	22.1250	88,656,455	9,178,222	6,744,942	8.9523	60,382,748	1,250,000	918,607	1.0000	918,607	15,880,869	11,670,621	149,957,811
2096	4,739,629	3,483,085	23.0210	80,184,095	7,022,923	5,161,044	9.2075	47,520,316	1,250,000	918,607	1.0000	918,607	13,012,552	9,562,736	128,623,019
2097	4,635,849	3,406,818	23.9534	81,604,884	6,727,827	4,944,183	9.4699	46,820,915	1,250,000	918,607	1.0000	918,607	12,613,676	9,269,608	129,344,406
2098	3,241,467	2,382,107	24.9235	59,370,449	2,544,683	1,870,051	9.7398	18,213,919	1,250,000	918,607	1.0000	918,607	7,036,150	5,170,765	78,502,975
2099	3,097,938	2,276,630	25.9329	59,039,614	2,114,095	1,553,618	10.0173	15,563,055	1,250,000	918,607	1.0000	918,607	6,462,033	4,748,854	75,521,275
2100	5,356,961	3,936,753	26.9832	106,226,198	8,891,163	6,533,987	10.3028	67,318,361	1,250,000	918,607	1.0000	918,607	15,498,124	11,389,347	174,463,166
2101	5,452,647	4,007,071	28.0760	112,502,537	9,178,222	6,744,942	10.5965	71,472,783	1,250,000	918,607	1.0000	918,607	15,880,869	11,670,621	184,893,927
2102	5,452,647	4,007,071	29.2131	117,058,978	9,178,222	6,744,942	10.8985	73,509,756	1,250,000	918,607	1.0000	918,607	15,880,869	11,670,621	191,487,341
2103	3,097,938	2,276,630	30.3962	69,200,896	2,114,095	1,553,618	11.2091	17,414,656	1,250,000	918,607	1.0000	918,607	6,462,033	4,748,854	87,534,159
2104	3,153,875	2,317,737	31.6272	73,303,536	2,265,661	1,665,001	11.5285	19,194,968	1,250,000	918,607	1.0000	918,607	6,669,536	4,901,345	93,417,111
2105	5,452,647	4,007,071	32.9081	131,865,107	9,178,222	6,744,942	11.8571	79,975,457	1,250,000	918,607	1.0000	918,607	15,880,869	11,670,621	212,759,172
2106	4,635,849	3,406,818	34.2409	116,652,528	6,727,827	4,944,183	12.1950	60,294,307	1,250,000	918,607	1.0000	918,607	12,613,676	9,269,608	177,865,442
2107	4,683,692	3,441,978	35.6277	122,629,742	6,871,356	5,049,660	12.5426	63,335,866	1,250,000	918,607	1.0000	918,607	12,805,048	9,410,244	186,884,215
2108	3,153,875	2,317,737	37.0706	85,919,906	2,265,661	1,665,001	12.9000	21,478,518	1,250,000	918,607	1.0000	918,607	6,669,536	4,901,345	108,317,031
2109	4,635,849	3,406,818	38.5720	131,407,799	6,727,827	4,944,183	13.2677	65,597,932	1,250,000	918,607	1.0000	918,607	12,613,676	9,269,608	197,924,338
2110	4,676,515	3,436,703	40.1341	137,928,992	6,849,827	5,033,839	13.6458	68,690,756	1,250,000	918,607	1.0000	918,607	12,776,342	9,389,149	207,538,354
2111	4,669,339	3,431,430	41.7596	143,295,132	6,828,297	5,018,017	14.0347	70,426,357	1,250,000	918,607	1.0000	918,607	12,747,636	9,368,053	214,640,096
2112	3,139,522	2,307,189	43.4508	100,249,222	2,222,602	1,633,358	14.4347	23,577,032	1,250,000	918,607	1.0000	918,607	6,612,124	4,859,154	124,744,860
2113	7,745,160	5,691,806	45.2106	257,329,968	16,055,761	11,799,146	14.8461	175,171,308	1,250,000	918,607	1.0000	918,607	25,050,921	18,409,559	433,419,883
2114	6,207,249	4,561,618	47.0416	214,585,787	11,442,029	8,408,581	15.2692	128,392,313	1,250,000	918,607	1.0000	918,607	18,899,278	13,888,806	343,896,707
2115	5,001,161	3,675,281	48.9468	179,893,239	7,823,765	5,749,572	15.7044	90,293,572	1,250,000	918,607	1.0000	918,607	14,074,926	10,343,459	271,105,418
2116	3,139,522	2,307,189	50.9291	117,503,075	13,878,680	10,199,241	16.1520	164,738,142	1,250,000	918,607	1.0000	918,607	18,268,202	13,425,037	283,159,824
2117	3,127,840	2,298,604	52.9918	121,807,184	2,203,801	1,619,541	16.6123	26,904,307	1,250,000	918,607	1.0000	918,607	6,581,641	4,836,753	149,630,097
2118	1,058,128	777,603	55.1379	42,875,395	2,284,593	1,678,914	17.0857	28,685,429	0	0	1.0000	0	3,342,721	2,456,517	71,560,824
	$740,716,704	$544,341,994		$5,178,979,867	$854,501,635	$627,960,894		$3,154,984,274	$106,250,000	$78,081,589		$78,081,589	$1,701,468,338	$1,250,384,477	$8,412,045,730

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Prairie Island Unit 2															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2034	$7,760,265	$5,702,906	1.9639	$11,199,938	$4,479,535	$3,291,946	1.6124	$5,307,933	$1,250,000	$918,607	1.0000	$918,607	$13,489,800	$9,913,459	$17,426,478
2035	46,911,429	34,474,531	2.0434	70,445,256	35,601,339	26,162,909	1.6584	43,388,568	1,250,000	918,607	1.0000	918,607	83,762,768	61,556,047	114,752,431
2036	67,514,041	49,615,092	2.1262	105,491,609	86,298,834	63,419,765	1.7056	108,168,751	1,250,000	918,607	1.0000	918,607	155,062,874	113,953,464	214,578,967
2037	72,593,441	53,347,870	2.2123	118,021,492	75,650,363	55,594,358	1.7542	97,523,623	1,250,000	918,607	1.0000	918,607	149,493,804	109,860,835	216,463,722
2038	46,603,525	34,248,257	2.3019	78,836,063	42,782,150	31,439,983	1.8042	56,724,017	1,250,000	918,607	1.0000	918,607	90,635,675	66,606,847	136,478,687
2039	40,341,063	29,646,064	2.3951	71,005,287	76,484,927	56,207,667	1.8556	104,298,947	1,250,000	918,607	1.0000	918,607	118,075,990	86,772,338	176,222,841
2040	37,417,178	27,497,343	2.4921	68,526,129	14,193,500	10,430,598	1.9085	19,906,796	1,250,000	918,607	1.0000	918,607	52,860,678	38,846,548	89,351,532
2041	23,380,886	17,182,275	2.5930	44,553,639	13,070,130	9,605,049	1.9629	18,853,752	1,250,000	918,607	1.0000	918,607	37,701,016	27,705,931	64,325,998
2042	16,738,669	12,301,006	2.6981	33,189,343	17,178,640	12,624,334	2.0189	25,487,268	1,250,000	918,607	1.0000	918,607	35,167,309	25,843,947	59,595,219
2043	9,790,576	7,194,952	2.8073	20,198,390	9,051,726	6,651,983	2.0764	13,812,177	1,250,000	918,607	1.0000	918,607	20,092,302	14,765,542	34,929,174
2044	3,676,270	2,701,638	2.9210	7,891,484	1,896,910	1,394,012	2.1356	2,977,052	1,250,000	918,607	1.0000	918,607	6,823,180	5,014,256	11,787,142
2045	5,973,091	4,389,538	3.0393	13,341,123	8,808,910	6,473,541	2.1964	14,218,485	1,250,000	918,607	1.0000	918,607	16,032,001	11,781,686	28,478,215
2046	5,204,136	3,824,444	3.1624	12,094,423	6,502,044	4,778,258	2.2590	10,794,085	1,250,000	918,607	1.0000	918,607	12,956,180	9,521,309	23,807,115
2047	5,204,136	3,824,444	3.2905	12,584,334	6,502,044	4,778,258	2.3234	11,101,805	1,250,000	918,607	1.0000	918,607	12,956,180	9,521,309	24,604,746
2048	3,676,270	2,701,638	3.4238	9,249,867	1,896,910	1,394,012	2.3896	3,331,131	1,250,000	918,607	1.0000	918,607	6,823,180	5,014,256	13,499,605
2049	5,204,136	3,824,444	3.5624	13,624,200	6,502,044	4,778,258	2.4577	11,743,525	1,250,000	918,607	1.0000	918,607	12,956,180	9,521,309	26,286,332
2050	5,973,091	4,389,538	3.7067	16,270,701	8,808,910	6,473,541	2.5278	16,363,816	1,250,000	918,607	1.0000	918,607	16,032,001	11,781,686	33,553,124
2051	5,779,136	4,247,003	3.8568	16,379,843	8,227,044	6,045,936	2.5998	15,718,224	1,250,000	918,607	1.0000	918,607	15,256,180	11,211,546	33,016,674
2052	5,983,136	4,396,920	4.0130	17,644,840	8,817,508	6,479,859	2.6739	17,326,496	1,250,000	918,607	1.0000	918,607	16,050,644	11,795,386	35,889,943
2053	3,666,225	2,694,256	4.1756	11,250,134	1,888,312	1,387,693	2.7501	3,816,295	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	15,985,036
2054	3,666,225	2,694,256	4.3447	11,705,733	1,888,312	1,387,693	2.8285	3,925,090	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	16,549,430
2055	5,973,091	4,389,538	4.5206	19,843,346	8,808,910	6,473,541	2.9091	18,832,177	1,250,000	918,607	1.0000	918,607	16,032,001	11,781,686	39,594,130
2056	5,214,180	3,831,825	4.7037	18,023,758	6,510,642	4,784,577	2.9920	14,315,454	1,250,000	918,607	1.0000	918,607	12,974,822	9,535,009	33,257,818
2057	5,204,136	3,824,444	4.8942	18,717,595	6,502,044	4,778,258	3.0773	14,704,134	1,250,000	918,607	1.0000	918,607	12,956,180	9,521,309	34,340,336
2058	3,666,225	2,694,256	5.0924	13,720,228	1,888,312	1,387,693	3.1650	4,392,049	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	19,030,884
2059	5,010,180	3,681,909	5.2987	19,509,330	5,920,178	4,350,653	3.2552	14,162,246	1,250,000	918,607	1.0000	918,607	12,180,358	8,951,169	34,590,184
2060	5,214,180	3,831,825	5.5133	21,126,003	6,510,642	4,784,577	3.3480	16,018,763	1,250,000	918,607	1.0000	918,607	12,974,822	9,535,009	38,063,373
2061	5,204,136	3,824,444	5.7366	21,939,307	6,502,044	4,778,258	3.4434	16,453,454	1,250,000	918,607	1.0000	918,607	12,956,180	9,521,309	39,311,368
2062	3,666,225	2,694,256	5.9689	16,081,743	1,888,312	1,387,693	3.5415	4,914,516	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	21,914,866
2063	8,279,957	6,084,821	6.2106	37,790,387	15,729,508	11,559,388	3.6425	42,105,071	1,250,000	918,607	1.0000	918,607	25,259,465	18,562,816	80,814,065
2064	6,558,136	4,819,479	6.4622	31,144,439	10,542,508	7,747,537	3.7463	29,024,597	1,250,000	918,607	1.0000	918,607	18,350,644	13,485,623	61,087,643
2065	5,204,136	3,824,444	6.7239	25,715,181	6,502,044	4,778,258	3.8531	18,411,107	1,250,000	918,607	1.0000	918,607	12,956,180	9,521,309	45,044,894
2066	3,666,225	2,694,256	6.9962	18,849,552	1,888,312	1,387,693	3.9629	5,499,289	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	25,267,448
2067	3,666,225	2,694,256	7.2795	19,612,835	1,888,312	1,387,693	4.0758	5,655,960	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	26,187,402
2068	6,752,091	4,962,014	7.5744	37,584,279	11,124,374	8,175,142	4.1920	34,270,194	1,250,000	918,607	1.0000	918,607	19,126,465	14,055,763	72,773,080
2069	5,973,091	4,389,538	7.8811	34,594,389	8,808,910	6,473,541	4.3115	27,910,670	1,250,000	918,607	1.0000	918,607	16,032,001	11,781,686	63,423,667
2070	3,666,225	2,694,256	8.2003	22,093,705	1,888,312	1,387,693	4.4343	6,153,448	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	29,165,760
2071	3,666,225	2,694,256	8.5324	22,988,468	1,888,312	1,387,693	4.5607	6,328,853	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	30,235,927
2072	7,327,091	5,384,573	8.8780	47,804,241	12,849,374	9,442,819	4.6907	44,293,432	1,250,000	918,607	1.0000	918,607	21,426,465	15,745,999	93,016,280
2073	3,666,225	2,694,256	9.2375	24,888,187	1,888,312	1,387,693	4.8244	6,694,787	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	32,501,581
2074	3,666,225	2,694,256	9.6117	25,896,378	1,888,312	1,387,693	4.9619	6,885,595	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	33,700,580
2075	7,842,824	5,763,578	10.0009	57,640,967	14,418,110	10,595,661	5.1033	54,072,835	1,250,000	918,607	1.0000	918,607	23,510,934	17,277,845	112,632,408
2076	3,676,270	2,701,638	10.4060	28,113,241	1,896,910	1,394,012	5.2487	7,316,750	1,250,000	918,607	1.0000	918,607	6,823,180	5,014,256	36,348,598
2077	3,666,225	2,694,256	10.8274	29,171,785	1,888,312	1,387,693	5.3983	7,491,184	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	37,581,576
2078	7,511,002	5,519,727	11.2659	62,184,690	13,422,642	9,864,106	5.5522	54,767,487	1,250,000	918,607	1.0000	918,607	22,183,644	16,302,439	117,870,783
2079	3,666,225	2,694,256	11.7222	31,582,605	1,888,312	1,387,693	5.7104	7,924,283	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	40,425,495
2080	3,676,270	2,701,638	12.1970	32,951,875	1,896,910	1,394,012	5.8731	8,187,171	1,250,000	918,607	1.0000	918,607	6,823,180	5,014,256	42,057,653
2081	3,666,225	2,694,256	12.6909	34,192,530	1,888,312	1,387,693	6.0405	8,382,361	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	43,493,498
2082	7,123,091	5,234,657	13.2049	69,123,117	12,258,910	9,008,896	6.2127	55,969,566	1,250,000	918,607	1.0000	918,607	20,632,001	15,162,159	126,011,290
2083	3,666,225	2,694,256	13.7397	37,018,266	1,888,312	1,387,693	6.3897	8,866,943	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	46,803,816
2084	3,676,270	2,701,638	14.2962	38,623,152	1,896,910	1,394,012	6.5719	9,161,307	1,250,000	918,607	1.0000	918,607	6,823,180	5,014,256	48,703,066
2085	3,666,225	2,694,256	14.8752	40,077,593	1,888,312	1,387,693	6.7592	9,379,696	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	50,375,896
2086	3,666,225	2,694,256	15.4776	41,700,613	1,888,312	1,387,693	6.9518	9,646,966	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	52,266,185
2087	3,666,225	2,694,256	16.1045	43,389,641	1,888,312	1,387,693	7.1499	9,921,868	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	54,230,116
2088	3,676,270	2,701,638	16.7567	45,270,532	1,896,910	1,394,012	7.3537	10,251,145	1,250,000	918,607	1.0000	918,607	6,823,180	5,014,256	56,440,284

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	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
2089	26,815,724	19,706,488	17.4353	343,588,526	71,336,809	52,424,389	7.5633	396,501,384	1,250,000	918,607	1.0000	918,607	99,402,533	73,049,484	741,008,517
2090	3,666,225	2,694,256	18.1415	48,877,840	3,822,743	2,809,279	7.7788	21,852,819	1,250,000	918,607	1.0000	918,607	8,738,968	6,422,142	71,649,266
2091	3,666,225	2,694,256	18.8762	50,857,310	1,888,312	1,387,693	8.0005	11,102,240	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	62,878,157
2092	3,676,270	2,701,638	19.6407	53,062,055	1,896,910	1,394,012	8.2285	11,470,627	1,250,000	918,607	1.0000	918,607	6,823,180	5,014,256	65,451,288
2093	3,050,095	2,241,471	20.4361	45,806,920	1,970,568	1,448,142	8.4630	12,255,624	1,250,000	918,607	1.0000	918,607	6,270,663	4,608,219	58,981,150
2094	3,145,781	2,311,789	21.2638	49,157,418	2,257,624	1,659,095	8.7042	14,441,095	1,250,000	918,607	1.0000	918,607	6,653,405	4,889,491	64,517,121
2095	5,452,647	4,007,071	22.1250	88,656,455	9,178,222	6,744,942	8.9523	60,382,748	1,250,000	918,607	1.0000	918,607	15,880,869	11,670,621	149,957,811
2096	4,739,629	3,483,085	23.0210	80,184,095	7,022,923	5,161,044	9.2075	47,520,316	1,250,000	918,607	1.0000	918,607	13,012,552	9,562,736	128,623,019
2097	4,635,849	3,406,818	23.9534	81,604,884	6,727,827	4,944,183	9.4699	46,820,915	1,250,000	918,607	1.0000	918,607	12,613,676	9,269,608	129,344,406
2098	3,241,467	2,382,107	24.9235	59,370,449	2,544,683	1,870,051	9.7398	18,213,919	1,250,000	918,607	1.0000	918,607	7,036,150	5,170,765	78,502,975
2099	3,097,938	2,276,630	25.9329	59,039,614	2,114,095	1,553,618	10.0173	15,563,055	1,250,000	918,607	1.0000	918,607	6,462,033	4,748,854	75,521,275
2100	5,356,961	3,936,753	26.9832	106,226,198	8,891,163	6,533,987	10.3028	67,318,361	1,250,000	918,607	1.0000	918,607	15,498,124	11,389,347	174,463,166
2101	5,452,647	4,007,071	28.0760	112,502,537	9,178,222	6,744,942	10.5965	71,472,783	1,250,000	918,607	1.0000	918,607	15,880,869	11,670,621	184,893,927
2102	5,452,647	4,007,071	29.2131	117,058,978	9,178,222	6,744,942	10.8985	73,509,756	1,250,000	918,607	1.0000	918,607	15,880,869	11,670,621	191,487,341
2103	3,097,938	2,276,630	30.3962	69,200,896	2,114,095	1,553,618	11.2091	17,414,656	1,250,000	918,607	1.0000	918,607	6,462,033	4,748,854	87,534,159
2104	3,153,875	2,317,737	31.6272	73,303,536	2,265,661	1,665,001	11.5285	19,194,968	1,250,000	918,607	1.0000	918,607	6,669,536	4,901,345	93,417,111
2105	5,452,647	4,007,071	32.9081	131,865,107	9,178,222	6,744,942	11.8571	79,975,457	1,250,000	918,607	1.0000	918,607	15,880,869	11,670,621	212,759,172
2106	4,635,849	3,406,818	34.2409	116,652,528	6,727,827	4,944,183	12.1950	60,294,307	1,250,000	918,607	1.0000	918,607	12,613,676	9,269,608	177,865,442
2107	4,683,692	3,441,978	35.6277	122,629,742	6,871,356	5,049,660	12.5426	63,335,866	1,250,000	918,607	1.0000	918,607	12,805,048	9,410,244	186,884,215
2108	3,153,875	2,317,737	37.0706	85,919,906	2,265,661	1,665,001	12.9000	21,478,518	1,250,000	918,607	1.0000	918,607	6,669,536	4,901,345	108,317,031
2109	4,635,849	3,406,818	38.5720	131,407,799	6,727,827	4,944,183	13.2677	65,597,932	1,250,000	918,607	1.0000	918,607	12,613,676	9,269,608	197,924,338
2110	4,676,515	3,436,703	40.1341	137,928,992	6,849,827	5,033,839	13.6458	68,690,756	1,250,000	918,607	1.0000	918,607	12,776,342	9,389,149	207,538,354
2111	4,669,339	3,431,430	41.7596	143,295,132	6,828,297	5,018,017	14.0347	70,426,357	1,250,000	918,607	1.0000	918,607	12,747,636	9,368,053	214,640,096
2112	3,139,522	2,307,189	43.4508	100,249,222	2,222,602	1,633,358	14.4347	23,577,032	1,250,000	918,607	1.0000	918,607	6,612,124	4,859,154	124,744,860
2113	7,745,160	5,691,806	45.2106	257,329,968	16,055,761	11,799,146	14.8461	175,171,308	1,250,000	918,607	1.0000	918,607	25,050,921	18,409,559	433,419,883
2114	6,207,249	4,561,618	47.0416	214,585,787	11,442,029	8,408,581	15.2692	128,392,313	1,250,000	918,607	1.0000	918,607	18,899,278	13,888,806	343,896,707
2115	5,001,161	3,675,281	48.9468	179,893,239	7,823,765	5,749,572	15.7044	90,293,572	1,250,000	918,607	1.0000	918,607	14,074,926	10,343,459	271,105,418
2116	3,139,522	2,307,189	50.9291	117,503,075	13,878,680	10,199,241	16.1520	164,738,142	1,250,000	918,607	1.0000	918,607	18,268,202	13,425,037	283,159,824
2117	3,127,840	2,298,604	52.9918	121,807,184	2,203,801	1,619,541	16.6123	26,904,307	1,250,000	918,607	1.0000	918,607	6,581,641	4,836,753	149,630,097
2118	1,058,128	777,603	55.1379	42,875,395	2,284,593	1,678,914	17.0857	28,685,429	0	-	1.0000	-	3,342,721	2,456,517	71,560,824
	$736,174,967	$541,004,338		$5,194,908,576	$862,601,579	$633,913,426		$3,175,749,753	$105,000,000	$77,162,982		$77,162,982	$1,703,776,546	$1,252,080,745	$8,447,821,310
	$2,785,920,120	$2,047,332,409		$24,198,794,924	$2,827,210,344	$2,077,675,998		$10,798,895,750	$211,250,000	$155,244,570		$155,244,570	$5,824,380,465	$4,280,252,977	$35,152,935,244

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EXTERNAL FUND CALCULATION

Monticello

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	623,672,182	15,769,559	-	6,696,113	646,137,854
2018	646,137,854	32,837,549	-	13,392,226	692,367,629
2019	692,367,629	36,055,337	-	48,876,564	777,299,530
2020	777,299,530	40,327,412	-	48,876,564	866,503,505
2021	866,503,505	44,814,372	-	48,876,564	960,194,440
2022	960,194,440	49,527,026	-	48,876,564	1,058,598,030
2023	1,058,598,030	54,476,726	-	48,876,564	1,161,951,320
2024	1,161,951,320	59,675,397	-	48,876,564	1,270,503,281
2025	1,270,503,281	65,135,561	-	48,876,564	1,384,515,405
2026	1,384,515,405	70,870,370	-	48,876,564	1,504,262,339
2027	1,504,262,339	76,893,641	-	48,876,564	1,630,032,544
2028	1,630,032,544	83,219,883	-	48,876,564	1,762,128,990
2029	1,762,128,990	89,864,334	-	48,876,564	1,900,869,887
2030	1,900,869,887	91,929,613	(35,447,395)	36,657,423	1,994,009,528
2031	1,994,009,528	95,513,056	(139,568,856)	-	1,949,953,728
2032	1,949,953,728	93,402,784	(235,103,207)	-	1,808,253,305
2033	1,808,253,305	86,615,333	(224,495,047)	-	1,670,373,591
2034	1,670,373,591	80,010,895	(141,890,436)	-	1,608,494,050
2035	1,608,494,050	77,046,865	(268,360,596)	-	1,417,180,319
2036	1,417,180,319	67,882,937	(104,537,352)	-	1,380,525,905
2037	1,380,525,905	66,127,191	(74,807,128)	-	1,371,845,968
2038	1,371,845,968	65,711,422	(70,470,367)	-	1,367,087,023
2039	1,367,087,023	65,483,468	(15,508,490)	-	1,417,062,002
2040	1,417,062,002	67,877,270	(16,145,665)	-	1,468,793,607
2041	1,468,793,607	70,355,214	(16,718,034)	-	1,522,430,787
2042	1,522,430,787	72,924,435	(17,358,857)	-	1,577,996,364
2043	1,577,996,364	75,586,026	(18,023,610)	-	1,635,558,779
2044	1,635,558,779	78,343,266	(18,765,674)	-	1,695,136,371
2045	1,695,136,371	81,197,032	(19,432,530)	-	1,756,900,873
2046	1,756,900,873	84,155,552	(20,178,433)	-	1,820,877,992
2047	1,820,877,992	87,220,056	(20,953,473)	-	1,887,144,575
2048	1,887,144,575	90,394,225	(26,984,005)	-	1,950,554,795
2049	1,950,554,795	93,431,575	(22,594,805)	-	2,021,391,565
2050	2,021,391,565	96,824,656	(35,853,028)	-	2,082,363,193
2051	2,082,363,193	99,745,197	(37,157,503)	-	2,144,950,887
2052	2,144,950,887	102,743,147	(38,579,910)	-	2,209,114,125
2053	2,209,114,125	105,816,567	(39,915,373)	-	2,275,015,318
2054	2,275,015,318	108,973,234	(41,371,799)	-	2,342,616,752
2055	2,342,616,752	112,211,342	(42,882,168)	-	2,411,945,926
2056	2,411,945,926	115,532,210	(44,529,708)	-	2,482,948,428

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External Levelized	2057	2,482,948,428	118,933,230	(46,075,584)	-	2,555,806,073
	2058	2,555,806,073	122,423,111	(113,115,965)	-	2,565,113,219
	2059	2,565,113,219	122,868,923	(49,512,681)	-	2,638,469,461
	2060	2,638,469,461	126,382,687	(51,421,830)	-	2,713,430,318
	2061	2,713,430,318	129,973,312	(53,212,278)	-	2,790,191,353
	2062	2,790,191,353	133,650,166	(55,166,430)	-	2,868,675,088
	2063	2,868,675,088	137,409,537	(57,194,466)	-	2,948,890,159
	2064	2,948,890,159	141,251,839	(59,407,738)	-	3,030,734,259
	2065	3,030,734,259	145,172,171	(61,482,516)	-	3,114,423,914
	2066	3,114,423,914	149,180,905	(114,512,212)	-	3,149,092,607
	2067	3,149,092,607	150,841,536	(66,098,430)	-	3,233,835,713
	2068	3,233,835,713	154,900,731	(195,052,653)	-	3,193,683,791
	2069	3,193,683,791	152,977,454	(71,070,115)	-	3,275,591,130
	2070	3,275,591,130	156,900,815	(73,697,053)	-	3,358,794,892
	2071	3,358,794,892	160,886,275	(76,423,540)	-	3,443,257,628
	2072	3,443,257,628	164,932,040	(79,400,766)	-	3,528,788,902
	2073	3,528,788,902	169,028,988	(82,189,645)	-	3,615,628,246
	2074	3,615,628,246	173,188,593	(85,237,868)	-	3,703,578,971
	2075	3,703,578,971	177,401,433	(88,400,458)	-	3,792,579,945
	2076	3,792,579,945	181,664,579	(91,855,321)	-	3,882,389,203
	2077	3,882,389,203	185,966,443	(95,090,888)	-	3,973,264,758
	2078	3,973,264,758	190,319,382	(98,627,820)	-	4,064,956,320
	2079	4,064,956,320	194,711,408	(102,298,874)	-	4,157,368,854
	2080	4,157,368,854	199,137,968	(106,309,556)	-	4,250,197,266
	2081	4,250,197,266	203,584,449	(110,064,413)	-	4,343,717,302
	2082	4,343,717,302	208,064,059	(114,170,534)	-	4,437,610,827
	2083	4,437,610,827	212,561,559	(118,432,292)	-	4,531,740,094
	2084	4,531,740,094	217,070,351	(123,090,567)	-	4,625,719,878
	2085	4,625,719,878	221,571,982	(127,450,327)	-	4,719,841,533
	2086	4,719,841,533	226,080,409	(132,217,906)	-	4,813,704,036
	2087	4,813,704,036	230,576,423	(137,168,061)	-	4,907,112,398
	2088	4,907,112,398	235,050,684	(161,510,305)	-	4,980,652,777
	2089	4,980,652,777	238,573,268	(147,641,765)	-	5,071,584,280
	2090	5,071,584,280	242,928,887	(153,180,919)	-	5,161,332,248
	2091	5,161,332,248	247,227,815	(158,931,496)	-	5,249,628,567
	2092	5,249,628,567	251,457,208	(193,314,969)	-	5,307,770,806
	2093	5,307,770,806	254,242,222	(221,931,179)	-	5,340,081,849
	2094	5,340,081,849	255,789,921	(185,045,343)	-	5,410,826,427
	2095	5,410,826,427	259,178,586	(1,058,535,380)	-	4,611,469,633
	2096	4,611,469,633	220,889,395	(255,730,524)	-	4,576,628,504
	2097	4,576,628,504	219,220,505	(140,268,948)	-	4,655,580,062
	2098	4,655,580,062	223,002,285	(145,776,468)	-	4,732,805,879
	2099	4,732,805,879	226,701,402	(151,502,020)	-	4,808,005,261
	2100	4,808,005,261	230,303,452	(157,454,618)	-	4,880,854,095
	2101	4,880,854,095	233,792,911	(163,642,973)	-	4,951,004,033
	2102	4,951,004,033	237,153,093	(170,076,691)	-	5,018,080,435

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2103	5,018,080,435	240,366,053	(176,765,162)	-	5,081,681,326
2104	5,081,681,326	243,412,535	(184,222,021)	-	5,140,871,840
2105	5,140,871,840	246,247,761	(190,948,331)	-	5,196,171,270
2106	5,196,171,270	248,896,604	(198,464,804)	-	5,246,603,070
2107	5,246,603,070	251,312,287	(206,279,730)	-	5,291,635,628
2108	5,291,635,628	253,469,347	(554,455,003)	-	4,990,649,971
2109	4,990,649,971	239,052,134	(222,851,861)	-	5,006,850,244
2110	5,006,850,244	239,828,127	(231,634,144)	-	5,015,044,227
2111	5,015,044,227	240,220,618	(240,765,936)	-	5,014,498,909
2112	5,014,498,909	240,194,498	(250,945,436)	-	5,003,747,971
2113	5,003,747,971	239,679,528	(360,493,113)	-	4,882,934,386
2114	4,882,934,386	233,892,557	(270,394,786)	-	4,846,432,156
2115	4,846,432,156	232,144,100	(281,066,441)	-	4,797,509,816
2116	4,797,509,816	229,800,720	(560,118,279)	-	4,467,192,257
2117	4,467,192,257	213,978,509	(303,699,284)	-	4,377,471,482
2118	4,377,471,482	209,680,884	(970,793,029)	-	3,616,359,336
2119	3,616,359,336	173,223,612	(322,957,700)	-	3,466,625,248
2120	3,466,625,248	166,051,349	(328,219,064)	-	3,304,457,533
2121	3,304,457,533	158,283,516	(340,125,566)	-	3,122,615,484
2122	3,122,615,484	149,573,282	(353,317,367)	-	2,918,871,398
2123	2,918,871,398	139,813,940	(375,903,562)	-	2,682,781,777
2124	2,682,781,777	128,505,247	(382,193,765)	-	2,429,093,258
2125	2,429,093,258	116,353,567	(396,081,860)	-	2,149,364,966
2126	2,149,364,966	102,954,582	(411,470,691)	-	1,840,848,856
2127	1,840,848,856	88,176,660	(437,648,062)	-	1,491,377,454
2128	1,491,377,454	71,436,980	(518,265,240)	-	1,044,549,194
2129	1,044,549,194	50,033,906	(461,361,733)	-	633,221,367
2130	633,221,367	30,331,303	(445,437,243)	-	218,115,428
2131	218,115,428	10,447,729	(228,563,157)	-	0

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Prairie Island Unit 1

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	374,367,055	9,434,360	-	24,632	383,826,047
2018	383,826,047	19,346,074	-	49,264	403,221,386
2019	403,221,386	21,144,688	-	32,632,158	456,998,232
2020	456,998,232	23,855,041	-	32,632,158	513,485,432
2021	513,485,432	26,701,996	-	32,632,158	572,819,587
2022	572,819,587	29,692,438	-	32,632,158	635,144,183
2023	635,144,183	32,833,597	-	32,632,158	700,609,938
2024	700,609,938	36,133,071	-	32,632,158	769,375,168
2025	769,375,168	39,598,839	-	32,632,158	841,606,165
2026	841,606,165	43,239,281	-	32,632,158	917,477,605
2027	917,477,605	47,063,202	-	32,632,158	997,172,965
2028	997,172,965	51,079,848	-	32,632,158	1,080,884,971
2029	1,080,884,971	55,298,933	-	32,632,158	1,168,816,062
2030	1,168,816,062	59,730,660	-	32,632,158	1,261,178,881
2031	1,261,178,881	64,385,746	-	32,632,158	1,358,196,785
2032	1,358,196,785	69,275,448	-	32,632,158	1,460,104,392
2033	1,460,104,392	69,285,803	(42,768,206)	21,863,546	1,508,485,535
2034	1,508,485,535	71,049,669	(131,752,423)	-	1,447,782,781
2035	1,447,782,781	68,190,569	(198,854,122)	-	1,317,119,228
2036	1,317,119,228	62,036,316	(173,386,483)	-	1,205,769,061
2037	1,205,769,061	56,791,723	(119,758,858)	-	1,142,801,927
2038	1,142,801,927	53,825,971	(48,446,231)	-	1,148,181,666
2039	1,148,181,666	54,079,356	(166,746,607)	-	1,035,514,416
2040	1,035,514,416	48,772,729	(78,122,006)	-	1,006,165,138
2041	1,006,165,138	47,390,378	(51,940,213)	-	1,001,615,304
2042	1,001,615,304	47,176,081	(47,702,666)	-	1,001,088,718
2043	1,001,088,718	47,151,279	(29,178,024)	-	1,019,061,973
2044	1,019,061,973	47,997,819	(11,787,142)	-	1,055,272,649
2045	1,055,272,649	49,703,342	(28,478,215)	-	1,076,497,776
2046	1,076,497,776	50,703,045	(23,807,115)	-	1,103,393,707
2047	1,103,393,707	51,969,844	(24,604,746)	-	1,130,758,804
2048	1,130,758,804	53,258,740	(13,499,605)	-	1,170,517,939
2049	1,170,517,939	55,131,395	(26,286,332)	-	1,199,363,002
2050	1,199,363,002	56,489,997	(33,553,124)	-	1,222,299,875
2051	1,222,299,875	57,570,324	(33,016,674)	-	1,246,853,526
2052	1,246,853,526	58,726,801	(35,889,943)	-	1,269,690,384
2053	1,269,690,384	59,802,417	(15,985,036)	-	1,313,507,765
2054	1,313,507,765	61,866,216	(16,549,430)	-	1,358,824,550
2055	1,358,824,550	64,000,636	(39,594,130)	-	1,383,231,056
2056	1,383,231,056	65,150,183	(33,257,818)	-	1,415,123,421

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External Levelized	2057	1,415,123,421	66,652,313	(34,340,336)	-	1,447,435,398
	2058	1,447,435,398	68,174,207	(19,030,884)	-	1,496,578,721
	2059	1,496,578,721	70,488,858	(34,590,184)	-	1,532,477,395
	2060	1,532,477,395	72,179,685	(38,063,373)	-	1,566,593,707
	2061	1,566,593,707	73,786,564	(39,311,368)	-	1,601,068,903
	2062	1,601,068,903	75,410,345	(21,914,866)	-	1,654,564,383
	2063	1,654,564,383	77,929,982	(80,814,065)	-	1,651,680,300
	2064	1,651,680,300	77,794,142	(61,087,643)	-	1,668,386,799
	2065	1,668,386,799	78,581,018	(45,044,894)	-	1,701,922,923
	2066	1,701,922,923	80,160,570	(25,267,448)	-	1,756,816,044
	2067	1,756,816,044	82,746,036	(26,187,402)	-	1,813,374,678
	2068	1,813,374,678	85,409,947	(72,773,080)	-	1,826,011,545
	2069	1,826,011,545	86,005,144	(63,423,667)	-	1,848,593,022
	2070	1,848,593,022	87,068,731	(29,165,760)	-	1,906,495,993
	2071	1,906,495,993	89,795,961	(30,235,927)	-	1,966,056,028
	2072	1,966,056,028	92,601,239	(93,016,280)	-	1,965,640,986
	2073	1,965,640,986	92,581,690	(32,501,581)	-	2,025,721,095
	2074	2,025,721,095	95,411,464	(33,700,580)	-	2,087,431,979
	2075	2,087,431,979	98,318,046	(112,632,408)	-	2,073,117,617
	2076	2,073,117,617	97,643,840	(36,348,598)	-	2,134,412,858
	2077	2,134,412,858	100,530,846	(37,581,576)	-	2,197,362,128
	2078	2,197,362,128	103,495,756	(117,870,783)	-	2,182,987,101
	2079	2,182,987,101	102,818,692	(40,425,495)	-	2,245,380,298
	2080	2,245,380,298	105,757,412	(42,057,653)	-	2,309,080,058
	2081	2,309,080,058	108,757,671	(43,493,498)	-	2,374,344,231
	2082	2,374,344,231	111,831,613	(126,011,290)	-	2,360,164,554
	2083	2,360,164,554	111,163,750	(46,803,816)	-	2,424,524,489
	2084	2,424,524,489	114,195,103	(48,703,066)	-	2,490,016,526
	2085	2,490,016,526	117,279,778	(50,375,896)	-	2,556,920,409
	2086	2,556,920,409	120,430,951	(52,266,185)	-	2,625,085,175
	2087	2,625,085,175	123,641,512	(54,230,116)	-	2,694,496,570
	2088	2,694,496,570	126,910,788	(56,440,284)	-	2,764,967,075
	2089	2,764,967,075	130,229,949	(751,760,396)	-	2,143,436,628
	2090	2,143,436,628	100,955,865	(60,591,035)	-	2,183,801,458
	2091	2,183,801,458	102,857,049	(62,878,157)	-	2,223,780,350
	2092	2,223,780,350	104,740,054	(65,451,288)	-	2,263,069,116
	2093	2,263,069,116	106,590,555	(58,981,132)	-	2,310,678,540
	2094	2,310,678,540	108,832,959	(64,517,121)	-	2,354,994,378
	2095	2,354,994,378	110,920,235	(149,957,811)	-	2,315,956,803
	2096	2,315,956,803	109,081,565	(128,623,019)	-	2,296,415,349
	2097	2,296,415,349	108,161,163	(129,344,406)	-	2,275,232,107
	2098	2,275,232,107	107,163,432	(78,502,975)	-	2,303,892,564
	2099	2,303,892,564	108,513,340	(75,521,275)	-	2,336,884,628
	2100	2,336,884,628	110,067,266	(174,463,166)	-	2,272,488,728
	2101	2,272,488,728	107,034,219	(184,893,927)	-	2,194,629,020
	2102	2,194,629,020	103,367,027	(191,487,341)	-	2,106,508,706

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2103	2,106,508,706	99,216,560	(87,534,159)	-	2,118,191,107
2104	2,118,191,107	99,766,801	(93,417,111)	-	2,124,540,798
2105	2,124,540,798	100,065,872	(212,759,172)	-	2,011,847,497
2106	2,011,847,497	94,758,017	(177,865,442)	-	1,928,740,073
2107	1,928,740,073	90,843,657	(186,884,215)	-	1,832,699,515
2108	1,832,699,515	86,320,147	(108,317,031)	-	1,810,702,632
2109	1,810,702,632	85,284,094	(197,924,338)	-	1,698,062,388
2110	1,698,062,388	79,978,738	(207,538,354)	-	1,570,502,772
2111	1,570,502,772	73,970,681	(214,640,096)	-	1,429,833,357
2112	1,429,833,357	67,345,151	(124,744,860)	-	1,372,433,648
2113	1,372,433,648	64,641,625	(433,419,883)	-	1,003,655,390
2114	1,003,655,390	47,272,169	(343,896,707)	-	707,030,852
2115	707,030,852	33,301,153	(271,105,418)	-	469,226,587
2116	469,226,587	22,100,572	(283,159,824)	-	208,167,335
2117	208,167,335	9,804,681	(149,630,097)	-	68,341,919
2118	68,341,919	3,218,904	(71,560,824)	-	(0)

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Prairie Island Unit 2

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	420,208,967	10,656,032	-	294,670	431,159,670
2018	431,159,670	21,874,735	-	589,341	453,623,746
2019	453,623,746	23,656,054	-	25,930,172	503,209,972
2020	503,209,972	26,170,075	-	25,930,172	555,310,219
2021	555,310,219	28,811,558	-	25,930,172	610,051,949
2022	610,051,949	31,586,964	-	25,930,172	667,569,084
2023	667,569,084	34,503,082	-	25,930,172	728,002,339
2024	728,002,339	37,567,048	-	25,930,172	791,499,559
2025	791,499,559	40,786,358	-	25,930,172	858,216,089
2026	858,216,089	44,168,886	-	25,930,172	928,315,146
2027	928,315,146	47,722,908	-	25,930,172	1,001,968,226
2028	1,001,968,226	51,457,119	-	25,930,172	1,079,355,517
2029	1,079,355,517	55,380,655	-	25,930,172	1,160,666,343
2030	1,160,666,343	59,503,113	-	25,930,172	1,246,099,629
2031	1,246,099,629	63,834,581	-	25,930,172	1,335,864,382
2032	1,335,864,382	68,385,654	-	25,930,172	1,430,180,208
2033	1,430,180,208	73,167,466	-	25,930,172	1,529,277,846
2034	1,529,277,846	72,227,823	(17,426,478)	21,522,043	1,605,601,234
2035	1,605,601,234	75,302,698	(114,752,431)	-	1,566,151,500
2036	1,566,151,500	73,452,505	(214,578,967)	-	1,425,025,039
2037	1,425,025,039	66,833,674	(216,463,722)	-	1,275,394,992
2038	1,275,394,992	59,816,025	(136,478,687)	-	1,198,732,330
2039	1,198,732,330	56,220,546	(176,222,841)	-	1,078,730,035
2040	1,078,730,035	50,592,439	(89,351,532)	-	1,039,970,942
2041	1,039,970,942	48,774,637	(64,325,998)	-	1,024,419,581
2042	1,024,419,581	48,045,278	(59,595,219)	-	1,012,869,641
2043	1,012,869,641	47,503,586	(34,929,174)	-	1,025,444,053
2044	1,025,444,053	48,093,326	(11,787,142)	-	1,061,750,237
2045	1,061,750,237	49,796,086	(28,478,215)	-	1,083,068,108
2046	1,083,068,108	50,795,894	(23,807,115)	-	1,110,056,888
2047	1,110,056,888	52,061,668	(24,604,746)	-	1,137,513,810
2048	1,137,513,810	53,349,398	(13,499,605)	-	1,177,363,603
2049	1,177,363,603	55,218,353	(26,286,332)	-	1,206,295,623
2050	1,206,295,623	56,575,265	(33,553,124)	-	1,229,317,764
2051	1,229,317,764	57,655,003	(33,016,674)	-	1,253,956,094
2052	1,253,956,094	58,810,541	(35,889,943)	-	1,276,876,691
2053	1,276,876,691	59,885,517	(15,985,036)	-	1,320,777,172
2054	1,320,777,172	61,944,449	(16,549,430)	-	1,366,172,191
2055	1,366,172,191	64,073,476	(39,594,130)	-	1,390,651,536
2056	1,390,651,536	65,221,557	(33,257,818)	-	1,422,615,275

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External Levelized	2057	1,422,615,275	66,720,656	(34,340,336)	-	1,454,995,596
	2058	1,454,995,596	68,239,293	(19,030,884)	-	1,504,204,005
	2059	1,504,204,005	70,547,168	(34,590,184)	-	1,540,160,989
	2060	1,540,160,989	72,233,550	(38,063,373)	-	1,574,331,166
	2061	1,574,331,166	73,836,132	(39,311,368)	-	1,608,855,930
	2062	1,608,855,930	75,455,343	(21,914,866)	-	1,662,396,408
	2063	1,662,396,408	77,966,392	(80,814,065)	-	1,659,548,734
	2064	1,659,548,734	77,832,836	(61,087,643)	-	1,676,293,927
	2065	1,676,293,927	78,618,185	(45,044,894)	-	1,709,867,217
	2066	1,709,867,217	80,192,772	(25,267,448)	-	1,764,792,541
	2067	1,764,792,541	82,768,770	(26,187,402)	-	1,821,373,910
	2068	1,821,373,910	85,422,436	(72,773,080)	-	1,834,023,266
	2069	1,834,023,266	86,015,691	(63,423,667)	-	1,856,615,291
	2070	1,856,615,291	87,075,257	(29,165,760)	-	1,914,524,787
	2071	1,914,524,787	89,791,213	(30,235,927)	-	1,974,080,073
	2072	1,974,080,073	92,584,355	(93,016,280)	-	1,973,648,148
	2073	1,973,648,148	92,564,098	(32,501,581)	-	2,033,710,665
	2074	2,033,710,665	95,381,030	(33,700,580)	-	2,095,391,115
	2075	2,095,391,115	98,273,843	(112,632,408)	-	2,081,032,550
	2076	2,081,032,550	97,600,427	(36,348,598)	-	2,142,284,378
	2077	2,142,284,378	100,473,137	(37,581,576)	-	2,205,175,940
	2078	2,205,175,940	103,422,752	(117,870,783)	-	2,190,727,908
	2079	2,190,727,908	102,745,139	(40,425,495)	-	2,253,047,552
	2080	2,253,047,552	105,667,930	(42,057,653)	-	2,316,657,830
	2081	2,316,657,830	108,651,252	(43,493,498)	-	2,381,815,584
	2082	2,381,815,584	111,707,151	(126,011,290)	-	2,367,511,445
	2083	2,367,511,445	111,036,287	(46,803,816)	-	2,431,743,916
	2084	2,431,743,916	114,048,790	(48,703,066)	-	2,497,089,640
	2085	2,497,089,640	117,113,504	(50,375,896)	-	2,563,827,248
	2086	2,563,827,248	120,243,498	(52,266,185)	-	2,631,804,561
	2087	2,631,804,561	123,431,634	(54,230,116)	-	2,701,006,078
	2088	2,701,006,078	126,677,185	(56,440,284)	-	2,771,242,980
	2089	2,771,242,980	129,971,296	(741,008,517)	-	2,160,205,758
	2090	2,160,205,758	101,313,650	(71,649,266)	-	2,189,870,142
	2091	2,189,870,142	102,704,910	(62,878,157)	-	2,229,696,895
	2092	2,229,696,895	104,572,784	(65,451,288)	-	2,268,818,391
	2093	2,268,818,391	106,407,583	(58,981,150)	-	2,316,244,823
	2094	2,316,244,823	108,631,882	(64,517,121)	-	2,360,359,585
	2095	2,360,359,585	110,700,865	(149,957,811)	-	2,321,102,639
	2096	2,321,102,639	108,859,714	(128,623,019)	-	2,301,339,333
	2097	2,301,339,333	107,932,815	(129,344,406)	-	2,279,927,743
	2098	2,279,927,743	106,928,611	(78,502,975)	-	2,308,353,379
	2099	2,308,353,379	108,261,773	(75,521,275)	-	2,341,093,877
	2100	2,341,093,877	109,797,303	(174,463,166)	-	2,276,428,014
	2101	2,276,428,014	106,764,474	(184,893,927)	-	2,198,298,560
	2102	2,198,298,560	103,100,202	(191,487,341)	-	2,109,911,422

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EXTERNAL FUND CALCULATION

2103	2,109,911,422	98,954,846	(87,534,159)	-	2,121,332,109
2104	2,121,332,109	99,490,476	(93,417,111)	-	2,127,405,474
2105	2,127,405,474	99,775,317	(212,759,172)	-	2,014,421,619
2106	2,014,421,619	94,476,374	(177,865,442)	-	1,931,032,551
2107	1,931,032,551	90,565,427	(186,884,215)	-	1,834,713,763
2108	1,834,713,763	86,048,075	(108,317,031)	-	1,812,444,808
2109	1,812,444,808	85,003,661	(197,924,338)	-	1,699,524,131
2110	1,699,524,131	79,707,682	(207,538,354)	-	1,571,693,459
2111	1,571,693,459	73,712,423	(214,640,096)	-	1,430,765,786
2112	1,430,765,786	67,102,915	(124,744,860)	-	1,373,123,841
2113	1,373,123,841	64,399,508	(433,419,883)	-	1,004,103,467
2114	1,004,103,467	47,092,453	(343,896,707)	-	707,299,213
2115	707,299,213	33,172,333	(271,105,418)	-	469,366,127
2116	469,366,127	22,013,271	(283,159,824)	-	208,219,574
2117	208,219,574	9,765,498	(149,630,097)	-	68,354,975
2118	68,354,975	3,205,848	(71,560,824)	-	0

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2019 ACCRUAL COMPARISON

	Present	Proposed	Difference
Monticello	$13,392,226	$68,679,001	$55,286,775
Prairie Island Unit 1	49,264	42,821,016	42,771,751
Prairie Island Unit 2	589,341	35,556,474	34,967,133
TOTAL	$14,030,831	$147,056,491	$133,025,660

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2019 MN RETAIL SUMMARY

	Remaining Life (yrs)	Operational Earnings Rate	Post-Shutdown Earnings Rate	Market Value Balance 6/30/2017	Book Value 6/30/2017	Unrealized Gain/Loss 6/30/2017	Tax-Effect Adjustment	Tax-Adjusted Fund Balance 6/30/2017	2019-2021 Decommissioning Accrual
Monticello	13.75	5.05%	4.97%	$660,140,345	$529,148,381	$130,991,964	$36,468,163	$623,672,182	**68,679,001**
Prairie Island Unit 1	16.67	5.05%	4.94%	399,941,696	308,078,761	91,862,935	25,574,641	374,367,055	**42,821,016**
Prairie Island Unit 2	17.83	5.09%	4.93%	448,597,551	346,627,064	101,970,487	28,388,583	420,208,967	**35,556,474**
TOTAL DECOMMISSIONING ACCRUAL				**$1,508,679,592**	**$1,183,854,206**	**$324,825,386**	**$90,431,387**	**$1,418,248,204**	**$147,056,491**

INPUT DATA

Escalation Rate (Labor)	4.05%
Escalation Rate (Non-Labor)	2.85%
Escalation Rate (PIIC)	0.00%
Jurisdictional Factor	73.4886%
Tax Rate for tax-effect adjustment	27.84%

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	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
Monticello															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2030	$21,103,620	$15,508,745	1.6755	$25,984,903	$8,935,561	$6,566,615	1.4410	$9,462,492	$0	$0	1.0000	$0	$30,039,182	$22,075,360	$35,447,395
2031	72,416,235	53,217,644	1.7434	92,779,641	42,961,344	31,571,670	1.4820	46,789,215	0	0	1.0000	0	115,377,579	84,789,314	139,568,856
2032	81,871,155	60,165,928	1.8140	109,140,994	112,447,584	82,636,104	1.5243	125,962,213	0	0	1.0000	0	194,318,740	142,802,032	235,103,206
2033	78,663,227	57,808,468	1.8874	109,107,702	100,155,663	73,602,948	1.5677	115,387,342	0	0	1.0000	0	178,818,889	131,411,416	224,495,044
2034	66,380,422	48,782,012	1.9639	95,802,993	38,894,668	28,583,129	1.6124	46,087,438	0	0	1.0000	0	105,275,090	77,365,141	141,890,431
2035	86,879,799	63,846,708	2.0434	130,464,363	113,147,093	83,150,162	1.6584	137,896,229	0	0	1.0000	0	200,026,892	146,996,870	268,360,592
2036	50,307,501	36,970,255	2.1262	78,606,156	20,688,341	15,203,562	1.7056	25,931,196	0	0	1.0000	0	70,995,842	52,173,817	104,537,352
2037	34,755,725	25,541,479	2.2123	56,505,415	14,196,879	10,433,081	1.7542	18,301,711	0	0	1.0000	0	48,952,604	35,974,561	74,807,126
2038	29,827,531	21,919,821	2.3019	50,457,236	15,091,277	11,090,361	1.8042	20,009,230	0	0	1.0000	0	44,918,808	33,010,182	70,466,465
2039	7,164,560	5,265,132	2.3951	12,610,517	2,086,795	1,533,555	1.8556	2,845,665	0	0	1.0000	0	9,251,355	6,798,687	15,456,182
2040	7,184,150	5,279,528	2.4921	13,157,112	2,092,376	1,537,657	1.9085	2,934,618	0	0	1.0000	0	9,276,526	6,817,185	16,091,729
2041	7,164,560	5,265,132	2.5930	13,652,486	2,086,795	1,533,555	1.9629	3,010,216	0	0	1.0000	0	9,251,355	6,798,687	16,662,702
2042	7,164,560	5,265,132	2.6981	14,205,851	2,086,795	1,533,555	2.0189	3,096,095	0	0	1.0000	0	9,251,355	6,798,687	17,301,946
2043	7,164,560	5,265,132	2.8073	14,780,804	2,086,795	1,533,555	2.0764	3,184,274	0	0	1.0000	0	9,251,355	6,798,687	17,965,078
2044	7,184,150	5,279,528	2.9210	15,421,501	2,092,376	1,537,657	2.1356	3,283,820	0	0	1.0000	0	9,276,526	6,817,185	18,705,321
2045	7,164,560	5,265,132	3.0393	16,002,314	2,086,795	1,533,555	2.1964	3,368,301	0	0	1.0000	0	9,251,355	6,798,687	19,370,615
2046	7,164,560	5,265,132	3.1624	16,650,452	2,086,795	1,533,555	2.2590	3,464,302	0	0	1.0000	0	9,251,355	6,798,687	20,114,754
2047	7,164,560	5,265,132	3.2905	17,324,915	2,086,795	1,533,555	2.3234	3,563,063	0	0	1.0000	0	9,251,355	6,798,687	20,887,978
2048	7,847,790	5,767,227	3.4238	19,745,833	4,083,316	3,000,770	2.3896	7,170,639	0	0	1.0000	0	11,931,106	8,767,997	26,916,472
2049	7,164,560	5,265,132	3.5624	18,756,505	2,086,795	1,533,555	2.4577	3,769,019	0	0	1.0000	0	9,251,355	6,798,687	22,525,524
2050	8,657,770	6,362,470	3.7067	23,583,767	6,566,405	4,825,556	2.5278	12,198,040	0	0	1.0000	0	15,224,175	11,188,026	35,781,808
2051	8,657,770	6,362,470	3.8568	24,538,774	6,566,405	4,825,556	2.5998	12,545,480	0	0	1.0000	0	15,224,175	11,188,026	37,084,255
2052	8,677,350	6,376,859	4.0130	25,590,335	6,571,986	4,829,657	2.6739	12,914,021	0	0	1.0000	0	15,249,336	11,206,516	38,504,356
2053	8,657,770	6,362,470	4.1756	26,567,130	6,566,405	4,825,556	2.7501	13,270,762	0	0	1.0000	0	15,224,175	11,188,026	39,837,891
2054	8,657,770	6,362,470	4.3447	27,643,023	6,566,405	4,825,556	2.8285	13,649,085	0	0	1.0000	0	15,224,175	11,188,026	41,292,108
2055	8,657,770	6,362,470	4.5206	28,762,182	6,566,405	4,825,556	2.9091	14,038,025	0	0	1.0000	0	15,224,175	11,188,026	42,800,207
2056	8,677,350	6,376,859	4.7037	29,994,832	6,571,986	4,829,657	2.9920	14,450,335	0	0	1.0000	0	15,249,336	11,206,516	44,445,167
2057	8,657,770	6,362,470	4.8942	31,139,201	6,566,405	4,825,556	3.0773	14,849,683	0	0	1.0000	0	15,224,175	11,188,026	45,988,884
2058	14,754,150	10,842,611	5.0924	55,214,915	24,855,555	18,265,988	3.1650	57,811,852	0	0	1.0000	0	39,609,705	29,108,599	113,026,766
2059	8,657,770	6,362,470	5.2987	33,712,820	6,566,405	4,825,556	3.2552	15,708,150	0	0	1.0000	0	15,224,175	11,188,026	49,420,970
2060	8,677,350	6,376,859	5.5133	35,157,537	6,571,986	4,829,657	3.3480	16,169,693	0	0	1.0000	0	15,249,336	11,206,516	51,327,230
2061	8,657,770	6,362,470	5.7366	36,498,945	6,566,405	4,825,556	3.4434	16,616,320	0	0	1.0000	0	15,224,175	11,188,026	53,115,265
2062	8,657,770	6,362,470	5.9689	37,976,947	6,566,405	4,825,556	3.5415	17,089,707	0	0	1.0000	0	15,224,175	11,188,026	55,066,654
2063	8,657,770	6,362,470	6.2106	39,514,756	6,566,405	4,825,556	3.6425	17,577,088	0	0	1.0000	0	15,224,175	11,188,026	57,091,844
2064	8,677,350	6,376,859	6.4622	41,208,538	6,571,986	4,829,657	3.7463	18,093,345	0	0	1.0000	0	15,249,336	11,206,516	59,301,884
2065	8,657,770	6,362,470	6.7239	42,780,612	6,566,405	4,825,556	3.8531	18,593,350	0	0	1.0000	0	15,224,175	11,188,026	61,373,962
2066	12,315,600	9,050,556	6.9962	63,319,502	17,539,895	12,889,815	3.9629	51,081,048	0	0	1.0000	0	29,855,495	21,940,371	114,400,551
2067	8,657,770	6,362,470	7.2795	46,315,600	6,566,405	4,825,556	4.0758	19,668,001	0	0	1.0000	0	15,224,175	11,188,026	65,983,601
2068	17,212,290	12,649,063	7.5744	95,809,063	32,176,796	23,646,262	4.1920	99,125,130	0	0	1.0000	0	49,389,086	36,295,325	194,934,193
2069	8,657,770	6,362,470	7.8811	50,143,262	6,566,405	4,825,556	4.3115	20,805,385	0	0	1.0000	0	15,224,175	11,188,026	70,948,647
2070	8,657,770	6,362,470	8.2003	52,174,163	6,566,405	4,825,556	4.4343	21,397,963	0	0	1.0000	0	15,224,175	11,188,026	73,572,125
2071	8,657,770	6,362,470	8.5324	54,287,139	6,566,405	4,825,556	4.5607	22,007,913	0	0	1.0000	0	15,224,175	11,188,026	76,295,052
2072	8,677,350	6,376,859	8.8780	56,613,754	6,571,986	4,829,657	4.6907	22,654,474	0	0	1.0000	0	15,249,336	11,206,516	79,268,228
2073	8,657,770	6,362,470	9.2375	58,773,316	6,566,405	4,825,556	4.8244	23,280,412	0	0	1.0000	0	15,224,175	11,188,026	82,053,729
2074	8,657,770	6,362,470	9.6117	61,154,153	6,566,405	4,825,556	4.9619	23,943,926	0	0	1.0000	0	15,224,175	11,188,026	85,098,079
2075	8,657,770	6,362,470	10.0009	63,630,426	6,566,405	4,825,556	5.1033	24,626,260	0	0	1.0000	0	15,224,175	11,188,026	88,256,686
2076	8,677,350	6,376,859	10.4060	66,357,595	6,571,986	4,829,657	5.2487	25,349,422	0	0	1.0000	0	15,249,336	11,206,516	91,707,017
2077	8,657,770	6,362,470	10.8274	68,889,007	6,566,405	4,825,556	5.3983	26,049,799	0	0	1.0000	0	15,224,175	11,188,026	94,938,806
2078	8,657,770	6,362,470	11.2659	71,678,950	6,566,405	4,825,556	5.5522	26,792,452	0	0	1.0000	0	15,224,175	11,188,026	98,471,402
2079	8,657,770	6,362,470	11.7222	74,582,146	6,566,405	4,825,556	5.7104	27,555,855	0	0	1.0000	0	15,224,175	11,188,026	102,138,001
2080	8,677,350	6,376,859	12.1970	77,778,550	6,571,986	4,829,657	5.8731	28,365,060	0	0	1.0000	0	15,249,336	11,206,516	106,143,610
2081	8,657,770	6,362,470	12.6909	80,745,470	6,566,405	4,825,556	6.0405	29,148,771	0	0	1.0000	0	15,224,175	11,188,026	109,894,241
2082	8,657,770	6,362,470	13.2049	84,015,780	6,566,405	4,825,556	6.2127	29,979,732	0	0	1.0000	0	15,224,175	11,188,026	113,995,512
2083	8,657,770	6,362,470	13.7397	87,418,429	6,566,405	4,825,556	6.3897	30,833,855	0	0	1.0000	0	15,224,175	11,188,026	118,252,284
2084	8,677,350	6,376,859	14.2962	91,164,852	6,571,986	4,829,657	6.5719	31,740,025	0	0	1.0000	0	15,249,336	11,206,516	122,904,877

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AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
2085	8,657,770	6,362,470	14.8752	94,643,013	6,566,405	4,825,556	6.7592	32,616,898	0	0	1.0000	0	15,224,175	11,188,026	127,259,911
2086	8,657,770	6,362,470	15.4776	98,475,765	6,566,405	4,825,556	6.9518	33,546,300	0	0	1.0000	0	15,224,175	11,188,026	132,022,065
2087	8,657,770	6,362,470	16.1045	102,464,398	6,566,405	4,825,556	7.1499	34,502,243	0	0	1.0000	0	15,224,175	11,188,026	136,966,641
2088	9,340,990	6,864,558	16.7567	115,027,347	8,562,916	6,292,763	7.3537	46,275,091	0	0	1.0000	0	17,903,906	13,157,321	161,302,438
2089	8,657,770	6,362,470	17.4353	110,931,573	6,566,405	4,825,556	7.5633	36,497,128	0	0	1.0000	0	15,224,175	11,188,026	147,428,700
2090	8,657,770	6,362,470	18.1415	115,424,749	6,566,405	4,825,556	7.7788	37,537,035	0	0	1.0000	0	15,224,175	11,188,026	152,961,784
2091	8,657,770	6,362,470	18.8762	120,099,256	6,566,405	4,825,556	8.0005	38,606,861	0	0	1.0000	0	15,224,175	11,188,026	158,706,116
2092	8,677,350	6,376,859	19.6407	125,245,975	6,571,986	4,829,657	8.2285	39,740,835	0	0	1.0000	0	15,249,336	11,206,516	164,986,810
2093	8,657,770	6,362,470	20.4361	130,024,073	6,566,405	4,825,556	8.4630	40,838,680	0	0	1.0000	0	15,224,175	11,188,026	170,862,753
2094	8,657,770	6,362,470	21.2638	135,290,289	6,566,405	4,825,556	8.7042	42,002,605	0	0	1.0000	0	15,224,175	11,188,026	177,292,894
2095	29,995,110	22,042,973	22.1250	487,700,768	79,650,261	58,533,825	8.9523	524,012,362	0	0	1.0000	0	109,645,371	80,576,798	1,011,713,130
2096	8,677,350	6,376,859	23.0210	146,801,672	6,571,986	4,829,657	9.2075	44,469,070	0	0	1.0000	0	15,249,336	11,206,516	191,270,742
2097	8,657,770	6,362,470	23.9534	152,402,788	6,566,405	4,825,556	9.4699	45,697,533	0	0	1.0000	0	15,224,175	11,188,026	198,100,321
2098	8,657,770	6,362,470	24.9235	158,575,020	6,566,405	4,825,556	9.7398	46,999,950	0	0	1.0000	0	15,224,175	11,188,026	205,574,971
2099	8,657,770	6,362,470	25.9329	164,997,298	6,566,405	4,825,556	10.0173	48,339,042	0	0	1.0000	0	15,224,175	11,188,026	213,336,340
2100	8,657,770	6,362,470	26.9832	171,679,800	6,566,405	4,825,556	10.3028	49,716,738	0	0	1.0000	0	15,224,175	11,188,026	221,396,538
2101	8,657,770	6,362,470	28.0760	178,632,707	6,566,405	4,825,556	10.5965	51,134,004	0	0	1.0000	0	15,224,175	11,188,026	229,766,711
2102	8,657,770	6,362,470	29.2131	185,867,472	6,566,405	4,825,556	10.8985	52,591,322	0	0	1.0000	0	15,224,175	11,188,026	238,458,794
2103	8,657,770	6,362,470	30.3962	193,394,910	6,566,405	4,825,556	11.2091	54,090,140	0	0	1.0000	0	15,224,175	11,188,026	247,485,050
2104	8,677,350	6,376,859	31.6272	201,682,196	6,571,986	4,829,657	11.5285	55,678,704	0	0	1.0000	0	15,249,336	11,206,516	257,360,900
2105	8,657,770	6,362,470	32.9081	209,376,798	6,566,405	4,825,556	11.8571	57,217,100	0	0	1.0000	0	15,224,175	11,188,026	266,593,898
2106	8,657,770	6,362,470	34.2409	217,856,698	6,566,405	4,825,556	12.1950	58,847,655	0	0	1.0000	0	15,224,175	11,188,026	276,704,354
2107	8,657,770	6,362,470	35.6277	226,680,171	6,566,405	4,825,556	12.5426	60,525,019	0	0	1.0000	0	15,224,175	11,188,026	287,205,190
2108	14,773,730	10,857,001	37.0706	402,475,524	24,861,136	18,270,089	12.9000	235,684,150	0	0	1.0000	0	39,634,866	29,127,090	638,159,674
2109	8,657,770	6,362,470	38.5720	245,413,192	6,566,405	4,825,556	13.2677	64,024,029	0	0	1.0000	0	15,224,175	11,188,026	309,437,221
2110	8,657,770	6,362,470	40.1341	255,352,006	6,566,405	4,825,556	13.6458	65,848,572	0	0	1.0000	0	15,224,175	11,188,026	321,200,578
2111	8,657,770	6,362,470	41.7596	265,694,201	6,566,405	4,825,556	14.0347	67,725,231	0	0	1.0000	0	15,224,175	11,188,026	333,419,432
2112	8,677,350	6,376,859	43.4508	277,079,626	6,571,986	4,829,657	14.4347	69,714,654	0	0	1.0000	0	15,249,336	11,206,516	346,794,281
2113	8,657,770	6,362,470	45.2106	287,651,085	6,566,405	4,825,556	14.8461	71,640,687	0	0	1.0000	0	15,224,175	11,188,026	359,291,772
2114	8,657,770	6,362,470	47.0416	299,300,767	6,566,405	4,825,556	15.2692	73,682,380	0	0	1.0000	0	15,224,175	11,188,026	372,983,147
2115	8,657,770	6,362,470	48.9468	311,422,545	6,566,405	4,825,556	15.7044	75,782,462	0	0	1.0000	0	15,224,175	11,188,026	387,205,007
2116	12,335,180	9,064,945	50.9291	461,669,511	17,545,476	12,893,916	16.1520	208,262,538	0	0	1.0000	0	29,880,656	21,958,862	669,932,049
2117	8,657,770	6,362,470	52.9918	337,158,736	6,566,405	4,825,556	16.6123	80,163,584	0	0	1.0000	0	15,224,175	11,188,026	417,322,320
2118	17,192,700	12,634,667	55.1379	696,648,984	32,171,215	23,642,161	17.0857	403,942,863	0	0	1.0000	0	49,363,915	36,276,827	1,100,591,847
2119	8,657,770	6,362,470	57.3710	365,021,265	6,566,405	4,825,556	17.5727	84,798,048	0	0	1.0000	0	15,224,175	11,188,026	449,819,313
2120	8,677,350	6,376,859	59.6946	380,664,049	6,571,986	4,829,657	18.0735	87,288,812	0	0	1.0000	0	15,249,336	11,206,516	467,952,861
2121	8,657,770	6,362,470	62.1122	395,187,007	6,566,405	4,825,556	18.5886	89,700,330	0	0	1.0000	0	15,224,175	11,188,026	484,887,338
2122	8,657,770	6,362,470	64.6277	411,191,801	6,566,405	4,825,556	19.1184	92,256,910	0	0	1.0000	0	15,224,175	11,188,026	503,448,710
2123	8,657,770	6,362,470	67.2451	427,844,930	6,566,405	4,825,556	19.6633	94,886,355	0	0	1.0000	0	15,224,175	11,188,026	522,731,285
2124	8,677,350	6,376,859	69.9686	446,179,899	6,571,986	4,829,657	20.2237	97,673,541	0	0	1.0000	0	15,249,336	11,206,516	543,853,439
2125	8,657,770	6,362,470	72.8023	463,202,448	6,566,405	4,825,556	20.8000	100,371,565	0	0	1.0000	0	15,224,175	11,188,026	563,574,012
2126	8,657,770	6,362,470	75.7508	481,962,190	6,566,405	4,825,556	21.3928	103,232,154	0	0	1.0000	0	15,224,175	11,188,026	585,194,345
2127	8,657,770	6,362,470	78.8187	501,481,612	6,566,405	4,825,556	22.0025	106,174,296	0	0	1.0000	0	15,224,175	11,188,026	607,655,908
2128	9,340,990	6,864,558	82.0109	562,968,618	8,562,916	6,292,763	22.6296	142,402,709	0	0	1.0000	0	17,903,906	13,157,321	705,371,327
2129	8,657,770	6,362,470	85.3323	542,924,196	6,566,405	4,825,556	23.2745	112,312,403	0	0	1.0000	0	15,224,175	11,188,026	655,236,600
2130	8,657,770	6,362,470	88.7883	564,912,893	6,566,405	4,825,556	23.9379	115,513,677	0	0	1.0000	0	15,224,175	11,188,026	680,426,570
2131	8,657,770	6,362,470	92.3842	587,791,698	6,566,405	4,825,556	24.6201	118,805,671	0	0	1.0000	0	15,224,175	11,188,026	706,597,370
2132	8,677,350	6,376,859	96.1257	612,980,038	6,571,986	4,829,657	25.3218	122,295,617	0	0	1.0000	0	15,249,336	11,206,516	735,275,655
2133	8,657,770	6,362,470	100.0188	636,366,612	6,566,405	4,825,556	26.0434	125,673,885	0	0	1.0000	0	15,224,175	11,188,026	762,040,497
2134	8,657,770	6,362,470	104.0696	662,139,705	6,566,405	4,825,556	26.7857	129,255,895	0	0	1.0000	0	15,224,175	11,188,026	791,395,600
2135	8,657,770	6,362,470	108.2844	688,956,243	6,566,405	4,825,556	27.5491	132,939,725	0	0	1.0000	0	15,224,175	11,188,026	821,895,968
2136	8,677,350	6,376,859	112.6699	718,480,069	6,571,986	4,829,657	28.3342	136,844,476	0	0	1.0000	0	15,249,336	11,206,516	855,324,546
2137	8,657,770	6,362,470	117.2331	745,892,078	6,566,405	4,825,556	29.1417	140,624,905	0	0	1.0000	0	15,224,175	11,188,026	886,516,984
2138	8,657,770	6,362,470	121.9810	776,100,450	6,566,405	4,825,556	29.9723	144,633,012	0	0	1.0000	0	15,224,175	11,188,026	920,733,462
2139	8,657,770	6,362,470	126.9212	807,532,324	6,566,405	4,825,556	30.8265	148,755,002	0	0	1.0000	0	15,224,175	11,188,026	956,287,326
2140	8,677,350	6,376,859	132.0616	842,138,207	6,571,986	4,829,657	31.7050	153,124,285	0	0	1.0000	0	15,249,336	11,206,516	995,262,492
2141	8,657,770	6,362,470	137.4100	874,266,999	6,566,405	4,825,556	32.6086	157,354,625	0	0	1.0000	0	15,224,175	11,188,026	1,031,621,624

Xcel Energy
Nuclear Decommissioning Accrual
200-Year Decommissioning Period
DECON Method

Docket No. E002/M-17-828
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Proposed

AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
2142	8,657,770	6,362,470	142.9752	909,675,417	6,566,405	4,825,556	33.5380	161,839,497	0	0	1.0000	0	15,224,175	11,188,026	1,071,514,914
2143	8,657,770	6,362,470	148.7656	946,516,663	6,566,405	4,825,556	34.4938	166,451,764	0	0	1.0000	0	15,224,175	11,188,026	1,112,968,427
2144	8,677,350	6,376,859	154.7907	987,078,473	6,571,986	4,829,657	35.4769	171,341,270	0	0	1.0000	0	15,249,336	11,206,516	1,158,419,743
2145	29,995,110	22,042,973	161.0597	3,550,234,550	70,578,445	51,867,079	36.4880	1,892,525,961	0	0	1.0000	0	100,573,555	73,910,051	5,442,760,511
2146	8,657,770	6,362,470	167.5826	1,066,239,260	6,566,405	4,825,556	37.5279	181,092,983	0	0	1.0000	0	15,224,175	11,188,026	1,247,332,243
2147	8,657,770	6,362,470	174.3697	1,109,421,980	6,566,405	4,825,556	38.5974	186,253,915	0	0	1.0000	0	15,224,175	11,188,026	1,295,675,896
2148	8,677,350	6,376,859	181.4317	1,156,964,375	6,571,986	4,829,657	39.6975	191,725,321	0	0	1.0000	0	15,249,336	11,206,516	1,348,689,696
2149	8,657,770	6,362,470	188.7796	1,201,104,536	6,566,405	4,825,556	40.8288	197,021,661	0	0	1.0000	0	15,224,175	11,188,026	1,398,126,197
2150	8,657,770	6,362,470	196.4252	1,249,749,437	6,566,405	4,825,556	41.9925	202,637,160	0	0	1.0000	0	15,224,175	11,188,026	1,452,386,597
2151	8,657,770	6,362,470	204.3804	1,300,364,158	6,566,405	4,825,556	43.1893	208,412,386	0	0	1.0000	0	15,224,175	11,188,026	1,508,776,544
2152	8,677,350	6,376,859	212.6578	1,356,088,812	6,571,986	4,829,657	44.4201	214,533,861	0	0	1.0000	0	15,249,336	11,206,516	1,570,622,673
2153	8,657,770	6,362,470	221.2705	1,407,826,912	6,566,405	4,825,556	45.6861	220,460,834	0	0	1.0000	0	15,224,175	11,188,026	1,628,287,746
2154	8,657,770	6,362,470	230.2319	1,464,843,550	6,566,405	4,825,556	46.9882	226,744,191	0	0	1.0000	0	15,224,175	11,188,026	1,691,587,741
2155	8,657,770	6,362,470	239.5563	1,524,169,765	6,566,405	4,825,556	48.3273	233,206,093	0	0	1.0000	0	15,224,175	11,188,026	1,757,375,858
2156	8,677,350	6,376,859	249.2584	1,589,485,679	6,571,986	4,829,657	49.7047	240,056,668	0	0	1.0000	0	15,249,336	11,206,516	1,829,542,347
2157	8,657,770	6,362,470	259.3533	1,650,127,583	6,566,405	4,825,556	51.1212	246,688,214	0	0	1.0000	0	15,224,175	11,188,026	1,896,815,797
2158	14,754,150	10,842,611	269.8571	2,925,955,689	24,855,555	18,265,988	52.5782	960,392,763	0	0	1.0000	0	39,609,705	29,108,599	3,886,348,451
2159	8,657,770	6,362,470	280.7864	1,786,495,039	6,566,405	4,825,556	54.0767	260,950,144	0	0	1.0000	0	15,224,175	11,188,026	2,047,445,183
2160	8,677,350	6,376,859	292.1582	1,863,051,656	6,571,986	4,829,657	55.6179	268,615,398	0	0	1.0000	0	15,249,336	11,206,516	2,131,667,054
2161	8,657,770	6,362,470	303.9906	1,934,131,064	6,566,405	4,825,556	57.2030	276,036,280	0	0	1.0000	0	15,224,175	11,188,026	2,210,167,344
2162	8,657,770	6,362,470	316.3022	2,012,463,250	6,566,405	4,825,556	58.8333	283,903,384	0	0	1.0000	0	15,224,175	11,188,026	2,296,366,634
2163	8,657,770	6,362,470	329.1125	2,093,968,399	6,566,405	4,825,556	60.5100	291,994,394	0	0	1.0000	0	15,224,175	11,188,026	2,385,962,792
2164	8,677,350	6,376,859	342.4415	2,183,701,172	6,571,986	4,829,657	62.2345	300,571,308	0	0	1.0000	0	15,249,336	11,206,516	2,484,272,480
2165	8,657,770	6,362,470	356.3104	2,267,014,221	6,566,405	4,825,556	64.0082	308,875,154	0	0	1.0000	0	15,224,175	11,188,026	2,575,889,374
2166	12,315,600	9,050,556	370.7410	3,355,412,309	17,539,895	12,889,815	65.8325	848,568,754	0	0	1.0000	0	29,855,495	21,940,371	4,203,981,063
2167	8,657,770	6,362,470	385.7560	2,454,360,967	6,566,405	4,825,556	67.7087	326,732,124	0	0	1.0000	0	15,224,175	11,188,026	2,781,093,090
2168	17,875,930	13,136,762	401.3791	5,272,821,890	34,167,736	25,109,375	69.6384	1,748,576,695	0	0	1.0000	0	52,043,666	38,246,137	7,021,398,585
2169	8,657,770	6,362,470	417.6350	2,657,190,147	6,566,405	4,825,556	71.6231	345,621,280	0	0	1.0000	0	15,224,175	11,188,026	3,002,811,427
2170	8,657,770	6,362,470	434.5492	2,764,806,236	6,566,405	4,825,556	73.6643	355,471,205	0	0	1.0000	0	15,224,175	11,188,026	3,120,277,441
2171	8,657,770	6,362,470	452.1484	2,876,780,618	6,566,405	4,825,556	75.7638	365,602,460	0	0	1.0000	0	15,224,175	11,188,026	3,242,383,078
2172	8,677,350	6,376,859	470.4604	3,000,059,650	6,571,986	4,829,657	77.9230	376,341,387	0	0	1.0000	0	15,249,336	11,206,516	3,376,401,038
2173	8,657,770	6,362,470	489.5141	3,114,518,762	6,566,405	4,825,556	80.1438	386,738,395	0	0	1.0000	0	15,224,175	11,188,026	3,501,257,157
2174	8,657,770	6,362,470	509.3394	3,240,656,638	6,566,405	4,825,556	82.4279	397,760,448	0	0	1.0000	0	15,224,175	11,188,026	3,638,417,086
2175	8,657,770	6,362,470	529.9676	3,371,902,941	6,566,405	4,825,556	84.7771	409,096,644	0	0	1.0000	0	15,224,175	11,188,026	3,780,999,585
2176	8,677,350	6,376,859	551.4313	3,516,399,665	6,571,986	4,829,657	87.1933	421,113,759	0	0	1.0000	0	15,249,336	11,206,516	3,937,513,425
2177	8,657,770	6,362,470	573.7643	3,650,558,130	6,566,405	4,825,556	89.6783	432,747,659	0	0	1.0000	0	15,224,175	11,188,026	4,083,305,789
2178	8,657,770	6,362,470	597.0018	3,798,406,026	6,566,405	4,825,556	92.2341	445,080,815	0	0	1.0000	0	15,224,175	11,188,026	4,243,486,841
2179	8,657,770	6,362,470	621.1803	3,952,241,006	6,566,405	4,825,556	94.8628	457,765,754	0	0	1.0000	0	15,224,175	11,188,026	4,410,006,760
2180	8,677,350	6,376,859	646.3381	4,121,606,950	6,571,986	4,829,657	97.5664	471,212,278	0	0	1.0000	0	15,249,336	11,206,516	4,592,819,228
2181	8,657,770	6,362,470	672.5148	4,278,855,221	6,566,405	4,825,556	100.3470	484,230,068	0	0	1.0000	0	15,224,175	11,188,026	4,763,085,289
2182	8,657,770	6,362,470	699.7517	4,452,149,179	6,566,405	4,825,556	103.2069	498,030,676	0	0	1.0000	0	15,224,175	11,188,026	4,950,179,855
2183	8,657,770	6,362,470	728.0916	4,632,460,942	6,566,405	4,825,556	106.1483	512,224,566	0	0	1.0000	0	15,224,175	11,188,026	5,144,685,508
2184	8,677,350	6,376,859	757.5793	4,830,976,401	6,571,986	4,829,657	109.1736	527,271,076	0	0	1.0000	0	15,249,336	11,206,516	5,358,247,477
2185	8,657,770	6,362,470	788.2613	5,015,288,851	6,566,405	4,825,556	112.2850	541,837,556	0	0	1.0000	0	15,224,175	11,188,026	5,557,126,407
2186	8,657,770	6,362,470	820.1859	5,218,408,160	6,566,405	4,825,556	115.4851	557,279,817	0	0	1.0000	0	15,224,175	11,188,026	5,775,687,978
2187	8,657,770	6,362,470	853.4034	5,429,753,507	6,566,405	4,825,556	118.7764	573,162,170	0	0	1.0000	0	15,224,175	11,188,026	6,002,915,676
2188	8,677,350	6,376,859	887.9662	5,662,435,282	6,571,986	4,829,657	122.1616	589,998,665	0	0	1.0000	0	15,249,336	11,206,516	6,252,433,947
2189	8,657,770	6,362,470	923.9289	5,878,469,883	6,566,405	4,825,556	125.6432	606,298,298	0	0	1.0000	0	15,224,175	11,188,026	6,484,768,180
2190	8,657,770	6,362,470	961.3480	6,116,547,783	6,566,405	4,825,556	129.2240	623,577,649	0	0	1.0000	0	15,224,175	11,188,026	6,740,125,432
2191	8,657,770	6,362,470	1,000.2826	6,364,268,006	6,566,405	4,825,556	132.9069	641,349,689	0	0	1.0000	0	15,224,175	11,188,026	7,005,617,695
2192	9,539,850	7,010,698	1,040.7940	7,296,692,215	9,159,486	6,731,174	136.6947	920,115,763	0	0	1.0000	0	18,699,336	13,741,871	8,216,807,977
2193	10,167,140	7,471,684	1,082.9462	8,091,431,966	11,094,525	8,153,206	140.5905	1,146,263,295	0	0	1.0000	0	21,261,665	15,624,890	9,237,695,262
2194	8,873,390	6,520,926	1,126.8055	7,347,815,273	7,213,275	5,300,931	144.5974	766,500,900	0	0	1.0000	0	16,086,665	11,821,857	8,114,316,172
2195	31,288,860	22,993,731	1,172.4411	26,958,794,965	74,459,695	54,719,353	148.7184	8,137,774,629	0	0	1.0000	0	105,748,555	77,713,084	35,096,569,593
2196	10,402,350	7,644,537	1,219.9250	9,325,761,294	11,746,986	8,632,690	152.9569	1,320,429,498	0	0	1.0000	0	22,149,336	16,277,227	10,646,190,792
2197	7,147,970	5,252,940	1,269.3320	6,667,724,564	2,037,025	1,496,980	157.3161	235,499,077	0	0	1.0000	0	9,184,995	6,749,920	6,903,223,641
2198	7,147,970	5,252,940	1,320.7399	6,937,767,167	2,037,025	1,496,980	161.7997	242,210,938	0	0	1.0000	0	9,184,995	6,749,920	7,179,978,104

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AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
2199	7,147,970	5,252,940	1,374.2299	7,218,746,916	2,037,025	1,496,980	166.4109	249,113,812	0	0	1.0000	0	9,184,995	6,749,920	7,467,860,728
2200	7,147,970	5,252,940	1,429.8862	7,511,106,109	2,037,025	1,496,980	171.1537	256,213,690	0	0	1.0000	0	9,184,995	6,749,920	7,767,319,798
2201	7,147,970	5,252,940	1,487.7966	7,815,305,953	2,037,025	1,496,980	176.0315	263,515,660	0	0	1.0000	0	9,184,995	6,749,920	8,078,821,612
2202	7,147,970	5,252,940	1,548.0523	8,131,825,517	2,037,025	1,496,980	181.0484	271,025,859	0	0	1.0000	0	9,184,995	6,749,920	8,402,851,376
2203	7,147,970	5,252,940	1,610.7485	8,461,164,880	2,037,025	1,496,980	186.2083	278,750,127	0	0	1.0000	0	9,184,995	6,749,920	8,739,915,007
2204	7,167,560	5,267,336	1,675.9838	8,827,970,129	2,042,606	1,501,081	191.5152	287,479,915	0	0	1.0000	0	9,210,166	6,768,418	9,115,450,044
2205	7,147,970	5,252,940	1,743.8611	9,160,397,352	2,037,025	1,496,980	196.9734	294,865,268	0	0	1.0000	0	9,184,995	6,749,920	9,455,262,620
2206	7,147,970	5,252,940	1,814.4875	9,531,393,579	2,037,025	1,496,980	202.5872	303,269,015	0	0	1.0000	0	9,184,995	6,749,920	9,834,662,594
2207	7,147,970	5,252,940	1,887.9742	9,917,414,789	2,037,025	1,496,980	208.3609	311,912,129	0	0	1.0000	0	9,184,995	6,749,920	10,229,326,918
2208	13,927,590	10,235,184	1,964.4372	20,106,377,146	22,322,696	16,404,626	214.2992	3,515,498,298	0	0	1.0000	0	36,250,286	26,639,811	23,621,875,444
2209	7,147,970	5,252,940	2,043.9969	10,736,992,637	2,037,025	1,496,980	220.4067	329,944,453	0	0	1.0000	0	9,184,995	6,749,920	11,066,937,090
2210	7,147,970	5,252,940	2,126.7788	11,171,840,973	2,037,025	1,496,980	226.6883	339,347,883	0	0	1.0000	0	9,184,995	6,749,920	11,511,188,856
2211	7,147,970	5,252,940	2,212.9133	11,624,300,315	2,037,025	1,496,980	233.1489	349,019,273	0	0	1.0000	0	9,184,995	6,749,920	11,973,319,588
2212	7,167,560	5,267,336	2,302.5363	12,128,232,789	2,042,606	1,501,081	239.7937	359,949,876	0	0	1.0000	0	9,210,166	6,768,418	12,488,182,665
2213	7,147,970	5,252,940	2,395.7890	12,584,935,356	11,235,929	8,257,122	246.6278	2,036,435,750	0	0	1.0000	0	18,383,899	13,510,061	14,621,371,106
2214	7,147,970	5,252,940	2,492.8185	13,094,625,476	2,037,025	1,496,980	253.6567	379,719,042	0	0	1.0000	0	9,184,995	6,749,920	13,474,344,519
2215	7,147,970	5,252,940	2,593.7776	13,624,957,550	2,037,025	1,496,980	260.8859	390,541,011	0	0	1.0000	0	9,184,995	6,749,920	14,015,498,561
2216	10,825,390	7,955,423	2,698.8256	21,470,298,074	13,016,096	9,565,341	268.3212	2,566,583,660	0	0	1.0000	0	23,841,486	17,520,763	24,036,881,734
2217	7,147,970	5,252,940	2,808.1281	14,750,927,819	2,037,025	1,496,980	275.9683	413,119,064	0	0	1.0000	0	9,184,995	6,749,920	15,164,046,883
2218	14,921,800	10,965,815	2,921.8572	32,040,545,612	29,162,168	21,430,855	283.8334	6,082,792,505	0	0	1.0000	0	44,083,968	32,396,670	38,123,338,117
2219	6,482,540	4,763,925	3,040.1925	14,483,248,755	3,844,408	2,825,200	291.9227	824,739,875	0	0	1.0000	0	10,326,948	7,589,124	15,307,988,630
2220	6,403,050	4,705,509	3,163.3203	14,885,031,666	3,563,171	2,618,523	300.2424	786,191,677	0	0	1.0000	0	9,966,221	7,324,032	15,671,223,343
2221	6,386,860	4,693,611	3,291.4347	15,448,714,288	3,557,358	2,614,251	308.7994	807,279,028	0	0	1.0000	0	9,944,218	7,307,862	16,255,993,316
2222	6,386,860	4,693,611	3,424.7378	16,074,387,191	3,557,358	2,614,251	317.6001	830,286,263	0	0	1.0000	0	9,944,218	7,307,862	16,904,673,455
2223	6,482,540	4,763,925	3,563.4397	16,975,959,121	3,844,408	2,825,200	326.6517	922,856,229	0	0	1.0000	0	10,326,948	7,589,124	17,898,815,350
2224	6,403,050	4,705,509	3,707.7590	17,446,892,787	3,563,171	2,618,523	335.9613	879,722,443	0	0	1.0000	0	9,966,221	7,324,032	18,326,615,231
2225	6,386,860	4,693,611	3,857.9233	18,107,591,442	3,557,358	2,614,251	345.5362	903,318,231	0	0	1.0000	0	9,944,218	7,307,862	19,010,909,673
2226	6,386,860	4,693,611	4,014.1692	18,840,948,925	3,557,358	2,614,251	355.3840	929,062,848	0	0	1.0000	0	9,944,218	7,307,862	19,770,011,773
2227	6,482,540	4,763,925	4,176.7430	19,897,689,984	3,844,408	2,825,200	365.5124	1,032,645,461	0	0	1.0000	0	10,326,948	7,589,124	20,930,335,445
2228	6,403,050	4,705,509	4,345.9011	20,449,676,086	3,563,171	2,618,523	375.9295	984,380,100	0	0	1.0000	0	9,966,221	7,324,032	21,434,056,187
2229	6,386,860	4,693,611	4,521.9101	21,224,087,226	3,557,358	2,614,251	386.6435	1,010,783,016	0	0	1.0000	0	9,944,218	7,307,862	22,234,870,241
2230	6,099,800	4,482,655	4,705.0475	21,091,103,808	2,696,178	1,981,382	397.6629	787,922,075	0	0	1.0000	0	8,795,978	6,464,037	21,879,025,883
2231	2,028,079	1,490,406	4,895.6019	7,296,434,457	5,022,573	3,691,016	408.9963	1,509,612,017	0	0	1.0000	0	7,050,652	5,181,422	8,806,046,474
	$2,255,855,813	$1,657,795,815		$717,266,338,345	$2,005,587,868	$1,473,877,521		$73,233,079,006	$0	$0		$0	$4,261,443,682	$3,131,673,337	$790,499,417,350

Xcel Energy
Nuclear Decommissioning Accrual
200-Year Decommissioning Period
DECON Method

Docket No. E002/M-17-828
Schedule F.7
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Proposed

AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
Prairie Island Unit 1															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2033	$22,324,352	$16,405,843	1.8874	$30,964,388	$9,448,311	$6,943,427	1.5677	$10,885,211	$1,250,000	$918,607	1.0000	$918,607	$33,022,663	$24,267,877	$42,768,206
2034	63,582,247	46,725,674	1.9639	91,764,550	32,971,808	24,230,505	1.6124	39,069,266	1,250,000	918,607	1.0000	918,607	97,804,054	71,874,785	131,752,423
2035	65,877,294	48,412,271	2.0434	98,925,635	81,239,940	59,702,057	1.6584	99,009,891	1,250,000	918,607	1.0000	918,607	148,367,234	109,032,935	198,854,133
2036	57,759,315	42,446,486	2.1262	90,249,718	65,595,019	48,204,831	1.7056	82,218,159	1,250,000	918,607	1.0000	918,607	124,604,334	91,569,923	173,386,484
2037	39,808,349	29,254,580	2.2123	64,719,908	41,981,869	30,851,869	1.7542	54,120,348	1,250,000	918,607	1.0000	918,607	83,040,219	61,025,056	119,758,863
2038	13,207,909	9,706,302	2.3019	22,342,936	18,994,690	13,958,923	1.8042	25,184,688	1,250,000	918,607	1.0000	918,607	33,452,599	24,583,831	48,446,231
2039	35,713,293	26,245,183	2.3951	62,859,838	75,509,032	55,490,496	1.8556	102,968,164	1,250,000	918,607	1.0000	918,607	112,472,326	82,654,286	166,746,609
2040	31,919,565	23,457,227	2.4921	58,457,756	13,365,605	9,822,190	1.9085	18,745,649	1,250,000	918,607	1.0000	918,607	46,535,170	34,198,024	78,122,012
2041	19,624,629	14,421,856	2.5930	37,395,872	9,445,873	6,941,635	1.9629	13,625,736	1,250,000	918,607	1.0000	918,607	30,320,501	22,282,098	51,940,215
2042	14,863,700	10,923,118	2.6981	29,471,665	11,668,700	8,575,159	2.0189	17,312,388	1,250,000	918,607	1.0000	918,607	27,782,400	20,416,884	47,702,660
2043	8,912,163	6,549,420	2.8073	18,386,186	6,432,175	4,726,912	2.0764	9,814,961	1,250,000	918,607	1.0000	918,607	16,594,338	12,194,939	29,119,754
2044	3,676,270	2,701,638	2.9210	7,891,484	1,824,877	1,341,076	2.1356	2,864,001	1,250,000	918,607	1.0000	918,607	6,751,147	4,961,320	11,674,091
2045	5,973,090	4,389,537	3.0393	13,341,121	8,737,075	6,420,750	2.1964	14,102,536	1,250,000	918,607	1.0000	918,607	15,960,165	11,728,895	28,362,264
2046	5,204,130	3,824,440	3.1624	12,094,409	6,430,205	4,725,465	2.2590	10,674,825	1,250,000	918,607	1.0000	918,607	12,884,335	9,468,512	23,687,841
2047	5,204,130	3,824,440	3.2905	12,584,319	6,430,205	4,725,465	2.3234	10,979,145	1,250,000	918,607	1.0000	918,607	12,884,335	9,468,512	24,482,072
2048	3,676,270	2,701,638	3.4238	9,249,867	1,824,877	1,341,076	2.3896	3,204,634	1,250,000	918,607	1.0000	918,607	6,751,147	4,961,320	13,373,108
2049	5,204,130	3,824,440	3.5624	13,624,185	6,430,205	4,725,465	2.4577	11,613,775	1,250,000	918,607	1.0000	918,607	12,884,335	9,468,512	26,156,567
2050	5,973,090	4,389,537	3.7067	16,270,699	8,737,075	6,420,750	2.5278	16,230,373	1,250,000	918,607	1.0000	918,607	15,960,165	11,728,895	33,419,678
2051	5,779,130	4,246,999	3.8568	16,379,826	8,155,205	5,993,143	2.5998	15,580,972	1,250,000	918,607	1.0000	918,607	15,184,335	11,158,749	32,879,405
2052	5,983,130	4,396,916	4.0130	17,644,823	8,745,477	6,426,924	2.6739	17,184,953	1,250,000	918,607	1.0000	918,607	15,978,607	11,742,447	35,748,383
2053	3,666,220	2,694,252	4.1756	11,250,119	1,816,475	1,334,902	2.7501	3,671,113	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	15,839,839
2054	3,666,220	2,694,252	4.3447	11,705,717	1,816,475	1,334,902	2.8285	3,775,769	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	16,400,093
2055	5,973,090	4,389,537	4.5206	19,843,343	8,737,075	6,420,750	2.9091	18,678,605	1,250,000	918,607	1.0000	918,607	15,960,165	11,728,895	39,440,555
2056	5,214,180	3,831,825	4.7037	18,023,758	6,438,607	4,731,639	2.9920	14,157,064	1,250,000	918,607	1.0000	918,607	12,902,787	9,482,071	33,099,428
2057	5,204,130	3,824,440	4.8942	18,717,574	6,430,205	4,725,465	3.0773	14,541,673	1,250,000	918,607	1.0000	918,607	12,884,335	9,468,512	34,177,854
2058	3,666,220	2,694,252	5.0924	13,720,209	1,816,475	1,334,902	3.1650	4,224,963	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	18,863,779
2059	5,010,180	3,681,909	5.2987	19,509,330	5,848,345	4,297,864	3.2552	13,990,408	1,250,000	918,607	1.0000	918,607	12,108,525	8,898,380	34,418,346
2060	5,214,180	3,831,825	5.5133	21,126,003	6,438,607	4,731,639	3.3480	15,841,527	1,250,000	918,607	1.0000	918,607	12,902,787	9,482,071	37,886,138
2061	5,204,130	3,824,440	5.7366	21,939,282	6,430,205	4,725,465	3.4434	16,271,666	1,250,000	918,607	1.0000	918,607	12,884,335	9,468,512	39,129,555
2062	3,666,220	2,694,252	5.9689	16,081,721	1,816,475	1,334,902	3.5415	4,727,554	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	21,727,882
2063	8,279,960	6,084,823	6.2106	37,790,401	15,657,675	11,506,599	3.6425	41,912,788	1,250,000	918,607	1.0000	918,607	25,187,635	18,510,029	80,621,796
2064	6,558,130	4,819,475	6.4622	31,144,411	10,470,477	7,694,602	3.7463	28,826,287	1,250,000	918,607	1.0000	918,607	18,278,607	13,432,684	60,889,305
2065	5,204,130	3,824,440	6.7239	25,715,151	6,430,205	4,725,465	3.8531	18,207,689	1,250,000	918,607	1.0000	918,607	12,884,335	9,468,512	44,841,447
2066	3,666,220	2,694,252	6.9962	18,849,526	1,816,475	1,334,902	3.9629	5,290,081	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	25,058,214
2067	3,666,220	2,694,252	7.2795	19,612,808	1,816,475	1,334,902	4.0758	5,440,792	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	25,972,206
2068	6,752,090	4,962,013	7.5744	37,584,274	11,052,337	8,122,202	4.1920	34,048,273	1,250,000	918,607	1.0000	918,607	19,054,427	14,002,823	72,551,153
2069	5,973,090	4,389,537	7.8811	34,594,384	8,737,075	6,420,750	4.3115	27,683,065	1,250,000	918,607	1.0000	918,607	15,960,165	11,728,895	63,196,056
2070	3,666,220	2,694,252	8.2003	22,093,675	1,816,475	1,334,902	4.4343	5,919,354	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	28,931,636
2071	3,666,220	2,694,252	8.5324	22,988,436	1,816,475	1,334,902	4.5607	6,088,085	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	29,995,129
2072	7,327,090	5,384,572	8.8780	47,804,235	12,777,337	9,389,880	4.6907	44,045,110	1,250,000	918,607	1.0000	918,607	21,354,427	15,693,059	92,767,952
2073	3,666,220	2,694,252	9.2375	24,888,153	1,816,475	1,334,902	4.8244	6,440,099	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	32,246,859
2074	3,666,220	2,694,252	9.6117	25,896,343	1,816,475	1,334,902	4.9619	6,623,648	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	33,438,597
2075	7,842,820	5,763,575	10.0009	57,640,937	14,346,275	10,542,870	5.1033	53,803,430	1,250,000	918,607	1.0000	918,607	23,439,095	17,225,052	112,362,974
2076	3,676,270	2,701,638	10.4060	28,113,241	1,824,877	1,341,076	5.2487	7,038,903	1,250,000	918,607	1.0000	918,607	6,751,147	4,961,320	36,070,752
2077	3,666,220	2,694,252	10.8274	29,171,745	1,816,475	1,334,902	5.3983	7,206,199	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	37,296,551
2078	7,511,000	5,519,725	11.2659	62,184,673	13,350,805	9,811,314	5.5522	54,474,377	1,250,000	918,607	1.0000	918,607	22,111,805	16,249,646	117,577,657
2079	3,666,220	2,694,252	11.7222	31,582,562	1,816,475	1,334,902	5.7104	7,622,822	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	40,123,990
2080	3,676,270	2,701,638	12.1970	32,951,875	1,824,877	1,341,076	5.8731	7,876,271	1,250,000	918,607	1.0000	918,607	6,751,147	4,961,320	41,746,752
2081	3,666,220	2,694,252	12.6909	34,192,483	1,816,475	1,334,902	6.0405	8,063,473	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	43,174,563
2082	7,123,090	5,234,656	13.2049	69,123,107	12,187,075	8,956,105	6.2127	55,641,597	1,250,000	918,607	1.0000	918,607	20,560,165	15,109,368	125,683,310
2083	3,666,220	2,694,252	13.7397	37,018,215	1,816,475	1,334,902	6.3897	8,529,620	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	46,466,442
2084	3,676,270	2,701,638	14.2962	38,623,152	1,824,877	1,341,076	6.5719	8,813,414	1,250,000	918,607	1.0000	918,607	6,751,147	4,961,320	48,355,173
2085	3,666,220	2,694,252	14.8752	40,077,538	1,816,475	1,334,902	6.7592	9,022,866	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	50,019,012
2086	3,666,220	2,694,252	15.4776	41,700,556	1,816,475	1,334,902	6.9518	9,279,968	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	51,899,131
2087	3,666,220	2,694,252	16.1045	43,389,582	1,816,475	1,334,902	7.1499	9,544,412	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	53,852,602

Xcel Energy
Nuclear Decommissioning Accrual
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Proposed

AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
2088	3,676,270	2,701,638	16.7567	45,270,532	1,824,877	1,341,076	7.3537	9,861,867	1,250,000	918,607	1.0000	918,607	6,751,147	4,961,320	56,051,006
2089	26,770,050	19,672,923	17.4353	343,003,308	73,210,048	53,801,006	7.5633	406,913,146	1,250,000	918,607	1.0000	918,607	101,230,098	74,392,535	750,835,061
2090	3,666,220	2,694,252	18.1415	48,877,774	1,816,475	1,334,902	7.7788	10,383,932	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	60,180,313
2091	3,666,220	2,694,252	18.8762	50,857,241	1,816,475	1,334,902	8.0005	10,679,880	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	62,455,727
2092	3,676,270	2,701,638	19.6407	53,062,055	1,824,877	1,341,076	8.2285	11,035,040	1,250,000	918,607	1.0000	918,607	6,751,147	4,961,320	65,015,702
2093	3,666,220	2,694,252	20.4361	55,060,005	1,816,475	1,334,902	8.4630	11,297,272	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	67,275,883
2094	3,666,220	2,694,252	21.2638	57,290,037	1,816,475	1,334,902	8.7042	11,619,250	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	69,827,894
2095	5,973,090	4,389,537	22.1250	97,118,516	8,737,075	6,420,750	8.9523	57,480,484	1,250,000	918,607	1.0000	918,607	15,960,165	11,728,895	155,517,607
2096	5,214,180	3,831,825	23.0210	88,212,454	6,438,607	4,731,639	9.2075	43,566,566	1,250,000	918,607	1.0000	918,607	12,902,787	9,482,071	132,697,627
2097	5,204,130	3,824,440	23.9534	91,608,338	6,430,205	4,725,465	9.4699	44,749,681	1,250,000	918,607	1.0000	918,607	12,884,335	9,468,512	137,276,626
2098	3,666,220	2,694,252	24.9235	67,150,191	1,816,475	1,334,902	9.7398	13,001,674	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	81,070,472
2099	3,666,220	2,694,252	25.9329	69,869,769	1,816,475	1,334,902	10.0173	13,372,109	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	84,160,485
2100	5,973,090	4,389,537	26.9832	118,443,767	8,737,075	6,420,750	10.3028	66,151,707	1,250,000	918,607	1.0000	918,607	15,960,165	11,728,895	185,514,081
2101	5,973,090	4,389,537	28.0760	123,240,654	8,737,075	6,420,750	10.5965	68,037,482	1,250,000	918,607	1.0000	918,607	15,960,165	11,728,895	192,196,742
2102	5,973,090	4,389,537	29.2131	128,231,997	8,737,075	6,420,750	10.8985	69,976,548	1,250,000	918,607	1.0000	918,607	15,960,165	11,728,895	199,127,152
2103	3,666,220	2,694,252	30.3962	81,895,024	1,816,475	1,334,902	11.2091	14,963,045	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	97,776,676
2104	3,676,270	2,701,638	31.6272	85,445,235	1,824,877	1,341,076	11.5285	15,460,589	1,250,000	918,607	1.0000	918,607	6,751,147	4,961,320	101,824,431
2105	5,973,090	4,389,537	32.9081	144,451,338	8,737,075	6,420,750	11.8571	76,131,479	1,250,000	918,607	1.0000	918,607	15,960,165	11,728,895	221,501,424
2106	5,204,130	3,824,440	34.2409	130,952,263	6,430,205	4,725,465	12.1950	57,627,046	1,250,000	918,607	1.0000	918,607	12,884,335	9,468,512	189,497,916
2107	5,204,130	3,824,440	35.6277	136,255,997	6,430,205	4,725,465	12.5426	59,269,617	1,250,000	918,607	1.0000	918,607	12,884,335	9,468,512	196,444,221
2108	3,676,270	2,701,638	37.0706	100,151,329	1,824,877	1,341,076	12.9000	17,299,874	1,250,000	918,607	1.0000	918,607	6,751,147	4,961,320	118,369,810
2109	5,204,130	3,824,440	38.5720	147,516,295	6,430,205	4,725,465	13.2677	62,696,052	1,250,000	918,607	1.0000	918,607	12,884,335	9,468,512	211,130,954
2110	5,204,130	3,824,440	40.1341	153,490,453	6,430,205	4,725,465	13.6458	64,482,750	1,250,000	918,607	1.0000	918,607	12,884,335	9,468,512	218,891,810
2111	5,204,130	3,824,440	41.7596	159,707,080	6,430,205	4,725,465	14.0347	66,320,483	1,250,000	918,607	1.0000	918,607	12,884,335	9,468,512	226,946,170
2112	3,676,270	2,701,638	43.4508	117,388,318	1,824,877	1,341,076	14.4347	19,358,023	1,250,000	918,607	1.0000	918,607	6,751,147	4,961,320	137,664,947
2113	8,279,960	6,084,823	45.2106	275,098,493	15,657,675	11,506,599	14.8461	170,828,123	1,250,000	918,607	1.0000	918,607	25,187,635	18,510,029	446,845,223
2114	6,742,050	4,954,635	47.0416	233,073,960	11,043,935	8,116,028	15.2692	123,925,262	1,250,000	918,607	1.0000	918,607	19,035,985	13,989,270	357,917,829
2115	5,535,960	4,068,297	48.9468	199,130,117	7,425,675	5,457,021	15.7044	85,699,248	1,250,000	918,607	1.0000	918,607	14,211,635	10,443,925	285,747,972
2116	3,676,270	2,701,638	50.9291	137,591,975	1,824,877	1,341,076	16.1520	21,661,052	1,250,000	918,607	1.0000	918,607	6,751,147	4,961,320	160,171,633
2117	3,666,220	2,694,252	52.9918	142,773,266	1,816,475	1,334,902	16.6123	22,175,785	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	165,867,658
2118	6,742,050	4,954,635	55.1379	273,188,172	11,043,935	8,116,028	17.0857	138,668,027	1,250,000	918,607	1.0000	918,607	19,035,985	13,989,270	412,774,806
2119	5,973,090	4,389,537	57.3710	251,832,154	8,737,075	6,420,750	17.5727	112,829,920	1,250,000	918,607	1.0000	918,607	15,960,165	11,728,895	365,580,681
2120	3,676,270	2,701,638	59.6946	161,273,179	1,824,877	1,341,076	18.0735	24,237,929	1,250,000	918,607	1.0000	918,607	6,751,147	4,961,320	186,429,715
2121	3,666,220	2,694,252	62.1122	167,345,923	1,816,475	1,334,902	18.5886	24,813,951	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	193,078,480
2122	7,511,000	5,519,725	64.6277	356,727,150	13,350,805	9,811,314	19.1184	187,576,623	1,250,000	918,607	1.0000	918,607	22,111,805	16,249,646	545,222,379
2123	3,666,220	2,694,252	67.2451	181,175,249	1,816,475	1,334,902	19.6633	26,248,569	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	208,342,425
2124	3,676,270	2,701,638	69.9686	189,029,805	1,824,877	1,341,076	20.2237	27,121,509	1,250,000	918,607	1.0000	918,607	6,751,147	4,961,320	217,069,921
2125	7,511,000	5,519,725	72.8023	401,848,696	13,350,805	9,811,314	20.8000	204,075,328	1,250,000	918,607	1.0000	918,607	22,111,805	16,249,646	606,842,631
2126	3,666,220	2,694,252	75.7508	204,091,749	1,816,475	1,334,902	21.3928	28,557,281	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	233,567,637
2127	3,666,220	2,694,252	78.8187	212,357,445	1,816,475	1,334,902	22.0025	29,371,171	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	242,647,223
2128	7,521,050	5,527,111	82.0109	453,283,338	13,359,207	9,817,488	22.6296	222,165,823	1,250,000	918,607	1.0000	918,607	22,130,257	16,263,206	676,367,768
2129	3,666,220	2,694,252	85.3323	229,906,725	1,816,475	1,334,902	23.2745	31,069,166	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	261,894,498
2130	3,666,220	2,694,252	88.7883	239,218,060	1,816,475	1,334,902	23.9379	31,954,739	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	272,091,406
2131	3,666,220	2,694,252	92.3842	248,906,321	1,816,475	1,334,902	24.6201	32,865,409	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	282,690,337
2132	7,521,050	5,527,111	96.1257	531,297,403	13,359,207	9,817,488	25.3218	248,596,464	1,250,000	918,607	1.0000	918,607	22,130,257	16,263,206	780,812,473
2133	3,666,220	2,694,252	100.0188	269,475,858	1,816,475	1,334,902	26.0434	34,765,375	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	305,159,839
2134	3,666,220	2,694,252	104.0696	280,389,734	1,816,475	1,334,902	26.7857	35,756,272	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	317,064,613
2135	3,666,220	2,694,252	108.2844	291,745,468	1,816,475	1,334,902	27.5491	36,775,336	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	329,439,410
2136	3,676,270	2,701,638	112.6699	304,393,245	1,824,877	1,341,076	28.3342	37,998,302	1,250,000	918,607	1.0000	918,607	6,751,147	4,961,320	343,310,154
2137	3,666,220	2,694,252	117.2331	315,855,521	1,816,475	1,334,902	29.1417	38,901,300	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	355,675,428
2138	3,666,220	2,694,252	121.9810	328,647,561	1,816,475	1,334,902	29.9723	40,010,069	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	369,576,237
2139	26,780,760	19,680,793	126.9212	2,497,909,896	71,160,065	52,294,503	30.8265	1,612,056,498	1,250,000	918,607	1.0000	918,607	99,190,825	72,893,903	4,110,885,000
2140	3,676,270	2,701,638	132.0616	356,782,592	1,824,877	1,341,076	31.7050	42,518,800	1,250,000	918,607	1.0000	918,607	6,751,147	4,961,320	400,219,998
2141	3,666,220	2,694,252	137.4100	370,217,176	1,816,475	1,334,902	32.6086	43,529,270	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	414,665,053
2142	3,666,220	2,694,252	142.9752	385,211,227	1,816,475	1,334,902	33.5380	44,769,928	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	430,899,762
2143	3,666,220	2,694,252	148.7656	400,812,024	1,816,475	1,334,902	34.4938	46,045,826	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	447,776,458
2144	3,676,270	2,701,638	154.7907	418,188,385	1,824,877	1,341,076	35.4769	47,577,202	1,250,000	918,607	1.0000	918,607	6,751,147	4,961,320	466,684,194

Xcel Energy
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Docket No. E002/M-17-828
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AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
2145	5,973,090	4,389,537	161.0597	706,977,587	8,737,075	6,420,750	36.4880	234,280,340	1,250,000	918,607	1.0000	918,607	15,960,165	11,728,895	942,176,534
2146	5,204,130	3,824,440	167.5826	640,909,579	6,430,205	4,725,465	37.5279	177,336,778	1,250,000	918,607	1.0000	918,607	12,884,335	9,468,512	819,164,963
2147	5,204,130	3,824,440	174.3697	666,866,434	6,430,205	4,725,465	38.5974	182,390,662	1,250,000	918,607	1.0000	918,607	12,884,335	9,468,512	850,175,704
2148	3,676,270	2,701,638	181.4317	490,162,713	1,824,877	1,341,076	39.6975	53,237,346	1,250,000	918,607	1.0000	918,607	6,751,147	4,961,320	544,318,666
2149	3,666,220	2,694,252	188.7796	508,619,826	1,816,475	1,334,902	40.8288	54,502,428	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	564,040,861
2150	5,973,090	4,389,537	196.4252	862,215,774	8,737,075	6,420,750	41.9925	269,623,361	1,250,000	918,607	1.0000	918,607	15,960,165	11,728,895	1,132,757,742
2151	5,973,090	4,389,537	204.3804	897,135,423	8,737,075	6,420,750	43.1893	277,307,715	1,250,000	918,607	1.0000	918,607	15,960,165	11,728,895	1,175,361,744
2152	5,983,130	4,396,916	212.6578	935,038,423	8,745,477	6,426,924	44.4201	285,484,624	1,250,000	918,607	1.0000	918,607	15,978,607	11,742,447	1,221,441,653
2153	3,666,220	2,694,252	221.2705	596,158,501	1,816,475	1,334,902	45.6861	60,986,445	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	658,063,552
2154	3,666,220	2,694,252	230.2319	620,302,771	1,816,475	1,334,902	46.9882	62,724,620	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	683,945,998
2155	6,304,910	4,633,387	239.5563	1,109,957,090	9,732,545	7,152,307	48.3273	345,651,681	1,250,000	918,607	1.0000	918,607	17,287,455	12,704,301	1,456,527,378
2156	5,214,180	3,831,825	249.2584	955,114,688	6,438,607	4,731,639	49.7047	235,184,696	1,250,000	918,607	1.0000	918,607	12,902,787	9,482,071	1,191,217,991
2157	5,204,130	3,824,440	259.3533	991,881,103	6,430,205	4,725,465	51.1212	241,571,441	1,250,000	918,607	1.0000	918,607	12,884,335	9,468,512	1,234,371,151
2158	3,666,220	2,694,252	269.8571	727,063,048	1,816,475	1,334,902	52.5782	70,186,720	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	798,168,374
2159	5,204,130	3,824,440	280.7864	1,073,850,706	6,430,205	4,725,465	54.0767	255,537,553	1,250,000	918,607	1.0000	918,607	12,884,335	9,468,512	1,330,306,865
2160	5,214,180	3,831,825	292.1582	1,119,499,235	6,438,607	4,731,639	55.6179	263,163,824	1,250,000	918,607	1.0000	918,607	12,902,787	9,482,071	1,383,581,665
2161	5,204,130	3,824,440	303.9906	1,162,593,774	6,430,205	4,725,465	57.2030	270,310,774	1,250,000	918,607	1.0000	918,607	12,884,335	9,468,512	1,433,823,154
2162	3,666,220	2,694,252	316.3022	852,197,854	1,816,475	1,334,902	58.8333	78,536,662	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	931,653,123
2163	8,279,960	6,084,823	329.1125	2,002,591,266	15,657,675	11,506,599	60.5100	696,264,321	1,250,000	918,607	1.0000	918,607	25,187,635	18,510,029	2,699,774,193
2164	6,752,090	4,962,013	342.4415	1,699,199,277	11,052,337	8,122,202	62.2345	505,481,208	1,250,000	918,607	1.0000	918,607	19,054,427	14,002,823	2,205,599,092
2165	5,204,130	3,824,440	356.3104	1,362,687,703	6,430,205	4,725,465	64.0082	302,468,508	1,250,000	918,607	1.0000	918,607	12,884,335	9,468,512	1,666,074,818
2166	3,666,220	2,694,252	370.7410	998,869,703	1,816,475	1,334,902	65.8325	87,879,905	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	1,087,668,215
2167	3,666,220	2,694,252	385.7560	1,039,323,898	1,816,475	1,334,902	67.7087	90,384,447	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	1,130,626,952
2168	6,752,090	4,962,013	401.3791	1,991,648,432	11,052,337	8,122,202	69.6384	565,617,182	1,250,000	918,607	1.0000	918,607	19,054,427	14,002,823	2,558,184,221
2169	5,973,090	4,389,537	417.6350	1,833,224,479	8,737,075	6,420,750	71.6231	459,874,047	1,250,000	918,607	1.0000	918,607	15,960,165	11,728,895	2,294,017,133
2170	3,666,220	2,694,252	434.5492	1,170,785,077	1,816,475	1,334,902	73.6643	98,334,587	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	1,270,038,271
2171	3,666,220	2,694,252	452.1484	1,218,201,758	1,816,475	1,334,902	75.7638	101,137,213	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	1,320,257,578
2172	7,521,050	5,527,111	470.4604	2,600,286,797	13,359,207	9,817,488	77.9230	765,008,105	1,250,000	918,607	1.0000	918,607	22,130,257	16,263,206	3,366,213,509
2173	3,666,220	2,694,252	489.5141	1,318,874,373	1,816,475	1,334,902	80.1438	106,984,081	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	1,426,777,061
2174	3,666,220	2,694,252	509.3394	1,372,288,728	1,816,475	1,334,902	82.4279	110,033,130	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	1,483,240,465
2175	7,511,000	5,519,725	529.9676	2,925,275,561	13,350,805	9,811,314	84.7771	831,774,735	1,250,000	918,607	1.0000	918,607	22,111,805	16,249,646	3,757,968,903
2176	3,676,270	2,701,638	551.4313	1,489,767,567	1,824,877	1,341,076	87.1933	116,932,801	1,250,000	918,607	1.0000	918,607	6,751,147	4,961,320	1,607,618,975
2177	3,666,220	2,694,252	573.7643	1,545,865,647	1,816,475	1,334,902	89.6783	119,711,700	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	1,666,495,954
2178	7,511,000	5,519,725	597.0018	3,295,285,929	13,350,805	9,811,314	92.2341	904,937,703	1,250,000	918,607	1.0000	918,607	22,111,805	16,249,646	4,201,142,239
2179	3,666,220	2,694,252	621.1803	1,673,616,303	1,816,475	1,334,902	94.8628	126,632,497	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	1,801,167,407
2180	3,676,270	2,701,638	646.3381	1,746,171,352	1,824,877	1,341,076	97.5664	130,843,911	1,250,000	918,607	1.0000	918,607	6,751,147	4,961,320	1,877,933,870
2181	3,666,220	2,694,252	672.5148	1,811,924,386	1,816,475	1,334,902	100.3470	133,953,364	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	1,946,796,356
2182	7,511,000	5,519,725	699.7517	3,862,437,150	13,350,805	9,811,314	103.2069	1,012,595,287	1,250,000	918,607	1.0000	918,607	22,111,805	16,249,646	4,875,951,044
2183	3,666,220	2,694,252	728.0916	1,961,662,293	1,816,475	1,334,902	106.1483	141,697,528	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	2,104,278,428
2184	3,676,270	2,701,638	757.5793	2,046,704,767	1,824,877	1,341,076	109.1736	146,410,043	1,250,000	918,607	1.0000	918,607	6,751,147	4,961,320	2,194,033,417
2185	3,666,220	2,694,252	788.2613	2,123,774,632	1,816,475	1,334,902	112.2850	149,889,418	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	2,274,582,657
2186	3,666,220	2,694,252	820.1859	2,209,787,551	1,816,475	1,334,902	115.4851	154,161,237	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	2,364,867,395
2187	3,666,220	2,694,252	853.4034	2,299,283,869	1,816,475	1,334,902	118.7764	158,554,798	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	2,458,757,274
2188	3,676,270	2,701,638	887.9662	2,398,962,927	1,824,877	1,341,076	122.1616	163,827,932	1,250,000	918,607	1.0000	918,607	6,751,147	4,961,320	2,563,709,466
2189	26,780,760	19,680,793	923.9289	18,183,653,653	71,160,065	52,294,503	125.6432	6,570,448,704	1,250,000	918,607	1.0000	918,607	99,190,825	72,893,903	24,755,020,964
2190	3,666,220	2,694,252	961.3480	2,590,113,830	1,816,475	1,334,902	129.2240	172,501,315	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	2,763,533,752
2191	3,666,220	2,694,252	1,000.2826	2,695,013,456	1,816,475	1,334,902	132.9069	177,417,624	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	2,873,349,687
2192	3,676,270	2,701,638	1,040.7940	2,811,848,267	1,824,877	1,341,076	136.6947	183,317,917	1,250,000	918,607	1.0000	918,607	6,751,147	4,961,320	2,996,084,790
2193	3,050,090	2,241,467	1,082.9462	2,427,388,206	1,970,568	1,448,142	140.5905	203,594,977	1,250,000	918,607	1.0000	918,607	6,270,658	4,608,216	2,631,901,790
2194	3,145,780	2,311,788	1,126.8055	2,604,935,693	2,257,628	1,659,098	144.5974	239,901,260	1,250,000	918,607	1.0000	918,607	6,653,408	4,889,493	2,845,755,560
2195	5,784,470	4,250,923	1,172.4411	4,983,957,252	10,173,688	7,476,496	148.7184	1,111,892,529	1,250,000	918,607	1.0000	918,607	17,208,158	12,646,026	6,096,768,388
2196	4,739,630	3,483,086	1,219.9250	4,249,103,136	7,022,925	5,161,046	152.9569	789,417,579	1,250,000	918,607	1.0000	918,607	13,012,555	9,562,738	5,039,439,321
2197	4,635,850	3,406,819	1,269.3320	4,324,384,534	6,727,828	4,944,183	157.3161	777,799,643	1,250,000	918,607	1.0000	918,607	12,613,678	9,269,609	5,103,102,785
2198	3,241,470	2,382,109	1,320.7399	3,146,146,967	2,544,688	1,870,054	161.7997	302,574,219	1,250,000	918,607	1.0000	918,607	7,036,158	5,170,771	3,449,639,793
2199	3,097,940	2,276,631	1,374.2299	3,128,614,812	2,114,098	1,553,620	166.4109	258,539,286	1,250,000	918,607	1.0000	918,607	6,462,038	4,748,858	3,388,072,705
2200	5,356,960	3,936,752	1,429.8862	5,629,107,982	8,891,168	6,533,991	171.1537	1,118,316,674	1,250,000	918,607	1.0000	918,607	15,498,128	11,389,350	6,748,343,262
2201	5,452,650	4,007,074	1,487.7966	5,961,710,528	9,178,228	6,744,947	176.0315	1,187,323,117	1,250,000	918,607	1.0000	918,607	15,880,878	11,670,627	7,149,952,252

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	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
2202	5,452,650	4,007,074	1,548.0523	6,203,159,555	9,178,228	6,744,947	181.0484	1,221,161,841	1,250,000	918,607	1.0000	918,607	15,880,878	11,670,627	7,425,240,003
2203	3,097,940	2,276,631	1,610.7485	3,667,080,462	2,114,098	1,553,620	186.2083	289,296,920	1,250,000	918,607	1.0000	918,607	6,462,038	4,748,858	3,957,295,989
2204	3,153,870	2,317,733	1,675.9838	3,884,483,723	2,265,665	1,665,004	191.5152	318,873,632	1,250,000	918,607	1.0000	918,607	6,669,535	4,901,345	4,204,275,961
2205	5,452,650	4,007,074	1,743.8611	6,987,779,835	9,178,228	6,744,947	196.9734	1,328,575,120	1,250,000	918,607	1.0000	918,607	15,880,878	11,670,627	8,317,273,562
2206	4,635,850	3,406,819	1,814.4875	6,181,630,718	6,727,828	4,944,183	202.5872	1,001,628,263	1,250,000	918,607	1.0000	918,607	12,613,678	9,269,609	7,184,177,587
2207	4,683,690	3,441,976	1,887.9742	6,498,361,979	6,871,358	5,049,661	208.3609	1,052,152,010	1,250,000	918,607	1.0000	918,607	12,805,048	9,410,244	7,551,432,596
2208	3,153,870	2,317,733	1,964.4372	4,553,041,818	2,265,665	1,665,004	214.2992	356,809,090	1,250,000	918,607	1.0000	918,607	6,669,535	4,901,345	4,910,769,515
2209	4,635,850	3,406,819	2,043.9969	6,963,527,731	6,727,828	4,944,183	220.4067	1,089,731,138	1,250,000	918,607	1.0000	918,607	12,613,678	9,269,609	8,054,177,476
2210	4,676,510	3,436,700	2,126.7788	7,309,099,791	6,849,828	5,033,839	226.6883	1,141,112,494	1,250,000	918,607	1.0000	918,607	12,776,338	9,389,146	8,451,130,892
2211	4,669,340	3,431,430	2,212.9133	7,593,458,063	6,828,298	5,018,017	233.1489	1,169,945,215	1,250,000	918,607	1.0000	918,607	12,747,638	9,368,055	8,764,321,886
2212	3,139,520	2,307,188	2,302.5363	5,312,383,769	2,222,605	1,633,360	239.7937	391,669,469	1,250,000	918,607	1.0000	918,607	6,612,125	4,859,155	5,704,971,845
2213	7,745,160	5,691,806	2,395.7890	13,636,366,398	16,055,768	11,799,152	246.6278	2,909,998,794	1,250,000	918,607	1.0000	918,607	25,050,928	18,409,565	16,547,283,798
2214	6,207,250	4,561,618	2,492.8185	11,371,286,392	11,442,028	8,408,581	253.6567	2,132,892,848	1,250,000	918,607	1.0000	918,607	18,899,278	13,888,806	13,505,097,847
2215	4,669,340	3,431,430	2,593.7776	8,900,367,417	6,828,298	5,018,017	260.8859	1,309,129,961	1,250,000	918,607	1.0000	918,607	12,747,638	9,368,055	10,210,415,985
2216	3,139,520	2,307,188	2,698.8256	6,226,697,626	13,878,683	10,199,243	268.3212	2,736,673,199	1,250,000	918,607	1.0000	918,607	18,268,203	13,425,038	8,964,289,432
2217	3,145,780	2,311,788	2,808.1281	6,491,797,491	2,257,628	1,659,098	275.9683	457,858,460	1,250,000	918,607	1.0000	918,607	6,653,408	4,889,493	6,950,574,559
2218	1,058,128	777,603	2,921.8572	2,272,044,845	2,283,531	1,678,134	283.8334	476,310,374	0	0	1.0000	0	3,341,659	2,455,737	2,748,355,219
	$1,259,022,756	$925,237,616		$257,498,187,414	$1,487,265,430	$1,092,969,857		$50,395,864,825	$231,250,000	$169,942,281		$169,942,281	$2,977,538,186	$2,188,149,754	$308,063,994,519

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Prairie Island Unit 2															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2034	$7,760,265	$5,702,906	1.9639	$11,199,938	$4,479,535	$3,291,946	1.6124	$5,307,933	$1,250,000	$918,607	1.0000	$918,607	$13,489,800	$9,913,459	$17,426,478
2035	46,911,429	34,474,531	2.0434	70,445,256	35,601,336	26,162,907	1.6584	43,388,565	1,250,000	918,607	1.0000	918,607	83,762,765	61,556,044	114,752,428
2036	67,514,041	49,615,092	2.1262	105,491,609	86,298,834	63,419,765	1.7056	108,168,751	1,250,000	918,607	1.0000	918,607	155,062,874	113,953,464	214,578,967
2037	72,593,441	53,347,870	2.2123	118,021,492	75,650,363	55,594,358	1.7542	97,523,623	1,250,000	918,607	1.0000	918,607	149,493,804	109,860,835	216,463,722
2038	46,603,525	34,248,257	2.3019	78,836,063	42,782,150	31,439,983	1.8042	56,724,017	1,250,000	918,607	1.0000	918,607	90,635,675	66,606,847	136,478,687
2039	40,341,063	29,646,064	2.3951	71,005,287	76,484,927	56,207,667	1.8556	104,298,947	1,250,000	918,607	1.0000	918,607	118,075,990	86,772,338	176,222,841
2040	37,417,178	27,497,343	2.4921	68,526,129	14,193,500	10,430,598	1.9085	19,906,796	1,250,000	918,607	1.0000	918,607	52,860,678	38,846,548	89,351,532
2041	23,380,886	17,182,275	2.5930	44,553,639	13,070,130	9,605,049	1.9629	18,853,752	1,250,000	918,607	1.0000	918,607	37,701,016	27,705,931	64,325,998
2042	16,738,669	12,301,006	2.6981	33,189,343	17,178,640	12,624,334	2.0189	25,487,268	1,250,000	918,607	1.0000	918,607	35,167,309	25,843,947	59,595,219
2043	9,790,575	7,194,952	2.8073	20,198,388	9,014,069	6,624,309	2.0764	13,754,715	1,250,000	918,607	1.0000	918,607	20,054,644	14,737,868	34,871,710
2044	3,676,269	2,701,637	2.9210	7,891,481	1,825,866	1,341,803	2.1356	2,865,554	1,250,000	918,607	1.0000	918,607	6,752,135	4,962,047	11,675,642
2045	5,973,090	4,389,537	3.0393	13,341,121	8,738,060	6,421,474	2.1964	14,104,126	1,250,000	918,607	1.0000	918,607	15,961,150	11,729,619	28,363,854
2046	5,204,135	3,824,444	3.1624	12,094,420	6,431,194	4,726,192	2.2590	10,676,467	1,250,000	918,607	1.0000	918,607	12,885,329	9,469,242	23,689,494
2047	5,204,135	3,824,444	3.2905	12,584,332	6,431,194	4,726,192	2.3234	10,980,834	1,250,000	918,607	1.0000	918,607	12,885,329	9,469,242	24,483,772
2048	3,676,269	2,701,637	3.4238	9,249,865	1,825,866	1,341,803	2.3896	3,206,372	1,250,000	918,607	1.0000	918,607	6,752,135	4,962,047	13,374,843
2049	5,204,135	3,824,444	3.5624	13,624,198	6,431,194	4,726,192	2.4577	11,615,561	1,250,000	918,607	1.0000	918,607	12,885,329	9,469,242	26,158,366
2050	5,973,090	4,389,537	3.7067	16,270,699	8,738,060	6,421,474	2.5278	16,232,202	1,250,000	918,607	1.0000	918,607	15,961,150	11,729,619	33,421,508
2051	5,779,135	4,247,003	3.8568	16,379,840	8,156,192	5,993,868	2.5998	15,582,857	1,250,000	918,607	1.0000	918,607	15,185,327	11,159,477	32,881,304
2052	5,983,135	4,396,919	4.0130	17,644,838	8,746,464	6,427,650	2.6739	17,186,894	1,250,000	918,607	1.0000	918,607	15,979,599	11,743,176	35,750,338
2053	3,666,224	2,694,255	4.1756	11,250,131	1,817,462	1,335,627	2.7501	3,673,107	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	15,841,845
2054	3,666,224	2,694,255	4.3447	11,705,730	1,817,462	1,335,627	2.8285	3,777,820	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	16,402,157
2055	5,973,090	4,389,537	4.5206	19,843,343	8,738,060	6,421,474	2.9091	18,680,710	1,250,000	918,607	1.0000	918,607	15,961,150	11,729,619	39,442,660
2056	5,214,179	3,831,825	4.7037	18,023,754	6,439,598	4,732,368	2.9920	14,159,244	1,250,000	918,607	1.0000	918,607	12,903,777	9,482,799	33,101,605
2057	5,204,135	3,824,444	4.8942	18,717,592	6,431,194	4,726,192	3.0773	14,543,910	1,250,000	918,607	1.0000	918,607	12,885,329	9,469,242	34,180,108
2058	3,666,224	2,694,255	5.0924	13,720,224	1,817,462	1,335,627	3.1650	4,227,259	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	18,866,090
2059	5,010,180	3,681,909	5.2987	19,509,330	5,849,328	4,298,587	3.2552	13,992,760	1,250,000	918,607	1.0000	918,607	12,109,508	8,899,102	34,420,697
2060	5,214,179	3,831,825	5.5133	21,125,999	6,439,598	4,732,368	3.3480	15,843,967	1,250,000	918,607	1.0000	918,607	12,903,777	9,482,799	37,888,573
2061	5,204,135	3,824,444	5.7366	21,939,303	6,431,194	4,726,192	3.4434	16,274,168	1,250,000	918,607	1.0000	918,607	12,885,329	9,469,242	39,132,078
2062	3,666,224	2,694,255	5.9689	16,081,739	1,817,462	1,335,627	3.5415	4,730,122	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	21,730,468
2063	8,279,956	6,084,820	6.2106	37,790,383	15,658,658	11,507,322	3.6425	41,915,419	1,250,000	918,607	1.0000	918,607	25,188,614	18,510,748	80,624,408
2064	6,558,135	4,819,479	6.4622	31,144,434	10,471,464	7,695,328	3.7463	28,829,006	1,250,000	918,607	1.0000	918,607	18,279,599	13,433,413	60,892,047
2065	5,204,135	3,824,444	6.7239	25,715,176	6,431,194	4,726,192	3.8531	18,210,489	1,250,000	918,607	1.0000	918,607	12,885,329	9,469,242	44,844,272
2066	3,666,224	2,694,255	6.9962	18,849,547	1,817,462	1,335,627	3.9629	5,292,955	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	25,061,109
2067	3,666,224	2,694,255	7.2795	19,612,829	1,817,462	1,335,627	4.0758	5,443,747	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	25,975,184
2068	6,752,090	4,962,013	7.5744	37,584,274	11,053,330	8,122,933	4.1920	34,051,333	1,250,000	918,607	1.0000	918,607	19,055,420	14,003,553	72,554,214
2069	5,973,090	4,389,537	7.8811	34,594,384	8,738,060	6,421,474	4.3115	27,686,186	1,250,000	918,607	1.0000	918,607	15,961,150	11,729,619	63,199,176
2070	3,666,224	2,694,255	8.2003	22,093,699	1,817,462	1,335,627	4.4343	5,922,570	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	28,934,876
2071	3,666,224	2,694,255	8.5324	22,988,461	1,817,462	1,335,627	4.5607	6,091,393	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	29,998,461
2072	7,327,090	5,384,572	8.8780	47,804,235	12,778,330	9,390,610	4.6907	44,048,535	1,250,000	918,607	1.0000	918,607	21,355,420	15,693,790	92,771,376
2073	3,666,224	2,694,255	9.2375	24,888,181	1,817,462	1,335,627	4.8244	6,443,598	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	32,250,385
2074	3,666,224	2,694,255	9.6117	25,896,371	1,817,462	1,335,627	4.9619	6,627,246	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	33,442,224
2075	7,842,823	5,763,577	10.0009	57,640,959	14,347,260	10,543,594	5.1033	53,807,124	1,250,000	918,607	1.0000	918,607	23,440,083	17,225,778	112,366,690
2076	3,676,269	2,701,637	10.4060	28,113,234	1,825,866	1,341,803	5.2487	7,042,720	1,250,000	918,607	1.0000	918,607	6,752,135	4,962,047	36,074,561
2077	3,666,224	2,694,255	10.8274	29,171,777	1,817,462	1,335,627	5.3983	7,210,114	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	37,300,497
2078	7,511,001	5,519,726	11.2659	62,184,681	13,351,792	9,812,039	5.5522	54,478,403	1,250,000	918,607	1.0000	918,607	22,112,793	16,250,372	117,581,691
2079	3,666,224	2,694,255	11.7222	31,582,596	1,817,462	1,335,627	5.7104	7,626,963	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	40,128,166
2080	3,676,269	2,701,637	12.1970	32,951,866	1,825,866	1,341,803	5.8731	7,880,541	1,250,000	918,607	1.0000	918,607	6,752,135	4,962,047	41,751,014
2081	3,666,224	2,694,255	12.6909	34,192,521	1,817,462	1,335,627	6.0405	8,067,853	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	43,178,981
2082	7,123,090	5,234,656	13.2049	69,123,107	12,188,060	8,956,829	6.2127	55,646,093	1,250,000	918,607	1.0000	918,607	20,561,150	15,110,092	125,687,807
2083	3,666,224	2,694,255	13.7397	37,018,255	1,817,462	1,335,627	6.3897	8,534,254	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	46,471,116
2084	3,676,269	2,701,637	14.2962	38,623,142	1,825,866	1,341,803	6.5719	8,818,193	1,250,000	918,607	1.0000	918,607	6,752,135	4,962,047	48,359,942
2085	3,666,224	2,694,255	14.8752	40,077,582	1,817,462	1,335,627	6.7592	9,027,768	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	50,023,957
2086	3,666,224	2,694,255	15.4776	41,700,601	1,817,462	1,335,627	6.9518	9,285,010	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	51,904,218
2087	3,666,224	2,694,255	16.1045	43,389,630	1,817,462	1,335,627	7.1499	9,549,598	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	53,857,834
2088	3,676,269	2,701,637	16.7567	45,270,519	1,825,866	1,341,803	7.3537	9,867,215	1,250,000	918,607	1.0000	918,607	6,752,135	4,962,047	56,056,341

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	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
2089	26,770,052	19,672,924	17.4353	343,003,333	73,063,378	53,693,220	7.5633	406,097,928	1,250,000	918,607	1.0000	918,607	101,083,430	74,284,751	750,019,869
2090	3,666,224	2,694,255	18.1415	48,877,827	1,817,462	1,335,627	7.7788	10,389,573	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	60,186,007
2091	3,666,224	2,694,255	18.8762	50,857,296	1,817,462	1,335,627	8.0005	10,685,682	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	62,461,585
2092	3,676,269	2,701,637	19.6407	53,062,040	1,825,866	1,341,803	8.2285	11,041,024	1,250,000	918,607	1.0000	918,607	6,752,135	4,962,047	65,021,671
2093	3,666,224	2,694,255	20.4361	55,060,065	1,817,462	1,335,627	8.4630	11,303,409	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	67,282,081
2094	3,666,224	2,694,255	21.2638	57,290,099	1,817,462	1,335,627	8.7042	11,625,562	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	69,834,269
2095	5,973,090	4,389,537	22.1250	97,118,516	8,738,060	6,421,474	8.9523	57,486,963	1,250,000	918,607	1.0000	918,607	15,961,150	11,729,619	155,524,086
2096	5,214,179	3,831,825	23.0210	88,212,437	6,439,598	4,732,368	9.2075	43,573,275	1,250,000	918,607	1.0000	918,607	12,903,777	9,482,799	132,704,319
2097	5,204,135	3,824,444	23.9534	91,608,426	6,431,194	4,726,192	9.4699	44,756,562	1,250,000	918,607	1.0000	918,607	12,885,329	9,469,242	137,283,595
2098	3,666,224	2,694,255	24.9235	67,150,264	1,817,462	1,335,627	9.7398	13,008,737	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	81,077,609
2099	3,666,224	2,694,255	25.9329	69,869,845	1,817,462	1,335,627	10.0173	13,379,374	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	84,167,826
2100	5,973,090	4,389,537	26.9832	118,443,767	8,738,060	6,421,474	10.3028	66,159,164	1,250,000	918,607	1.0000	918,607	15,961,150	11,729,619	185,521,538
2101	5,973,090	4,389,537	28.0760	123,240,654	8,738,060	6,421,474	10.5965	68,045,150	1,250,000	918,607	1.0000	918,607	15,961,150	11,729,619	192,204,411
2102	5,973,090	4,389,537	29.2131	128,231,997	8,738,060	6,421,474	10.8985	69,984,436	1,250,000	918,607	1.0000	918,607	15,961,150	11,729,619	199,135,039
2103	3,666,224	2,694,255	30.3962	81,895,114	1,817,462	1,335,627	11.2091	14,971,174	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	97,784,894
2104	3,676,269	2,701,637	31.6272	85,445,211	1,825,866	1,341,803	11.5285	15,468,973	1,250,000	918,607	1.0000	918,607	6,752,135	4,962,047	101,832,791
2105	5,973,090	4,389,537	32.9081	144,451,338	8,738,060	6,421,474	11.8571	76,140,061	1,250,000	918,607	1.0000	918,607	15,961,150	11,729,619	221,510,005
2106	5,204,135	3,824,444	34.2409	130,952,389	6,431,194	4,726,192	12.1950	57,635,907	1,250,000	918,607	1.0000	918,607	12,885,329	9,469,242	189,506,903
2107	5,204,135	3,824,444	35.6277	136,256,128	6,431,194	4,726,192	12.5426	59,278,731	1,250,000	918,607	1.0000	918,607	12,885,329	9,469,242	196,453,466
2108	3,676,269	2,701,637	37.0706	100,151,302	1,825,866	1,341,803	12.9000	17,309,255	1,250,000	918,607	1.0000	918,607	6,752,135	4,962,047	118,379,164
2109	5,204,135	3,824,444	38.5720	147,516,437	6,431,194	4,726,192	13.2677	62,705,693	1,250,000	918,607	1.0000	918,607	12,885,329	9,469,242	211,140,737
2110	5,204,135	3,824,444	40.1341	153,490,600	6,431,194	4,726,192	13.6458	64,492,666	1,250,000	918,607	1.0000	918,607	12,885,329	9,469,242	218,901,873
2111	5,204,135	3,824,444	41.7596	159,707,233	6,431,194	4,726,192	14.0347	66,330,682	1,250,000	918,607	1.0000	918,607	12,885,329	9,469,242	226,956,522
2112	3,676,269	2,701,637	43.4508	117,388,286	1,825,866	1,341,803	14.4347	19,368,520	1,250,000	918,607	1.0000	918,607	6,752,135	4,962,047	137,675,412
2113	8,279,956	6,084,820	45.2106	275,098,360	15,658,658	11,507,322	14.8461	170,838,846	1,250,000	918,607	1.0000	918,607	25,188,614	18,510,748	446,855,813
2114	6,742,046	4,954,632	47.0416	233,073,822	11,044,926	8,116,757	15.2692	123,936,380	1,250,000	918,607	1.0000	918,607	19,036,972	13,989,996	357,928,808
2115	5,535,957	4,068,295	48.9468	199,130,009	7,426,662	5,457,747	15.7044	85,710,637	1,250,000	918,607	1.0000	918,607	14,212,619	10,444,648	285,759,253
2116	3,676,269	2,701,637	50.9291	137,591,937	1,825,866	1,341,803	16.1520	21,672,797	1,250,000	918,607	1.0000	918,607	6,752,135	4,962,047	160,183,341
2117	3,666,224	2,694,255	52.9918	142,773,422	1,817,462	1,335,627	16.6123	22,187,832	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	165,879,861
2118	6,742,046	4,954,632	55.1379	273,188,010	11,044,926	8,116,757	17.0857	138,680,468	1,250,000	918,607	1.0000	918,607	19,036,972	13,989,996	412,787,085
2119	5,973,090	4,389,537	57.3710	251,832,154	8,738,060	6,421,474	17.5727	112,842,638	1,250,000	918,607	1.0000	918,607	15,961,150	11,729,619	365,593,399
2120	3,676,269	2,701,637	59.6946	161,273,136	1,825,866	1,341,803	18.0735	24,251,071	1,250,000	918,607	1.0000	918,607	6,752,135	4,962,047	186,442,814
2121	3,666,224	2,694,255	62.1122	167,346,105	1,817,462	1,335,627	18.5886	24,827,431	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	193,092,143
2122	7,511,001	5,519,726	64.6277	356,727,197	13,351,792	9,812,039	19.1184	187,590,487	1,250,000	918,607	1.0000	918,607	22,112,793	16,250,372	545,236,291
2123	3,666,224	2,694,255	67.2451	181,175,447	1,817,462	1,335,627	19.6633	26,262,829	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	208,356,883
2124	3,676,269	2,701,637	69.9686	189,029,753	1,825,866	1,341,803	20.2237	27,136,215	1,250,000	918,607	1.0000	918,607	6,752,135	4,962,047	217,084,576
2125	7,511,001	5,519,726	72.8023	401,848,749	13,351,792	9,812,039	20.8000	204,090,412	1,250,000	918,607	1.0000	918,607	22,112,793	16,250,372	606,857,768
2126	3,666,224	2,694,255	75.7508	204,091,972	1,817,462	1,335,627	21.3928	28,572,795	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	233,583,374
2127	3,666,224	2,694,255	78.8187	212,357,677	1,817,462	1,335,627	22.0025	29,387,127	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	242,663,411
2128	7,521,045	5,527,107	82.0109	453,283,037	13,360,196	9,818,215	22.6296	222,182,279	1,250,000	918,607	1.0000	918,607	22,131,241	16,263,929	676,383,922
2129	3,666,224	2,694,255	85.3323	229,906,976	1,817,462	1,335,627	23.2745	31,086,044	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	261,911,627
2130	3,666,224	2,694,255	88.7883	239,218,321	1,817,462	1,335,627	23.9379	31,972,099	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	272,109,027
2131	3,666,224	2,694,255	92.3842	248,906,593	1,817,462	1,335,627	24.6201	32,883,264	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	282,708,463
2132	7,521,045	5,527,107	96.1257	531,297,049	13,360,196	9,818,215	25.3218	248,614,877	1,250,000	918,607	1.0000	918,607	22,131,241	16,263,929	780,830,534
2133	3,666,224	2,694,255	100.0188	269,476,152	1,817,462	1,335,627	26.0434	34,784,261	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	305,179,020
2134	3,666,224	2,694,255	104.0696	280,390,040	1,817,462	1,335,627	26.7857	35,775,697	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	317,084,344
2135	3,666,224	2,694,255	108.2844	291,745,786	1,817,462	1,335,627	27.5491	36,795,314	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	329,459,707
2136	3,676,269	2,701,637	112.6699	304,393,162	1,825,866	1,341,803	28.3342	38,018,906	1,250,000	918,607	1.0000	918,607	6,752,135	4,962,047	343,330,675
2137	3,666,224	2,694,255	117.2331	315,855,866	1,817,462	1,335,627	29.1417	38,922,433	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	355,696,906
2138	3,666,224	2,694,255	121.9810	328,647,919	1,817,462	1,335,627	29.9723	40,031,805	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	369,598,331
2139	26,780,755	19,680,790	126.9212	2,497,909,429	71,161,056	52,295,231	30.8265	1,612,078,944	1,250,000	918,607	1.0000	918,607	99,191,811	72,894,628	4,110,906,980
2140	3,676,269	2,701,637	132.0616	356,782,495	1,825,866	1,341,803	31.7050	42,541,855	1,250,000	918,607	1.0000	918,607	6,752,135	4,962,047	400,242,957
2141	3,666,224	2,694,255	137.4100	370,217,580	1,817,462	1,335,627	32.6086	43,552,918	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	414,689,104
2142	3,666,224	2,694,255	142.9752	385,211,647	1,817,462	1,335,627	33.5380	44,794,249	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	430,924,504
2143	3,666,224	2,694,255	148.7656	400,812,462	1,817,462	1,335,627	34.4938	46,070,841	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	447,801,910
2144	3,676,269	2,701,637	154.7907	418,188,271	1,825,866	1,341,803	35.4769	47,603,001	1,250,000	918,607	1.0000	918,607	6,752,135	4,962,047	466,709,878
2145	5,973,090	4,389,537	161.0597	706,977,587	8,738,060	6,421,474	36.4880	234,306,748	1,250,000	918,607	1.0000	918,607	15,961,150	11,729,619	942,202,942

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AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
2146	5,204,135	3,824,444	167.5826	640,910,194	6,431,194	4,726,192	37.5279	177,364,048	1,250,000	918,607	1.0000	918,607	12,885,329	9,469,242	819,192,849
2147	5,204,135	3,824,444	174.3697	666,867,075	6,431,194	4,726,192	38.5974	182,418,710	1,250,000	918,607	1.0000	918,607	12,885,329	9,469,242	850,204,392
2148	3,676,269	2,701,637	181.4317	490,162,580	1,825,866	1,341,803	39.6975	53,266,213	1,250,000	918,607	1.0000	918,607	6,752,135	4,962,047	544,347,400
2149	3,666,224	2,694,255	188.7796	508,620,381	1,817,462	1,335,627	40.8288	54,532,036	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	564,071,025
2150	5,973,090	4,389,537	196.4252	862,215,774	8,738,060	6,421,474	41.9925	269,653,752	1,250,000	918,607	1.0000	918,607	15,961,150	11,729,619	1,132,788,133
2151	5,973,090	4,389,537	204.3804	897,135,423	8,738,060	6,421,474	43.1893	277,338,972	1,250,000	918,607	1.0000	918,607	15,961,150	11,729,619	1,175,393,002
2152	5,983,135	4,396,919	212.6578	935,039,204	8,746,464	6,427,650	44.4201	285,516,860	1,250,000	918,607	1.0000	918,607	15,979,599	11,743,176	1,221,474,671
2153	3,666,224	2,694,255	221.2705	596,159,151	1,817,462	1,335,627	45.6861	61,019,576	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	658,097,334
2154	3,666,224	2,694,255	230.2319	620,303,448	1,817,462	1,335,627	46.9882	62,758,696	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	683,980,750
2155	6,304,913	4,633,389	239.5563	1,109,957,618	9,733,528	7,153,029	48.3273	345,686,586	1,250,000	918,607	1.0000	918,607	17,288,441	12,705,025	1,456,562,811
2156	5,214,179	3,831,825	249.2584	955,114,505	6,439,598	4,732,368	49.7047	235,220,914	1,250,000	918,607	1.0000	918,607	12,903,777	9,482,799	1,191,254,025
2157	5,204,135	3,824,444	259.3533	991,882,056	6,431,194	4,726,192	51.1212	241,608,589	1,250,000	918,607	1.0000	918,607	12,885,329	9,469,242	1,234,409,252
2158	3,666,224	2,694,255	269.8571	727,063,841	1,817,462	1,335,627	52.5782	70,224,849	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	798,207,297
2159	5,204,135	3,824,444	280.7864	1,073,851,738	6,431,194	4,726,192	54.0767	255,576,848	1,250,000	918,607	1.0000	918,607	12,885,329	9,469,242	1,330,347,193
2160	5,214,179	3,831,825	292.1582	1,119,499,020	6,439,598	4,732,368	55.6179	263,204,350	1,250,000	918,607	1.0000	918,607	12,903,777	9,482,799	1,383,621,977
2161	5,204,135	3,824,444	303.9906	1,162,594,891	6,431,194	4,726,192	57.2030	270,352,341	1,250,000	918,607	1.0000	918,607	12,885,329	9,469,242	1,433,865,839
2162	3,666,224	2,694,255	316.3022	852,198,784	1,817,462	1,335,627	58.8333	78,579,328	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	931,696,719
2163	8,279,956	6,084,820	329.1125	2,002,590,298	15,658,658	11,507,322	60.5100	696,308,024	1,250,000	918,607	1.0000	918,607	25,188,614	18,510,748	2,699,816,930
2164	6,752,090	4,962,013	342.4415	1,699,199,277	11,053,330	8,122,933	62.2345	505,526,647	1,250,000	918,607	1.0000	918,607	19,055,420	14,003,553	2,205,644,530
2165	5,204,135	3,824,444	356.3104	1,362,689,012	6,431,194	4,726,192	64.0082	302,515,021	1,250,000	918,607	1.0000	918,607	12,885,329	9,469,242	1,666,122,640
2166	3,666,224	2,694,255	370.7410	998,870,793	1,817,462	1,335,627	65.8325	87,927,646	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	1,087,717,046
2167	3,666,224	2,694,255	385.7560	1,039,325,032	1,817,462	1,335,627	67.7087	90,433,549	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	1,130,677,188
2168	6,752,090	4,962,013	401.3791	1,991,648,432	11,053,330	8,122,933	69.6384	565,668,027	1,250,000	918,607	1.0000	918,607	19,055,420	14,003,553	2,558,235,066
2169	5,973,090	4,389,537	417.6350	1,833,224,479	8,738,060	6,421,474	71.6231	459,925,883	1,250,000	918,607	1.0000	918,607	15,961,150	11,729,619	2,294,068,968
2170	3,666,224	2,694,255	434.5492	1,170,786,355	1,817,462	1,335,627	73.6643	98,388,008	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	1,270,092,970
2171	3,666,224	2,694,255	452.1484	1,218,203,087	1,817,462	1,335,627	75.7638	101,192,156	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	1,320,313,851
2172	7,521,045	5,527,107	470.4604	2,600,285,068	13,360,196	9,818,215	77.9230	765,064,770	1,250,000	918,607	1.0000	918,607	22,131,241	16,263,929	3,366,268,444
2173	3,666,224	2,694,255	489.5141	1,318,875,811	1,817,462	1,335,627	80.1438	107,042,201	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	1,426,836,620
2174	3,666,224	2,694,255	509.3394	1,372,290,225	1,817,462	1,335,627	82.4279	110,092,906	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	1,483,301,738
2175	7,511,001	5,519,726	529.9676	2,925,275,950	13,351,792	9,812,039	84.7771	831,836,215	1,250,000	918,607	1.0000	918,607	22,112,793	16,250,372	3,758,030,772
2176	3,676,269	2,701,637	551.4313	1,489,767,162	1,825,866	1,341,803	87.1933	116,996,206	1,250,000	918,607	1.0000	918,607	6,752,135	4,962,047	1,607,681,975
2177	3,666,224	2,694,255	573.7643	1,545,867,334	1,817,462	1,335,627	89.6783	119,776,734	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	1,666,562,675
2178	7,511,001	5,519,726	597.0018	3,295,286,368	13,351,792	9,812,039	92.2341	905,004,590	1,250,000	918,607	1.0000	918,607	22,112,793	16,250,372	4,201,209,565
2179	3,666,224	2,694,255	621.1803	1,673,618,129	1,817,462	1,335,627	94.8628	126,701,291	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	1,801,238,027
2180	3,676,269	2,701,637	646.3381	1,746,170,877	1,825,866	1,341,803	97.5664	130,914,860	1,250,000	918,607	1.0000	918,607	6,752,135	4,962,047	1,878,004,344
2181	3,666,224	2,694,255	672.5148	1,811,926,362	1,817,462	1,335,627	100.3470	134,026,135	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	1,946,871,104
2182	7,511,001	5,519,726	699.7517	3,862,437,664	13,351,792	9,812,039	103.2069	1,012,670,132	1,250,000	918,607	1.0000	918,607	22,112,793	16,250,372	4,876,026,404
2183	3,666,224	2,694,255	728.0916	1,961,664,434	1,817,462	1,335,627	106.1483	141,774,506	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	2,104,357,547
2184	3,676,269	2,701,637	757.5793	2,046,704,211	1,825,866	1,341,803	109.1736	146,489,432	1,250,000	918,607	1.0000	918,607	6,752,135	4,962,047	2,194,112,250
2185	3,666,224	2,694,255	788.2613	2,123,776,949	1,817,462	1,335,627	112.2850	149,970,847	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	2,274,666,403
2186	3,666,224	2,694,255	820.1859	2,209,789,962	1,817,462	1,335,627	115.4851	154,244,986	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	2,364,953,555
2187	3,666,224	2,694,255	853.4034	2,299,286,377	1,817,462	1,335,627	118.7764	158,640,934	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	2,458,845,919
2188	3,676,269	2,701,637	887.9662	2,398,962,274	1,825,866	1,341,803	122.1616	163,916,766	1,250,000	918,607	1.0000	918,607	6,752,135	4,962,047	2,563,797,647
2189	26,780,755	19,680,790	923.9289	18,183,650,259	71,161,056	52,295,231	125.6432	6,570,540,189	1,250,000	918,607	1.0000	918,607	99,191,811	72,894,628	24,755,109,055
2190	3,666,224	2,694,255	961.3480	2,590,116,656	1,817,462	1,335,627	129.2240	172,595,028	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	2,763,630,291
2191	3,666,224	2,694,255	1,000.2826	2,695,016,396	1,817,462	1,335,627	132.9069	177,514,008	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	2,873,449,011
2192	3,676,269	2,701,637	1,040.7940	2,811,847,502	1,825,866	1,341,803	136.6947	183,417,319	1,250,000	918,607	1.0000	918,607	6,752,135	4,962,047	2,996,183,428
2193	3,050,093	2,241,469	1,082.9462	2,427,390,594	1,970,568	1,448,142	140.5905	203,594,977	1,250,000	918,607	1.0000	918,607	6,270,661	4,608,218	2,631,904,177
2194	3,145,779	2,311,787	1,126.8055	2,604,934,865	2,257,627	1,659,097	144.5974	239,901,154	1,250,000	918,607	1.0000	918,607	6,653,406	4,889,492	2,845,754,626
2195	5,784,468	4,250,922	1,172.4411	4,983,955,529	10,173,693	7,476,500	148.7184	1,111,893,075	1,250,000	918,607	1.0000	918,607	17,208,161	12,646,029	6,096,767,211
2196	4,739,628	3,483,084	1,219.9250	4,249,101,343	7,022,926	5,161,047	152.9569	789,417,691	1,250,000	918,607	1.0000	918,607	13,012,554	9,562,738	5,039,437,641
2197	4,635,847	3,406,817	1,269.3320	4,324,381,736	6,727,830	4,944,185	157.3161	777,799,875	1,250,000	918,607	1.0000	918,607	12,613,677	9,269,609	5,103,100,217
2198	3,241,466	2,382,106	1,320.7399	3,146,143,085	2,544,687	1,870,054	161.7997	302,574,100	1,250,000	918,607	1.0000	918,607	7,036,153	5,170,767	3,449,635,792
2199	3,097,936	2,276,628	1,374.2299	3,128,610,773	2,114,098	1,553,620	166.4109	258,539,286	1,250,000	918,607	1.0000	918,607	6,462,034	4,748,855	3,388,068,666
2200	5,356,959	3,936,752	1,429.8862	5,629,106,931	8,891,166	6,533,989	171.1537	1,118,316,422	1,250,000	918,607	1.0000	918,607	15,498,125	11,389,348	6,748,341,960
2201	5,452,645	4,007,070	1,487.7966	5,961,705,061	9,178,225	6,744,945	176.0315	1,187,322,729	1,250,000	918,607	1.0000	918,607	15,880,870	11,670,622	7,149,946,397
2202	5,452,645	4,007,070	1,548.0523	6,203,153,867	9,178,225	6,744,945	181.0484	1,221,161,442	1,250,000	918,607	1.0000	918,607	15,880,870	11,670,622	7,425,233,915

Xcel Energy
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AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
2203	3,097,936	2,276,628	1,610.7485	3,667,075,727	2,114,098	1,553,620	186.2083	289,296,920	1,250,000	918,607	1.0000	918,607	6,462,034	4,748,855	3,957,291,254
2204	3,153,874	2,317,736	1,675.9838	3,884,488,649	2,265,664	1,665,004	191.5152	318,873,491	1,250,000	918,607	1.0000	918,607	6,669,538	4,901,347	4,204,280,747
2205	5,452,645	4,007,070	1,743.8611	6,987,773,427	9,178,225	6,744,945	196.9734	1,328,574,686	1,250,000	918,607	1.0000	918,607	15,880,870	11,670,622	8,317,266,720
2206	4,635,847	3,406,817	1,814.4875	6,181,626,718	6,727,830	4,944,185	202.5872	1,001,628,560	1,250,000	918,607	1.0000	918,607	12,613,677	9,269,609	7,184,173,885
2207	4,683,690	3,441,976	1,887.9742	6,498,361,979	6,871,359	5,049,662	208.3609	1,052,152,164	1,250,000	918,607	1.0000	918,607	12,805,049	9,410,245	7,551,432,749
2208	3,153,874	2,317,736	1,964.4372	4,553,047,592	2,265,664	1,665,004	214.2992	356,808,932	1,250,000	918,607	1.0000	918,607	6,669,538	4,901,347	4,910,775,132
2209	4,635,847	3,406,817	2,043.9969	6,963,523,225	6,727,830	4,944,185	220.4067	1,089,731,462	1,250,000	918,607	1.0000	918,607	12,613,677	9,269,609	8,054,173,294
2210	4,676,514	3,436,703	2,126.7788	7,309,106,042	6,849,830	5,033,841	226.6883	1,141,112,828	1,250,000	918,607	1.0000	918,607	12,776,344	9,389,150	8,451,137,477
2211	4,669,337	3,431,428	2,212.9133	7,593,453,185	6,828,301	5,018,020	233.1489	1,169,945,729	1,250,000	918,607	1.0000	918,607	12,747,638	9,368,055	8,764,317,521
2212	3,139,521	2,307,189	2,302.5363	5,312,385,461	2,222,606	1,633,361	239.7937	391,669,645	1,250,000	918,607	1.0000	918,607	6,612,127	4,859,156	5,704,973,713
2213	7,745,159	5,691,805	2,395.7890	13,636,364,637	16,055,764	11,799,149	246.6278	2,909,998,069	1,250,000	918,607	1.0000	918,607	25,050,923	18,409,561	16,547,281,313
2214	6,207,248	4,561,617	2,492.8185	11,371,282,728	11,442,033	8,408,584	253.6567	2,132,893,780	1,250,000	918,607	1.0000	918,607	18,899,281	13,888,808	13,505,095,115
2215	4,669,337	3,431,428	2,593.7776	8,900,361,698	6,828,301	5,018,020	260.8859	1,309,130,537	1,250,000	918,607	1.0000	918,607	12,747,638	9,368,055	10,210,410,842
2216	3,139,521	2,307,189	2,698.8256	6,226,699,609	13,878,684	10,199,244	268.3212	2,736,673,397	1,250,000	918,607	1.0000	918,607	18,268,205	13,425,040	8,964,291,613
2217	3,145,779	2,311,787	2,808.1281	6,491,795,428	2,257,627	1,659,097	275.9683	457,858,258	1,250,000	918,607	1.0000	918,607	6,653,406	4,889,492	6,950,572,292
2218	1,058,128	777,603	2,921.8572	2,272,044,845	2,283,531	1,678,134	283.8334	476,310,374	-	-	1.0000	-	3,341,659	2,455,737	2,748,355,219
	$1,254,481,263	$921,900,139		$257,514,109,402	$1,495,365,399	$1,098,922,407		$50,419,031,894	$230,000,000	$169,023,674		$169,023,674	$2,979,846,662	$2,189,846,220	$308,102,164,970
	$4,769,359,832	$3,504,933,570		$1,232,278,635,160	$4,988,218,698	$3,665,769,786		$174,047,975,724	$461,250,000	$338,965,955		$338,965,955	$10,218,828,530	$7,509,669,311	$1,406,665,576,839

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EXTERNAL FUND CALCULATION

Monticello

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	623,672,182	15,832,261	-	6,696,113	646,200,556
2018	646,200,556	32,971,282	-	13,392,226	692,564,064
2019	692,564,064	36,708,630	-	68,679,001	797,951,695
2020	797,951,695	42,030,705	-	68,679,001	908,661,402
2021	908,661,402	47,621,546	-	68,679,001	1,024,961,949
2022	1,024,961,949	53,494,723	-	68,679,001	1,147,135,674
2023	1,147,135,674	59,664,496	-	68,679,001	1,275,479,171
2024	1,275,479,171	66,145,843	-	68,679,001	1,410,304,016
2025	1,410,304,016	72,954,498	-	68,679,001	1,551,937,515
2026	1,551,937,515	80,106,989	-	68,679,001	1,700,723,505
2027	1,700,723,505	87,620,682	-	68,679,001	1,857,023,188
2028	1,857,023,188	95,513,816	-	68,679,001	2,021,216,006
2029	2,021,216,006	103,805,553	-	68,679,001	2,193,700,560
2030	2,193,700,560	110,306,923	(35,447,395)	51,509,251	2,320,069,339
2031	2,320,069,339	115,307,446	(139,568,856)	-	2,295,807,930
2032	2,295,807,930	114,101,654	(235,103,206)	-	2,174,806,377
2033	2,174,806,377	108,087,877	(224,495,044)	-	2,058,399,210
2034	2,058,399,210	102,302,441	(141,890,431)	-	2,018,811,220
2035	2,018,811,220	100,334,918	(268,360,592)	-	1,850,785,546
2036	1,850,785,546	91,984,042	(104,537,352)	-	1,838,232,235
2037	1,838,232,235	91,360,142	(74,807,126)	-	1,854,785,251
2038	1,854,785,251	92,182,827	(70,466,465)	-	1,876,501,613
2039	1,876,501,613	93,262,130	(15,456,182)	-	1,954,307,561
2040	1,954,307,561	97,129,086	(16,091,729)	-	2,035,344,917
2041	2,035,344,917	101,156,642	(16,662,702)	-	2,119,838,858
2042	2,119,838,858	105,355,991	(17,301,946)	-	2,207,892,903
2043	2,207,892,903	109,732,277	(17,965,078)	-	2,299,660,102
2044	2,299,660,102	114,293,107	(18,705,321)	-	2,395,247,888
2045	2,395,247,888	119,043,820	(19,370,615)	-	2,494,921,093
2046	2,494,921,093	123,997,578	(20,114,754)	-	2,598,803,918
2047	2,598,803,918	129,160,555	(20,887,978)	-	2,707,076,494
2048	2,707,076,494	134,541,702	(26,916,472)	-	2,814,701,724
2049	2,814,701,724	139,890,676	(22,525,524)	-	2,932,066,876
2050	2,932,066,876	145,723,724	(35,781,808)	-	3,042,008,791
2051	3,042,008,791	151,187,837	(37,084,255)	-	3,156,112,374
2052	3,156,112,374	156,858,785	(38,504,356)	-	3,274,466,803
2053	3,274,466,803	162,741,000	(39,837,891)	-	3,397,369,912
2054	3,397,369,912	168,849,285	(41,292,108)	-	3,524,927,088
2055	3,524,927,088	175,188,876	(42,800,207)	-	3,657,315,757
2056	3,657,315,757	181,768,593	(44,445,167)	-	3,794,639,184

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2057	3,794,639,184	188,593,567	(45,988,884)	-	3,937,243,867
2058	3,937,243,867	195,681,020	(113,026,766)	-	4,019,898,121
2059	4,019,898,121	199,788,937	(49,420,970)	-	4,170,266,088
2060	4,170,266,088	207,262,225	(51,327,230)	-	4,326,201,083
2061	4,326,201,083	215,012,194	(53,115,265)	-	4,488,098,012
2062	4,488,098,012	223,058,471	(55,066,654)	-	4,656,089,830
2063	4,656,089,830	231,407,665	(57,091,844)	-	4,830,405,651
2064	4,830,405,651	240,071,161	(59,301,884)	-	5,011,174,928
2065	5,011,174,928	249,055,394	(61,373,962)	-	5,198,856,360
2066	5,198,856,360	258,383,161	(114,400,551)	-	5,342,838,971
2067	5,342,838,971	265,539,097	(65,983,601)	-	5,542,394,466
2068	5,542,394,466	275,457,005	(194,934,193)	-	5,622,917,278
2069	5,622,917,278	279,458,989	(70,948,647)	-	5,831,427,620
2070	5,831,427,620	289,821,953	(73,572,125)	-	6,047,677,448
2071	6,047,677,448	300,569,569	(76,295,052)	-	6,271,951,965
2072	6,271,951,965	311,716,013	(79,268,228)	-	6,504,399,749
2073	6,504,399,749	323,268,668	(82,053,729)	-	6,745,614,688
2074	6,745,614,688	335,257,050	(85,098,079)	-	6,995,773,659
2075	6,995,773,659	347,689,951	(88,256,686)	-	7,255,206,924
2076	7,255,206,924	360,583,784	(91,707,017)	-	7,524,083,691
2077	7,524,083,691	373,946,959	(94,938,806)	-	7,803,091,844
2078	7,803,091,844	387,813,665	(98,471,402)	-	8,092,434,106
2079	8,092,434,106	402,193,975	(102,138,001)	-	8,392,490,081
2080	8,392,490,081	417,106,757	(106,143,610)	-	8,703,453,228
2081	8,703,453,228	432,561,625	(109,894,241)	-	9,026,120,612
2082	9,026,120,612	448,598,194	(113,995,512)	-	9,360,723,295
2083	9,360,723,295	465,227,948	(118,252,284)	-	9,707,698,959
2084	9,707,698,959	482,472,638	(122,904,877)	-	10,067,266,720
2085	10,067,266,720	500,343,156	(127,259,911)	-	10,440,349,964
2086	10,440,349,964	518,885,393	(132,022,065)	-	10,827,213,292
2087	10,827,213,292	538,112,501	(136,966,641)	-	11,228,359,152
2088	11,228,359,152	558,049,450	(161,302,438)	-	11,625,106,164
2089	11,625,106,164	577,767,776	(147,428,700)	-	12,055,445,240
2090	12,055,445,240	599,155,628	(152,961,784)	-	12,501,639,084
2091	12,501,639,084	621,331,462	(158,706,116)	-	12,964,264,430
2092	12,964,264,430	644,323,942	(164,986,810)	-	13,443,601,562
2093	13,443,601,562	668,146,998	(170,862,753)	-	13,940,885,807
2094	13,940,885,807	692,862,025	(177,292,894)	-	14,456,454,938
2095	14,456,454,938	718,485,810	(1,011,713,130)	-	14,163,227,618
2096	14,163,227,618	703,912,413	(191,270,742)	-	14,675,869,289
2097	14,675,869,289	729,390,704	(198,100,321)	-	15,207,159,672
2098	15,207,159,672	755,795,836	(205,574,971)	-	15,757,380,537
2099	15,757,380,537	783,141,813	(213,336,340)	-	16,327,186,010
2100	16,327,186,010	811,461,145	(221,396,538)	-	16,917,250,616
2101	16,917,250,616	840,787,356	(229,766,711)	-	17,528,271,261
2102	17,528,271,261	871,155,082	(238,458,794)	-	18,160,967,549

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External Levelized	2103	18,160,967,549	902,600,087	(247,485,050)	-	18,816,082,586
	2104	18,816,082,586	935,159,305	(257,360,900)	-	19,493,880,991
	2105	19,493,880,991	968,845,885	(266,593,898)	-	20,196,132,978
	2106	20,196,132,978	1,003,747,809	(276,704,354)	-	20,923,176,433
	2107	20,923,176,433	1,039,881,869	(287,205,190)	-	21,675,853,112
	2108	21,675,853,112	1,077,289,900	(638,159,674)	-	22,114,983,337
	2109	22,114,983,337	1,099,114,672	(309,437,221)	-	22,904,660,788
	2110	22,904,660,788	1,138,361,641	(321,200,578)	-	23,721,821,851
	2111	23,721,821,851	1,178,974,546	(333,419,432)	-	24,567,376,965
	2112	24,567,376,965	1,220,998,635	(346,794,281)	-	25,441,581,319
	2113	25,441,581,319	1,264,446,592	(359,291,772)	-	26,346,736,139
	2114	26,346,736,139	1,309,432,786	(372,983,147)	-	27,283,185,778
	2115	27,283,185,778	1,355,974,333	(387,205,007)	-	28,251,955,104
	2116	28,251,955,104	1,404,122,169	(669,932,049)	-	28,986,145,224
	2117	28,986,145,224	1,440,611,418	(417,322,320)	-	30,009,434,321
	2118	30,009,434,321	1,491,468,886	(1,100,591,847)	-	30,400,311,360
	2119	30,400,311,360	1,510,895,475	(449,819,313)	-	31,461,387,522
	2120	31,461,387,522	1,563,630,960	(467,952,861)	-	32,557,065,621
	2121	32,557,065,621	1,618,086,161	(484,887,338)	-	33,690,264,444
	2122	33,690,264,444	1,674,406,143	(503,448,710)	-	34,861,221,877
	2123	34,861,221,877	1,732,602,727	(522,731,285)	-	36,071,093,319
	2124	36,071,093,319	1,792,733,338	(543,853,439)	-	37,319,973,218
	2125	37,319,973,218	1,854,802,669	(563,574,012)	-	38,611,201,874
	2126	38,611,201,874	1,918,976,733	(585,194,345)	-	39,944,984,263
	2127	39,944,984,263	1,985,265,718	(607,655,908)	-	41,322,594,072
	2128	41,322,594,072	2,053,732,925	(705,371,327)	-	42,670,955,670
	2129	42,670,955,670	2,120,746,497	(655,236,600)	-	44,136,465,568
	2130	44,136,465,568	2,193,582,339	(680,426,570)	-	45,649,621,337
	2131	45,649,621,337	2,268,786,180	(706,597,370)	-	47,211,810,147
	2132	47,211,810,147	2,346,426,964	(735,275,655)	-	48,822,961,457
	2133	48,822,961,457	2,426,501,184	(762,040,497)	-	50,487,422,145
	2134	50,487,422,145	2,509,224,881	(791,395,600)	-	52,205,251,425
	2135	52,205,251,425	2,594,600,996	(821,895,968)	-	53,977,956,452
	2136	53,977,956,452	2,682,704,436	(855,324,546)	-	55,805,336,342
	2137	55,805,336,342	2,773,525,216	(886,516,984)	-	57,692,344,575
	2138	57,692,344,575	2,867,309,525	(920,733,462)	-	59,638,920,638
	2139	59,638,920,638	2,964,054,356	(956,287,326)	-	61,646,687,668
	2140	61,646,687,668	3,063,840,377	(995,262,492)	-	63,715,265,553
	2141	63,715,265,553	3,166,648,698	(1,031,621,624)	-	65,850,292,627
	2142	65,850,292,627	3,272,759,544	(1,071,514,914)	-	68,051,537,256
	2143	68,051,537,256	3,382,161,402	(1,112,968,427)	-	70,320,730,232
	2144	70,320,730,232	3,494,940,293	(1,158,419,743)	-	72,657,250,781
	2145	72,657,250,781	3,611,065,364	(5,442,760,511)	-	70,825,555,634
	2146	70,825,555,634	3,520,030,115	(1,247,332,243)	-	73,098,253,506
	2147	73,098,253,506	3,632,983,199	(1,295,675,896)	-	75,435,560,809
	2148	75,435,560,809	3,749,147,372	(1,348,689,696)	-	77,836,018,485

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2149	77,836,018,485	3,868,450,119	(1,398,126,197)	-	80,306,342,407
2150	80,306,342,407	3,991,225,218	(1,452,386,597)	-	82,845,181,027
2151	82,845,181,027	4,117,405,497	(1,508,776,544)	-	85,453,809,981
2152	85,453,809,981	4,247,054,356	(1,570,622,673)	-	88,130,241,663
2153	88,130,241,663	4,380,073,011	(1,628,287,746)	-	90,882,026,928
2154	90,882,026,928	4,516,836,738	(1,691,587,741)	-	93,707,275,925
2155	93,707,275,925	4,657,251,613	(1,757,375,858)	-	96,607,151,681
2156	96,607,151,681	4,801,375,439	(1,829,542,347)	-	99,578,984,772
2157	99,578,984,772	4,949,075,543	(1,896,815,797)	-	102,631,244,519
2158	102,631,244,519	5,100,772,853	(3,886,348,451)	-	103,845,668,920
2159	103,845,668,920	5,161,129,745	(2,047,445,183)	-	106,959,353,482
2160	106,959,353,482	5,315,879,868	(2,131,667,054)	-	110,143,566,297
2161	110,143,566,297	5,474,135,245	(2,210,167,344)	-	113,407,534,197
2162	113,407,534,197	5,636,354,450	(2,296,366,634)	-	116,747,522,013
2163	116,747,522,013	5,802,351,844	(2,385,962,792)	-	120,163,911,065
2164	120,163,911,065	5,972,146,380	(2,484,272,480)	-	123,651,784,965
2165	123,651,784,965	6,145,493,713	(2,575,889,374)	-	127,221,389,303
2166	127,221,389,303	6,322,903,048	(4,203,981,063)	-	129,340,311,289
2167	129,340,311,289	6,428,213,471	(2,781,093,090)	-	132,987,431,670
2168	132,987,431,670	6,609,475,354	(7,021,398,585)	-	132,575,508,439
2169	132,575,508,439	6,589,002,769	(3,002,811,427)	-	136,161,699,782
2170	136,161,699,782	6,767,236,479	(3,120,277,441)	-	139,808,658,820
2171	139,808,658,820	6,948,490,343	(3,242,383,078)	-	143,514,766,085
2172	143,514,766,085	7,132,683,874	(3,376,401,038)	-	147,271,048,922
2173	147,271,048,922	7,319,371,131	(3,501,257,157)	-	151,089,162,896
2174	151,089,162,896	7,509,131,396	(3,638,417,086)	-	154,959,877,206
2175	154,959,877,206	7,701,505,897	(3,780,999,585)	-	158,880,383,519
2176	158,880,383,519	7,896,355,061	(3,937,513,425)	-	162,839,225,155
2177	162,839,225,155	8,093,109,490	(4,083,305,789)	-	166,849,028,856
2178	166,849,028,856	8,292,396,734	(4,243,486,841)	-	170,897,938,750
2179	170,897,938,750	8,493,627,556	(4,410,006,760)	-	174,981,559,546
2180	174,981,559,546	8,696,583,509	(4,592,819,228)	-	179,085,323,828
2181	179,085,323,828	8,900,540,594	(4,763,085,289)	-	183,222,779,133
2182	183,222,779,133	9,106,172,123	(4,950,179,855)	-	187,378,771,401
2183	187,378,771,401	9,312,724,939	(5,144,685,508)	-	191,546,810,832
2184	191,546,810,832	9,519,876,498	(5,358,247,477)	-	195,708,439,853
2185	195,708,439,853	9,726,709,461	(5,557,126,407)	-	199,878,022,907
2186	199,878,022,907	9,933,937,738	(5,775,687,978)	-	204,036,272,667
2187	204,036,272,667	10,140,602,752	(6,002,915,676)	-	208,173,959,742
2188	208,173,959,742	10,346,245,799	(6,252,433,947)	-	212,267,771,595
2189	212,267,771,595	10,549,708,248	(6,484,768,180)	-	216,332,711,663
2190	216,332,711,663	10,751,735,770	(6,740,125,432)	-	220,344,322,001
2191	220,344,322,001	10,951,112,803	(7,005,617,695)	-	224,289,817,109
2192	224,289,817,109	11,147,203,910	(8,216,807,977)	-	227,220,213,042
2193	227,220,213,042	11,292,844,588	(9,237,695,262)	-	229,275,362,369
2194	229,275,362,369	11,394,985,510	(8,114,316,172)	-	232,556,031,706

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2195	232,556,031,706	11,558,034,776	(35,096,569,593)	-	209,017,496,888
2196	209,017,496,888	10,388,169,595	(10,646,190,792)	-	208,759,475,691
2197	208,759,475,691	10,375,345,942	(6,903,223,641)	-	212,231,597,992
2198	212,231,597,992	10,547,910,420	(7,179,978,104)	-	215,599,530,308
2199	215,599,530,308	10,715,296,656	(7,467,860,728)	-	218,846,966,236
2200	218,846,966,236	10,876,694,222	(7,767,319,798)	-	221,956,340,659
2201	221,956,340,659	11,031,230,131	(8,078,821,612)	-	224,908,749,178
2202	224,908,749,178	11,177,964,834	(8,402,851,376)	-	227,683,862,636
2203	227,683,862,636	11,315,887,973	(8,739,915,007)	-	230,259,835,602
2204	230,259,835,602	11,443,913,829	(9,115,450,044)	-	232,588,299,388
2205	232,588,299,388	11,559,638,480	(9,455,262,620)	-	234,692,675,247
2206	234,692,675,247	11,664,225,960	(9,834,662,594)	-	236,522,238,613
2207	236,522,238,613	11,755,155,259	(10,229,326,918)	-	238,048,066,953
2208	238,048,066,953	11,830,988,928	(23,621,875,444)	-	226,257,180,437
2209	226,257,180,437	11,244,981,868	(11,066,937,090)	-	226,435,225,215
2210	226,435,225,215	11,253,830,693	(11,511,188,856)	-	226,177,867,052
2211	226,177,867,052	11,241,039,992	(11,973,319,588)	-	225,445,587,456
2212	225,445,587,456	11,204,645,697	(12,488,182,665)	-	224,162,050,487
2213	224,162,050,487	11,140,853,909	(14,621,371,106)	-	220,681,533,291
2214	220,681,533,291	10,967,872,205	(13,474,344,519)	-	218,175,060,976
2215	218,175,060,976	10,843,300,531	(14,015,498,561)	-	215,002,862,946
2216	215,002,862,946	10,685,642,288	(24,036,881,734)	-	201,651,623,501
2217	201,651,623,501	10,022,085,688	(15,164,046,883)	-	196,509,662,306
2218	196,509,662,306	9,766,530,217	(38,123,338,117)	-	168,152,854,406
2219	168,152,854,406	8,357,196,864	(15,307,988,630)	-	161,202,062,639
2220	161,202,062,639	8,011,742,513	(15,671,223,343)	-	153,542,581,810
2221	153,542,581,810	7,631,066,316	(16,255,993,316)	-	144,917,654,810
2222	144,917,654,810	7,202,407,444	(16,904,673,455)	-	135,215,388,799
2223	135,215,388,799	6,720,204,823	(17,898,815,350)	-	124,036,778,272
2224	124,036,778,272	6,164,627,880	(18,326,615,231)	-	111,874,790,922
2225	111,874,790,922	5,560,177,109	(19,010,909,673)	-	98,424,058,358
2226	98,424,058,358	4,891,675,700	(19,770,011,773)	-	83,545,722,285
2227	83,545,722,285	4,152,222,398	(20,930,335,445)	-	66,767,609,238
2228	66,767,609,238	3,318,350,179	(21,434,056,187)	-	48,651,903,230
2229	48,651,903,230	2,417,999,591	(22,234,870,241)	-	28,835,032,579
2230	28,835,032,579	1,433,101,119	(21,879,025,883)	-	8,389,107,815
2231	8,389,107,815	416,938,658	(8,806,046,474)	-	0

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Prairie Island Unit 1

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	374,367,055	9,453,079	-	24,632	383,844,766
2018	383,844,766	19,385,405	-	49,264	403,279,435
2019	403,279,435	21,446,842	-	42,821,016	467,547,293
2020	467,547,293	24,692,369	-	42,821,016	535,060,678
2021	535,060,678	28,101,795	-	42,821,016	605,983,488
2022	605,983,488	31,683,397	-	42,821,016	680,487,900
2023	680,487,900	35,445,870	-	42,821,016	758,754,786
2024	758,754,786	39,398,347	-	42,821,016	840,974,149
2025	840,974,149	43,550,425	-	42,821,016	927,345,590
2026	927,345,590	47,912,183	-	42,821,016	1,018,078,788
2027	1,018,078,788	52,494,209	-	42,821,016	1,113,394,013
2028	1,113,394,013	57,307,628	-	42,821,016	1,213,522,657
2029	1,213,522,657	62,364,125	-	42,821,016	1,318,707,798
2030	1,318,707,798	67,675,974	-	42,821,016	1,429,204,788
2031	1,429,204,788	73,256,072	-	42,821,016	1,545,281,876
2032	1,545,281,876	79,117,965	-	42,821,016	1,667,220,857
2033	1,667,220,857	83,069,355	(42,768,206)	28,690,080	1,736,212,087
2034	1,736,212,087	85,768,877	(131,752,423)	-	1,690,228,541
2035	1,690,228,541	83,497,290	(198,854,133)	-	1,574,871,698
2036	1,574,871,698	77,798,662	(173,386,484)	-	1,479,283,876
2037	1,479,283,876	73,076,623	(119,758,863)	-	1,432,601,637
2038	1,432,601,637	70,770,521	(48,446,231)	-	1,454,925,926
2039	1,454,925,926	71,873,341	(166,746,609)	-	1,360,052,659
2040	1,360,052,659	67,186,601	(78,122,012)	-	1,349,117,248
2041	1,349,117,248	66,646,392	(51,940,215)	-	1,363,823,426
2042	1,363,823,426	67,372,877	(47,702,660)	-	1,383,493,643
2043	1,383,493,643	68,344,586	(29,119,754)	-	1,422,718,475
2044	1,422,718,475	70,282,293	(11,674,091)	-	1,481,326,676
2045	1,481,326,676	73,177,538	(28,362,264)	-	1,526,141,949
2046	1,526,141,949	75,391,412	(23,687,841)	-	1,577,845,521
2047	1,577,845,521	77,945,569	(24,482,072)	-	1,631,309,018
2048	1,631,309,018	80,586,665	(13,373,108)	-	1,698,522,575
2049	1,698,522,575	83,907,015	(26,156,567)	-	1,756,273,023
2050	1,756,273,023	86,759,887	(33,419,678)	-	1,809,613,232
2051	1,809,613,232	89,394,894	(32,879,405)	-	1,866,128,721
2052	1,866,128,721	92,186,759	(35,748,383)	-	1,922,567,097
2053	1,922,567,097	94,974,815	(15,839,839)	-	2,001,702,073
2054	2,001,702,073	98,884,082	(16,400,093)	-	2,084,186,063
2055	2,084,186,063	102,958,792	(39,440,555)	-	2,147,704,300
2056	2,147,704,300	106,096,592	(33,099,428)	-	2,220,701,464

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2057	2,220,701,464	109,702,652	(34,177,854)	-	2,296,226,262
2058	2,296,226,262	113,433,577	(18,863,779)	-	2,390,796,060
2059	2,390,796,060	118,105,325	(34,418,346)	-	2,474,483,039
2060	2,474,483,039	122,239,462	(37,886,138)	-	2,558,836,364
2061	2,558,836,364	126,406,516	(39,129,555)	-	2,646,113,325
2062	2,646,113,325	130,717,998	(21,727,882)	-	2,755,103,442
2063	2,755,103,442	136,102,110	(80,621,796)	-	2,810,583,756
2064	2,810,583,756	138,842,838	(60,889,305)	-	2,888,537,289
2065	2,888,537,289	142,693,742	(44,841,447)	-	2,986,389,584
2066	2,986,389,584	147,527,645	(25,058,214)	-	3,108,859,015
2067	3,108,859,015	153,577,635	(25,972,206)	-	3,236,464,444
2068	3,236,464,444	159,881,344	(72,551,153)	-	3,323,794,634
2069	3,323,794,634	164,195,455	(63,196,056)	-	3,424,794,033
2070	3,424,794,033	169,184,825	(28,931,636)	-	3,565,047,222
2071	3,565,047,222	176,113,333	(29,995,129)	-	3,711,165,426
2072	3,711,165,426	183,331,572	(92,767,952)	-	3,801,729,047
2073	3,801,729,047	187,805,415	(32,246,859)	-	3,957,287,603
2074	3,957,287,603	195,490,008	(33,438,597)	-	4,119,339,013
2075	4,119,339,013	203,495,347	(112,362,974)	-	4,210,471,386
2076	4,210,471,386	207,997,286	(36,070,752)	-	4,382,397,921
2077	4,382,397,921	216,490,457	(37,296,551)	-	4,561,591,827
2078	4,561,591,827	225,342,636	(117,577,657)	-	4,669,356,807
2079	4,669,356,807	230,666,226	(40,123,990)	-	4,859,899,043
2080	4,859,899,043	240,079,013	(41,746,752)	-	5,058,231,304
2081	5,058,231,304	249,876,626	(43,174,563)	-	5,264,933,367
2082	5,264,933,367	260,087,708	(125,683,310)	-	5,399,337,765
2083	5,399,337,765	266,727,286	(46,466,442)	-	5,619,598,608
2084	5,619,598,608	277,608,171	(48,355,173)	-	5,848,851,606
2085	5,848,851,606	288,933,269	(50,019,012)	-	6,087,765,864
2086	6,087,765,864	300,735,634	(51,899,131)	-	6,336,602,366
2087	6,336,602,366	313,028,157	(53,852,602)	-	6,595,777,921
2088	6,595,777,921	325,831,429	(56,051,006)	-	6,865,558,345
2089	6,865,558,345	339,158,582	(750,835,061)	-	6,453,881,866
2090	6,453,881,866	318,821,764	(60,180,313)	-	6,712,523,318
2091	6,712,523,318	331,598,652	(62,455,727)	-	6,981,666,242
2092	6,981,666,242	344,894,312	(65,015,702)	-	7,261,544,853
2093	7,261,544,853	358,720,316	(67,275,883)	-	7,552,989,285
2094	7,552,989,285	373,117,671	(69,827,894)	-	7,856,279,062
2095	7,856,279,062	388,100,186	(155,517,607)	-	8,088,861,641
2096	8,088,861,641	399,589,765	(132,697,627)	-	8,355,753,779
2097	8,355,753,779	412,774,237	(137,276,626)	-	8,631,251,390
2098	8,631,251,390	426,383,819	(81,070,472)	-	8,976,564,736
2099	8,976,564,736	443,442,298	(84,160,485)	-	9,335,846,549
2100	9,335,846,549	461,190,820	(185,514,081)	-	9,611,523,287
2101	9,611,523,287	474,809,250	(192,196,742)	-	9,894,135,795
2102	9,894,135,795	488,770,308	(199,127,152)	-	10,183,778,951

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External Levelized	2103	10,183,778,951	503,078,680	(97,776,676)	-	10,589,080,955
	2104	10,589,080,955	523,100,599	(101,824,431)	-	11,010,357,124
	2105	11,010,357,124	543,911,642	(221,501,424)	-	11,332,767,342
	2106	11,332,767,342	559,838,707	(189,497,916)	-	11,703,108,132
	2107	11,703,108,132	578,133,542	(196,444,221)	-	12,084,797,453
	2108	12,084,797,453	596,988,994	(118,369,810)	-	12,563,416,637
	2109	12,563,416,637	620,632,782	(211,130,954)	-	12,972,918,465
	2110	12,972,918,465	640,862,172	(218,891,810)	-	13,394,888,828
	2111	13,394,888,828	661,707,508	(226,946,170)	-	13,829,650,166
	2112	13,829,650,166	683,184,718	(137,664,947)	-	14,375,169,937
	2113	14,375,169,937	710,133,395	(446,845,223)	-	14,638,458,109
	2114	14,638,458,109	723,139,831	(357,917,829)	-	15,003,680,111
	2115	15,003,680,111	741,181,797	(285,747,972)	-	15,459,113,936
	2116	15,459,113,936	763,680,228	(160,171,633)	-	16,062,622,531
	2117	16,062,622,531	793,493,553	(165,867,658)	-	16,690,248,426
	2118	16,690,248,426	824,498,272	(412,774,806)	-	17,101,971,893
	2119	17,101,971,893	844,837,412	(365,580,681)	-	17,581,228,623
	2120	17,581,228,623	868,512,694	(186,429,715)	-	18,263,311,602
	2121	18,263,311,602	902,207,593	(193,078,480)	-	18,972,440,715
	2122	18,972,440,715	937,238,571	(545,222,379)	-	19,364,456,907
	2123	19,364,456,907	956,604,171	(208,342,425)	-	20,112,718,653
	2124	20,112,718,653	993,568,301	(217,069,921)	-	20,889,217,033
	2125	20,889,217,033	1,031,927,321	(606,842,631)	-	21,314,301,724
	2126	21,314,301,724	1,052,926,505	(233,567,637)	-	22,133,660,592
	2127	22,133,660,592	1,093,402,833	(242,647,223)	-	22,984,416,202
	2128	22,984,416,202	1,135,430,160	(676,367,768)	-	23,443,478,595
	2129	23,443,478,595	1,158,107,843	(261,894,498)	-	24,339,691,940
	2130	24,339,691,940	1,202,380,782	(272,091,406)	-	25,269,981,315
	2131	25,269,981,315	1,248,337,077	(282,690,337)	-	26,235,628,055
	2132	26,235,628,055	1,296,040,026	(780,812,473)	-	26,750,855,608
	2133	26,750,855,608	1,321,492,267	(305,159,839)	-	27,767,188,035
	2134	27,767,188,035	1,371,699,089	(317,064,613)	-	28,821,822,511
	2135	28,821,822,511	1,423,798,032	(329,439,410)	-	29,916,181,133
	2136	29,916,181,133	1,477,859,348	(343,310,154)	-	31,050,730,327
	2137	31,050,730,327	1,533,906,078	(355,675,428)	-	32,228,960,977
	2138	32,228,960,977	1,592,110,672	(369,576,237)	-	33,451,495,412
	2139	33,451,495,412	1,652,503,873	(4,110,885,000)	-	30,993,114,285
	2140	30,993,114,285	1,531,059,846	(400,219,998)	-	32,123,954,133
	2141	32,123,954,133	1,586,923,334	(414,665,053)	-	33,296,212,414
	2142	33,296,212,414	1,644,832,893	(430,899,762)	-	34,510,145,546
	2143	34,510,145,546	1,704,801,190	(447,776,458)	-	35,767,170,278
	2144	35,767,170,278	1,766,898,212	(466,684,194)	-	37,067,384,296
	2145	37,067,384,296	1,831,128,784	(942,176,534)	-	37,956,336,546
	2146	37,956,336,546	1,875,043,025	(819,164,963)	-	39,012,214,609
	2147	39,012,214,609	1,927,203,402	(850,175,704)	-	40,089,242,307
	2148	40,089,242,307	1,980,408,570	(544,318,666)	-	41,525,332,210

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2149	41,525,332,210	2,051,351,411	(564,040,861)	-	43,012,642,761
2150	43,012,642,761	2,124,824,552	(1,132,757,742)	-	44,004,709,571
2151	44,004,709,571	2,173,832,653	(1,175,361,744)	-	45,003,180,480
2152	45,003,180,480	2,223,157,116	(1,221,441,653)	-	46,004,895,942
2153	46,004,895,942	2,272,641,860	(658,063,552)	-	47,619,474,249
2154	47,619,474,249	2,352,402,028	(683,945,998)	-	49,287,930,279
2155	49,287,930,279	2,434,823,756	(1,456,527,378)	-	50,266,226,657
2156	50,266,226,657	2,483,151,597	(1,191,217,991)	-	51,558,160,263
2157	51,558,160,263	2,546,973,117	(1,234,371,151)	-	52,870,762,229
2158	52,870,762,229	2,611,815,654	(798,168,374)	-	54,684,409,508
2159	54,684,409,508	2,701,409,830	(1,330,306,865)	-	56,055,512,473
2160	56,055,512,473	2,769,142,316	(1,383,581,665)	-	57,441,073,124
2161	57,441,073,124	2,837,589,012	(1,433,823,154)	-	58,844,838,982
2162	58,844,838,982	2,906,935,046	(931,653,123)	-	60,820,120,904
2163	60,820,120,904	3,004,513,973	(2,699,774,193)	-	61,124,860,684
2164	61,124,860,684	3,019,568,118	(2,205,599,092)	-	61,938,829,710
2165	61,938,829,710	3,059,778,188	(1,666,074,818)	-	63,332,533,079
2166	63,332,533,079	3,128,627,134	(1,087,668,215)	-	65,373,491,998
2167	65,373,491,998	3,229,450,505	(1,130,626,952)	-	67,472,315,551
2168	67,472,315,551	3,333,132,388	(2,558,184,221)	-	68,247,263,718
2169	68,247,263,718	3,371,414,828	(2,294,017,133)	-	69,324,661,413
2170	69,324,661,413	3,424,638,274	(1,270,038,271)	-	71,479,261,415
2171	71,479,261,415	3,531,075,514	(1,320,257,578)	-	73,690,079,352
2172	73,690,079,352	3,640,289,920	(3,366,213,509)	-	73,964,155,763
2173	73,964,155,763	3,653,829,295	(1,426,777,061)	-	76,191,207,997
2174	76,191,207,997	3,763,845,675	(1,483,240,465)	-	78,471,813,207
2175	78,471,813,207	3,876,507,572	(3,757,968,903)	-	78,590,351,877
2176	78,590,351,877	3,882,363,383	(1,607,618,975)	-	80,865,096,285
2177	80,865,096,285	3,994,735,756	(1,666,495,954)	-	83,193,336,087
2178	83,193,336,087	4,109,750,803	(4,201,142,239)	-	83,101,944,651
2179	83,101,944,651	4,105,236,066	(1,801,167,407)	-	85,406,013,310
2180	85,406,013,310	4,219,057,058	(1,877,933,870)	-	87,747,136,497
2181	87,747,136,497	4,334,708,543	(1,946,796,356)	-	90,135,048,684
2182	90,135,048,684	4,452,671,405	(4,875,951,044)	-	89,711,769,045
2183	89,711,769,045	4,431,761,391	(2,104,278,428)	-	92,039,252,007
2184	92,039,252,007	4,546,739,049	(2,194,033,417)	-	94,391,957,639
2185	94,391,957,639	4,662,962,707	(2,274,582,657)	-	96,780,337,689
2186	96,780,337,689	4,780,948,682	(2,364,867,395)	-	99,196,418,976
2187	99,196,418,976	4,900,303,097	(2,458,757,274)	-	101,637,964,800
2188	101,637,964,800	5,020,915,461	(2,563,709,466)	-	104,095,170,795
2189	104,095,170,795	5,142,301,437	(24,755,020,964)	-	84,482,451,268
2190	84,482,451,268	4,173,433,093	(2,763,533,752)	-	85,892,350,609
2191	85,892,350,609	4,243,082,120	(2,873,349,687)	-	87,262,083,042
2192	87,262,083,042	4,310,746,902	(2,996,084,790)	-	88,576,745,154
2193	88,576,745,154	4,375,691,211	(2,631,901,790)	-	90,320,534,575
2194	90,320,534,575	4,461,834,408	(2,845,755,560)	-	91,936,613,423

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2195	91,936,613,423	4,541,668,703	(6,096,768,388)	-	90,381,513,738
2196	90,381,513,738	4,464,846,779	(5,039,439,321)	-	89,806,921,195
2197	89,806,921,195	4,436,461,907	(5,103,102,785)	-	89,140,280,318
2198	89,140,280,318	4,403,529,848	(3,449,639,793)	-	90,094,170,372
2199	90,094,170,372	4,450,652,016	(3,388,072,705)	-	91,156,749,684
2200	91,156,749,684	4,503,143,434	(6,748,343,262)	-	88,911,549,856
2201	88,911,549,856	4,392,230,563	(7,149,952,252)	-	86,153,828,167
2202	86,153,828,167	4,255,999,111	(7,425,240,003)	-	82,984,587,275
2203	82,984,587,275	4,099,438,611	(3,957,295,989)	-	83,126,729,898
2204	83,126,729,898	4,106,460,457	(4,204,275,961)	-	83,028,914,393
2205	83,028,914,393	4,101,628,371	(8,317,273,562)	-	78,813,269,203
2206	78,813,269,203	3,893,375,499	(7,184,177,587)	-	75,522,467,114
2207	75,522,467,114	3,730,809,875	(7,551,432,596)	-	71,701,844,393
2208	71,701,844,393	3,542,071,113	(4,910,769,515)	-	70,333,145,992
2209	70,333,145,992	3,474,457,412	(8,054,177,476)	-	65,753,425,928
2210	65,753,425,928	3,248,219,241	(8,451,130,892)	-	60,550,514,276
2211	60,550,514,276	2,991,195,405	(8,764,321,886)	-	54,777,387,796
2212	54,777,387,796	2,706,002,957	(5,704,971,845)	-	51,778,418,908
2213	51,778,418,908	2,557,853,894	(16,547,283,798)	-	37,788,989,004
2214	37,788,989,004	1,866,776,057	(13,505,097,847)	-	26,150,667,214
2215	26,150,667,214	1,291,842,960	(10,210,415,985)	-	17,232,094,189
2216	17,232,094,189	851,265,453	(8,964,289,432)	-	9,119,070,210
2217	9,119,070,210	450,482,068	(6,950,574,559)	-	2,618,977,720
2218	2,618,977,720	129,377,499	(2,748,355,219)	-	0

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Prairie Island Unit 2

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	420,208,967	10,698,068	-	294,670	431,201,705
2018	431,201,705	21,963,166	-	589,341	453,754,212
2019	453,754,212	24,001,002	-	35,556,474	513,311,688
2020	513,311,688	27,032,477	-	35,556,474	575,900,639
2021	575,900,639	30,218,255	-	35,556,474	641,675,369
2022	641,675,369	33,566,189	-	35,556,474	710,798,031
2023	710,798,031	37,084,532	-	35,556,474	783,439,038
2024	783,439,038	40,781,959	-	35,556,474	859,777,471
2025	859,777,471	44,667,586	-	35,556,474	940,001,531
2026	940,001,531	48,750,990	-	35,556,474	1,024,308,996
2027	1,024,308,996	53,042,240	-	35,556,474	1,112,907,710
2028	1,112,907,710	57,551,915	-	35,556,474	1,206,016,099
2029	1,206,016,099	62,291,132	-	35,556,474	1,303,863,705
2030	1,303,863,705	67,271,575	-	35,556,474	1,406,691,755
2031	1,406,691,755	72,505,523	-	35,556,474	1,514,753,751
2032	1,514,753,751	78,005,878	-	35,556,474	1,628,316,104
2033	1,628,316,104	83,786,202	-	35,556,474	1,747,658,780
2034	1,747,658,780	86,887,046	(17,426,478)	29,511,874	1,846,631,222
2035	1,846,631,222	91,038,919	(114,752,428)	-	1,822,917,714
2036	1,822,917,714	89,869,843	(214,578,967)	-	1,698,208,590
2037	1,698,208,590	83,721,683	(216,463,722)	-	1,565,466,552
2038	1,565,466,552	77,177,501	(136,478,687)	-	1,506,165,366
2039	1,506,165,366	74,253,953	(176,222,841)	-	1,404,196,477
2040	1,404,196,477	69,226,886	(89,351,532)	-	1,384,071,832
2041	1,384,071,832	68,234,741	(64,325,998)	-	1,387,980,575
2042	1,387,980,575	68,427,442	(59,595,219)	-	1,396,812,799
2043	1,396,812,799	68,862,871	(34,871,710)	-	1,430,803,960
2044	1,430,803,960	70,538,635	(11,675,642)	-	1,489,666,953
2045	1,489,666,953	73,440,581	(28,363,854)	-	1,534,743,680
2046	1,534,743,680	75,662,863	(23,689,494)	-	1,586,717,049
2047	1,586,717,049	78,225,151	(24,483,772)	-	1,640,458,427
2048	1,640,458,427	80,874,600	(13,374,843)	-	1,707,958,185
2049	1,707,958,185	84,202,339	(26,158,366)	-	1,766,002,157
2050	1,766,002,157	87,063,906	(33,421,508)	-	1,819,644,556
2051	1,819,644,556	89,708,477	(32,881,304)	-	1,876,471,728
2052	1,876,471,728	92,510,056	(35,750,338)	-	1,933,231,446
2053	1,933,231,446	95,308,310	(15,841,845)	-	2,012,697,911
2054	2,012,697,911	99,226,007	(16,402,157)	-	2,095,521,762
2055	2,095,521,762	103,309,223	(39,442,660)	-	2,159,388,324
2056	2,159,388,324	106,457,844	(33,101,605)	-	2,232,744,564

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2057	2,232,744,564	110,074,307	(34,180,108)	-	2,308,638,762
2058	2,308,638,762	113,815,891	(18,866,090)	-	2,403,588,564
2059	2,403,588,564	118,496,916	(34,420,697)	-	2,487,664,783
2060	2,487,664,783	122,641,874	(37,888,573)	-	2,572,418,084
2061	2,572,418,084	126,820,212	(39,132,078)	-	2,660,106,217
2062	2,660,106,217	131,143,237	(21,730,468)	-	2,769,518,986
2063	2,769,518,986	136,537,286	(80,624,408)	-	2,825,431,864
2064	2,825,431,864	139,293,791	(60,892,047)	-	2,903,833,608
2065	2,903,833,608	143,158,997	(44,844,272)	-	3,002,148,332
2066	3,002,148,332	148,005,913	(25,061,109)	-	3,125,093,136
2067	3,125,093,136	154,067,092	(25,975,184)	-	3,253,185,044
2068	3,253,185,044	160,382,023	(72,554,214)	-	3,341,012,853
2069	3,341,012,853	164,711,934	(63,199,176)	-	3,442,525,611
2070	3,442,525,611	169,716,513	(28,934,876)	-	3,583,307,247
2071	3,583,307,247	176,657,047	(29,998,461)	-	3,729,965,834
2072	3,729,965,834	183,887,316	(92,771,376)	-	3,821,081,773
2073	3,821,081,773	188,379,331	(32,250,385)	-	3,977,210,719
2074	3,977,210,719	196,076,488	(33,442,224)	-	4,139,844,984
2075	4,139,844,984	204,094,358	(112,366,690)	-	4,231,572,651
2076	4,231,572,651	208,616,532	(36,074,561)	-	4,404,114,623
2077	4,404,114,623	217,122,851	(37,300,497)	-	4,583,936,976
2078	4,583,936,976	225,988,093	(117,581,691)	-	4,692,343,378
2079	4,692,343,378	231,332,529	(40,128,166)	-	4,883,547,740
2080	4,883,547,740	240,758,904	(41,751,014)	-	5,082,555,630
2081	5,082,555,630	250,569,993	(43,178,981)	-	5,289,946,642
2082	5,289,946,642	260,794,369	(125,687,807)	-	5,425,053,204
2083	5,425,053,204	267,455,123	(46,471,116)	-	5,646,037,211
2084	5,646,037,211	278,349,635	(48,359,942)	-	5,876,026,904
2085	5,876,026,904	289,688,126	(50,023,957)	-	6,115,691,073
2086	6,115,691,073	301,503,570	(51,904,218)	-	6,365,290,425
2087	6,365,290,425	313,808,818	(53,857,834)	-	6,625,241,409
2088	6,625,241,409	326,624,401	(56,056,341)	-	6,895,809,469
2089	6,895,809,469	339,963,407	(750,019,869)	-	6,485,753,007
2090	6,485,753,007	319,747,623	(60,186,007)	-	6,745,314,623
2091	6,745,314,623	332,544,011	(62,461,585)	-	7,015,397,049
2092	7,015,397,049	345,859,075	(65,021,671)	-	7,296,234,453
2093	7,296,234,453	359,704,359	(67,282,081)	-	7,588,656,731
2094	7,588,656,731	374,120,777	(69,834,269)	-	7,892,943,239
2095	7,892,943,239	389,122,102	(155,524,086)	-	8,126,541,255
2096	8,126,541,255	400,638,484	(132,704,319)	-	8,394,475,420
2097	8,394,475,420	413,847,638	(137,283,595)	-	8,671,039,462
2098	8,671,039,462	427,482,245	(81,077,609)	-	9,017,444,099
2099	9,017,444,099	444,559,994	(84,167,826)	-	9,377,836,267
2100	9,377,836,267	462,327,328	(185,521,538)	-	9,654,642,057
2101	9,654,642,057	475,973,853	(192,204,411)	-	9,938,411,500
2102	9,938,411,500	489,963,687	(199,135,039)	-	10,229,240,147

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External Levelized	2103	10,229,240,147	504,301,539	(97,784,894)	-	10,635,756,792
	2104	10,635,756,792	524,342,810	(101,832,791)	-	11,058,266,811
	2105	11,058,266,811	545,172,554	(221,510,005)	-	11,381,929,359
	2106	11,381,929,359	561,129,117	(189,506,903)	-	11,753,551,573
	2107	11,753,551,573	579,450,093	(196,453,466)	-	12,136,548,200
	2108	12,136,548,200	598,331,826	(118,379,164)	-	12,616,500,863
	2109	12,616,500,863	621,993,493	(211,140,737)	-	13,027,353,618
	2110	13,027,353,618	642,248,533	(218,901,873)	-	13,450,700,279
	2111	13,450,700,279	663,119,524	(226,956,522)	-	13,886,863,281
	2112	13,886,863,281	684,622,360	(137,675,412)	-	14,433,810,228
	2113	14,433,810,228	711,586,844	(446,855,813)	-	14,698,541,260
	2114	14,698,541,260	724,638,084	(357,928,808)	-	15,065,250,536
	2115	15,065,250,536	742,716,851	(285,759,253)	-	15,522,208,134
	2116	15,522,208,134	765,244,861	(160,183,341)	-	16,127,269,653
	2117	16,127,269,653	795,074,394	(165,879,861)	-	16,756,464,186
	2118	16,756,464,186	826,093,684	(412,787,085)	-	17,169,770,786
	2119	17,169,770,786	846,469,700	(365,593,399)	-	17,650,647,087
	2120	17,650,647,087	870,176,901	(186,442,814)	-	18,334,381,175
	2121	18,334,381,175	903,884,992	(193,092,143)	-	19,045,174,023
	2122	19,045,174,023	938,927,079	(545,236,291)	-	19,438,864,811
	2123	19,438,864,811	958,336,035	(208,356,883)	-	20,188,843,964
	2124	20,188,843,964	995,310,007	(217,084,576)	-	20,967,069,395
	2125	20,967,069,395	1,033,676,521	(606,857,768)	-	21,393,888,148
	2126	21,393,888,148	1,054,718,686	(233,583,374)	-	22,215,023,460
	2127	22,215,023,460	1,095,200,657	(242,663,411)	-	23,067,560,706
	2128	23,067,560,706	1,137,230,743	(676,383,922)	-	23,528,407,526
	2129	23,528,407,526	1,159,950,491	(261,911,627)	-	24,426,446,390
	2130	24,426,446,390	1,204,223,807	(272,109,027)	-	25,358,561,170
	2131	25,358,561,170	1,250,177,066	(282,708,463)	-	26,326,029,773
	2132	26,326,029,773	1,297,873,268	(780,830,534)	-	26,843,072,507
	2133	26,843,072,507	1,323,363,475	(305,179,020)	-	27,861,256,962
	2134	27,861,256,962	1,373,559,968	(317,084,344)	-	28,917,732,586
	2135	28,917,732,586	1,425,644,216	(329,459,707)	-	30,013,917,095
	2136	30,013,917,095	1,479,686,113	(343,330,675)	-	31,150,272,533
	2137	31,150,272,533	1,535,708,436	(355,696,906)	-	32,330,284,062
	2138	32,330,284,062	1,593,883,004	(369,598,331)	-	33,554,568,735
	2139	33,554,568,735	1,654,240,239	(4,110,906,980)	-	31,097,901,994
	2140	31,097,901,994	1,533,126,568	(400,242,957)	-	32,230,785,606
	2141	32,230,785,606	1,588,977,730	(414,689,104)	-	33,405,074,232
	2142	33,405,074,232	1,646,870,160	(430,924,504)	-	34,621,019,888
	2143	34,621,019,888	1,706,816,280	(447,801,910)	-	35,880,034,259
	2144	35,880,034,259	1,768,885,689	(466,709,878)	-	37,182,210,070
	2145	37,182,210,070	1,833,082,956	(942,202,942)	-	38,073,090,085
	2146	38,073,090,085	1,877,003,341	(819,192,849)	-	39,130,900,577
	2147	39,130,900,577	1,929,153,398	(850,204,392)	-	40,209,849,583
	2148	40,209,849,583	1,982,345,584	(544,347,400)	-	41,647,847,768

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2149	41,647,847,768	2,053,238,895	(564,071,025)	-	43,137,015,638
2150	43,137,015,638	2,126,654,871	(1,132,788,133)	-	44,130,882,376
2151	44,130,882,376	2,175,652,501	(1,175,393,002)	-	45,131,141,876
2152	45,131,141,876	2,224,965,294	(1,221,474,671)	-	46,134,632,499
2153	46,134,632,499	2,274,437,382	(658,097,334)	-	47,750,972,547
2154	47,750,972,547	2,354,122,947	(683,980,750)	-	49,421,114,743
2155	49,421,114,743	2,436,460,957	(1,456,562,811)	-	50,401,012,889
2156	50,401,012,889	2,484,769,935	(1,191,254,025)	-	51,694,528,799
2157	51,694,528,799	2,548,540,270	(1,234,409,252)	-	53,008,659,817
2158	53,008,659,817	2,613,326,929	(798,207,297)	-	54,823,779,449
2159	54,823,779,449	2,702,812,327	(1,330,347,193)	-	56,196,244,583
2160	56,196,244,583	2,770,474,858	(1,383,621,977)	-	57,583,097,464
2161	57,583,097,464	2,838,846,705	(1,433,865,839)	-	58,988,078,330
2162	58,988,078,330	2,908,112,262	(931,696,719)	-	60,964,493,873
2163	60,964,493,873	3,005,549,548	(2,699,816,930)	-	61,270,226,492
2164	61,270,226,492	3,020,622,166	(2,205,644,530)	-	62,085,204,127
2165	62,085,204,127	3,060,800,563	(1,666,122,640)	-	63,479,882,051
2166	63,479,882,051	3,129,558,185	(1,087,717,046)	-	65,521,723,190
2167	65,521,723,190	3,230,220,953	(1,130,677,188)	-	67,621,266,955
2168	67,621,266,955	3,333,728,461	(2,558,235,066)	-	68,396,760,350
2169	68,396,760,350	3,371,960,285	(2,294,068,968)	-	69,474,651,667
2170	69,474,651,667	3,425,100,327	(1,270,092,970)	-	71,629,659,024
2171	71,629,659,024	3,531,342,190	(1,320,313,851)	-	73,840,687,364
2172	73,840,687,364	3,640,345,887	(3,366,268,444)	-	74,114,764,806
2173	74,114,764,806	3,653,857,905	(1,426,836,620)	-	76,341,786,092
2174	76,341,786,092	3,763,650,054	(1,483,301,738)	-	78,622,134,408
2175	78,622,134,408	3,876,071,226	(3,758,030,772)	-	78,740,174,862
2176	78,740,174,862	3,881,890,621	(1,607,681,975)	-	81,014,383,508
2177	81,014,383,508	3,994,009,107	(1,666,562,675)	-	83,341,829,939
2178	83,341,829,939	4,108,752,216	(4,201,209,565)	-	83,249,372,590
2179	83,249,372,590	4,104,194,069	(1,801,238,027)	-	85,552,328,632
2180	85,552,328,632	4,217,729,802	(1,878,004,344)	-	87,892,054,089
2181	87,892,054,089	4,333,078,267	(1,946,871,104)	-	90,278,261,251
2182	90,278,261,251	4,450,718,280	(4,876,026,404)	-	89,852,953,127
2183	89,852,953,127	4,429,750,589	(2,104,357,547)	-	92,178,346,169
2184	92,178,346,169	4,544,392,466	(2,194,112,250)	-	94,528,626,386
2185	94,528,626,386	4,660,261,281	(2,274,666,403)	-	96,914,221,264
2186	96,914,221,264	4,777,871,108	(2,364,953,555)	-	99,327,138,817
2187	99,327,138,817	4,896,827,944	(2,458,845,919)	-	101,765,120,842
2188	101,765,120,842	5,017,020,458	(2,563,797,647)	-	104,218,343,653
2189	104,218,343,653	5,137,964,342	(24,755,109,055)	-	84,601,198,940
2190	84,601,198,940	4,170,839,108	(2,763,630,291)	-	86,008,407,757
2191	86,008,407,757	4,240,214,502	(2,873,449,011)	-	87,375,173,249
2192	87,375,173,249	4,307,596,041	(2,996,183,428)	-	88,686,585,862
2193	88,686,585,862	4,372,248,683	(2,631,904,177)	-	90,426,930,368
2194	90,426,930,368	4,458,047,667	(2,845,754,626)	-	92,039,223,409

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2195	92,039,223,409	4,537,533,714	(6,096,767,211)	-	90,479,989,912
2196	90,479,989,912	4,460,663,503	(5,039,437,641)	-	89,901,215,775
2197	89,901,215,775	4,432,129,938	(5,103,100,217)	-	89,230,245,495
2198	89,230,245,495	4,399,051,103	(3,449,635,792)	-	90,179,660,806
2199	90,179,660,806	4,445,857,278	(3,388,068,666)	-	91,237,449,418
2200	91,237,449,418	4,498,006,256	(6,748,341,960)	-	88,987,113,715
2201	88,987,113,715	4,387,064,706	(7,149,946,397)	-	86,224,232,024
2202	86,224,232,024	4,250,854,639	(7,425,233,915)	-	83,049,852,747
2203	83,049,852,747	4,094,357,740	(3,957,291,254)	-	83,186,919,233
2204	83,186,919,233	4,101,115,118	(4,204,280,747)	-	83,083,753,604
2205	83,083,753,604	4,096,029,053	(8,317,266,720)	-	78,862,515,937
2206	78,862,515,937	3,887,922,036	(7,184,173,885)	-	75,566,264,088
2207	75,566,264,088	3,725,416,820	(7,551,432,749)	-	71,740,248,158
2208	71,740,248,158	3,536,794,234	(4,910,775,132)	-	70,366,267,261
2209	70,366,267,261	3,469,056,976	(8,054,173,294)	-	65,781,150,943
2210	65,781,150,943	3,243,010,741	(8,451,137,477)	-	60,573,024,208
2211	60,573,024,208	2,986,250,093	(8,764,317,521)	-	54,794,956,780
2212	54,794,956,780	2,701,391,369	(5,704,973,713)	-	51,791,374,436
2213	51,791,374,436	2,553,314,760	(16,547,281,313)	-	37,797,407,883
2214	37,797,407,883	1,863,412,209	(13,505,095,115)	-	26,155,724,977
2215	26,155,724,977	1,289,477,241	(10,210,410,842)	-	17,234,791,376
2216	17,234,791,376	849,675,215	(8,964,291,613)	-	9,120,174,978
2217	9,120,174,978	449,624,626	(6,950,572,292)	-	2,619,227,312
2218	2,619,227,312	129,127,906	(2,748,355,219)	-	0

Xcel Energy
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2019 ACCRUAL COMPARISON

	Present	Proposed	Difference
Monticello	$13,392,226	$10,433,064	($2,959,162)
Prairie Island Unit 1	49,264	11,200,807	11,151,543
Prairie Island Unit 2	589,341	3,262,942	2,673,601
TOTAL	$14,030,831	$24,896,813	$10,865,982

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2019 MN RETAIL SUMMARY

	Remaining Life (yrs)	Operational Earnings Rate	Post-Shutdown Earnings Rate	Market Value Balance 6/30/2017	Book Value 6/30/2017	Unrealized Gain/Loss 6/30/2017	Tax-Effect Adjustment	Tax-Adjusted Fund Balance 6/30/2017	2019-2021 Decommissioning Accrual
Monticello	13.75	5.10%	4.83%	$660,140,345	$529,148,381	$130,991,964	$36,468,163	$623,672,182	**10,433,064**
Prairie Island Unit 1	16.67	5.13%	4.82%	399,941,696	308,078,761	91,862,935	25,574,641	374,367,055	**11,200,807**
Prairie Island Unit 2	17.83	5.14%	4.83%	448,597,551	346,627,064	101,970,487	28,388,583	420,208,967	**3,262,942**
TOTAL DECOMMISSIONING ACCRUAL				**$1,508,679,592**	**$1,183,854,206**	**$324,825,386**	**$90,431,387**	**$1,418,248,204**	**$24,896,813**

INPUT DATA

Escalation Rate (Labor)	4.05%
Escalation Rate (Non-Labor)	2.85%
Escalation Rate (PIIC)	0.00%
Jurisdictional Factor	73.4886%
Tax Rate for tax-effect adjustment	27.84%

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AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
Monticello															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2030	$17,759,328	$13,051,073	1.6755	$21,867,073	$8,763,593	$6,440,238	1.4410	$9,280,383	$0	$0	1.0000	$0	$26,522,921	$19,491,311	$31,147,456
2031	63,231,064	46,467,594	1.7434	81,011,604	46,823,276	34,409,748	1.4820	50,995,247	0	0	1.0000	0	110,054,340	80,877,343	132,006,851
2032	30,098,747	22,119,134	1.8140	40,124,109	21,963,833	16,140,903	1.5243	24,603,579	0	0	1.0000	0	52,062,580	38,260,037	64,727,688
2033	30,011,960	22,055,355	1.8874	41,627,277	35,867,567	26,358,556	1.5677	41,322,308	0	0	1.0000	0	65,879,526	48,413,911	82,949,586
2034	24,261,956	17,829,760	1.9639	35,015,866	18,617,567	13,681,781	1.6124	22,060,503	0	0	1.0000	0	42,879,522	31,511,541	57,076,369
2035	43,935,865	32,287,832	2.0434	65,976,955	88,132,650	64,767,410	1.6584	107,410,272	0	0	1.0000	0	132,068,514	97,055,241	173,387,228
2036	8,481,485	6,232,921	2.1262	13,252,436	4,523,995	3,324,618	1.7056	5,670,469	0	0	1.0000	0	13,005,479	9,557,539	18,922,905
2037	8,458,357	6,215,924	2.2123	13,751,489	4,511,770	3,315,635	1.7542	5,816,286	0	0	1.0000	0	12,970,127	9,531,559	19,567,775
2038	8,458,357	6,215,924	2.3019	14,308,436	4,511,770	3,315,635	1.8042	5,982,068	0	0	1.0000	0	12,970,127	9,531,559	20,290,504
2039	8,458,357	6,215,924	2.3951	14,887,760	4,511,770	3,315,635	1.8556	6,152,491	0	0	1.0000	0	12,970,127	9,531,559	21,040,251
2040	8,481,485	6,232,921	2.4921	15,533,061	4,523,995	3,324,618	1.9085	6,345,034	0	0	1.0000	0	13,005,479	9,557,539	21,878,095
2041	8,458,357	6,215,924	2.5930	16,117,891	4,511,770	3,315,635	1.9629	6,508,259	0	0	1.0000	0	12,970,127	9,531,559	22,626,150
2042	8,458,357	6,215,924	2.6981	16,771,185	4,511,770	3,315,635	2.0189	6,693,935	0	0	1.0000	0	12,970,127	9,531,559	23,465,119
2043	8,458,357	6,215,924	2.8073	17,449,964	4,511,770	3,315,635	2.0764	6,884,584	0	0	1.0000	0	12,970,127	9,531,559	24,334,547
2044	8,481,485	6,232,921	2.9210	18,206,361	4,523,995	3,324,618	2.1356	7,100,055	0	0	1.0000	0	13,005,479	9,557,539	25,306,416
2045	8,458,357	6,215,924	3.0393	18,892,058	4,511,770	3,315,635	2.1964	7,282,460	0	0	1.0000	0	12,970,127	9,531,559	26,174,518
2046	8,458,357	6,215,924	3.1624	19,657,238	4,511,770	3,315,635	2.2590	7,490,018	0	0	1.0000	0	12,970,127	9,531,559	27,147,257
2047	8,458,357	6,215,924	3.2905	20,453,498	4,511,770	3,315,635	2.3234	7,703,545	0	0	1.0000	0	12,970,127	9,531,559	28,157,044
2048	9,145,130	6,720,624	3.4238	23,010,071	6,514,932	4,787,729	2.3896	11,440,757	0	0	1.0000	0	15,660,061	11,508,353	34,450,829
2049	8,458,357	6,215,924	3.5624	22,143,608	4,511,767	3,315,632	2.4577	8,148,830	0	0	1.0000	0	12,970,124	9,531,556	30,292,438
2050	9,951,558	7,313,256	3.7067	27,108,046	8,991,374	6,607,631	2.5278	16,702,769	0	0	1.0000	0	18,942,932	13,920,887	43,810,815
2051	9,951,558	7,313,256	3.8568	28,205,765	8,991,374	6,607,631	2.5998	17,178,518	0	0	1.0000	0	18,942,932	13,920,887	45,384,284
2052	10,837,186	7,964,091	4.0130	31,959,898	11,591,099	8,518,131	2.6739	22,776,630	0	0	1.0000	0	22,428,284	16,482,222	54,736,528
2053	11,460,933	8,422,474	4.1756	35,168,881	13,519,499	9,935,284	2.7501	27,323,025	0	0	1.0000	0	24,980,432	18,357,758	62,491,907
2054	10,167,183	7,471,716	4.3447	32,462,363	9,638,249	7,083,010	2.8285	20,034,293	0	0	1.0000	0	19,805,432	14,554,725	52,496,656
2055	11,245,308	8,264,014	4.5206	37,358,302	12,872,624	9,459,905	2.9091	27,519,810	0	0	1.0000	0	24,117,932	17,723,919	64,878,112
2056	11,699,686	8,597,930	4.7037	40,442,083	14,178,599	10,419,647	2.9920	31,175,584	0	0	1.0000	0	25,878,284	19,017,577	71,617,667
2057	8,441,765	6,203,731	4.8942	30,362,300	4,461,997	3,279,057	3.0773	10,090,642	0	0	1.0000	0	12,903,762	9,482,788	40,452,942
2058	8,441,765	6,203,731	5.0924	31,591,879	4,461,997	3,279,057	3.1650	10,378,216	0	0	1.0000	0	12,903,762	9,482,788	41,970,095
2059	8,441,765	6,203,731	5.2987	32,871,709	4,461,997	3,279,057	3.2552	10,673,987	0	0	1.0000	0	12,903,762	9,482,788	43,545,695
2060	8,464,894	6,220,728	5.5133	34,296,740	4,474,222	3,288,041	3.3480	11,008,361	0	0	1.0000	0	12,939,115	9,508,769	45,305,101
2061	8,441,765	6,203,731	5.7366	35,588,322	4,461,997	3,279,057	3.4434	11,291,105	0	0	1.0000	0	12,903,762	9,482,788	46,879,428
2062	8,441,765	6,203,731	5.9689	37,029,449	4,461,997	3,279,057	3.5415	11,612,781	0	0	1.0000	0	12,903,762	9,482,788	48,642,230
2063	8,441,765	6,203,731	6.2106	38,528,891	4,461,997	3,279,057	3.6425	11,943,965	0	0	1.0000	0	12,903,762	9,482,788	50,472,856
2064	8,464,894	6,220,728	6.4622	40,199,589	4,474,222	3,288,041	3.7463	12,317,987	0	0	1.0000	0	12,939,115	9,508,769	52,517,576
2065	8,441,765	6,203,731	6.7239	41,713,266	4,461,997	3,279,057	3.8531	12,634,535	0	0	1.0000	0	12,903,762	9,482,788	54,347,801
2066	8,441,765	6,203,731	6.9962	43,402,542	4,461,997	3,279,057	3.9629	12,994,575	0	0	1.0000	0	12,903,762	9,482,788	56,397,117
2067	8,441,765	6,203,731	7.2795	45,160,059	4,461,997	3,279,057	4.0758	13,364,781	0	0	1.0000	0	12,903,762	9,482,788	58,524,840
2068	8,464,894	6,220,728	7.5744	47,118,282	4,474,222	3,288,041	4.1920	13,783,467	0	0	1.0000	0	12,939,115	9,508,769	60,901,750
2069	8,441,765	6,203,731	7.8811	48,892,223	4,461,997	3,279,057	4.3115	14,137,655	0	0	1.0000	0	12,903,762	9,482,788	63,029,878
2070	8,441,765	6,203,731	8.2003	50,872,454	4,461,997	3,279,057	4.4343	14,540,323	0	0	1.0000	0	12,903,762	9,482,788	65,412,777
2071	8,441,765	6,203,731	8.5324	52,932,713	4,461,997	3,279,057	4.5607	14,954,796	0	0	1.0000	0	12,903,762	9,482,788	67,887,509
2072	8,464,894	6,220,728	8.8780	55,227,624	4,474,222	3,288,041	4.6907	15,423,213	0	0	1.0000	0	12,939,115	9,508,769	70,650,837
2073	8,441,765	6,203,731	9.2375	57,306,964	4,461,997	3,279,057	4.8244	15,819,483	0	0	1.0000	0	12,903,762	9,482,788	73,126,447
2074	8,441,765	6,203,731	9.6117	59,628,400	4,461,997	3,279,057	4.9619	16,270,353	0	0	1.0000	0	12,903,762	9,482,788	75,898,753
2075	8,441,765	6,203,731	10.0009	62,042,892	4,461,997	3,279,057	5.1033	16,734,012	0	0	1.0000	0	12,903,762	9,482,788	78,776,904
2076	8,464,894	6,220,728	10.4060	64,732,896	4,474,222	3,288,041	5.2487	17,257,940	0	0	1.0000	0	12,939,115	9,508,769	81,990,836
2077	8,441,765	6,203,731	10.8274	67,170,276	4,461,997	3,279,057	5.3983	17,701,334	0	0	1.0000	0	12,903,762	9,482,788	84,871,609
2078	8,920,197	6,555,324	11.2659	73,851,620	5,897,293	4,333,835	5.5522	24,062,321	0	0	1.0000	0	14,817,490	10,889,159	97,913,941
2079	9,015,884	6,625,643	11.7222	77,667,108	6,184,352	4,544,791	5.7104	25,952,574	0	0	1.0000	0	15,200,236	11,170,433	103,619,682
2080	8,943,325	6,572,320	12.1970	80,162,588	5,909,518	4,342,819	5.8731	25,505,811	0	0	1.0000	0	14,852,842	10,915,139	105,668,399
2081	8,920,197	6,555,324	12.6909	83,192,957	5,897,293	4,333,835	6.0405	26,178,533	0	0	1.0000	0	14,817,490	10,889,159	109,371,489
2082	8,920,197	6,555,324	13.2049	86,562,393	5,897,293	4,333,835	6.2127	26,924,819	0	0	1.0000	0	14,817,490	10,889,159	113,487,212
2083	9,015,884	6,625,643	13.7397	91,034,342	6,184,352	4,544,791	6.3897	29,039,850	0	0	1.0000	0	15,200,236	11,170,433	120,074,192
2084	8,943,325	6,572,320	14.2962	93,959,202	5,909,518	4,342,819	6.5719	28,540,573	0	0	1.0000	0	14,852,842	10,915,139	122,499,775

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AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
2085	46,126,149	33,897,440	14.8752	504,231,201	12,314,062	9,049,426	6.7592	61,166,882	0	0	1.0000	0	58,440,212	42,946,866	565,398,083
2086	53,631,139	39,412,748	15.4776	610,014,753	46,945,385	34,499,485	6.9518	239,833,517	0	0	1.0000	0	100,576,524	73,912,233	849,848,270
2087	57,419,114	42,196,476	16.1045	679,553,153	80,273,242	58,991,645	7.1499	421,784,362	0	0	1.0000	0	137,692,356	101,188,121	1,101,337,516
2088	52,652,752	38,693,746	16.7567	648,379,491	33,214,319	24,408,722	7.3537	179,494,423	0	0	1.0000	0	85,867,070	63,102,468	827,873,914
2089	50,913,638	37,415,697	17.4353	652,353,896	30,841,715	22,665,130	7.5633	171,423,181	0	0	1.0000	0	81,755,354	60,080,827	823,777,077
2090	32,667,889	24,007,160	18.1415	435,525,885	23,001,023	16,903,119	7.7788	131,485,985	0	0	1.0000	0	55,668,913	40,910,279	567,011,870
2091	21,071,356	15,485,035	18.8762	292,298,617	16,131,940	11,855,130	8.0005	94,846,965	0	0	1.0000	0	37,203,297	27,340,165	387,145,582
2092	8,832,651	6,490,987	19.6407	127,487,533	6,762,156	4,969,411	8.2285	40,890,795	0	0	1.0000	0	15,594,807	11,460,398	168,378,328
	$967,171,883	$710,760,631		$6,275,707,486	$750,282,438	$551,371,714		$2,329,665,815	$0	$0		$0	$1,717,454,322	$1,262,132,345	$8,605,373,301

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	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
Prairie Island Unit 1															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2033	$18,446,908	$13,556,366	1.8874	$25,586,285	$4,190,856	$3,079,799	1.5677	$4,828,201	$1,250,000	$918,607	1.0000	$918,607	$23,887,764	$17,554,772	$31,333,093
2034	46,142,627	33,909,549	1.9639	66,594,964	29,162,161	21,430,850	1.6124	34,555,103	1,250,000	918,607	1.0000	918,607	76,554,787	56,259,006	102,068,673
2035	16,398,923	12,051,331	2.0434	24,625,691	15,491,742	11,384,657	1.6584	18,880,315	1,250,000	918,607	1.0000	918,607	33,140,665	24,354,595	44,424,613
2036	12,659,656	9,303,398	2.1262	19,780,886	13,774,811	10,122,909	1.7056	17,265,634	1,250,000	918,607	1.0000	918,607	27,684,467	20,344,915	37,965,127
2037	12,625,333	9,278,174	2.2123	20,526,105	13,734,545	10,093,318	1.7542	17,705,699	1,250,000	918,607	1.0000	918,607	27,609,877	20,290,100	39,150,411
2038	15,404,499	11,320,543	2.3019	26,058,758	22,072,045	16,220,427	1.8042	29,264,894	1,250,000	918,607	1.0000	918,607	38,726,543	28,459,577	56,242,259
2039	32,688,492	24,022,300	2.3951	57,535,811	76,524,027	56,236,401	1.8556	104,352,265	1,250,000	918,607	1.0000	918,607	110,462,519	81,177,308	162,806,683
2040	4,604,176	3,383,542	2.4921	8,432,126	4,477,123	3,290,173	1.9085	6,279,295	1,250,000	918,607	1.0000	918,607	10,331,299	7,592,322	15,630,028
2041	4,591,596	3,374,297	2.5930	8,749,553	4,461,475	3,278,674	1.9629	6,435,709	1,250,000	918,607	1.0000	918,607	10,303,071	7,571,578	16,103,868
2042	4,591,596	3,374,297	2.6981	9,104,191	4,461,475	3,278,674	2.0189	6,619,314	1,250,000	918,607	1.0000	918,607	10,303,071	7,571,578	16,642,112
2043	4,591,596	3,374,297	2.8073	9,472,665	4,461,475	3,278,674	2.0764	6,807,838	1,250,000	918,607	1.0000	918,607	10,303,071	7,571,578	17,199,109
2044	4,604,176	3,383,542	2.9210	9,883,328	4,477,123	3,290,173	2.1356	7,026,494	1,250,000	918,607	1.0000	918,607	10,331,299	7,592,322	17,828,428
2045	4,591,596	3,374,297	3.0393	10,255,502	4,461,475	3,278,674	2.1964	7,201,279	1,250,000	918,607	1.0000	918,607	10,303,071	7,571,578	18,375,387
2046	4,591,596	3,374,297	3.1624	10,670,878	4,461,475	3,278,674	2.2590	7,406,524	1,250,000	918,607	1.0000	918,607	10,303,071	7,571,578	18,996,008
2047	4,591,596	3,374,297	3.2905	11,103,125	4,461,475	3,278,674	2.3234	7,617,670	1,250,000	918,607	1.0000	918,607	10,303,071	7,571,578	19,639,402
2048	4,604,176	3,383,542	3.4238	11,584,573	4,477,123	3,290,173	2.3896	7,862,198	1,250,000	918,607	1.0000	918,607	10,331,299	7,592,322	20,365,377
2049	4,591,596	3,374,297	3.5624	12,020,596	4,461,475	3,278,674	2.4577	8,057,996	1,250,000	918,607	1.0000	918,607	10,303,071	7,571,578	20,997,200
2050	4,591,596	3,374,297	3.7067	12,507,507	4,461,475	3,278,674	2.5278	8,287,831	1,250,000	918,607	1.0000	918,607	10,303,071	7,571,578	21,713,946
2051	4,591,596	3,374,297	3.8568	13,013,990	4,461,475	3,278,674	2.5998	8,523,896	1,250,000	918,607	1.0000	918,607	10,303,071	7,571,578	22,456,492
2052	4,604,176	3,383,542	4.0130	13,578,156	4,477,123	3,290,173	2.6739	8,797,594	1,250,000	918,607	1.0000	918,607	10,331,299	7,592,322	23,294,357
2053	4,687,283	3,444,616	4.1756	14,383,339	4,748,534	3,489,629	2.7501	9,596,829	1,250,000	918,607	1.0000	918,607	10,685,817	7,852,852	24,898,776
2054	4,782,969	3,514,934	4.3447	15,271,336	5,035,593	3,700,585	2.8285	10,467,104	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	26,657,046
2055	4,782,969	3,514,934	4.5206	15,889,613	5,035,593	3,700,585	2.9091	10,765,371	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	27,573,591
2056	4,843,392	3,559,339	4.7037	16,742,062	5,194,771	3,817,562	2.9920	11,422,146	1,250,000	918,607	1.0000	918,607	11,288,163	8,295,508	29,082,815
2057	4,735,126	3,479,775	4.8942	17,030,716	4,892,064	3,595,107	3.0773	11,063,224	1,250,000	918,607	1.0000	918,607	10,877,190	7,993,490	29,012,547
2058	4,878,656	3,585,253	5.0924	18,257,545	5,322,652	3,911,540	3.1650	12,380,025	1,250,000	918,607	1.0000	918,607	11,451,308	8,415,401	31,556,176
2059	4,735,126	3,479,775	5.2987	18,438,286	4,892,064	3,595,107	3.2552	11,702,793	1,250,000	918,607	1.0000	918,607	10,877,190	7,993,490	31,059,686
2060	4,699,862	3,453,861	5.5133	19,042,170	4,764,182	3,501,129	3.3480	11,721,778	1,250,000	918,607	1.0000	918,607	10,714,044	7,873,596	31,682,556
2061	4,782,969	3,514,934	5.7366	20,163,773	5,035,593	3,700,585	3.4434	12,742,593	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	33,824,973
2062	4,782,969	3,514,934	5.9689	20,980,292	5,035,593	3,700,585	3.5415	13,105,621	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	35,004,520
2063	4,735,126	3,479,775	6.2106	21,611,493	4,892,064	3,595,107	3.6425	13,095,178	1,250,000	918,607	1.0000	918,607	10,877,190	7,993,490	35,625,278
2064	4,795,548	3,524,179	6.4622	22,773,949	5,051,241	3,712,084	3.7463	13,906,581	1,250,000	918,607	1.0000	918,607	11,096,789	8,154,870	37,599,137
2065	4,782,969	3,514,934	6.7239	23,634,068	5,035,593	3,700,585	3.8531	14,258,723	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	38,811,398
2066	4,735,126	3,479,775	6.9962	24,345,204	4,892,064	3,595,107	3.9629	14,247,051	1,250,000	918,607	1.0000	918,607	10,877,190	7,993,490	39,510,862
2067	4,782,969	3,514,934	7.2795	25,586,965	5,035,593	3,700,585	4.0758	15,082,843	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	41,588,415
2068	4,795,548	3,524,179	7.5744	26,693,541	5,051,241	3,712,084	4.1920	15,561,056	1,250,000	918,607	1.0000	918,607	11,096,789	8,154,870	43,173,205
2069	4,735,126	3,479,775	7.8811	27,424,457	4,892,064	3,595,107	4.3115	15,500,305	1,250,000	918,607	1.0000	918,607	10,877,190	7,993,490	43,843,369
2070	4,782,969	3,514,934	8.2003	28,823,517	5,035,593	3,700,585	4.4343	16,409,503	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	46,151,627
2071	4,782,969	3,514,934	8.5324	29,990,827	5,035,593	3,700,585	4.5607	16,877,257	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	47,786,690
2072	4,795,548	3,524,179	8.8780	31,287,661	5,051,241	3,712,084	4.6907	17,412,273	1,250,000	918,607	1.0000	918,607	11,096,789	8,154,870	49,618,541
2073	4,782,969	3,514,934	9.2375	32,469,207	5,035,593	3,700,585	4.8244	17,853,101	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	51,240,915
2074	4,782,969	3,514,934	9.6117	33,784,496	5,035,593	3,700,585	4.9619	18,361,931	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	53,065,034
2075	5,114,792	3,758,786	10.0009	37,591,247	6,031,061	4,432,140	5.1033	22,618,539	1,250,000	918,607	1.0000	918,607	12,395,853	9,109,533	61,128,392
2076	4,795,548	3,524,179	10.4060	36,672,606	5,051,241	3,712,084	5.2487	19,483,616	1,250,000	918,607	1.0000	918,607	11,096,789	8,154,870	57,074,829
2077	4,782,969	3,514,934	10.8274	38,057,601	5,035,593	3,700,585	5.3983	19,976,866	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	58,953,075
2078	3,942,348	2,897,174	11.2659	32,639,275	3,256,582	2,393,215	5.5522	13,287,607	0	0	1.0000	0	7,198,929	5,290,389	45,926,882
2079	3,942,348	2,897,174	11.7222	33,961,256	3,256,582	2,393,215	5.7104	13,666,214	0	0	1.0000	0	7,198,929	5,290,389	47,627,470
2080	3,953,149	2,905,112	12.1970	35,433,647	3,265,504	2,399,772	5.8731	14,094,099	0	0	1.0000	0	7,218,652	5,304,883	49,527,746
2081	3,942,348	2,897,174	12.6909	36,767,748	3,256,582	2,393,215	6.0405	14,456,214	0	0	1.0000	0	7,198,929	5,290,389	51,223,963
2082	3,942,348	2,897,174	13.2049	38,256,896	3,256,582	2,393,215	6.2127	14,868,326	0	0	1.0000	0	7,198,929	5,290,389	53,125,222
2083	3,942,348	2,897,174	13.7397	39,806,305	3,256,582	2,393,215	6.3897	15,291,925	0	0	1.0000	0	7,198,929	5,290,389	55,098,229
2084	3,953,149	2,905,112	14.2962	41,532,058	3,265,504	2,399,772	6.5719	15,771,059	0	0	1.0000	0	7,218,652	5,304,883	57,303,117
2085	3,942,348	2,897,174	14.8752	43,096,046	3,256,582	2,393,215	6.7592	16,176,218	0	0	1.0000	0	7,198,929	5,290,389	59,272,264
2086	3,942,348	2,897,174	15.4776	44,841,304	3,256,582	2,393,215	6.9518	16,637,151	0	0	1.0000	0	7,198,929	5,290,389	61,478,455
2087	11,802,691	8,673,627	16.1045	139,684,421	4,951,569	3,638,837	7.1499	26,017,319	0	0	1.0000	0	16,754,260	12,312,463	165,701,740

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AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
2088	45,111,220	33,151,584	16.7567	555,511,141	11,805,071	8,675,376	7.3537	63,796,110	0	0	1.0000	0	56,916,291	41,826,959	619,307,251
2089	51,818,304	38,080,522	17.4353	663,945,327	62,277,980	45,767,187	7.5633	346,150,962	0	0	1.0000	0	114,096,283	83,847,709	1,010,096,289
2090	44,187,860	32,473,019	18.1415	589,109,275	56,754,748	41,708,244	7.7788	324,440,085	0	0	1.0000	0	100,942,608	74,181,263	913,549,360
2091	35,668,367	26,212,167	18.8762	494,786,111	31,834,151	23,394,458	8.0005	187,167,358	0	0	1.0000	0	67,502,519	49,606,625	681,953,469
2092	13,715,750	10,079,506	19.6407	197,968,561	10,259,487	7,539,548	8.2285	62,039,173	0	0	1.0000	0	23,975,237	17,619,055	260,007,735
2093	18,089,191	13,293,485	20.4361	271,666,992	6,228,187	4,577,005	8.4630	38,735,191	0	0	1.0000	0	24,317,379	17,870,490	310,402,183
2094	12,584,719	9,248,328	21.2638	196,654,598	9,264,588	6,808,412	8.7042	59,261,777	0	0	1.0000	0	21,849,307	16,056,740	255,916,375
2095	9,102,372	6,689,202	22.1250	147,998,586	6,700,962	4,924,440	8.9523	44,085,066	0	0	1.0000	0	15,803,334	11,613,642	192,083,653
	$611,385,166	$449,298,117		$4,601,690,206	$588,533,792	$432,504,973		$1,975,329,908	$56,250,000	$41,337,312		$41,337,312	$1,256,168,958	$923,140,402	$6,618,357,426

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Nuclear Decommissioning Accrual
60-Year Decommissioning Period
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Proposed

AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
Prairie Island Unit 2															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2034	$7,248,794	$5,327,034	1.9639	$10,461,762	$2,826,485	$2,077,143	1.6124	$3,349,185	$1,250,000	$918,607	1.0000	$918,607	$11,325,279	$8,322,784	$14,729,554
2035	44,817,806	32,935,958	2.0434	67,301,336	32,275,248	23,718,613	1.6584	39,334,948	1,250,000	918,607	1.0000	918,607	78,343,054	57,573,177	107,554,890
2036	23,021,476	16,918,150	2.1262	35,971,370	19,944,127	14,656,651	1.7056	24,998,384	1,250,000	918,607	1.0000	918,607	44,215,603	32,493,407	61,888,360
2037	10,761,111	7,908,185	2.2123	17,495,278	12,388,936	9,104,450	1.7542	15,971,026	1,250,000	918,607	1.0000	918,607	24,400,047	17,931,242	34,384,910
2038	13,540,277	9,950,554	2.3019	22,905,180	20,726,436	15,231,558	1.8042	27,480,777	1,250,000	918,607	1.0000	918,607	35,516,713	26,100,719	51,304,564
2039	31,160,880	22,899,680	2.3951	54,847,024	75,415,818	55,421,994	1.8556	102,841,052	1,250,000	918,607	1.0000	918,607	107,826,698	79,240,281	158,606,683
2040	4,659,832	3,424,443	2.4921	8,534,055	4,485,457	3,296,297	1.9085	6,290,984	1,250,000	918,607	1.0000	918,607	10,395,289	7,639,347	15,743,645
2041	4,647,099	3,415,086	2.5930	8,855,319	4,469,786	3,284,781	1.9629	6,447,697	1,250,000	918,607	1.0000	918,607	10,366,886	7,618,474	16,221,623
2042	4,647,099	3,415,086	2.6981	9,214,244	4,469,786	3,284,781	2.0189	6,631,645	1,250,000	918,607	1.0000	918,607	10,366,886	7,618,474	16,764,496
2043	4,647,099	3,415,086	2.8073	9,587,172	4,469,786	3,284,781	2.0764	6,820,520	1,250,000	918,607	1.0000	918,607	10,366,886	7,618,474	17,326,298
2044	4,659,832	3,424,443	2.9210	10,002,799	4,485,457	3,296,297	2.1356	7,039,573	1,250,000	918,607	1.0000	918,607	10,395,289	7,639,347	17,960,978
2045	4,647,099	3,415,086	3.0393	10,379,472	4,469,786	3,284,781	2.1964	7,214,693	1,250,000	918,607	1.0000	918,607	10,366,886	7,618,474	18,512,772
2046	4,647,099	3,415,086	3.1624	10,799,869	4,469,786	3,284,781	2.2590	7,420,321	1,250,000	918,607	1.0000	918,607	10,366,886	7,618,474	19,138,796
2047	4,647,099	3,415,086	3.2905	11,237,341	4,469,786	3,284,781	2.3234	7,631,861	1,250,000	918,607	1.0000	918,607	10,366,886	7,618,474	19,787,809
2048	4,659,832	3,424,443	3.4238	11,724,609	4,485,457	3,296,297	2.3896	7,876,832	1,250,000	918,607	1.0000	918,607	10,395,289	7,639,347	20,520,048
2049	4,647,099	3,415,086	3.5624	12,165,903	4,469,786	3,284,781	2.4577	8,073,007	1,250,000	918,607	1.0000	918,607	10,366,886	7,618,474	21,157,517
2050	4,647,099	3,415,086	3.7067	12,658,700	4,469,786	3,284,781	2.5278	8,303,270	1,250,000	918,607	1.0000	918,607	10,366,886	7,618,474	21,880,577
2051	4,647,099	3,415,086	3.8568	13,171,304	4,469,786	3,284,781	2.5998	8,539,774	1,250,000	918,607	1.0000	918,607	10,366,886	7,618,474	22,629,686
2052	4,659,832	3,424,443	4.0130	13,742,291	4,485,457	3,296,297	2.6739	8,813,970	1,250,000	918,607	1.0000	918,607	10,395,289	7,639,347	23,474,867
2053	4,742,786	3,485,405	4.1756	14,553,658	4,756,846	3,495,737	2.7501	9,613,628	1,250,000	918,607	1.0000	918,607	10,749,633	7,899,750	25,085,893
2054	4,838,472	3,555,723	4.3447	15,448,552	5,043,904	3,706,692	2.8285	10,484,379	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	26,851,538
2055	4,838,472	3,555,723	4.5206	16,074,003	5,043,904	3,706,692	2.9091	10,783,138	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	27,775,749
2056	4,899,048	3,600,240	4.7037	16,934,447	5,203,105	3,823,687	2.9920	11,440,470	1,250,000	918,607	1.0000	918,607	11,352,153	8,342,533	29,293,524
2057	4,790,629	3,520,564	4.8942	17,230,346	4,900,375	3,601,215	3.0773	11,082,018	1,250,000	918,607	1.0000	918,607	10,941,005	8,040,386	29,230,971
2058	4,934,159	3,626,042	5.0924	18,465,259	5,330,963	3,917,648	3.1650	12,399,355	1,250,000	918,607	1.0000	918,607	11,515,123	8,462,297	31,783,221
2059	4,790,629	3,520,564	5.2987	18,654,414	4,900,375	3,601,215	3.2552	11,722,675	1,250,000	918,607	1.0000	918,607	10,941,005	8,040,386	31,295,696
2060	4,755,518	3,494,761	5.5133	19,267,668	4,772,516	3,507,253	3.3480	11,742,283	1,250,000	918,607	1.0000	918,607	10,778,034	7,920,621	31,928,558
2061	4,838,472	3,555,723	5.7366	20,397,763	5,043,904	3,706,692	3.4434	12,763,624	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	34,079,994
2062	4,838,472	3,555,723	5.9689	21,223,758	5,043,904	3,706,692	3.5415	13,127,251	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	35,269,615
2063	4,790,629	3,520,564	6.2106	21,864,817	4,900,375	3,601,215	3.6425	13,117,425	1,250,000	918,607	1.0000	918,607	10,941,005	8,040,386	35,900,849
2064	4,851,204	3,565,080	6.4622	23,038,258	5,059,575	3,718,208	3.7463	13,929,524	1,250,000	918,607	1.0000	918,607	11,160,779	8,201,895	37,886,389
2065	4,838,472	3,555,723	6.7239	23,908,329	5,043,904	3,706,692	3.8531	14,282,256	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	39,109,192
2066	4,790,629	3,520,564	6.9962	24,630,572	4,900,375	3,601,215	3.9629	14,271,254	1,250,000	918,607	1.0000	918,607	10,941,005	8,040,386	39,820,433
2067	4,838,472	3,555,723	7.2795	25,883,889	5,043,904	3,706,692	4.0758	15,107,736	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	41,910,232
2068	4,851,204	3,565,080	7.5744	27,003,340	5,059,575	3,718,208	4.1920	15,586,730	1,250,000	918,607	1.0000	918,607	11,160,779	8,201,895	43,508,676
2069	4,790,629	3,520,564	7.8811	27,745,920	4,900,375	3,601,215	4.3115	15,526,638	1,250,000	918,607	1.0000	918,607	10,941,005	8,040,386	44,191,164
2070	4,838,472	3,555,723	8.2003	29,157,999	5,043,904	3,706,692	4.4343	16,436,585	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	46,513,191
2071	4,838,472	3,555,723	8.5324	30,338,855	5,043,904	3,706,692	4.5607	16,905,111	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	48,162,573
2072	4,851,204	3,565,080	8.8780	31,650,778	5,059,575	3,718,208	4.6907	17,441,000	1,250,000	918,607	1.0000	918,607	11,160,779	8,201,895	50,010,385
2073	4,838,472	3,555,723	9.2375	32,845,995	5,043,904	3,706,692	4.8244	17,882,566	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	51,647,168
2074	4,838,472	3,555,723	9.6117	34,176,547	5,043,904	3,706,692	4.9619	18,392,236	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	53,487,390
2075	5,170,295	3,799,575	10.0009	37,999,173	6,039,372	4,438,247	5.1033	22,649,707	1,250,000	918,607	1.0000	918,607	12,459,668	9,156,430	61,567,488
2076	4,851,204	3,565,080	10.4060	37,098,220	5,059,575	3,718,208	5.2487	19,515,760	1,250,000	918,607	1.0000	918,607	11,160,779	8,201,895	57,532,587
2077	4,838,472	3,555,723	10.8274	38,499,240	5,043,904	3,706,692	5.3983	20,009,837	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	59,427,684
2078	823,359	605,074	11.2659	6,816,708	3,272,479	2,404,897	5.5522	13,352,471	0	-	1.0000	-	4,095,838	3,009,972	20,169,179
2079	823,359	605,074	11.7222	7,092,804	3,272,479	2,404,897	5.7104	13,732,926	0	-	1.0000	-	4,095,838	3,009,972	20,825,729
2080	825,615	606,732	12.1970	7,400,312	3,281,444	2,411,486	5.8731	14,162,899	0	-	1.0000	-	4,107,059	3,018,218	21,563,211
2081	823,359	605,074	12.6909	7,678,939	3,272,479	2,404,897	6.0405	14,526,782	0	-	1.0000	-	4,095,838	3,009,972	22,205,721
2082	823,359	605,074	13.2049	7,989,947	3,272,479	2,404,897	6.2127	14,940,906	0	-	1.0000	-	4,095,838	3,009,972	22,930,853
2083	823,359	605,074	13.7397	8,313,541	3,272,479	2,404,897	6.3897	15,366,573	0	-	1.0000	-	4,095,838	3,009,972	23,680,114
2084	825,615	606,732	14.2962	8,673,964	3,281,444	2,411,486	6.5719	15,848,045	0	-	1.0000	-	4,107,059	3,018,218	24,522,010
2085	823,359	605,074	14.8752	9,000,603	3,272,479	2,404,897	6.7592	16,255,182	0	-	1.0000	-	4,095,838	3,009,972	25,255,785
2086	823,359	605,074	15.4776	9,365,100	3,272,479	2,404,897	6.9518	16,718,365	0	-	1.0000	-	4,095,838	3,009,972	26,083,465
2087	823,359	605,074	16.1045	9,744,421	3,272,479	2,404,897	7.1499	17,194,775	0	-	1.0000	-	4,095,838	3,009,972	26,939,197
2088	11,274,587	8,285,531	16.7567	138,838,152	5,987,760	4,400,318	7.3537	32,358,621	0	-	1.0000	-	17,262,347	12,685,849	171,196,773

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AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
2089	29,172,411	21,438,383	17.4353	373,784,641	10,590,974	7,783,154	7.5633	58,866,327	0	-	1.0000	-	39,763,385	29,221,537	432,650,967
2090	57,665,154	42,377,288	18.1415	768,787,572	90,528,180	66,527,851	7.7788	517,506,845	0	-	1.0000	-	148,193,335	108,905,139	1,286,294,416
2091	55,538,057	40,814,115	18.8762	770,415,403	42,217,329	31,024,904	8.0005	248,214,748	0	-	1.0000	-	97,755,386	71,839,020	1,018,630,150
2092	51,408,076	37,779,052	19.6407	742,007,025	32,588,487	23,948,808	8.2285	197,062,766	0	-	1.0000	-	83,996,563	61,727,860	939,069,791
2093	23,223,558	17,066,657	20.4361	348,775,903	8,238,061	6,054,032	8.4630	51,235,271	0	-	1.0000	-	31,461,619	23,120,689	400,011,174
2094	14,460,844	10,627,065	21.2638	225,971,787	14,186,680	10,425,586	8.7042	90,746,385	0	-	1.0000	-	28,647,524	21,052,651	316,718,172
2095	10,459,350	7,686,425	22.1250	170,062,157	10,261,051	7,540,698	8.9523	67,506,588	-	-	1.0000	-	20,720,401	15,227,123	237,568,746
	$573,536,674	$421,483,808		$4,595,865,805	$595,414,118	$437,561,225		$2,092,889,180	$55,000,000	$40,418,705		$40,418,705	$1,223,950,791	$899,463,737	$6,729,173,689
	$2,152,093,723	$1,581,542,556		$15,473,263,497	$1,934,230,348	$1,421,437,911		$6,397,884,902	$111,250,000	$81,756,016		$81,756,016	$4,197,574,071	$3,084,736,483	$21,952,904,416

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EXTERNAL FUND CALCULATION

Monticello

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	623,672,182	15,989,016	-	6,696,113	646,357,311
2018	646,357,311	33,305,725	-	13,392,226	693,055,262
2019	693,055,262	35,611,861	-	10,433,064	739,100,187
2020	739,100,187	37,960,153	-	10,433,064	787,493,404
2021	787,493,404	40,428,207	-	10,433,064	838,354,675
2022	838,354,675	43,022,132	-	10,433,064	891,809,871
2023	891,809,871	45,748,347	-	10,433,064	947,991,282
2024	947,991,282	48,613,598	-	10,433,064	1,007,037,944
2025	1,007,037,944	51,624,978	-	10,433,064	1,069,095,987
2026	1,069,095,987	54,789,938	-	10,433,064	1,134,318,989
2027	1,134,318,989	58,116,312	-	10,433,064	1,202,868,365
2028	1,202,868,365	61,612,330	-	10,433,064	1,274,913,759
2029	1,274,913,759	65,286,645	-	10,433,064	1,350,633,468
2030	1,350,633,468	65,424,565	(31,147,456)	7,824,798	1,392,735,375
2031	1,392,735,375	67,269,119	(132,006,851)	-	1,327,997,643
2032	1,327,997,643	64,142,286	(64,727,688)	-	1,327,412,241
2033	1,327,412,241	64,114,011	(82,949,586)	-	1,308,576,666
2034	1,308,576,666	63,204,253	(57,076,369)	-	1,314,704,550
2035	1,314,704,550	63,500,230	(173,387,228)	-	1,204,817,552
2036	1,204,817,552	58,192,688	(18,922,905)	-	1,244,087,335
2037	1,244,087,335	60,089,418	(19,567,775)	-	1,284,608,979
2038	1,284,608,979	62,046,614	(20,290,504)	-	1,326,365,089
2039	1,326,365,089	64,063,434	(21,040,251)	-	1,369,388,271
2040	1,369,388,271	66,141,454	(21,878,095)	-	1,413,651,630
2041	1,413,651,630	68,279,374	(22,626,150)	-	1,459,304,853
2042	1,459,304,853	70,484,424	(23,465,119)	-	1,506,324,158
2043	1,506,324,158	72,755,457	(24,334,547)	-	1,554,745,068
2044	1,554,745,068	75,094,187	(25,306,416)	-	1,604,532,839
2045	1,604,532,839	77,498,936	(26,174,518)	-	1,655,857,257
2046	1,655,857,257	79,977,906	(27,147,257)	-	1,708,687,906
2047	1,708,687,906	82,529,626	(28,157,044)	-	1,763,060,488
2048	1,763,060,488	85,155,822	(34,450,829)	-	1,813,765,481
2049	1,813,765,481	87,604,873	(30,292,438)	-	1,871,077,916
2050	1,871,077,916	90,373,063	(43,810,815)	-	1,917,640,165
2051	1,917,640,165	92,622,020	(45,384,284)	-	1,964,877,901
2052	1,964,877,901	94,903,603	(54,736,528)	-	2,005,044,976
2053	2,005,044,976	96,843,672	(62,491,907)	-	2,039,396,741
2054	2,039,396,741	98,502,863	(52,496,656)	-	2,085,402,948
2055	2,085,402,948	100,724,962	(64,878,112)	-	2,121,249,798
2056	2,121,249,798	102,456,365	(71,617,667)	-	2,152,088,496

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2057	2,152,088,496	103,945,874	(40,452,942)	-	2,215,581,428
2058	2,215,581,428	107,012,583	(41,970,095)	-	2,280,623,917
2059	2,280,623,917	110,154,135	(43,545,695)	-	2,347,232,356
2060	2,347,232,356	113,371,323	(45,305,101)	-	2,415,298,579
2061	2,415,298,579	116,658,921	(46,879,428)	-	2,485,078,072
2062	2,485,078,072	120,029,271	(48,642,230)	-	2,556,465,113
2063	2,556,465,113	123,477,265	(50,472,856)	-	2,629,469,522
2064	2,629,469,522	127,003,378	(52,517,576)	-	2,703,955,324
2065	2,703,955,324	130,601,042	(54,347,801)	-	2,780,208,565
2066	2,780,208,565	134,284,074	(56,397,117)	-	2,858,095,521
2067	2,858,095,521	138,046,014	(58,524,840)	-	2,937,616,695
2068	2,937,616,695	141,886,886	(60,901,750)	-	3,018,601,832
2069	3,018,601,832	145,798,468	(63,029,878)	-	3,101,370,423
2070	3,101,370,423	149,796,191	(65,412,777)	-	3,185,753,837
2071	3,185,753,837	153,871,910	(67,887,509)	-	3,271,738,238
2072	3,271,738,238	158,024,957	(70,650,837)	-	3,359,112,359
2073	3,359,112,359	162,245,127	(73,126,447)	-	3,448,231,039
2074	3,448,231,039	166,549,559	(75,898,753)	-	3,538,881,845
2075	3,538,881,845	170,927,993	(78,776,904)	-	3,631,032,934
2076	3,631,032,934	175,378,891	(81,990,836)	-	3,724,420,988
2077	3,724,420,988	179,889,534	(84,871,609)	-	3,819,438,913
2078	3,819,438,913	184,478,899	(97,913,941)	-	3,906,003,871
2079	3,906,003,871	188,659,987	(103,619,682)	-	3,991,044,176
2080	3,991,044,176	192,767,434	(105,668,399)	-	4,078,143,211
2081	4,078,143,211	196,974,317	(109,371,489)	-	4,165,746,039
2082	4,165,746,039	201,205,534	(113,487,212)	-	4,253,464,361
2083	4,253,464,361	205,442,329	(120,074,192)	-	4,338,832,498
2084	4,338,832,498	209,565,610	(122,499,775)	-	4,425,898,332
2085	4,425,898,332	213,770,889	(565,398,083)	-	4,074,271,139
2086	4,074,271,139	196,787,296	(849,848,270)	-	3,421,210,166
2087	3,421,210,166	165,244,451	(1,101,337,516)	-	2,485,117,101
2088	2,485,117,101	120,031,156	(827,873,914)	-	1,777,274,343
2089	1,777,274,343	85,842,351	(823,777,077)	-	1,039,339,617
2090	1,039,339,617	50,200,104	(567,011,870)	-	522,527,851
2091	522,527,851	25,238,095	(387,145,582)	-	160,620,364
2092	160,620,364	7,757,964	(168,378,328)	-	(0)

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EXTERNAL FUND CALCULATION

Prairie Island Unit 1

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	374,367,055	9,602,831	-	24,632	383,994,518
2018	383,994,518	19,700,182	-	49,264	403,743,965
2019	403,743,965	20,999,366	-	11,200,807	435,944,138
2020	435,944,138	22,651,235	-	11,200,807	469,796,181
2021	469,796,181	24,387,845	-	11,200,807	505,384,833
2022	505,384,833	26,213,543	-	11,200,807	542,799,183
2023	542,799,183	28,132,899	-	11,200,807	582,132,889
2024	582,132,889	30,150,718	-	11,200,807	623,484,415
2025	623,484,415	32,272,051	-	11,200,807	666,957,274
2026	666,957,274	34,502,209	-	11,200,807	712,660,290
2027	712,660,290	36,846,774	-	11,200,807	760,707,871
2028	760,707,871	39,311,614	-	11,200,807	811,220,293
2029	811,220,293	41,902,902	-	11,200,807	864,324,002
2030	864,324,002	44,627,122	-	11,200,807	920,151,932
2031	920,151,932	47,491,095	-	11,200,807	978,843,834
2032	978,843,834	50,501,989	-	11,200,807	1,040,546,631
2033	1,040,546,631	50,335,207	(31,333,093)	7,504,541	1,067,053,286
2034	1,067,053,286	51,431,968	(102,068,673)	-	1,016,416,581
2035	1,016,416,581	48,991,279	(44,424,613)	-	1,020,983,247
2036	1,020,983,247	49,211,393	(37,965,127)	-	1,032,229,513
2037	1,032,229,513	49,753,463	(39,150,411)	-	1,042,832,565
2038	1,042,832,565	50,264,530	(56,242,259)	-	1,036,854,835
2039	1,036,854,835	49,976,403	(162,806,683)	-	924,024,555
2040	924,024,555	44,537,984	(15,630,028)	-	952,932,510
2041	952,932,510	45,931,347	(16,103,868)	-	982,759,989
2042	982,759,989	47,369,031	(16,642,112)	-	1,013,486,908
2043	1,013,486,908	48,850,069	(17,199,109)	-	1,045,137,867
2044	1,045,137,867	50,375,645	(17,828,428)	-	1,077,685,085
2045	1,077,685,085	51,944,421	(18,375,387)	-	1,111,254,118
2046	1,111,254,118	53,562,449	(18,996,008)	-	1,145,820,559
2047	1,145,820,559	55,228,551	(19,639,402)	-	1,181,409,707
2048	1,181,409,707	56,943,948	(20,365,377)	-	1,217,988,278
2049	1,217,988,278	58,707,035	(20,997,200)	-	1,255,698,114
2050	1,255,698,114	60,524,649	(21,713,946)	-	1,294,508,817
2051	1,294,508,817	62,395,325	(22,456,492)	-	1,334,447,650
2052	1,334,447,650	64,320,377	(23,294,357)	-	1,375,473,670
2053	1,375,473,670	66,297,831	(24,898,776)	-	1,416,872,725
2054	1,416,872,725	68,293,265	(26,657,046)	-	1,458,508,944
2055	1,458,508,944	70,300,131	(27,573,591)	-	1,501,235,485
2056	1,501,235,485	72,359,550	(29,082,815)	-	1,544,512,220

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2057	1,544,512,220	74,445,489	(29,012,547)	-	1,589,945,162
2058	1,589,945,162	76,635,357	(31,556,176)	-	1,635,024,342
2059	1,635,024,342	78,808,173	(31,059,686)	-	1,682,772,830
2060	1,682,772,830	81,109,650	(31,682,556)	-	1,732,199,925
2061	1,732,199,925	83,492,036	(33,824,973)	-	1,781,866,988
2062	1,781,866,988	85,885,989	(35,004,520)	-	1,832,748,457
2063	1,832,748,457	88,338,476	(35,625,278)	-	1,885,461,654
2064	1,885,461,654	90,879,252	(37,599,137)	-	1,938,741,769
2065	1,938,741,769	93,447,353	(38,811,398)	-	1,993,377,725
2066	1,993,377,725	96,080,806	(39,510,862)	-	2,049,947,670
2067	2,049,947,670	98,807,478	(41,588,415)	-	2,107,166,732
2068	2,107,166,732	101,565,436	(43,173,205)	-	2,165,558,964
2069	2,165,558,964	104,379,942	(43,843,369)	-	2,226,095,536
2070	2,226,095,536	107,297,805	(46,151,627)	-	2,287,241,715
2071	2,287,241,715	110,245,051	(47,786,690)	-	2,349,700,075
2072	2,349,700,075	113,255,544	(49,618,541)	-	2,413,337,078
2073	2,413,337,078	116,322,847	(51,240,915)	-	2,478,419,010
2074	2,478,419,010	119,459,796	(53,065,034)	-	2,544,813,773
2075	2,544,813,773	122,660,024	(61,128,392)	-	2,606,345,405
2076	2,606,345,405	125,625,849	(57,074,829)	-	2,674,896,424
2077	2,674,896,424	128,930,008	(58,953,075)	-	2,744,873,357
2078	2,744,873,357	132,302,896	(45,926,882)	-	2,831,249,371
2079	2,831,249,371	136,466,220	(47,627,470)	-	2,920,088,121
2080	2,920,088,121	140,748,247	(49,527,746)	-	3,011,308,622
2081	3,011,308,622	145,145,076	(51,223,963)	-	3,105,229,735
2082	3,105,229,735	149,672,073	(53,125,222)	-	3,201,776,587
2083	3,201,776,587	154,325,631	(55,098,229)	-	3,301,003,989
2084	3,301,003,989	159,108,392	(57,303,117)	-	3,402,809,265
2085	3,402,809,265	164,015,407	(59,272,264)	-	3,507,552,407
2086	3,507,552,407	169,064,026	(61,478,455)	-	3,615,137,979
2087	3,615,137,979	174,249,651	(165,701,740)	-	3,623,685,889
2088	3,623,685,889	174,661,660	(619,307,251)	-	3,179,040,298
2089	3,179,040,298	153,229,742	(1,010,096,289)	-	2,322,173,751
2090	2,322,173,751	111,928,775	(913,549,360)	-	1,520,553,166
2091	1,520,553,166	73,290,663	(681,953,469)	-	911,890,360
2092	911,890,360	43,953,115	(260,007,735)	-	695,835,741
2093	695,835,741	33,539,283	(310,402,183)	-	418,972,840
2094	418,972,840	20,194,491	(255,916,375)	-	183,250,957
2095	183,250,957	8,832,696	(192,083,653)	-	(0)

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EXTERNAL FUND CALCULATION

Prairie Island Unit 2

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	420,208,967	10,803,157	-	294,670	431,306,795
2018	431,306,795	22,184,315	-	589,341	454,080,451
2019	454,080,451	23,423,593	-	3,262,942	480,766,985
2020	480,766,985	24,795,281	-	3,262,942	508,825,208
2021	508,825,208	26,237,473	-	3,262,942	538,325,623
2022	538,325,623	27,753,795	-	3,262,942	569,342,359
2023	569,342,359	29,348,055	-	3,262,942	601,953,356
2024	601,953,356	31,024,260	-	3,262,942	636,240,557
2025	636,240,557	32,786,622	-	3,262,942	672,290,121
2026	672,290,121	34,639,570	-	3,262,942	710,192,633
2027	710,192,633	36,587,759	-	3,262,942	750,043,334
2028	750,043,334	38,636,085	-	3,262,942	791,942,360
2029	791,942,360	40,789,695	-	3,262,942	835,994,997
2030	835,994,997	43,054,000	-	3,262,942	882,311,939
2031	882,311,939	45,434,691	-	3,262,942	931,009,572
2032	931,009,572	47,937,750	-	3,262,942	982,210,264
2033	982,210,264	50,569,465	-	3,262,942	1,036,042,671
2034	1,036,042,671	50,106,265	(14,729,554)	2,708,242	1,074,127,623
2035	1,074,127,623	51,880,364	(107,554,890)	-	1,018,453,097
2036	1,018,453,097	49,191,285	(61,888,360)	-	1,005,756,021
2037	1,005,756,021	48,578,016	(34,384,910)	-	1,019,949,126
2038	1,019,949,126	49,263,543	(51,304,564)	-	1,017,908,105
2039	1,017,908,105	49,164,961	(158,606,683)	-	908,466,384
2040	908,466,384	43,878,926	(15,743,645)	-	936,601,665
2041	936,601,665	45,237,860	(16,221,623)	-	965,617,903
2042	965,617,903	46,639,345	(16,764,496)	-	995,492,752
2043	995,492,752	48,082,300	(17,326,298)	-	1,026,248,754
2044	1,026,248,754	49,567,815	(17,960,978)	-	1,057,855,590
2045	1,057,855,590	51,094,425	(18,512,772)	-	1,090,437,244
2046	1,090,437,244	52,668,119	(19,138,796)	-	1,123,966,566
2047	1,123,966,566	54,287,585	(19,787,809)	-	1,158,466,342
2048	1,158,466,342	55,953,924	(20,520,048)	-	1,193,900,219
2049	1,193,900,219	57,665,381	(21,157,517)	-	1,230,408,083
2050	1,230,408,083	59,428,710	(21,880,577)	-	1,267,956,216
2051	1,267,956,216	61,242,285	(22,629,686)	-	1,306,568,816
2052	1,306,568,816	63,107,274	(23,474,867)	-	1,346,201,222
2053	1,346,201,222	65,021,519	(25,085,893)	-	1,386,136,849
2054	1,386,136,849	66,950,410	(26,851,538)	-	1,426,235,721
2055	1,426,235,721	68,887,185	(27,775,749)	-	1,467,347,158
2056	1,467,347,158	70,872,868	(29,293,524)	-	1,508,926,501

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2057	1,508,926,501	72,881,150	(29,230,971)	-	1,552,576,680
2058	1,552,576,680	74,989,454	(31,783,221)	-	1,595,782,913
2059	1,595,782,913	77,076,315	(31,295,696)	-	1,641,563,532
2060	1,641,563,532	79,287,519	(31,928,558)	-	1,688,922,493
2061	1,688,922,493	81,574,956	(34,079,994)	-	1,736,417,455
2062	1,736,417,455	83,868,963	(35,269,615)	-	1,785,016,803
2063	1,785,016,803	86,216,312	(35,900,849)	-	1,835,332,265
2064	1,835,332,265	88,646,548	(37,886,389)	-	1,886,092,425
2065	1,886,092,425	91,098,264	(39,109,192)	-	1,938,081,497
2066	1,938,081,497	93,609,336	(39,820,433)	-	1,991,870,400
2067	1,991,870,400	96,207,340	(41,910,232)	-	2,046,167,508
2068	2,046,167,508	98,829,891	(43,508,676)	-	2,101,488,722
2069	2,101,488,722	101,501,905	(44,191,164)	-	2,158,799,463
2070	2,158,799,463	104,270,014	(46,513,191)	-	2,216,556,286
2071	2,216,556,286	107,059,669	(48,162,573)	-	2,275,453,381
2072	2,275,453,381	109,904,398	(50,010,385)	-	2,335,347,395
2073	2,335,347,395	112,797,279	(51,647,168)	-	2,396,497,506
2074	2,396,497,506	115,750,830	(53,487,390)	-	2,458,760,945
2075	2,458,760,945	118,758,154	(61,567,488)	-	2,515,951,611
2076	2,515,951,611	121,520,463	(57,532,587)	-	2,579,939,487
2077	2,579,939,487	124,611,077	(59,427,684)	-	2,645,122,880
2078	2,645,122,880	127,759,435	(20,169,179)	-	2,752,713,136
2079	2,752,713,136	132,956,044	(20,825,729)	-	2,864,843,451
2080	2,864,843,451	138,371,939	(21,563,211)	-	2,981,652,179
2081	2,981,652,179	144,013,800	(22,205,721)	-	3,103,460,257
2082	3,103,460,257	149,897,130	(22,930,853)	-	3,230,426,535
2083	3,230,426,535	156,029,602	(23,680,114)	-	3,362,776,023
2084	3,362,776,023	162,422,082	(24,522,010)	-	3,500,676,095
2085	3,500,676,095	169,082,655	(25,255,785)	-	3,644,502,965
2086	3,644,502,965	176,029,493	(26,083,465)	-	3,794,448,993
2087	3,794,448,993	183,271,886	(26,939,197)	-	3,950,781,682
2088	3,950,781,682	190,822,755	(171,196,773)	-	3,970,407,664
2089	3,970,407,664	191,770,690	(432,650,967)	-	3,729,527,387
2090	3,729,527,387	180,136,173	(1,286,294,416)	-	2,623,369,144
2091	2,623,369,144	126,708,730	(1,018,630,150)	-	1,731,447,723
2092	1,731,447,723	83,628,925	(939,069,791)	-	876,006,857
2093	876,006,857	42,311,131	(400,011,174)	-	518,306,814
2094	518,306,814	25,034,219	(316,718,172)	-	226,622,861
2095	226,622,861	10,945,884	(237,568,746)	-	0

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2019 ACCRUAL COMPARISON

	Present	Proposed	Difference
Monticello	$13,392,226	$26,166,876	$12,774,650
Prairie Island Unit 1	49,264	20,626,223	20,576,959
Prairie Island Unit 2	589,341	9,043,741	8,454,400
TOTAL	$14,030,831	$55,836,840	$41,806,009

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2019 MN RETAIL SUMMARY

	Remaining Life (yrs)	Operational Earnings Rate	Post-Shutdown Earnings Rate	Market Value Balance 6/30/2017	Book Value 6/30/2017	Unrealized Gain/Loss 6/30/2017	Tax-Effect Adjustment	Tax-Adjusted Fund Balance 6/30/2017	2019-2021 Decommissioning Accrual
Monticello	8.75	5.10%	4.83%	$660,140,345	$529,148,381	$130,991,964	$36,468,163	$623,672,182	**26,166,876**
Prairie Island Unit 1	11.67	5.13%	4.82%	399,941,696	308,078,761	91,862,935	25,574,641	374,367,055	**20,626,223**
Prairie Island Unit 2	12.83	5.14%	4.83%	448,597,551	346,627,064	101,970,487	28,388,583	420,208,967	**9,043,741**
TOTAL DECOMMISSIONING ACCRUAL				**$1,508,679,592**	**$1,183,854,206**	**$324,825,386**	**$90,431,387**	**$1,418,248,204**	**$55,836,840**

INPUT DATA

Escalation Rate (Labor)	4.05%
Escalation Rate (Non-Labor)	2.85%
Escalation Rate (PIIC)	0.00%
Jurisdictional Factor	73.4886%
Tax Rate for tax-effect adjustment	27.84%

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AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
Monticello															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2025	$17,759,328	$13,051,073	1.3738	$17,929,565	$8,763,593	$6,440,238	1.2521	$8,063,822	$0	$0	1.0000	$0	$26,522,921	$19,491,311	$25,993,386
2026	63,231,064	46,467,594	1.4295	66,425,426	46,823,276	34,409,748	1.2878	44,312,874	0	0	1.0000	0	110,054,340	80,877,343	110,738,300
2027	30,098,747	22,119,134	1.4874	32,900,000	21,963,833	16,140,903	1.3245	21,378,627	0	0	1.0000	0	52,062,580	38,260,037	54,278,627
2028	30,011,960	22,055,355	1.5476	34,132,868	35,867,567	26,358,556	1.3622	35,905,625	0	0	1.0000	0	65,879,526	48,413,911	70,038,493
2029	24,261,956	17,829,760	1.6103	28,711,263	18,617,567	13,681,781	1.4010	19,168,175	0	0	1.0000	0	42,879,522	31,511,541	47,879,438
2030	43,935,865	32,287,832	1.6755	54,098,262	88,132,650	64,767,410	1.4410	93,329,837	0	0	1.0000	0	132,068,514	97,055,241	147,428,099
2031	8,481,485	6,232,921	1.7434	10,866,474	4,523,995	3,324,618	1.4820	4,927,084	0	0	1.0000	0	13,005,479	9,557,539	15,793,558
2032	8,458,357	6,215,924	1.8140	11,275,686	4,511,770	3,315,635	1.5243	5,054,022	0	0	1.0000	0	12,970,127	9,531,559	16,329,708
2033	8,458,357	6,215,924	1.8874	11,731,935	4,511,770	3,315,635	1.5677	5,197,920	0	0	1.0000	0	12,970,127	9,531,559	16,929,855
2034	8,458,357	6,215,924	1.9639	12,207,453	4,511,770	3,315,635	1.6124	5,346,129	0	0	1.0000	0	12,970,127	9,531,559	17,553,582
2035	8,481,485	6,232,921	2.0434	12,736,350	4,523,995	3,324,618	1.6584	5,513,547	0	0	1.0000	0	13,005,479	9,557,539	18,249,897
2036	8,458,357	6,215,924	2.1262	13,216,298	4,511,770	3,315,635	1.7056	5,655,146	0	0	1.0000	0	12,970,127	9,531,559	18,871,444
2037	8,458,357	6,215,924	2.2123	13,751,489	4,511,770	3,315,635	1.7542	5,816,286	0	0	1.0000	0	12,970,127	9,531,559	19,567,775
2038	8,458,357	6,215,924	2.3019	14,308,436	4,511,770	3,315,635	1.8042	5,982,068	0	0	1.0000	0	12,970,127	9,531,559	20,290,504
2039	8,481,485	6,232,921	2.3951	14,928,468	4,523,995	3,324,618	1.8556	6,169,162	0	0	1.0000	0	13,005,479	9,557,539	21,097,630
2040	8,458,357	6,215,924	2.4921	15,490,704	4,511,770	3,315,635	1.9085	6,327,889	0	0	1.0000	0	12,970,127	9,531,559	21,818,593
2041	8,458,357	6,215,924	2.5930	16,117,891	4,511,770	3,315,635	1.9629	6,508,259	0	0	1.0000	0	12,970,127	9,531,559	22,626,150
2042	8,458,357	6,215,924	2.6981	16,771,185	4,511,770	3,315,635	2.0189	6,693,935	0	0	1.0000	0	12,970,127	9,531,559	23,465,119
2043	9,145,130	6,720,624	2.8073	18,866,807	6,514,932	4,787,729	2.0764	9,941,241	0	0	1.0000	0	15,660,061	11,508,353	28,808,047
2044	8,458,357	6,215,924	2.9210	18,156,714	4,511,767	3,315,632	2.1356	7,080,864	0	0	1.0000	0	12,970,124	9,531,556	25,237,579
2045	9,951,558	7,313,256	3.0393	22,227,179	8,991,374	6,607,631	2.1964	14,513,000	0	0	1.0000	0	18,942,932	13,920,887	36,740,179
2046	9,951,558	7,313,256	3.1624	23,127,440	8,991,374	6,607,631	2.2590	14,926,638	0	0	1.0000	0	18,942,932	13,920,887	38,054,078
2047	10,837,186	7,964,091	3.2905	26,205,842	11,591,099	8,518,131	2.3234	19,791,025	0	0	1.0000	0	22,428,284	16,482,222	45,996,867
2048	11,460,933	8,422,474	3.4238	28,836,866	13,519,499	9,935,284	2.3896	23,741,355	0	0	1.0000	0	24,980,432	18,357,758	52,578,221
2049	10,167,183	7,471,716	3.5624	26,617,240	9,638,249	7,083,010	2.4577	17,407,913	0	0	1.0000	0	19,805,432	14,554,725	44,025,153
2050	11,245,308	8,264,014	3.7067	30,632,221	12,872,624	9,459,905	2.5278	23,912,748	0	0	1.0000	0	24,117,932	17,723,919	54,544,969
2051	11,699,686	8,597,930	3.8568	33,160,496	14,178,599	10,419,647	2.5998	27,088,999	0	0	1.0000	0	25,878,284	19,017,577	60,249,495
2052	8,441,765	6,203,731	4.0130	24,895,572	4,461,997	3,279,057	2.6739	8,767,871	0	0	1.0000	0	12,903,762	9,482,788	33,663,443
2053	8,441,765	6,203,731	4.1756	25,904,299	4,461,997	3,279,057	2.7501	9,017,735	0	0	1.0000	0	12,903,762	9,482,788	34,922,034
2054	8,441,765	6,203,731	4.3447	26,953,349	4,461,997	3,279,057	2.8285	9,274,813	0	0	1.0000	0	12,903,762	9,482,788	36,228,162
2055	8,464,894	6,220,728	4.5206	28,121,423	4,474,222	3,288,041	2.9091	9,565,240	0	0	1.0000	0	12,939,115	9,508,769	37,686,663
2056	8,441,765	6,203,731	4.7037	29,180,489	4,461,997	3,279,057	2.9920	9,810,939	0	0	1.0000	0	12,903,762	9,482,788	38,991,428
2057	8,441,765	6,203,731	4.8942	30,362,300	4,461,997	3,279,057	3.0773	10,090,642	0	0	1.0000	0	12,903,762	9,482,788	40,452,942
2058	8,441,765	6,203,731	5.0924	31,591,879	4,461,997	3,279,057	3.1650	10,378,216	0	0	1.0000	0	12,903,762	9,482,788	41,970,095
2059	8,464,894	6,220,728	5.2987	32,961,772	4,474,222	3,288,041	3.2552	10,703,230	0	0	1.0000	0	12,939,115	9,508,769	43,665,002
2060	8,441,765	6,203,731	5.5133	34,203,029	4,461,997	3,279,057	3.3480	10,978,283	0	0	1.0000	0	12,903,762	9,482,788	45,181,313
2061	8,441,765	6,203,731	5.7366	35,588,322	4,461,997	3,279,057	3.4434	11,291,105	0	0	1.0000	0	12,903,762	9,482,788	46,879,428
2062	8,441,765	6,203,731	5.9689	37,029,449	4,461,997	3,279,057	3.5415	11,612,781	0	0	1.0000	0	12,903,762	9,482,788	48,642,230
2063	8,464,894	6,220,728	6.2106	38,634,454	4,474,222	3,288,041	3.6425	11,976,689	0	0	1.0000	0	12,939,115	9,508,769	50,611,142
2064	8,441,765	6,203,731	6.4622	40,089,750	4,461,997	3,279,057	3.7463	12,284,332	0	0	1.0000	0	12,903,762	9,482,788	52,374,081
2065	8,441,765	6,203,731	6.7239	41,713,266	4,461,997	3,279,057	3.8531	12,634,535	0	0	1.0000	0	12,903,762	9,482,788	54,347,801
2066	8,441,765	6,203,731	6.9962	43,402,542	4,461,997	3,279,057	3.9629	12,994,575	0	0	1.0000	0	12,903,762	9,482,788	56,397,117
2067	8,464,894	6,220,728	7.2795	45,283,790	4,474,222	3,288,041	4.0758	13,401,397	0	0	1.0000	0	12,939,115	9,508,769	58,685,187
2068	8,441,765	6,203,731	7.5744	46,989,539	4,461,997	3,279,057	4.1920	13,745,807	0	0	1.0000	0	12,903,762	9,482,788	60,735,346
2069	8,441,765	6,203,731	7.8811	48,892,223	4,461,997	3,279,057	4.3115	14,137,655	0	0	1.0000	0	12,903,762	9,482,788	63,029,878
2070	8,441,765	6,203,731	8.2003	50,872,454	4,461,997	3,279,057	4.4343	14,540,323	0	0	1.0000	0	12,903,762	9,482,788	65,412,777
2071	8,464,894	6,220,728	8.5324	53,077,740	4,474,222	3,288,041	4.5607	14,995,768	0	0	1.0000	0	12,939,115	9,508,769	68,073,508
2072	8,441,765	6,203,731	8.8780	55,076,723	4,461,997	3,279,057	4.6907	15,381,073	0	0	1.0000	0	12,903,762	9,482,788	70,457,796
2073	8,920,197	6,555,324	9.2375	60,554,802	5,897,293	4,333,835	4.8244	20,908,155	0	0	1.0000	0	14,817,490	10,889,159	81,462,957
2074	9,015,884	6,625,643	9.6117	63,683,689	6,184,352	4,544,791	4.9619	22,550,798	0	0	1.0000	0	15,200,236	11,170,433	86,234,487
2075	8,943,325	6,572,320	10.0009	65,729,116	5,909,518	4,342,819	5.1033	22,162,709	0	0	1.0000	0	14,852,842	10,915,139	87,891,824
2076	8,920,197	6,555,324	10.4060	68,214,698	5,897,293	4,333,835	5.2487	22,747,002	0	0	1.0000	0	14,817,490	10,889,159	90,961,699
2077	8,920,197	6,555,324	10.8274	70,977,111	5,897,293	4,333,835	5.3983	23,395,343	0	0	1.0000	0	14,817,490	10,889,159	94,372,454
2078	9,015,884	6,625,643	11.2659	74,643,827	6,184,352	4,544,791	5.5522	25,233,588	0	0	1.0000	0	15,200,236	11,170,433	99,877,415
2079	8,943,325	6,572,320	11.7222	77,042,050	5,909,518	4,342,819	5.7104	24,799,234	0	0	1.0000	0	14,852,842	10,915,139	101,841,284

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60-Year Decommissioning Period
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5-Year Early Shutdown

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AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
2080	46,126,149	33,897,440	12.1970	413,447,077	12,314,062	9,049,426	5.8731	53,148,185	0	0	1.0000	0	58,440,212	42,946,866	466,595,262
2081	53,631,139	39,412,748	12.6909	500,183,247	46,945,385	34,499,485	6.0405	208,394,136	0	0	1.0000	0	100,576,524	73,912,233	708,577,384
2082	57,419,114	42,196,476	13.2049	557,200,251	80,273,242	58,991,645	6.2127	366,497,393	0	0	1.0000	0	137,692,356	101,188,121	923,697,643
2083	52,652,752	38,693,746	13.7397	531,640,460	33,214,319	24,408,722	6.3897	155,964,414	0	0	1.0000	0	85,867,070	63,102,468	687,604,874
2084	50,913,638	37,415,697	14.2962	534,902,283	30,841,715	22,665,130	6.5719	148,952,970	0	0	1.0000	0	81,755,354	60,080,827	683,855,253
2085	32,667,889	24,007,160	14.8752	357,111,300	23,001,023	16,903,119	6.7592	114,251,564	0	0	1.0000	0	55,668,913	40,910,279	471,362,864
2086	21,071,356	15,485,035	15.4776	239,671,177	16,131,940	11,855,130	6.9518	82,414,491	0	0	1.0000	0	37,203,297	27,340,165	322,085,668
2087	8,832,651	6,490,987	16.1045	104,534,104	6,762,156	4,969,411	7.1499	35,530,788	0	0	1.0000	0	15,594,807	11,460,398	140,064,893
	$967,171,883	$710,760,631		$5,145,790,110	$750,282,438	$551,371,714		$2,024,287,970	$0	$0		$0	$1,717,454,322	$1,262,132,345	$7,170,078,080

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	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
Prairie Island Unit 1															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2028	$18,446,908	$13,556,366	1.5476	$20,979,832	$4,190,856	$3,079,799	1.3622	$4,195,302	$1,250,000	$918,607	1.0000	$918,607	$23,887,764	$17,554,772	$26,093,741
2029	46,142,627	33,909,549	1.6103	54,604,547	29,162,161	21,430,850	1.4010	30,024,621	1,250,000	918,607	1.0000	918,607	76,554,787	56,259,006	85,547,775
2030	16,398,923	12,051,331	1.6755	20,192,006	15,491,742	11,384,657	1.4410	16,405,291	1,250,000	918,607	1.0000	918,607	33,140,665	24,354,595	37,515,903
2031	12,659,656	9,303,398	1.7434	16,219,545	13,774,811	10,122,909	1.4820	15,002,152	1,250,000	918,607	1.0000	918,607	27,684,467	20,344,915	32,140,303
2032	12,625,333	9,278,174	1.8140	16,830,608	13,734,545	10,093,318	1.5243	15,385,245	1,250,000	918,607	1.0000	918,607	27,609,877	20,290,100	33,134,460
2033	15,404,499	11,320,543	1.8874	21,366,393	22,072,045	16,220,427	1.5677	25,428,763	1,250,000	918,607	1.0000	918,607	38,726,543	28,459,577	47,713,763
2034	32,688,492	24,022,300	1.9639	47,177,395	76,524,027	56,236,401	1.6124	90,675,573	1,250,000	918,607	1.0000	918,607	110,462,519	81,177,308	138,771,575
2035	4,604,176	3,383,542	2.0434	6,913,931	4,477,123	3,290,173	1.6584	5,456,423	1,250,000	918,607	1.0000	918,607	10,331,299	7,592,322	13,288,961
2036	4,591,596	3,374,297	2.1262	7,174,431	4,461,475	3,278,674	1.7056	5,592,106	1,250,000	918,607	1.0000	918,607	10,303,071	7,571,578	13,685,143
2037	4,591,596	3,374,297	2.2123	7,464,958	4,461,475	3,278,674	1.7542	5,751,449	1,250,000	918,607	1.0000	918,607	10,303,071	7,571,578	14,135,014
2038	4,591,596	3,374,297	2.3019	7,767,295	4,461,475	3,278,674	1.8042	5,915,383	1,250,000	918,607	1.0000	918,607	10,303,071	7,571,578	14,601,285
2039	4,604,176	3,383,542	2.3951	8,103,923	4,477,123	3,290,173	1.8556	6,105,245	1,250,000	918,607	1.0000	918,607	10,331,299	7,592,322	15,127,775
2040	4,591,596	3,374,297	2.4921	8,409,086	4,461,475	3,278,674	1.9085	6,257,349	1,250,000	918,607	1.0000	918,607	10,303,071	7,571,578	15,585,042
2041	4,591,596	3,374,297	2.5930	8,749,553	4,461,475	3,278,674	1.9629	6,435,709	1,250,000	918,607	1.0000	918,607	10,303,071	7,571,578	16,103,868
2042	4,591,596	3,374,297	2.6981	9,104,191	4,461,475	3,278,674	2.0189	6,619,314	1,250,000	918,607	1.0000	918,607	10,303,071	7,571,578	16,642,112
2043	4,604,176	3,383,542	2.8073	9,498,619	4,477,123	3,290,173	2.0764	6,831,715	1,250,000	918,607	1.0000	918,607	10,331,299	7,592,322	17,248,941
2044	4,591,596	3,374,297	2.9210	9,856,322	4,461,475	3,278,674	2.1356	7,001,935	1,250,000	918,607	1.0000	918,607	10,303,071	7,571,578	17,776,865
2045	4,591,596	3,374,297	3.0393	10,255,502	4,461,475	3,278,674	2.1964	7,201,279	1,250,000	918,607	1.0000	918,607	10,303,071	7,571,578	18,375,387
2046	4,591,596	3,374,297	3.1624	10,670,878	4,461,475	3,278,674	2.2590	7,406,524	1,250,000	918,607	1.0000	918,607	10,303,071	7,571,578	18,996,008
2047	4,604,176	3,383,542	3.2905	11,133,546	4,477,123	3,290,173	2.3234	7,644,388	1,250,000	918,607	1.0000	918,607	10,331,299	7,592,322	19,696,541
2048	4,687,283	3,444,616	3.4238	11,793,677	4,748,534	3,489,629	2.3896	8,338,818	1,250,000	918,607	1.0000	918,607	10,685,817	7,852,852	21,051,102
2049	4,782,969	3,514,934	3.5624	12,521,603	5,035,593	3,700,585	2.4577	9,094,927	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	22,535,136
2050	4,782,969	3,514,934	3.7067	13,028,808	5,035,593	3,700,585	2.5278	9,354,338	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	23,301,752
2051	4,843,392	3,559,339	3.8568	13,727,658	5,194,771	3,817,562	2.5998	9,924,898	1,250,000	918,607	1.0000	918,607	11,288,163	8,295,508	24,571,163
2052	4,735,126	3,479,775	4.0130	13,964,338	4,892,064	3,595,107	2.6739	9,612,957	1,250,000	918,607	1.0000	918,607	10,877,190	7,993,490	24,495,903
2053	4,878,656	3,585,253	4.1756	14,970,584	5,322,652	3,911,540	2.7501	10,757,127	1,250,000	918,607	1.0000	918,607	11,451,308	8,415,401	26,646,318
2054	4,735,126	3,479,775	4.3447	15,118,580	4,892,064	3,595,107	2.8285	10,168,761	1,250,000	918,607	1.0000	918,607	10,877,190	7,993,490	26,205,948
2055	4,699,862	3,453,861	4.5206	15,613,523	4,764,182	3,501,129	2.9091	10,185,133	1,250,000	918,607	1.0000	918,607	10,714,044	7,873,596	26,717,263
2056	4,782,969	3,514,934	4.7037	16,533,197	5,035,593	3,700,585	2.9920	11,072,149	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	28,523,954
2057	4,782,969	3,514,934	4.8942	17,202,792	5,035,593	3,700,585	3.0773	11,387,809	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	29,509,208
2058	4,735,126	3,479,775	5.0924	17,720,408	4,892,064	3,595,107	3.1650	11,378,515	1,250,000	918,607	1.0000	918,607	10,877,190	7,993,490	30,017,529
2059	4,795,548	3,524,179	5.2987	18,673,567	5,051,241	3,712,084	3.2552	12,083,576	1,250,000	918,607	1.0000	918,607	11,096,789	8,154,870	31,675,750
2060	4,782,969	3,514,934	5.5133	19,378,888	5,035,593	3,700,585	3.3480	12,389,557	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	32,687,053
2061	4,735,126	3,479,775	5.7366	19,962,079	4,892,064	3,595,107	3.4434	12,379,392	1,250,000	918,607	1.0000	918,607	10,877,190	7,993,490	33,260,079
2062	4,782,969	3,514,934	5.9689	20,980,292	5,035,593	3,700,585	3.5415	13,105,621	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	35,004,520
2063	4,795,548	3,524,179	6.2106	21,887,266	5,051,241	3,712,084	3.6425	13,521,266	1,250,000	918,607	1.0000	918,607	11,096,789	8,154,870	36,327,139
2064	4,735,126	3,479,775	6.4622	22,487,004	4,892,064	3,595,107	3.7463	13,468,350	1,250,000	918,607	1.0000	918,607	10,877,190	7,993,490	36,873,962
2065	4,782,969	3,514,934	6.7239	23,634,068	5,035,593	3,700,585	3.8531	14,258,723	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	38,811,398
2066	4,782,969	3,514,934	6.9962	24,591,185	5,035,593	3,700,585	3.9629	14,665,047	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	40,174,838
2067	4,795,548	3,524,179	7.2795	25,654,261	5,051,241	3,712,084	4.0758	15,129,712	1,250,000	918,607	1.0000	918,607	11,096,789	8,154,870	41,702,580
2068	4,782,969	3,514,934	7.5744	26,623,520	5,035,593	3,700,585	4.1920	15,512,851	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	43,054,977
2069	4,782,969	3,514,934	7.8811	27,701,550	5,035,593	3,700,585	4.3115	15,955,071	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	44,575,228
2070	5,114,792	3,758,786	8.2003	30,823,176	6,031,061	4,432,140	4.4343	19,653,437	1,250,000	918,607	1.0000	918,607	12,395,853	9,109,533	51,395,220
2071	4,795,548	3,524,179	8.5324	30,069,705	5,051,241	3,712,084	4.5607	16,929,702	1,250,000	918,607	1.0000	918,607	11,096,789	8,154,870	47,918,013
2072	4,782,969	3,514,934	8.8780	31,205,588	5,035,593	3,700,585	4.6907	17,358,333	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	49,482,528
2073	3,942,348	2,897,174	9.2375	26,762,647	3,256,582	2,393,215	4.8244	11,545,826	0	0	1.0000	0	7,198,929	5,290,389	38,308,473
2074	3,942,348	2,897,174	9.6117	27,846,769	3,256,582	2,393,215	4.9619	11,874,893	0	0	1.0000	0	7,198,929	5,290,389	39,721,662
2075	3,953,149	2,905,112	10.0009	29,053,731	3,265,504	2,399,772	5.1033	12,246,754	0	0	1.0000	0	7,218,652	5,304,883	41,300,486
2076	3,942,348	2,897,174	10.4060	30,147,995	3,256,582	2,393,215	5.2487	12,561,267	0	0	1.0000	0	7,198,929	5,290,389	42,709,262
2077	3,942,348	2,897,174	10.8274	31,368,864	3,256,582	2,393,215	5.3983	12,919,292	0	0	1.0000	0	7,198,929	5,290,389	44,288,156
2078	3,942,348	2,897,174	11.2659	32,639,275	3,256,582	2,393,215	5.5522	13,287,607	0	0	1.0000	0	7,198,929	5,290,389	45,926,882
2079	3,953,149	2,905,112	11.7222	34,054,300	3,265,504	2,399,772	5.7104	13,703,656	0	0	1.0000	0	7,218,652	5,304,883	47,757,956
2080	3,942,348	2,897,174	12.1970	35,336,834	3,256,582	2,393,215	5.8731	14,055,590	0	0	1.0000	0	7,198,929	5,290,389	49,392,424
2081	3,942,348	2,897,174	12.6909	36,767,748	3,256,582	2,393,215	6.0405	14,456,214	0	0	1.0000	0	7,198,929	5,290,389	51,223,963
2082	11,802,691	8,673,627	13.2049	114,534,373	4,951,569	3,638,837	6.2127	22,607,001	0	0	1.0000	0	16,754,260	12,312,463	137,141,374

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	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
2083	45,111,220	33,151,584	13.7397	455,492,813	11,805,071	8,675,376	6.3897	55,433,048	0	0	1.0000	0	56,916,291	41,826,959	510,925,861
2084	51,818,304	38,080,522	14.2962	544,406,760	62,277,980	45,767,187	6.5719	300,777,373	0	0	1.0000	0	114,096,283	83,847,709	845,184,134
2085	44,187,860	32,473,019	14.8752	483,042,653	56,754,748	41,708,244	6.7592	281,914,360	0	0	1.0000	0	100,942,608	74,181,263	764,957,013
2086	35,668,367	26,212,167	15.4776	405,701,439	31,834,151	23,394,458	6.9518	162,633,590	0	0	1.0000	0	67,502,519	49,606,625	568,335,029
2087	13,715,750	10,079,506	16.1045	162,325,411	10,259,487	7,539,548	7.1499	53,907,017	0	0	1.0000	0	23,975,237	17,619,055	216,232,427
2088	18,089,191	13,293,485	16.7567	222,754,942	6,228,187	4,577,005	7.3537	33,657,920	0	0	1.0000	0	24,317,379	17,870,490	256,412,862
2089	12,584,719	9,248,328	17.4353	161,247,374	9,264,588	6,808,412	7.5633	51,494,060	0	0	1.0000	0	21,849,307	16,056,740	212,741,434
2090	9,102,372	6,689,202	18.1415	121,352,152	6,700,962	4,924,440	7.7788	38,306,236	0	0	1.0000	0	15,803,334	11,613,642	159,658,387
	$611,385,166	$449,298,117		$3,773,175,957	$588,533,792	$432,504,973		$1,716,403,540	$56,250,000	$41,337,312		$41,337,312	$1,256,168,958	$923,140,402	$5,530,916,809

Xcel Energy
Nuclear Decommissioning Accrual
60-Year Decommissioning Period
SAFSTOR Method
5-Year Early Shutdown

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Proposed

AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
Prairie Island Unit 2															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2029	$7,248,794	$5,327,034	1.6103	$8,578,123	$2,826,485	$2,077,143	1.4010	$2,910,077	$1,250,000	$918,607	1.0000	$918,607	$11,325,279	$8,322,784	$12,406,807
2030	44,817,806	32,935,958	1.6755	55,184,197	32,275,248	23,718,613	1.4410	34,178,521	1,250,000	918,607	1.0000	918,607	78,343,054	57,573,177	90,281,325
2031	23,021,476	16,918,150	1.7434	29,495,102	19,944,127	14,656,651	1.4820	21,721,156	1,250,000	918,607	1.0000	918,607	44,215,603	32,493,407	52,134,866
2032	10,761,111	7,908,185	1.8140	14,345,447	12,388,936	9,104,450	1.5243	13,877,913	1,250,000	918,607	1.0000	918,607	24,400,047	17,931,242	29,141,967
2033	13,540,277	9,950,554	1.8874	18,780,675	20,726,436	15,231,558	1.5677	23,878,514	1,250,000	918,607	1.0000	918,607	35,516,713	26,100,719	43,577,796
2034	31,160,880	22,899,680	1.9639	44,972,682	75,415,818	55,421,994	1.6124	89,362,423	1,250,000	918,607	1.0000	918,607	107,826,698	79,240,281	135,253,712
2035	4,659,832	3,424,443	2.0434	6,997,507	4,485,457	3,296,297	1.6584	5,466,580	1,250,000	918,607	1.0000	918,607	10,395,289	7,639,347	13,382,694
2036	4,647,099	3,415,086	2.1262	7,261,156	4,469,786	3,284,781	1.7056	5,602,523	1,250,000	918,607	1.0000	918,607	10,366,886	7,618,474	13,782,286
2037	4,647,099	3,415,086	2.2123	7,555,195	4,469,786	3,284,781	1.7542	5,762,163	1,250,000	918,607	1.0000	918,607	10,366,886	7,618,474	14,235,965
2038	4,647,099	3,415,086	2.3019	7,861,187	4,469,786	3,284,781	1.8042	5,926,402	1,250,000	918,607	1.0000	918,607	10,366,886	7,618,474	14,706,196
2039	4,659,832	3,424,443	2.3951	8,201,884	4,485,457	3,296,297	1.8556	6,116,609	1,250,000	918,607	1.0000	918,607	10,395,289	7,639,347	15,237,100
2040	4,647,099	3,415,086	2.4921	8,510,736	4,469,786	3,284,781	1.9085	6,269,005	1,250,000	918,607	1.0000	918,607	10,366,886	7,618,474	15,698,348
2041	4,647,099	3,415,086	2.5930	8,855,319	4,469,786	3,284,781	1.9629	6,447,697	1,250,000	918,607	1.0000	918,607	10,366,886	7,618,474	16,221,623
2042	4,647,099	3,415,086	2.6981	9,214,244	4,469,786	3,284,781	2.0189	6,631,645	1,250,000	918,607	1.0000	918,607	10,366,886	7,618,474	16,764,496
2043	4,659,832	3,424,443	2.8073	9,613,439	4,485,457	3,296,297	2.0764	6,844,432	1,250,000	918,607	1.0000	918,607	10,395,289	7,639,347	17,376,478
2044	4,647,099	3,415,086	2.9210	9,975,467	4,469,786	3,284,781	2.1356	7,014,979	1,250,000	918,607	1.0000	918,607	10,366,886	7,618,474	17,909,053
2045	4,647,099	3,415,086	3.0393	10,379,472	4,469,786	3,284,781	2.1964	7,214,693	1,250,000	918,607	1.0000	918,607	10,366,886	7,618,474	18,512,772
2046	4,647,099	3,415,086	3.1624	10,799,869	4,469,786	3,284,781	2.2590	7,420,321	1,250,000	918,607	1.0000	918,607	10,366,886	7,618,474	19,138,796
2047	4,659,832	3,424,443	3.2905	11,268,130	4,485,457	3,296,297	2.3234	7,658,617	1,250,000	918,607	1.0000	918,607	10,395,289	7,639,347	19,845,355
2048	4,742,786	3,485,405	3.4238	11,933,330	4,756,846	3,495,737	2.3896	8,353,414	1,250,000	918,607	1.0000	918,607	10,749,633	7,899,750	21,205,352
2049	4,838,472	3,555,723	3.5624	12,666,909	5,043,904	3,706,692	2.4577	9,109,938	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	22,695,454
2050	4,838,472	3,555,723	3.7067	13,180,000	5,043,904	3,706,692	2.5278	9,369,777	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	23,468,384
2051	4,899,048	3,600,240	3.8568	13,885,404	5,203,105	3,823,687	2.5998	9,940,820	1,250,000	918,607	1.0000	918,607	11,352,153	8,342,533	24,744,831
2052	4,790,629	3,520,564	4.0130	14,128,025	4,900,375	3,601,215	2.6739	9,629,288	1,250,000	918,607	1.0000	918,607	10,941,005	8,040,386	24,675,920
2053	4,934,159	3,626,042	4.1756	15,140,903	5,330,963	3,917,648	2.7501	10,773,923	1,250,000	918,607	1.0000	918,607	11,515,123	8,462,297	26,833,433
2054	4,790,629	3,520,564	4.3447	15,295,796	4,900,375	3,601,215	2.8285	10,186,036	1,250,000	918,607	1.0000	918,607	10,941,005	8,040,386	26,400,439
2055	4,755,518	3,494,761	4.5206	15,798,419	4,772,516	3,507,253	2.9091	10,202,949	1,250,000	918,607	1.0000	918,607	10,778,034	7,920,621	26,919,975
2056	4,838,472	3,555,723	4.7037	16,725,056	5,043,904	3,706,692	2.9920	11,090,423	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	28,734,087
2057	4,838,472	3,555,723	4.8942	17,402,422	5,043,904	3,706,692	3.0773	11,406,604	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	29,727,633
2058	4,790,629	3,520,564	5.0924	17,928,122	4,900,375	3,601,215	3.1650	11,397,845	1,250,000	918,607	1.0000	918,607	10,941,005	8,040,386	30,244,574
2059	4,851,204	3,565,080	5.2987	18,890,288	5,059,575	3,718,208	3.2552	12,103,512	1,250,000	918,607	1.0000	918,607	11,160,779	8,201,895	31,912,407
2060	4,838,472	3,555,723	5.5133	19,603,770	5,043,904	3,706,692	3.3480	12,410,006	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	32,932,383
2061	4,790,629	3,520,564	5.7366	20,196,069	4,900,375	3,601,215	3.4434	12,400,423	1,250,000	918,607	1.0000	918,607	10,941,005	8,040,386	33,515,100
2062	4,838,472	3,555,723	5.9689	21,223,758	5,043,904	3,706,692	3.5415	13,127,251	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	35,269,615
2063	4,851,204	3,565,080	6.2106	22,141,284	5,059,575	3,718,208	3.6425	13,543,574	1,250,000	918,607	1.0000	918,607	11,160,779	8,201,895	36,603,465
2064	4,790,629	3,520,564	6.4622	22,750,591	4,900,375	3,601,215	3.7463	13,491,231	1,250,000	918,607	1.0000	918,607	10,941,005	8,040,386	37,160,429
2065	4,838,472	3,555,723	6.7239	23,908,329	5,043,904	3,706,692	3.8531	14,282,256	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	39,109,192
2066	4,838,472	3,555,723	6.9962	24,876,552	5,043,904	3,706,692	3.9629	14,689,251	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	40,484,410
2067	4,851,204	3,565,080	7.2795	25,951,998	5,059,575	3,718,208	4.0758	15,154,674	1,250,000	918,607	1.0000	918,607	11,160,779	8,201,895	42,025,278
2068	4,838,472	3,555,723	7.5744	26,932,472	5,043,904	3,706,692	4.1920	15,538,454	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	43,389,533
2069	4,838,472	3,555,723	7.8811	28,023,012	5,043,904	3,706,692	4.3115	15,981,404	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	44,923,023
2070	5,170,295	3,799,575	8.2003	31,157,658	6,039,372	4,438,247	4.4343	19,680,520	1,250,000	918,607	1.0000	918,607	12,459,668	9,156,430	51,756,785
2071	4,851,204	3,565,080	8.5324	30,418,686	5,059,575	3,718,208	4.5607	16,957,633	1,250,000	918,607	1.0000	918,607	11,160,779	8,201,895	48,294,926
2072	4,838,472	3,555,723	8.8780	31,567,713	5,043,904	3,706,692	4.6907	17,386,981	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	49,873,301
2073	823,359	605,074	9.2375	5,589,375	3,272,479	2,404,897	4.8244	11,602,187	0	-	1.0000	-	4,095,838	3,009,972	17,191,562
2074	823,359	605,074	9.6117	5,815,794	3,272,479	2,404,897	4.9619	11,932,860	0	-	1.0000	-	4,095,838	3,009,972	17,748,654
2075	825,615	606,732	10.0009	6,067,868	3,281,444	2,411,486	5.1033	12,306,537	0	-	1.0000	-	4,107,059	3,018,218	18,374,405
2076	823,359	605,074	10.4060	6,296,405	3,272,479	2,404,897	5.2487	12,622,585	0	-	1.0000	-	4,095,838	3,009,972	18,918,989
2077	823,359	605,074	10.8274	6,551,383	3,272,479	2,404,897	5.3983	12,982,357	0	-	1.0000	-	4,095,838	3,009,972	19,533,740
2078	823,359	605,074	11.2659	6,816,708	3,272,479	2,404,897	5.5522	13,352,471	0	-	1.0000	-	4,095,838	3,009,972	20,169,179
2079	825,615	606,732	11.7222	7,112,236	3,281,444	2,411,486	5.7104	13,770,550	0	-	1.0000	-	4,107,059	3,018,218	20,882,786
2080	823,359	605,074	12.1970	7,380,093	3,272,479	2,404,897	5.8731	14,124,203	0	-	1.0000	-	4,095,838	3,009,972	21,504,295
2081	823,359	605,074	12.6909	7,678,939	3,272,479	2,404,897	6.0405	14,526,782	0	-	1.0000	-	4,095,838	3,009,972	22,205,721
2082	823,359	605,074	13.2049	7,989,947	3,272,479	2,404,897	6.2127	14,940,906	0	-	1.0000	-	4,095,838	3,009,972	22,930,853
2083	11,274,587	8,285,531	13.7397	113,840,706	5,987,760	4,400,318	6.3897	28,116,714	0	-	1.0000	-	17,262,347	12,685,849	141,957,420

Xcel Energy
Nuclear Decommissioning Accrual
60-Year Decommissioning Period
SAFSTOR Method
5-Year Early Shutdown

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Proposed

AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
2084	29,172,411	21,438,383	14.2962	306,487,412	10,590,974	7,783,154	6.5719	51,150,108	0	-	1.0000	-	39,763,385	29,221,537	357,637,520
2085	57,665,154	42,377,288	14.8752	630,370,636	90,528,180	66,527,851	6.7592	449,675,048	0	-	1.0000	-	148,193,335	108,905,139	1,080,045,684
2086	55,538,057	40,814,115	15.4776	631,704,550	42,217,329	31,024,904	6.9518	215,678,931	0	-	1.0000	-	97,755,386	71,839,020	847,383,481
2087	51,408,076	37,779,052	16.1045	608,412,741	32,588,487	23,948,808	7.1499	171,231,582	0	-	1.0000	-	83,996,563	61,727,860	779,644,323
2088	23,223,558	17,066,657	16.7567	285,980,846	8,238,061	6,054,032	7.3537	44,519,534	0	-	1.0000	-	31,461,619	23,120,689	330,500,380
2089	14,460,844	10,627,065	17.4353	185,286,068	14,186,680	10,425,586	7.5633	78,851,834	0	-	1.0000	-	28,647,524	21,052,651	264,137,902
2090	10,459,350	7,686,425	18.1415	139,443,282	10,261,051	7,540,698	7.7788	58,657,580	-	-	1.0000	-	20,720,401	15,227,123	198,100,862
	$573,536,674	$421,483,808		$3,768,401,389	$595,414,118	$437,561,225		$1,818,555,225	$55,000,000	$40,418,705		$40,418,705	$1,223,950,791	$899,463,737	$5,627,375,318
	$2,152,093,723	$1,581,542,556		$12,687,367,456	$1,934,230,348	$1,421,437,911		$5,559,246,735	$111,250,000	$81,756,016		$81,756,016	$4,197,574,071	$3,084,736,483	$18,328,370,207

Xcel Energy
Nuclear Decommissioning Accrual
60-Year Decommissioning Period
SAFSTOR Method
5-Year Early Shutdown

Docket No. E002/M-17-828
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Proposed

EXTERNAL FUND CALCULATION

Monticello

External Levelized

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	623,672,182	15,989,016	-	6,696,113	646,357,311
2018	646,357,311	33,305,725	-	13,392,226	693,055,262
2019	693,055,262	36,013,074	-	26,166,876	755,235,212
2020	755,235,212	39,184,251	-	26,166,876	820,586,339
2021	820,586,339	42,517,159	-	26,166,876	889,270,373
2022	889,270,373	46,020,044	-	26,166,876	961,457,294
2023	961,457,294	49,701,577	-	26,166,876	1,037,325,747
2024	1,037,325,747	53,570,868	-	26,166,876	1,117,063,492
2025	1,117,063,492	54,428,114	(25,993,386)	19,625,157	1,165,123,377
2026	1,165,123,377	56,275,459	(110,738,300)	-	1,110,660,536
2027	1,110,660,536	53,644,904	(54,278,627)	-	1,110,026,813
2028	1,110,026,813	53,614,295	(70,038,493)	-	1,093,602,616
2029	1,093,602,616	52,821,006	(47,879,438)	-	1,098,544,184
2030	1,098,544,184	53,059,684	(147,428,099)	-	1,004,175,769
2031	1,004,175,769	48,501,690	(15,793,558)	-	1,036,883,900
2032	1,036,883,900	50,081,492	(16,329,708)	-	1,070,635,685
2033	1,070,635,685	51,711,704	(16,929,855)	-	1,105,417,533
2034	1,105,417,533	53,391,667	(17,553,582)	-	1,141,255,617
2035	1,141,255,617	55,122,646	(18,249,897)	-	1,178,128,367
2036	1,178,128,367	56,903,600	(18,871,444)	-	1,216,160,523
2037	1,216,160,523	58,740,553	(19,567,775)	-	1,255,333,301
2038	1,255,333,301	60,632,598	(20,290,504)	-	1,295,675,396
2039	1,295,675,396	62,581,122	(21,097,630)	-	1,337,158,888
2040	1,337,158,888	64,584,774	(21,818,593)	-	1,379,925,069
2041	1,379,925,069	66,650,381	(22,626,150)	-	1,423,949,300
2042	1,423,949,300	68,776,751	(23,465,119)	-	1,469,260,932
2043	1,469,260,932	70,965,303	(28,808,047)	-	1,511,418,187
2044	1,511,418,187	73,001,498	(25,237,579)	-	1,559,182,107
2045	1,559,182,107	75,308,496	(36,740,179)	-	1,597,750,424
2046	1,597,750,424	77,171,345	(38,054,078)	-	1,636,867,691
2047	1,636,867,691	79,060,709	(45,996,867)	-	1,669,931,534
2048	1,669,931,534	80,657,693	(52,578,221)	-	1,698,011,006
2049	1,698,011,006	82,013,932	(44,025,153)	-	1,735,999,784
2050	1,735,999,784	83,848,790	(54,544,969)	-	1,765,303,604
2051	1,765,303,604	85,264,164	(60,249,495)	-	1,790,318,274
2052	1,790,318,274	86,472,373	(33,663,443)	-	1,843,127,204
2053	1,843,127,204	89,023,044	(34,922,034)	-	1,897,228,214
2054	1,897,228,214	91,636,123	(36,228,162)	-	1,952,636,174
2055	1,952,636,174	94,312,327	(37,686,663)	-	2,009,261,839
2056	2,009,261,839	97,047,347	(38,991,428)	-	2,067,317,758

Xcel Energy **Docket No. E002/M-17-828**
Nuclear Decommissioning Accrual **Schedule F.9**
60-Year Decommissioning Period **Page 10 of 14**
SAFSTOR Method
5-Year Early Shutdown **Proposed**

EXTERNAL FUND CALCULATION

2057	2,067,317,758	99,851,448	(40,452,942)	-	2,126,716,264
2058	2,126,716,264	102,720,396	(41,970,095)	-	2,187,466,565
2059	2,187,466,565	105,654,635	(43,665,002)	-	2,249,456,198
2060	2,249,456,198	108,648,734	(45,181,313)	-	2,312,923,619
2061	2,312,923,619	111,714,211	(46,879,428)	-	2,377,758,402
2062	2,377,758,402	114,845,731	(48,642,230)	-	2,443,961,903
2063	2,443,961,903	118,043,360	(50,611,142)	-	2,511,394,121
2064	2,511,394,121	121,300,336	(52,374,081)	-	2,580,320,376
2065	2,580,320,376	124,629,474	(54,347,801)	-	2,650,602,049
2066	2,650,602,049	128,024,079	(56,397,117)	-	2,722,229,011
2067	2,722,229,011	131,483,661	(58,685,187)	-	2,795,027,486
2068	2,795,027,486	134,999,828	(60,735,346)	-	2,869,291,967
2069	2,869,291,967	138,586,802	(63,029,878)	-	2,944,848,891
2070	2,944,848,891	142,236,201	(65,412,777)	-	3,021,672,315
2071	3,021,672,315	145,946,773	(68,073,508)	-	3,099,545,580
2072	3,099,545,580	149,708,052	(70,457,796)	-	3,178,795,836
2073	3,178,795,836	153,535,839	(81,462,957)	-	3,250,868,718
2074	3,250,868,718	157,016,959	(86,234,487)	-	3,321,651,190
2075	3,321,651,190	160,435,752	(87,891,824)	-	3,394,195,118
2076	3,394,195,118	163,939,624	(90,961,699)	-	3,467,173,043
2077	3,467,173,043	167,464,458	(94,372,454)	-	3,540,265,046
2078	3,540,265,046	170,994,802	(99,877,415)	-	3,611,382,433
2079	3,611,382,433	174,429,772	(101,841,284)	-	3,683,970,920
2080	3,683,970,920	177,935,795	(466,595,262)	-	3,395,311,454
2081	3,395,311,454	163,993,543	(708,577,384)	-	2,850,727,613
2082	2,850,727,613	137,690,144	(923,697,643)	-	2,064,720,113
2083	2,064,720,113	99,725,981	(687,604,874)	-	1,476,841,221
2084	1,476,841,221	71,331,431	(683,855,253)	-	864,317,399
2085	864,317,399	41,746,530	(471,362,864)	-	434,701,065
2086	434,701,065	20,996,061	(322,085,668)	-	133,611,459
2087	133,611,459	6,453,433	(140,064,893)	-	(0)

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60-Year Decommissioning Period **Page 11 of 14**
SAFSTOR Method
5-Year Early Shutdown **Proposed**

EXTERNAL FUND CALCULATION

Prairie Island Unit 1

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	374,367,055	9,602,831	-	24,632	383,994,518
2018	383,994,518	19,700,182	-	49,264	403,743,965
2019	403,743,965	21,241,128	-	20,626,223	445,611,316
2020	445,611,316	23,388,923	-	20,626,223	489,626,462
2021	489,626,462	25,646,900	-	20,626,223	535,899,585
2022	535,899,585	28,020,711	-	20,626,223	584,546,519
2023	584,546,519	30,516,299	-	20,626,223	635,689,041
2024	635,689,041	33,139,910	-	20,626,223	689,455,175
2025	689,455,175	35,898,113	-	20,626,223	745,979,511
2026	745,979,511	38,797,812	-	20,626,223	805,403,545
2027	805,403,545	41,846,264	-	20,626,223	867,876,032
2028	867,876,032	42,164,676	(26,093,741)	13,819,569	897,766,537
2029	897,766,537	43,272,347	(85,547,775)	-	855,491,109
2030	855,491,109	41,234,671	(37,515,903)	-	859,209,877
2031	859,209,877	41,413,916	(32,140,303)	-	868,483,490
2032	868,483,490	41,860,904	(33,134,460)	-	877,209,934
2033	877,209,934	42,281,519	(47,713,763)	-	871,777,690
2034	871,777,690	42,019,685	(138,771,575)	-	775,025,800
2035	775,025,800	37,356,244	(13,288,961)	-	799,093,082
2036	799,093,082	38,516,287	(13,685,143)	-	823,924,226
2037	823,924,226	39,713,148	(14,135,014)	-	849,502,359
2038	849,502,359	40,946,014	(14,601,285)	-	875,847,088
2039	875,847,088	42,215,830	(15,127,775)	-	902,935,143
2040	902,935,143	43,521,474	(15,585,042)	-	930,871,576
2041	930,871,576	44,868,010	(16,103,868)	-	959,635,717
2042	959,635,717	46,254,442	(16,642,112)	-	989,248,047
2043	989,248,047	47,681,756	(17,248,941)	-	1,019,680,861
2044	1,019,680,861	49,148,618	(17,776,865)	-	1,051,052,614
2045	1,051,052,614	50,660,736	(18,375,387)	-	1,083,337,963
2046	1,083,337,963	52,216,890	(18,996,008)	-	1,116,558,845
2047	1,116,558,845	53,818,136	(19,696,541)	-	1,150,680,440
2048	1,150,680,440	55,462,797	(21,051,102)	-	1,185,092,135
2049	1,185,092,135	57,121,441	(22,535,136)	-	1,219,678,439
2050	1,219,678,439	58,788,501	(23,301,752)	-	1,255,165,188
2051	1,255,165,188	60,498,962	(24,571,163)	-	1,291,092,987
2052	1,291,092,987	62,230,682	(24,495,903)	-	1,328,827,766
2053	1,328,827,766	64,049,498	(26,646,318)	-	1,366,230,946
2054	1,366,230,946	65,852,332	(26,205,948)	-	1,405,877,330
2055	1,405,877,330	67,763,287	(26,717,263)	-	1,446,923,355
2056	1,446,923,355	69,741,706	(28,523,954)	-	1,488,141,107

External Levelized

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SAFSTOR Method
5-Year Early Shutdown **Proposed**

EXTERNAL FUND CALCULATION

2057	1,488,141,107	71,728,401	(29,509,208)	-	1,530,360,300
2058	1,530,360,300	73,763,366	(30,017,529)	-	1,574,106,137
2059	1,574,106,137	75,871,916	(31,675,750)	-	1,618,302,302
2060	1,618,302,302	78,002,171	(32,687,053)	-	1,663,617,421
2061	1,663,617,421	80,186,360	(33,260,079)	-	1,710,543,702
2062	1,710,543,702	82,448,206	(35,004,520)	-	1,757,987,389
2063	1,757,987,389	84,734,992	(36,327,139)	-	1,806,395,242
2064	1,806,395,242	87,068,251	(36,873,962)	-	1,856,589,531
2065	1,856,589,531	89,487,615	(38,811,398)	-	1,907,265,748
2066	1,907,265,748	91,930,209	(40,174,838)	-	1,959,021,119
2067	1,959,021,119	94,424,818	(41,702,580)	-	2,011,743,357
2068	2,011,743,357	96,966,030	(43,054,977)	-	2,065,654,409
2069	2,065,654,409	99,564,543	(44,575,228)	-	2,120,643,724
2070	2,120,643,724	102,215,028	(51,395,220)	-	2,171,463,532
2071	2,171,463,532	104,664,542	(47,918,013)	-	2,228,210,060
2072	2,228,210,060	107,399,725	(49,482,528)	-	2,286,127,258
2073	2,286,127,258	110,191,334	(38,308,473)	-	2,358,010,119
2074	2,358,010,119	113,656,088	(39,721,662)	-	2,431,944,544
2075	2,431,944,544	117,219,727	(41,300,486)	-	2,507,863,786
2076	2,507,863,786	120,879,034	(42,709,262)	-	2,586,033,559
2077	2,586,033,559	124,646,818	(44,288,156)	-	2,666,392,220
2078	2,666,392,220	128,520,105	(45,926,882)	-	2,748,985,443
2079	2,748,985,443	132,501,098	(47,757,956)	-	2,833,728,585
2080	2,833,728,585	136,585,718	(49,392,424)	-	2,920,921,879
2081	2,920,921,879	140,788,435	(51,223,963)	-	3,010,486,351
2082	3,010,486,351	145,105,442	(137,141,374)	-	3,018,450,419
2083	3,018,450,419	145,489,310	(510,925,861)	-	2,653,013,868
2084	2,653,013,868	127,875,268	(845,184,134)	-	1,935,705,003
2085	1,935,705,003	93,300,981	(764,957,013)	-	1,264,048,971
2086	1,264,048,971	60,927,160	(568,335,029)	-	756,641,102
2087	756,641,102	36,470,101	(216,232,427)	-	576,878,776
2088	576,878,776	27,805,557	(256,412,862)	-	348,271,470
2089	348,271,470	16,786,685	(212,741,434)	-	152,316,721
2090	152,316,721	7,341,666	(159,658,387)	-	(0)

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SAFSTOR Method
5-Year Early Shutdown **Proposed**

EXTERNAL FUND CALCULATION

Prairie Island Unit 2

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	420,208,967	10,803,157	-	294,670	431,306,795
2018	431,306,795	22,184,315	-	589,341	454,080,451
2019	454,080,451	23,572,159	-	9,043,741	486,696,351
2020	486,696,351	25,248,617	-	9,043,741	520,988,709
2021	520,988,709	27,011,244	-	9,043,741	557,043,694
2022	557,043,694	28,864,470	-	9,043,741	594,951,905
2023	594,951,905	30,812,952	-	9,043,741	634,808,598
2024	634,808,598	32,861,586	-	9,043,741	676,713,926
2025	676,713,926	35,015,520	-	9,043,741	720,773,187
2026	720,773,187	37,280,166	-	9,043,741	767,097,094
2027	767,097,094	39,661,215	-	9,043,741	815,802,050
2028	815,802,050	42,164,649	-	9,043,741	867,010,440
2029	867,010,440	42,057,882	(12,406,807)	7,506,305	904,167,820
2030	904,167,820	43,671,306	(90,281,325)	-	857,557,801
2031	857,557,801	41,420,042	(52,134,866)	-	846,842,977
2032	846,842,977	40,902,516	(29,141,967)	-	858,603,525
2033	858,603,525	41,470,550	(43,577,796)	-	856,496,280
2034	856,496,280	41,368,770	(135,253,712)	-	762,611,338
2035	762,611,338	36,834,128	(13,382,694)	-	786,062,772
2036	786,062,772	37,966,832	(13,782,286)	-	810,247,318
2037	810,247,318	39,134,945	(14,235,965)	-	835,146,298
2038	835,146,298	40,337,566	(14,706,196)	-	860,777,668
2039	860,777,668	41,575,561	(15,237,100)	-	887,116,129
2040	887,116,129	42,847,709	(15,698,348)	-	914,265,490
2041	914,265,490	44,159,023	(16,221,623)	-	942,202,891
2042	942,202,891	45,508,400	(16,764,496)	-	970,946,794
2043	970,946,794	46,896,730	(17,376,478)	-	1,000,467,046
2044	1,000,467,046	48,322,558	(17,909,053)	-	1,030,880,552
2045	1,030,880,552	49,791,531	(18,512,772)	-	1,062,159,311
2046	1,062,159,311	51,302,295	(19,138,796)	-	1,094,322,809
2047	1,094,322,809	52,855,792	(19,845,355)	-	1,127,333,246
2048	1,127,333,246	54,450,196	(21,205,352)	-	1,160,578,091
2049	1,160,578,091	56,055,922	(22,695,454)	-	1,193,938,559
2050	1,193,938,559	57,667,232	(23,468,384)	-	1,228,137,407
2051	1,228,137,407	59,319,037	(24,744,831)	-	1,262,711,613
2052	1,262,711,613	60,988,971	(24,675,920)	-	1,299,024,664
2053	1,299,024,664	62,742,891	(26,833,433)	-	1,334,934,122
2054	1,334,934,122	64,477,318	(26,400,439)	-	1,373,011,002
2055	1,373,011,002	66,316,431	(26,919,975)	-	1,412,407,458
2056	1,412,407,458	68,219,280	(28,734,087)	-	1,451,892,652

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5-Year Early Shutdown **Proposed**

EXTERNAL FUND CALCULATION

2057	1,451,892,652	70,126,415	(29,727,633)	-	1,492,291,434
2058	1,492,291,434	72,077,676	(30,244,574)	-	1,534,124,536
2059	1,534,124,536	74,098,215	(31,912,407)	-	1,576,310,345
2060	1,576,310,345	76,135,790	(32,932,383)	-	1,619,513,752
2061	1,619,513,752	78,222,514	(33,515,100)	-	1,664,221,166
2062	1,664,221,166	80,381,882	(35,269,615)	-	1,709,333,434
2063	1,709,333,434	82,560,805	(36,603,465)	-	1,755,290,773
2064	1,755,290,773	84,780,544	(37,160,429)	-	1,802,910,889
2065	1,802,910,889	87,080,596	(39,109,192)	-	1,850,882,293
2066	1,850,882,293	89,397,615	(40,484,410)	-	1,899,795,497
2067	1,899,795,497	91,760,123	(42,025,278)	-	1,949,530,341
2068	1,949,530,341	94,162,315	(43,389,533)	-	2,000,303,124
2069	2,000,303,124	96,614,641	(44,923,023)	-	2,051,994,743
2070	2,051,994,743	99,111,346	(51,756,785)	-	2,099,349,304
2071	2,099,349,304	101,398,571	(48,294,926)	-	2,152,452,949
2072	2,152,452,949	103,963,477	(49,873,301)	-	2,206,543,125
2073	2,206,543,125	106,576,033	(17,191,562)	-	2,295,927,596
2074	2,295,927,596	110,893,303	(17,748,654)	-	2,389,072,245
2075	2,389,072,245	115,392,189	(18,374,405)	-	2,486,090,030
2076	2,486,090,030	120,078,148	(18,918,989)	-	2,587,249,189
2077	2,587,249,189	124,964,136	(19,533,740)	-	2,692,679,585
2078	2,692,679,585	130,056,424	(20,169,179)	-	2,802,566,830
2079	2,802,566,830	135,363,978	(20,882,786)	-	2,917,048,022
2080	2,917,048,022	140,893,419	(21,504,295)	-	3,036,437,146
2081	3,036,437,146	146,659,914	(22,205,721)	-	3,160,891,338
2082	3,160,891,338	152,671,052	(22,930,853)	-	3,290,631,537
2083	3,290,631,537	158,937,503	(141,957,420)	-	3,307,611,620
2084	3,307,611,620	159,757,641	(357,637,520)	-	3,109,731,741
2085	3,109,731,741	150,200,043	(1,080,045,684)	-	2,179,886,100
2086	2,179,886,100	105,288,499	(847,383,481)	-	1,437,791,118
2087	1,437,791,118	69,445,311	(779,644,323)	-	727,592,106
2088	727,592,106	35,142,699	(330,500,380)	-	432,234,424
2089	432,234,424	20,876,923	(264,137,902)	-	188,973,445
2090	188,973,445	9,127,417	(198,100,862)	-	(0)

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SAFSTOR Method
20-Year Life Extension

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Proposed

2019 ACCRUAL COMPARISON

	Present	Proposed	Difference
Monticello	$13,392,226	($5,964,498)	($19,356,724)
Prairie Island Unit 1	49,264	(1,034,991)	(1,084,255)
Prairie Island Unit 2	589,341	(5,516,417)	(6,105,758)
TOTAL	$14,030,831	($12,515,906)	($26,546,737)

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60-Year Decommissioning Period **Page 2 of 17**
SAFSTOR Method
20-Year Life Extension **Proposed**

2019 MN RETAIL SUMMARY

	Remaining Life (yrs)	Operational Earnings Rate	Post-Shutdown Earnings Rate	Market Value Balance 6/30/2017	Book Value 6/30/2017	Unrealized Gain/Loss 6/30/2017	Tax-Effect Adjustment	Tax-Adjusted Fund Balance 6/30/2017	2019-2021 Decommissioning Accrual
Monticello	33.75	5.10%	4.83%	$660,140,345	$529,148,381	$130,991,964	$36,468,163	$623,672,182	**(5,964,498)**
Prairie Island Unit 1	36.67	5.13%	4.82%	399,941,696	308,078,761	91,862,935	25,574,641	374,367,055	**(1,034,991)**
Prairie Island Unit 2	37.83	5.14%	4.83%	448,597,551	346,627,064	101,970,487	28,388,583	420,208,967	**(5,516,417)**
TOTAL DECOMMISSIONING ACCRUAL				**$1,508,679,592**	**$1,183,854,206**	**$324,825,386**	**$90,431,387**	**$1,418,248,204**	**($12,515,906)**

INPUT DATA

Escalation Rate (Labor)	4.05%
Escalation Rate (Non-Labor)	2.85%
Escalation Rate (PIIC)	0.00%
Jurisdictional Factor	73.4886%
Tax Rate for tax-effect adjustment	27.84%

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Proposed

AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
Monticello															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2050	$17,759,328	$13,051,073	3.7067	$48,376,414	$8,763,593	$6,440,238	2.5278	$16,279,633	$0	$0	1.0000	$0	$26,522,921	$19,491,311	$64,656,047
2051	63,231,064	46,467,594	3.8568	179,216,218	46,823,276	34,409,748	2.5998	89,458,463	0	0	1.0000	0	110,054,340	80,877,343	268,674,682
2052	30,098,747	22,119,134	4.0130	88,764,085	21,963,833	16,140,903	2.6739	43,159,162	0	0	1.0000	0	52,062,580	38,260,037	131,923,246
2053	30,011,960	22,055,355	4.1756	92,094,341	35,867,567	26,358,556	2.7501	72,488,665	0	0	1.0000	0	65,879,526	48,413,911	164,583,006
2054	24,261,956	17,829,760	4.3447	77,464,960	18,617,567	13,681,781	2.8285	38,698,916	0	0	1.0000	0	42,879,522	31,511,541	116,163,876
2055	43,935,865	32,287,832	4.5206	145,960,372	88,132,650	64,767,410	2.9091	188,414,872	0	0	1.0000	0	132,068,514	97,055,241	334,375,244
2056	8,481,485	6,232,921	4.7037	29,317,788	4,523,995	3,324,618	2.9920	9,947,258	0	0	1.0000	0	13,005,479	9,557,539	39,265,046
2057	8,458,357	6,215,924	4.8942	30,421,976	4,511,770	3,315,635	3.0773	10,203,202	0	0	1.0000	0	12,970,127	9,531,559	40,625,178
2058	8,458,357	6,215,924	5.0924	31,653,972	4,511,770	3,315,635	3.1650	10,493,983	0	0	1.0000	0	12,970,127	9,531,559	42,147,955
2059	8,458,357	6,215,924	5.2987	32,936,317	4,511,770	3,315,635	3.2552	10,793,054	0	0	1.0000	0	12,970,127	9,531,559	43,729,371
2060	8,481,485	6,232,921	5.5133	34,363,961	4,523,995	3,324,618	3.3480	11,130,822	0	0	1.0000	0	13,005,479	9,557,539	45,494,783
2061	8,458,357	6,215,924	5.7366	35,658,270	4,511,770	3,315,635	3.4434	11,417,056	0	0	1.0000	0	12,970,127	9,531,559	47,075,326
2062	8,458,357	6,215,924	5.9689	37,102,229	4,511,770	3,315,635	3.5415	11,742,320	0	0	1.0000	0	12,970,127	9,531,559	48,844,549
2063	8,458,357	6,215,924	6.2106	38,604,618	4,511,770	3,315,635	3.6425	12,077,199	0	0	1.0000	0	12,970,127	9,531,559	50,681,817
2064	8,481,485	6,232,921	6.4622	40,278,379	4,523,995	3,324,618	3.7463	12,455,017	0	0	1.0000	0	13,005,479	9,557,539	52,733,396
2065	8,458,357	6,215,924	6.7239	41,795,252	4,511,770	3,315,635	3.8531	12,775,472	0	0	1.0000	0	12,970,127	9,531,559	54,570,723
2066	8,458,357	6,215,924	6.9962	43,487,848	4,511,770	3,315,635	3.9629	13,139,528	0	0	1.0000	0	12,970,127	9,531,559	56,627,376
2067	8,458,357	6,215,924	7.2795	45,248,819	4,511,770	3,315,635	4.0758	13,513,863	0	0	1.0000	0	12,970,127	9,531,559	58,762,683
2068	9,145,130	6,720,624	7.5744	50,904,692	6,514,932	4,787,729	4.1920	20,070,160	0	0	1.0000	0	15,660,061	11,508,353	70,974,852
2069	8,458,357	6,215,924	7.8811	48,988,319	4,511,767	3,315,632	4.3115	14,295,349	0	0	1.0000	0	12,970,124	9,531,556	63,283,668
2070	9,951,558	7,313,256	8.2003	59,970,892	8,991,374	6,607,631	4.4343	29,300,217	0	0	1.0000	0	18,942,932	13,920,887	89,271,109
2071	9,951,558	7,313,256	8.5324	62,399,625	8,991,374	6,607,631	4.5607	30,135,422	0	0	1.0000	0	18,942,932	13,920,887	92,535,046
2072	10,837,186	7,964,091	8.8780	70,705,201	11,591,099	8,518,131	4.6907	39,955,996	0	0	1.0000	0	22,428,284	16,482,222	110,661,197
2073	11,460,933	8,422,474	9.2375	77,802,601	13,519,499	9,935,284	4.8244	47,931,786	0	0	1.0000	0	24,980,432	18,357,758	125,734,387
2074	10,167,183	7,471,716	9.6117	71,815,889	9,638,249	7,083,010	4.9619	35,145,187	0	0	1.0000	0	19,805,432	14,554,725	106,961,075
2075	11,245,308	8,264,014	10.0009	82,647,578	12,872,624	9,459,905	5.1033	48,276,734	0	0	1.0000	0	24,117,932	17,723,919	130,924,313
2076	11,699,686	8,597,930	10.4060	89,470,059	14,178,599	10,419,647	5.2487	54,689,602	0	0	1.0000	0	25,878,284	19,017,577	144,159,660
2077	8,441,765	6,203,731	10.8274	67,170,276	4,461,997	3,279,057	5.3983	17,701,334	0	0	1.0000	0	12,903,762	9,482,788	84,871,609
2078	8,441,765	6,203,731	11.2659	69,890,612	4,461,997	3,279,057	5.5522	18,205,981	0	0	1.0000	0	12,903,762	9,482,788	88,096,592
2079	8,441,765	6,203,731	11.7222	72,721,374	4,461,997	3,279,057	5.7104	18,724,728	0	0	1.0000	0	12,903,762	9,482,788	91,446,102
2080	8,464,894	6,220,728	12.1970	75,874,220	4,474,222	3,288,041	5.8731	19,310,993	0	0	1.0000	0	12,939,115	9,508,769	95,185,212
2081	8,441,765	6,203,731	12.6909	78,730,928	4,461,997	3,279,057	6.0405	19,807,144	0	0	1.0000	0	12,903,762	9,482,788	98,538,072
2082	8,441,765	6,203,731	13.2049	81,919,646	4,461,997	3,279,057	6.2127	20,371,798	0	0	1.0000	0	12,903,762	9,482,788	102,291,444
2083	8,441,765	6,203,731	13.7397	85,237,401	4,461,997	3,279,057	6.3897	20,952,191	0	0	1.0000	0	12,903,762	9,482,788	106,189,592
2084	8,464,894	6,220,728	14.2962	88,932,772	4,474,222	3,288,041	6.5719	21,608,675	0	0	1.0000	0	12,939,115	9,508,769	110,541,448
2085	8,441,765	6,203,731	14.8752	92,281,737	4,461,997	3,279,057	6.7592	22,163,803	0	0	1.0000	0	12,903,762	9,482,788	114,445,540
2086	8,441,765	6,203,731	15.4776	96,018,865	4,461,997	3,279,057	6.9518	22,795,349	0	0	1.0000	0	12,903,762	9,482,788	118,814,214
2087	8,441,765	6,203,731	16.1045	99,907,984	4,461,997	3,279,057	7.1499	23,444,930	0	0	1.0000	0	12,903,762	9,482,788	123,352,914
2088	8,464,894	6,220,728	16.7567	104,238,874	4,474,222	3,288,041	7.3537	24,179,266	0	0	1.0000	0	12,939,115	9,508,769	128,418,139
2089	8,441,765	6,203,731	17.4353	108,163,909	4,461,997	3,279,057	7.5633	24,800,493	0	0	1.0000	0	12,903,762	9,482,788	132,964,401
2090	8,441,765	6,203,731	18.1415	112,544,983	4,461,997	3,279,057	7.7788	25,507,129	0	0	1.0000	0	12,903,762	9,482,788	138,052,113
2091	8,441,765	6,203,731	18.8762	117,102,865	4,461,997	3,279,057	8.0005	26,234,096	0	0	1.0000	0	12,903,762	9,482,788	143,336,961
2092	8,464,894	6,220,728	19.6407	122,179,453	4,474,222	3,288,041	8.2285	27,055,644	0	0	1.0000	0	12,939,115	9,508,769	149,235,097
2093	8,441,765	6,203,731	20.4361	126,780,064	4,461,997	3,279,057	8.4630	27,750,660	0	0	1.0000	0	12,903,762	9,482,788	154,530,725
2094	8,441,765	6,203,731	21.2638	131,914,892	4,461,997	3,279,057	8.7042	28,541,569	0	0	1.0000	0	12,903,762	9,482,788	160,456,461
2095	8,441,765	6,203,731	22.1250	137,257,545	4,461,997	3,279,057	8.9523	29,355,103	0	0	1.0000	0	12,903,762	9,482,788	166,612,648
2096	8,464,894	6,220,728	23.0210	143,207,380	4,474,222	3,288,041	9.2075	30,274,636	0	0	1.0000	0	12,939,115	9,508,769	173,482,016
2097	8,441,765	6,203,731	23.9534	148,600,447	4,461,997	3,279,057	9.4699	31,052,343	0	0	1.0000	0	12,903,762	9,482,788	179,652,790
2098	8,920,197	6,555,324	24.9235	163,381,608	5,897,293	4,333,835	9.7398	42,210,690	0	0	1.0000	0	14,817,490	10,889,159	205,592,298
2099	9,015,884	6,625,643	25.9329	171,822,127	6,184,352	4,544,791	10.0173	45,526,534	0	0	1.0000	0	15,200,236	11,170,433	217,348,661
2100	8,943,325	6,572,320	26.9832	177,342,227	5,909,518	4,342,819	10.3028	44,743,197	0	0	1.0000	0	14,852,842	10,915,139	222,085,423
2101	8,920,197	6,555,324	28.0760	184,047,266	5,897,293	4,333,835	10.5965	45,923,487	0	0	1.0000	0	14,817,490	10,889,159	229,970,753
2102	8,920,197	6,555,324	29.2131	191,501,325	5,897,293	4,333,835	10.8985	47,232,305	0	0	1.0000	0	14,817,490	10,889,159	238,733,629
2103	9,015,884	6,625,643	30.3962	201,394,358	6,184,352	4,544,791	11.2091	50,943,015	0	0	1.0000	0	15,200,236	11,170,433	252,337,374
2104	8,943,325	6,572,320	31.6272	207,864,081	5,909,518	4,342,819	11.5285	50,066,190	0	0	1.0000	0	14,852,842	10,915,139	257,930,271

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AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
2105	46,126,149	33,897,440	32.9081	1,115,500,348	12,314,062	9,049,426	11.8571	107,299,952	0	0	1.0000	0	58,440,212	42,946,866	1,222,800,300
2106	53,631,139	39,412,748	34.2409	1,349,527,973	46,945,385	34,499,485	12.1950	420,721,214	0	0	1.0000	0	100,576,524	73,912,233	1,770,249,187
2107	57,419,114	42,196,476	35.6277	1,503,363,401	80,273,242	58,991,645	12.5426	739,908,606	0	0	1.0000	0	137,692,356	101,188,121	2,243,272,007
2108	52,652,752	38,693,746	37.0706	1,434,400,375	33,214,319	24,408,722	12.9000	314,872,520	0	0	1.0000	0	85,867,070	63,102,468	1,749,272,895
2109	50,913,638	37,415,697	38.5720	1,443,198,252	30,841,715	22,665,130	13.2677	300,714,150	0	0	1.0000	0	81,755,354	60,080,827	1,743,912,402
2110	32,667,889	24,007,160	40.1341	963,505,742	23,001,023	16,903,119	13.6458	230,656,586	0	0	1.0000	0	55,668,913	40,910,279	1,194,162,328
2111	21,071,356	15,485,035	41.7596	646,648,865	16,131,940	11,855,130	14.0347	166,383,189	0	0	1.0000	0	37,203,297	27,340,165	813,032,054
2112	8,832,651	6,490,987	43.4508	282,038,589	6,762,156	4,969,411	14.4347	71,731,950	0	0	1.0000	0	15,594,807	11,460,398	353,770,539
	$967,171,883	$710,760,631		$13,883,663,437	$750,282,438	$551,371,714		$4,086,760,388	$0	$0		$0	$1,717,454,322	$1,262,132,345	$17,970,423,825

Xcel Energy
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60-Year Decommissioning Period
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20-Year Life Extension

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Proposed

AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
Prairie Island Unit 1															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2053	$18,446,908	$13,556,366	4.1756	$56,605,961	$4,190,856	$3,079,799	2.7501	$8,469,756	$1,250,000	$918,607	1.0000	$918,607	$23,887,764	$17,554,772	$65,994,324
2054	46,142,627	33,909,549	4.3447	147,326,818	29,162,161	21,430,850	2.8285	60,617,159	1,250,000	918,607	1.0000	918,607	76,554,787	56,259,006	208,862,585
2055	16,398,923	12,051,331	4.5206	54,479,249	15,491,742	11,384,657	2.9091	33,119,105	1,250,000	918,607	1.0000	918,607	33,140,665	24,354,595	88,516,961
2056	12,659,656	9,303,398	4.7037	43,760,395	13,774,811	10,122,909	2.9920	30,287,745	1,250,000	918,607	1.0000	918,607	27,684,467	20,344,915	74,966,746
2057	12,625,333	9,278,174	4.8942	45,409,241	13,734,545	10,093,318	3.0773	31,060,169	1,250,000	918,607	1.0000	918,607	27,609,877	20,290,100	77,388,016
2058	15,404,499	11,320,543	5.0924	57,648,734	22,072,045	16,220,427	3.1650	51,337,650	1,250,000	918,607	1.0000	918,607	38,726,543	28,459,577	109,904,991
2059	32,688,492	24,022,300	5.2987	127,286,962	76,524,027	56,236,401	3.2552	183,060,732	1,250,000	918,607	1.0000	918,607	110,462,519	81,177,308	311,266,301
2060	4,604,176	3,383,542	5.5133	18,654,485	4,477,123	3,290,173	3.3480	11,015,499	1,250,000	918,607	1.0000	918,607	10,331,299	7,592,322	30,588,591
2061	4,591,596	3,374,297	5.7366	19,356,993	4,461,475	3,278,674	3.4434	11,289,785	1,250,000	918,607	1.0000	918,607	10,303,071	7,571,578	31,565,385
2062	4,591,596	3,374,297	5.9689	20,140,843	4,461,475	3,278,674	3.5415	11,611,423	1,250,000	918,607	1.0000	918,607	10,303,071	7,571,578	32,670,872
2063	4,591,596	3,374,297	6.2106	20,956,410	4,461,475	3,278,674	3.6425	11,942,569	1,250,000	918,607	1.0000	918,607	10,303,071	7,571,578	33,817,586
2064	4,604,176	3,383,542	6.4622	21,865,128	4,477,123	3,290,173	3.7463	12,325,975	1,250,000	918,607	1.0000	918,607	10,331,299	7,592,322	35,109,710
2065	4,591,596	3,374,297	6.7239	22,688,437	4,461,475	3,278,674	3.8531	12,633,057	1,250,000	918,607	1.0000	918,607	10,303,071	7,571,578	36,240,101
2066	4,591,596	3,374,297	6.9962	23,607,258	4,461,475	3,278,674	3.9629	12,993,056	1,250,000	918,607	1.0000	918,607	10,303,071	7,571,578	37,518,921
2067	4,591,596	3,374,297	7.2795	24,563,197	4,461,475	3,278,674	4.0758	13,363,218	1,250,000	918,607	1.0000	918,607	10,303,071	7,571,578	38,845,022
2068	4,604,176	3,383,542	7.5744	25,628,304	4,477,123	3,290,173	4.1920	13,792,405	1,250,000	918,607	1.0000	918,607	10,331,299	7,592,322	40,339,316
2069	4,591,596	3,374,297	7.8811	26,593,174	4,461,475	3,278,674	4.3115	14,136,001	1,250,000	918,607	1.0000	918,607	10,303,071	7,571,578	41,647,782
2070	4,591,596	3,374,297	8.2003	27,670,249	4,461,475	3,278,674	4.4343	14,538,623	1,250,000	918,607	1.0000	918,607	10,303,071	7,571,578	43,127,479
2071	4,591,596	3,374,297	8.5324	28,790,854	4,461,475	3,278,674	4.5607	14,953,047	1,250,000	918,607	1.0000	918,607	10,303,071	7,571,578	44,662,507
2072	4,604,176	3,383,542	8.8780	30,039,090	4,477,123	3,290,173	4.6907	15,433,215	1,250,000	918,607	1.0000	918,607	10,331,299	7,592,322	46,390,912
2073	4,687,283	3,444,616	9.2375	31,819,642	4,748,534	3,489,629	4.8244	16,835,367	1,250,000	918,607	1.0000	918,607	10,685,817	7,852,852	49,573,616
2074	4,782,969	3,514,934	9.6117	33,784,496	5,035,593	3,700,585	4.9619	18,361,931	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	53,065,034
2075	4,782,969	3,514,934	10.0009	35,152,508	5,035,593	3,700,585	5.1033	18,885,194	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	54,956,309
2076	4,843,392	3,559,339	10.4060	37,038,480	5,194,771	3,817,562	5.2487	20,037,239	1,250,000	918,607	1.0000	918,607	11,288,163	8,295,508	57,994,326
2077	4,735,126	3,479,775	10.8274	37,676,920	4,892,064	3,595,107	5.3983	19,407,468	1,250,000	918,607	1.0000	918,607	10,877,190	7,993,490	58,002,994
2078	4,878,656	3,585,253	11.2659	40,391,107	5,322,652	3,911,540	5.5522	21,717,653	1,250,000	918,607	1.0000	918,607	11,451,308	8,415,401	63,027,367
2079	4,735,126	3,479,775	11.7222	40,790,622	4,892,064	3,595,107	5.7104	20,529,501	1,250,000	918,607	1.0000	918,607	10,877,190	7,993,490	62,238,730
2080	4,699,862	3,453,861	12.1970	42,126,739	4,764,182	3,501,129	5.8731	20,562,478	1,250,000	918,607	1.0000	918,607	10,714,044	7,873,596	63,607,824
2081	4,782,969	3,514,934	12.6909	44,607,682	5,035,593	3,700,585	6.0405	22,353,382	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	67,879,670
2082	4,782,969	3,514,934	13.2049	46,414,358	5,035,593	3,700,585	6.2127	22,990,622	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	70,323,587
2083	4,735,126	3,479,775	13.7397	47,811,069	4,892,064	3,595,107	6.3897	22,971,657	1,250,000	918,607	1.0000	918,607	10,877,190	7,993,490	71,701,333
2084	4,795,548	3,524,179	14.2962	50,382,367	5,051,241	3,712,084	6.5719	24,395,445	1,250,000	918,607	1.0000	918,607	11,096,789	8,154,870	75,696,420
2085	4,782,969	3,514,934	14.8752	52,285,353	5,035,593	3,700,585	6.7592	25,012,992	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	78,216,952
2086	4,735,126	3,479,775	15.4776	53,858,571	4,892,064	3,595,107	6.9518	24,992,467	1,250,000	918,607	1.0000	918,607	10,877,190	7,993,490	79,769,645
2087	4,782,969	3,514,934	16.1045	56,606,262	5,035,593	3,700,585	7.1499	26,458,810	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	83,983,679
2088	4,795,548	3,524,179	16.7567	59,053,610	5,051,241	3,712,084	7.3537	27,297,553	1,250,000	918,607	1.0000	918,607	11,096,789	8,154,870	87,269,769
2089	4,735,126	3,479,775	17.4353	60,670,927	4,892,064	3,595,107	7.5633	27,190,875	1,250,000	918,607	1.0000	918,607	10,877,190	7,993,490	88,780,409
2090	4,782,969	3,514,934	18.1415	63,766,184	5,035,593	3,700,585	7.7788	28,786,108	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	93,470,899
2091	4,782,969	3,514,934	18.8762	66,348,606	5,035,593	3,700,585	8.0005	29,606,528	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	96,873,741
2092	4,795,548	3,524,179	19.6407	69,217,342	5,051,241	3,712,084	8.2285	30,544,884	1,250,000	918,607	1.0000	918,607	11,096,789	8,154,870	100,680,833
2093	4,782,969	3,514,934	20.4361	71,831,552	5,035,593	3,700,585	8.4630	31,318,048	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	104,068,207
2094	4,782,969	3,514,934	21.2638	74,740,864	5,035,593	3,700,585	8.7042	32,210,629	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	107,870,100
2095	5,114,792	3,758,786	22.1250	83,163,149	6,031,061	4,432,140	8.9523	39,677,844	1,250,000	918,607	1.0000	918,607	12,395,853	9,109,533	123,759,600
2096	4,795,548	3,524,179	23.0210	81,130,124	5,051,241	3,712,084	9.2075	34,179,014	1,250,000	918,607	1.0000	918,607	11,096,789	8,154,870	116,227,745
2097	4,782,969	3,514,934	23.9534	84,194,631	5,035,593	3,700,585	9.4699	35,044,167	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	120,157,405
2098	3,942,348	2,897,174	24.9235	72,207,722	3,256,582	2,393,215	9.7398	23,309,434	0	0	1.0000	0	7,198,929	5,290,389	95,517,156
2099	3,942,348	2,897,174	25.9329	75,132,129	3,256,582	2,393,215	10.0173	23,973,551	0	0	1.0000	0	7,198,929	5,290,389	99,105,680
2100	3,953,149	2,905,112	26.9832	78,389,210	3,265,504	2,399,772	10.3028	24,724,367	0	0	1.0000	0	7,218,652	5,304,883	103,113,576
2101	3,942,348	2,897,174	28.0760	81,341,063	3,256,582	2,393,215	10.5965	25,359,701	0	0	1.0000	0	7,198,929	5,290,389	106,700,764
2102	3,942,348	2,897,174	29.2131	84,635,440	3,256,582	2,393,215	10.8985	26,082,452	0	0	1.0000	0	7,198,929	5,290,389	110,717,892
2103	3,942,348	2,897,174	30.3962	88,063,087	3,256,582	2,393,215	11.2091	26,825,784	0	0	1.0000	0	7,198,929	5,290,389	114,888,871
2104	3,953,149	2,905,112	31.6272	91,880,548	3,265,504	2,399,772	11.5285	27,665,767	0	0	1.0000	0	7,218,652	5,304,883	119,546,315
2105	3,942,348	2,897,174	32.9081	95,340,499	3,256,582	2,393,215	11.8571	28,376,588	0	0	1.0000	0	7,198,929	5,290,389	123,717,087
2106	3,942,348	2,897,174	34.2409	99,201,853	3,256,582	2,393,215	12.1950	29,185,255	0	0	1.0000	0	7,198,929	5,290,389	128,387,108
2107	11,802,691	8,673,627	35.6277	309,021,370	4,951,569	3,638,837	12.5426	45,640,474	0	0	1.0000	0	16,754,260	12,312,463	354,661,844

Xcel Energy
Nuclear Decommissioning Accrual
60-Year Decommissioning Period
SAFSTOR Method
20-Year Life Extension

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Proposed

AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
2108	45,111,220	33,151,584	37.0706	1,228,949,094	11,805,071	8,675,376	12.9000	111,912,347	0	0	1.0000	0	56,916,291	41,826,959	1,340,861,441
2109	51,818,304	38,080,522	38.5720	1,468,841,899	62,277,980	45,767,187	13.2677	607,225,301	0	0	1.0000	0	114,096,283	83,847,709	2,076,067,200
2110	44,187,860	32,473,019	40.1341	1,303,275,394	56,754,748	41,708,244	13.6458	569,142,350	0	0	1.0000	0	100,942,608	74,181,263	1,872,417,744
2111	35,668,367	26,212,167	41.7596	1,094,609,618	31,834,151	23,394,458	14.0347	328,334,194	0	0	1.0000	0	67,502,519	49,606,625	1,422,943,812
2112	13,715,750	10,079,506	43.4508	437,962,617	10,259,487	7,539,548	14.4347	108,831,118	0	0	1.0000	0	23,975,237	17,619,055	546,793,735
2113	18,089,191	13,293,485	45.2106	601,006,439	6,228,187	4,577,005	14.8461	67,950,670	0	0	1.0000	0	24,317,379	17,870,490	668,957,109
2114	12,584,719	9,248,328	47.0416	435,056,148	9,264,588	6,808,412	15.2692	103,959,000	0	0	1.0000	0	21,849,307	16,056,740	539,015,148
2115	9,102,372	6,689,202	48.9468	327,415,015	6,700,962	4,924,440	15.7044	77,335,379	0	0	1.0000	0	15,803,334	11,613,642	404,750,394
	$611,385,166	$449,298,117		$10,180,264,092	$588,533,792	$432,504,973		$3,465,181,777	$56,250,000	$41,337,312		$41,337,312	$1,256,168,958	$923,140,402	$13,686,783,181

Xcel Energy
Nuclear Decommissioning Accrual
60-Year Decommissioning Period
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20-Year Life Extension

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Proposed

AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
Prairie Island Unit 2															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2054	$7,248,794	$5,327,034	4.3447	$23,144,365	$2,826,485	$2,077,143	2.8285	$5,875,198	$1,250,000	$918,607	1.0000	$918,607	$11,325,279	$8,322,784	$29,938,170
2055	44,817,806	32,935,958	4.5206	148,890,290	32,275,248	23,718,613	2.9091	68,999,817	1,250,000	918,607	1.0000	918,607	78,343,054	57,573,177	218,808,713
2056	23,021,476	16,918,150	4.7037	79,577,901	19,944,127	14,656,651	2.9920	43,852,699	1,250,000	918,607	1.0000	918,607	44,215,603	32,493,407	124,349,207
2057	10,761,111	7,908,185	4.8942	38,704,239	12,388,936	9,104,450	3.0773	28,017,124	1,250,000	918,607	1.0000	918,607	24,400,047	17,931,242	67,639,969
2058	13,540,277	9,950,554	5.0924	50,672,200	20,726,436	15,231,558	3.1650	48,207,881	1,250,000	918,607	1.0000	918,607	35,516,713	26,100,719	99,798,689
2059	31,160,880	22,899,680	5.2987	121,338,535	75,415,818	55,421,994	3.2552	180,409,674	1,250,000	918,607	1.0000	918,607	107,826,698	79,240,281	302,666,816
2060	4,659,832	3,424,443	5.5133	18,879,983	4,485,457	3,296,297	3.3480	11,036,004	1,250,000	918,607	1.0000	918,607	10,395,289	7,639,347	30,834,593
2061	4,647,099	3,415,086	5.7366	19,590,984	4,469,786	3,284,781	3.4434	11,310,816	1,250,000	918,607	1.0000	918,607	10,366,886	7,618,474	31,820,406
2062	4,647,099	3,415,086	5.9689	20,384,308	4,469,786	3,284,781	3.5415	11,633,053	1,250,000	918,607	1.0000	918,607	10,366,886	7,618,474	32,935,968
2063	4,647,099	3,415,086	6.2106	21,209,734	4,469,786	3,284,781	3.6425	11,964,816	1,250,000	918,607	1.0000	918,607	10,366,886	7,618,474	34,093,157
2064	4,659,832	3,424,443	6.4622	22,129,437	4,485,457	3,296,297	3.7463	12,348,919	1,250,000	918,607	1.0000	918,607	10,395,289	7,639,347	35,396,963
2065	4,647,099	3,415,086	6.7239	22,962,698	4,469,786	3,284,781	3.8531	12,656,591	1,250,000	918,607	1.0000	918,607	10,366,886	7,618,474	36,537,896
2066	4,647,099	3,415,086	6.9962	23,892,626	4,469,786	3,284,781	3.9629	13,017,260	1,250,000	918,607	1.0000	918,607	10,366,886	7,618,474	37,828,493
2067	4,647,099	3,415,086	7.2795	24,860,120	4,469,786	3,284,781	4.0758	13,388,111	1,250,000	918,607	1.0000	918,607	10,366,886	7,618,474	39,166,838
2068	4,659,832	3,424,443	7.5744	25,938,103	4,485,457	3,296,297	4.1920	13,818,079	1,250,000	918,607	1.0000	918,607	10,395,289	7,639,347	40,674,788
2069	4,647,099	3,415,086	7.8811	26,914,636	4,469,786	3,284,781	4.3115	14,162,334	1,250,000	918,607	1.0000	918,607	10,366,886	7,618,474	41,995,577
2070	4,647,099	3,415,086	8.2003	28,004,731	4,469,786	3,284,781	4.4343	14,565,705	1,250,000	918,607	1.0000	918,607	10,366,886	7,618,474	43,489,044
2071	4,647,099	3,415,086	8.5324	29,138,882	4,469,786	3,284,781	4.5607	14,980,902	1,250,000	918,607	1.0000	918,607	10,366,886	7,618,474	45,038,390
2072	4,659,832	3,424,443	8.8780	30,402,207	4,485,457	3,296,297	4.6907	15,461,942	1,250,000	918,607	1.0000	918,607	10,395,289	7,639,347	46,782,756
2073	4,742,786	3,485,405	9.2375	32,196,431	4,756,846	3,495,737	4.8244	16,864,836	1,250,000	918,607	1.0000	918,607	10,749,633	7,899,750	49,979,873
2074	4,838,472	3,555,723	9.6117	34,176,547	5,043,904	3,706,692	4.9619	18,392,236	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	53,487,390
2075	4,838,472	3,555,723	10.0009	35,560,435	5,043,904	3,706,692	5.1033	18,916,363	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	55,395,404
2076	4,899,048	3,600,240	10.4060	37,464,093	5,203,105	3,823,687	5.2487	20,069,383	1,250,000	918,607	1.0000	918,607	11,352,153	8,342,533	58,452,083
2077	4,790,629	3,520,564	10.8274	38,118,558	4,900,375	3,601,215	5.3983	19,440,438	1,250,000	918,607	1.0000	918,607	10,941,005	8,040,386	58,477,603
2078	4,934,159	3,626,042	11.2659	40,850,632	5,330,963	3,917,648	5.5522	21,751,564	1,250,000	918,607	1.0000	918,607	11,515,123	8,462,297	63,520,802
2079	4,790,629	3,520,564	11.7222	41,268,759	4,900,375	3,601,215	5.7104	20,564,377	1,250,000	918,607	1.0000	918,607	10,941,005	8,040,386	62,751,743
2080	4,755,518	3,494,761	12.1970	42,625,606	4,772,516	3,507,253	5.8731	20,598,447	1,250,000	918,607	1.0000	918,607	10,778,034	7,920,621	64,142,659
2081	4,838,472	3,555,723	12.6909	45,125,331	5,043,904	3,706,692	6.0405	22,390,275	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	68,434,212
2082	4,838,472	3,555,723	13.2049	46,952,973	5,043,904	3,706,692	6.2127	23,028,567	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	70,900,147
2083	4,790,629	3,520,564	13.7397	48,371,498	4,900,375	3,601,215	6.3897	23,010,683	1,250,000	918,607	1.0000	918,607	10,941,005	8,040,386	72,300,787
2084	4,851,204	3,565,080	14.2962	50,967,093	5,059,575	3,718,208	6.5719	24,435,694	1,250,000	918,607	1.0000	918,607	11,160,779	8,201,895	76,321,393
2085	4,838,472	3,555,723	14.8752	52,892,098	5,043,904	3,706,692	6.7592	25,054,274	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	78,864,979
2086	4,790,629	3,520,564	15.4776	54,489,887	4,900,375	3,601,215	6.9518	25,034,925	1,250,000	918,607	1.0000	918,607	10,941,005	8,040,386	80,443,419
2087	4,838,472	3,555,723	16.1045	57,263,148	5,043,904	3,706,692	7.1499	26,502,479	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	84,684,234
2088	4,851,204	3,565,080	16.7567	59,738,971	5,059,575	3,718,208	7.3537	27,342,589	1,250,000	918,607	1.0000	918,607	11,160,779	8,201,895	88,000,167
2089	4,790,629	3,520,564	17.4353	61,382,095	4,900,375	3,601,215	7.5633	27,237,068	1,250,000	918,607	1.0000	918,607	10,941,005	8,040,386	89,537,771
2090	4,838,472	3,555,723	18.1415	64,506,157	5,043,904	3,706,692	7.7788	28,833,618	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	94,258,382
2091	4,838,472	3,555,723	18.8762	67,118,547	5,043,904	3,706,692	8.0005	29,655,391	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	97,692,545
2092	4,851,204	3,565,080	19.6407	70,020,661	5,059,575	3,718,208	8.2285	30,595,278	1,250,000	918,607	1.0000	918,607	11,160,779	8,201,895	101,534,546
2093	4,838,472	3,555,723	20.4361	72,665,120	5,043,904	3,706,692	8.4630	31,369,736	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	104,953,464
2094	4,838,472	3,555,723	21.2638	75,608,193	5,043,904	3,706,692	8.7042	32,263,791	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	108,790,590
2095	5,170,295	3,799,575	22.1250	84,065,605	6,039,372	4,438,247	8.9523	39,732,521	1,250,000	918,607	1.0000	918,607	12,459,668	9,156,430	124,716,733
2096	4,851,204	3,565,080	23.0210	82,071,700	5,059,575	3,718,208	9.2075	34,235,404	1,250,000	918,607	1.0000	918,607	11,160,779	8,201,895	117,225,711
2097	4,838,472	3,555,723	23.9534	85,171,666	5,043,904	3,706,692	9.4699	35,102,005	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	121,192,278
2098	823,359	605,074	24.9235	15,080,573	3,272,479	2,404,897	9.7398	23,423,219	0	-	1.0000	-	4,095,838	3,009,972	38,503,792
2099	823,359	605,074	25.9329	15,691,335	3,272,479	2,404,897	10.0173	24,090,578	0	-	1.0000	-	4,095,838	3,009,972	39,781,913
2100	825,615	606,732	26.9832	16,371,576	3,281,444	2,411,486	10.3028	24,845,059	0	-	1.0000	-	4,107,059	3,018,218	41,216,634
2101	823,359	605,074	28.0760	16,988,070	3,272,479	2,404,897	10.5965	25,483,495	0	-	1.0000	-	4,095,838	3,009,972	42,471,564
2102	823,359	605,074	29.2131	17,676,100	3,272,479	2,404,897	10.8985	26,209,774	0	-	1.0000	-	4,095,838	3,009,972	43,885,874
2103	823,359	605,074	30.3962	18,391,963	3,272,479	2,404,897	11.2091	26,956,735	0	-	1.0000	-	4,095,838	3,009,972	45,348,698
2104	825,615	606,732	31.6272	19,189,240	3,281,444	2,411,486	11.5285	27,800,817	0	-	1.0000	-	4,107,059	3,018,218	46,990,057
2105	823,359	605,074	32.9081	19,911,850	3,272,479	2,404,897	11.8571	28,515,108	0	-	1.0000	-	4,095,838	3,009,972	48,426,958
2106	823,359	605,074	34.2409	20,718,293	3,272,479	2,404,897	12.1950	29,327,723	0	-	1.0000	-	4,095,838	3,009,972	50,046,016
2107	823,359	605,074	35.6277	21,557,410	3,272,479	2,404,897	12.5426	30,163,665	0	-	1.0000	-	4,095,838	3,009,972	51,721,076
2108	11,274,587	8,285,531	37.0706	307,149,594	5,987,760	4,400,318	12.9000	56,764,107	0	-	1.0000	-	17,262,347	12,685,849	363,913,701

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AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
2109	29,172,411	21,438,383	38.5720	826,921,313	10,590,974	7,783,154	13.2677	103,264,549	0	-	1.0000	-	39,763,385	29,221,537	930,185,861
2110	57,665,154	42,377,288	40.1341	1,700,774,317	90,528,180	66,527,851	13.6458	907,825,744	0	-	1.0000	-	148,193,335	108,905,139	2,608,600,062
2111	55,538,057	40,814,115	41.7596	1,704,381,128	42,217,329	31,024,904	14.0347	435,425,226	0	-	1.0000	-	97,755,386	71,839,020	2,139,806,354
2112	51,408,076	37,779,052	43.4508	1,641,530,028	32,588,487	23,948,808	14.4347	345,693,858	0	-	1.0000	-	83,996,563	61,727,860	1,987,223,886
2113	23,223,558	17,066,657	45.2106	771,593,789	8,238,061	6,054,032	14.8461	89,878,762	0	-	1.0000	-	31,461,619	23,120,689	861,472,551
2114	14,460,844	10,627,065	47.0416	499,914,146	14,186,680	10,425,586	15.2692	159,190,356	0	-	1.0000	-	28,647,524	21,052,651	659,104,503
2115	10,459,350	7,686,425	48.9468	376,225,916	10,261,051	7,540,698	15.7044	118,422,134	0	-	1.0000	-	20,720,401	15,227,123	494,648,050
	$573,536,674	$421,483,808		$10,167,374,423	$595,414,118	$437,561,225		$3,671,409,774	$55,000,000	$40,418,705		$40,418,705	$1,223,950,791	$899,463,737	$13,879,202,902
	$2,152,093,723	$1,581,542,556		$34,231,301,951	$1,934,230,348	$1,421,437,911		$11,223,351,940	$111,250,000	$81,756,016		$81,756,016	$4,197,574,071	$3,084,736,483	$45,536,409,907

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EXTERNAL FUND CALCULATION

Monticello

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	$623,672,182	15,989,016	-	6,696,113	646,357,311
2018	646,357,311	33,305,725	-	13,392,226	693,055,262
2019	693,055,262	35,193,724	-	(5,964,498)	722,284,487
2020	722,284,487	36,684,414	-	(5,964,498)	753,004,404
2021	753,004,404	38,251,130	-	(5,964,498)	785,291,036
2022	785,291,036	39,897,748	-	(5,964,498)	819,224,286
2023	819,224,286	41,628,344	-	(5,964,498)	854,888,132
2024	854,888,132	43,447,200	-	(5,964,498)	892,370,834
2025	892,370,834	45,358,818	-	(5,964,498)	931,765,153
2026	931,765,153	47,367,928	-	(5,964,498)	973,168,584
2027	973,168,584	49,479,503	-	(5,964,498)	1,016,683,589
2028	1,016,683,589	51,698,768	-	(5,964,498)	1,062,417,859
2029	1,062,417,859	54,031,216	-	(5,964,498)	1,110,484,577
2030	1,110,484,577	56,482,619	-	(5,964,498)	1,161,002,698
2031	1,161,002,698	59,059,043	-	(5,964,498)	1,214,097,243
2032	1,214,097,243	61,766,865	-	(5,964,498)	1,269,899,610
2033	1,269,899,610	64,612,785	-	(5,964,498)	1,328,547,897
2034	1,328,547,897	67,603,848	-	(5,964,498)	1,390,187,247
2035	1,390,187,247	70,747,455	-	(5,964,498)	1,454,970,204
2036	1,454,970,204	74,051,386	-	(5,964,498)	1,523,057,092
2037	1,523,057,092	77,523,817	-	(5,964,498)	1,594,616,411
2038	1,594,616,411	81,173,342	-	(5,964,498)	1,669,825,255
2039	1,669,825,255	85,008,993	-	(5,964,498)	1,748,869,750
2040	1,748,869,750	89,040,263	-	(5,964,498)	1,831,945,515
2041	1,831,945,515	93,277,127	-	(5,964,498)	1,919,258,143
2042	1,919,258,143	97,730,071	-	(5,964,498)	2,011,023,716
2043	2,011,023,716	102,410,115	-	(5,964,498)	2,107,469,333
2044	2,107,469,333	107,328,841	-	(5,964,498)	2,208,833,676
2045	2,208,833,676	112,498,423	-	(5,964,498)	2,315,367,601
2046	2,315,367,601	117,931,653	-	(5,964,498)	2,427,334,756
2047	2,427,334,756	123,641,978	-	(5,964,498)	2,545,012,236
2048	2,545,012,236	129,643,529	-	(5,964,498)	2,668,691,267
2049	2,668,691,267	135,951,160	-	(5,964,498)	2,798,677,929
2050	2,798,677,929	135,068,112	($64,656,047)	(4,473,373)	2,864,616,621
2051	2,864,616,621	138,360,983	(268,674,682)	-	2,734,302,922
2052	2,734,302,922	132,066,831	(131,923,246)	-	2,734,446,507
2053	2,734,446,507	132,073,766	(164,583,006)	-	2,701,937,267
2054	2,701,937,267	130,503,570	(116,163,876)	-	2,716,276,961
2055	2,716,276,961	131,196,177	(334,375,244)	-	2,513,097,894
2056	2,513,097,894	121,382,628	(39,265,046)	-	2,595,215,476

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External Levelized	2057	2,595,215,476	125,348,908	(40,625,178)	-	2,679,939,206
	2058	2,679,939,206	129,441,064	(42,147,955)	-	2,767,232,314
	2059	2,767,232,314	133,657,321	(43,729,371)	-	2,857,160,265
	2060	2,857,160,265	138,000,841	(45,494,783)	-	2,949,666,323
	2061	2,949,666,323	142,468,883	(47,075,326)	-	3,045,059,880
	2062	3,045,059,880	147,076,392	(48,844,549)	-	3,143,291,723
	2063	3,143,291,723	151,820,990	(50,681,817)	-	3,244,430,896
	2064	3,244,430,896	156,706,012	(52,733,396)	-	3,348,403,512
	2065	3,348,403,512	161,727,890	(54,570,723)	-	3,455,560,678
	2066	3,455,560,678	166,903,581	(56,627,376)	-	3,565,836,883
	2067	3,565,836,883	172,229,921	(58,762,683)	-	3,679,304,122
	2068	3,679,304,122	177,710,389	(70,974,852)	-	3,786,039,659
	2069	3,786,039,659	182,865,716	(63,283,668)	-	3,905,621,706
	2070	3,905,621,706	188,641,528	(89,271,109)	-	4,004,992,125
	2071	4,004,992,125	193,441,120	(92,535,046)	-	4,105,898,198
	2072	4,105,898,198	198,314,883	(110,661,197)	-	4,193,551,884
	2073	4,193,551,884	202,548,556	(125,734,387)	-	4,270,366,053
	2074	4,270,366,053	206,258,680	(106,961,075)	-	4,369,663,658
	2075	4,369,663,658	211,054,755	(130,924,313)	-	4,449,794,100
	2076	4,449,794,100	214,925,055	(144,159,660)	-	4,520,559,494
	2077	4,520,559,494	218,343,024	(84,871,609)	-	4,654,030,909
	2078	4,654,030,909	224,789,693	(88,096,592)	-	4,790,724,009
	2079	4,790,724,009	231,391,970	(91,446,102)	-	4,930,669,877
	2080	4,930,669,877	238,151,355	(95,185,212)	-	5,073,636,020
	2081	5,073,636,020	245,056,620	(98,538,072)	-	5,220,154,567
	2082	5,220,154,567	252,133,466	(102,291,444)	-	5,369,996,589
	2083	5,369,996,589	259,370,835	(106,189,592)	-	5,523,177,832
	2084	5,523,177,832	266,769,489	(110,541,448)	-	5,679,405,874
	2085	5,679,405,874	274,315,304	(114,445,540)	-	5,839,275,637
	2086	5,839,275,637	282,037,013	(118,814,214)	-	6,002,498,437
	2087	6,002,498,437	289,920,674	(123,352,914)	-	6,169,066,197
	2088	6,169,066,197	297,965,897	(128,418,139)	-	6,338,613,955
	2089	6,338,613,955	306,155,054	(132,964,401)	-	6,511,804,608
	2090	6,511,804,608	314,520,163	(138,052,113)	-	6,688,272,658
	2091	6,688,272,658	323,043,569	(143,336,961)	-	6,867,979,266
	2092	6,867,979,266	331,723,399	(149,235,097)	-	7,050,467,568
	2093	7,050,467,568	340,537,584	(154,530,725)	-	7,236,474,427
	2094	7,236,474,427	349,521,715	(160,456,461)	-	7,425,539,680
	2095	7,425,539,680	358,653,567	(166,612,648)	-	7,617,580,599
	2096	7,617,580,599	367,929,143	(173,482,016)	-	7,812,027,726
	2097	7,812,027,726	377,320,939	(179,652,790)	-	8,009,695,875
	2098	8,009,695,875	386,868,311	(205,592,298)	-	8,190,971,888
	2099	8,190,971,888	395,623,942	(217,348,661)	-	8,369,247,169
	2100	8,369,247,169	404,234,638	(222,085,423)	-	8,551,396,384
	2101	8,551,396,384	413,032,445	(229,970,753)	-	8,734,458,077
	2102	8,734,458,077	421,874,325	(238,733,629)	-	8,917,598,772

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2103	8,917,598,772	430,720,021	(252,337,374)	-	9,095,981,420
2104	9,095,981,420	439,335,903	(257,930,271)	-	9,277,387,051
2105	9,277,387,051	448,097,795	(1,222,800,300)	-	8,502,684,546
2106	8,502,684,546	410,679,664	(1,770,249,187)	-	7,143,115,022
2107	7,143,115,022	345,012,456	(2,243,272,007)	-	5,244,855,471
2108	5,244,855,471	253,326,519	(1,749,272,895)	-	3,748,909,095
2109	3,748,909,095	181,072,309	(1,743,912,402)	-	2,186,069,003
2110	2,186,069,003	105,587,133	(1,194,162,328)	-	1,097,493,808
2111	1,097,493,808	53,008,951	(813,032,054)	-	337,470,704
2112	337,470,704	16,299,835	(353,770,539)	-	0

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EXTERNAL FUND CALCULATION

Prairie Island Unit 1

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	374,367,055	9,602,831	-	24,632	383,994,518
2018	383,994,518	19,700,182	-	49,264	403,743,965
2019	403,743,965	20,685,518	-	(1,034,991)	423,394,491
2020	423,394,491	21,693,590	-	(1,034,991)	444,053,090
2021	444,053,090	22,753,376	-	(1,034,991)	465,771,475
2022	465,771,475	23,867,529	-	(1,034,991)	488,604,013
2023	488,604,013	25,038,838	-	(1,034,991)	512,607,860
2024	512,607,860	26,270,236	-	(1,034,991)	537,843,105
2025	537,843,105	27,564,804	-	(1,034,991)	564,372,917
2026	564,372,917	28,925,783	-	(1,034,991)	592,263,709
2027	592,263,709	30,356,581	-	(1,034,991)	621,585,299
2028	621,585,299	31,860,778	-	(1,034,991)	652,411,086
2029	652,411,086	33,442,141	-	(1,034,991)	684,818,236
2030	684,818,236	35,104,628	-	(1,034,991)	718,887,873
2031	718,887,873	36,852,400	-	(1,034,991)	754,705,282
2032	754,705,282	38,689,833	-	(1,034,991)	792,360,125
2033	792,360,125	40,621,527	-	(1,034,991)	831,946,660
2034	831,946,660	42,652,316	-	(1,034,991)	873,563,985
2035	873,563,985	44,787,285	-	(1,034,991)	917,316,279
2036	917,316,279	47,031,778	-	(1,034,991)	963,313,066
2037	963,313,066	49,391,413	-	(1,034,991)	1,011,669,487
2038	1,011,669,487	51,872,097	-	(1,034,991)	1,062,506,593
2039	1,062,506,593	54,480,041	-	(1,034,991)	1,115,951,643
2040	1,115,951,643	57,221,772	-	(1,034,991)	1,172,138,424
2041	1,172,138,424	60,104,154	-	(1,034,991)	1,231,207,586
2042	1,231,207,586	63,134,402	-	(1,034,991)	1,293,306,996
2043	1,293,306,996	66,320,101	-	(1,034,991)	1,358,592,107
2044	1,358,592,107	69,669,228	-	(1,034,991)	1,427,226,343
2045	1,427,226,343	73,190,164	-	(1,034,991)	1,499,381,516
2046	1,499,381,516	76,891,724	-	(1,034,991)	1,575,238,249
2047	1,575,238,249	80,783,175	-	(1,034,991)	1,654,986,433
2048	1,654,986,433	84,874,256	-	(1,034,991)	1,738,825,698
2049	1,738,825,698	89,175,211	-	(1,034,991)	1,826,965,917
2050	1,826,965,917	93,696,804	-	(1,034,991)	1,919,627,730
2051	1,919,627,730	98,450,355	-	(1,034,991)	2,017,043,094
2052	2,017,043,094	103,447,763	-	(1,034,991)	2,119,455,866
2053	2,119,455,866	102,141,061	($65,994,324)	(693,444)	2,154,909,159
2054	2,154,909,159	103,866,621	(208,862,585)	-	2,049,913,196
2055	2,049,913,196	98,805,816	(88,516,961)	-	2,060,202,050
2056	2,060,202,050	99,301,739	(74,966,746)	-	2,084,537,043

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EXTERNAL FUND CALCULATION

External Levelized	2057	2,084,537,043	100,474,685	(77,388,016)	-	2,107,623,712
	2058	2,107,623,712	101,587,463	(109,904,991)	-	2,099,306,183
	2059	2,099,306,183	101,186,558	(311,266,301)	-	1,889,226,441
	2060	1,889,226,441	91,060,714	(30,588,591)	-	1,949,698,564
	2061	1,949,698,564	93,975,471	(31,565,385)	-	2,012,108,650
	2062	2,012,108,650	96,983,637	(32,670,872)	-	2,076,421,414
	2063	2,076,421,414	100,083,512	(33,817,586)	-	2,142,687,341
	2064	2,142,687,341	103,277,530	(35,109,710)	-	2,210,855,160
	2065	2,210,855,160	106,563,219	(36,240,101)	-	2,281,178,277
	2066	2,281,178,277	109,952,793	(37,518,921)	-	2,353,612,149
	2067	2,353,612,149	113,444,106	(38,845,022)	-	2,428,211,233
	2068	2,428,211,233	117,039,781	(40,339,316)	-	2,504,911,698
	2069	2,504,911,698	120,736,744	(41,647,782)	-	2,584,000,660
	2070	2,584,000,660	124,548,832	(43,127,479)	-	2,665,422,013
	2071	2,665,422,013	128,473,341	(44,662,507)	-	2,749,232,847
	2072	2,749,232,847	132,513,023	(46,390,912)	-	2,835,354,958
	2073	2,835,354,958	136,664,109	(49,573,616)	-	2,922,445,451
	2074	2,922,445,451	140,861,871	(53,065,034)	-	3,010,242,288
	2075	3,010,242,288	145,093,678	(54,956,309)	-	3,100,379,658
	2076	3,100,379,658	149,438,299	(57,994,326)	-	3,191,823,632
	2077	3,191,823,632	153,845,899	(58,002,994)	-	3,287,666,537
	2078	3,287,666,537	158,465,527	(63,027,367)	-	3,383,104,696
	2079	3,383,104,696	163,065,646	(62,238,730)	-	3,483,931,613
	2080	3,483,931,613	167,925,504	(63,607,824)	-	3,588,249,292
	2081	3,588,249,292	172,953,616	(67,879,670)	-	3,693,323,238
	2082	3,693,323,238	178,018,180	(70,323,587)	-	3,801,017,830
	2083	3,801,017,830	183,209,059	(71,701,333)	-	3,912,525,556
	2084	3,912,525,556	188,583,732	(75,696,420)	-	4,025,412,868
	2085	4,025,412,868	194,024,900	(78,216,952)	-	4,141,220,817
	2086	4,141,220,817	199,606,843	(79,769,645)	-	4,261,058,016
	2087	4,261,058,016	205,382,996	(83,983,679)	-	4,382,457,332
	2088	4,382,457,332	211,234,443	(87,269,769)	-	4,506,422,007
	2089	4,506,422,007	217,209,541	(88,780,409)	-	4,634,851,138
	2090	4,634,851,138	223,399,825	(93,470,899)	-	4,764,780,065
	2091	4,764,780,065	229,662,399	(96,873,741)	-	4,897,568,723
	2092	4,897,568,723	236,062,812	(100,680,833)	-	5,032,950,703
	2093	5,032,950,703	242,588,224	(104,068,207)	-	5,171,470,720
	2094	5,171,470,720	249,264,889	(107,870,100)	-	5,312,865,509
	2095	5,312,865,509	256,080,118	(123,759,600)	-	5,445,186,026
	2096	5,445,186,026	262,457,966	(116,227,745)	-	5,591,416,247
	2097	5,591,416,247	269,506,263	(120,157,405)	-	5,740,765,105
	2098	5,740,765,105	276,704,878	(95,517,156)	-	5,921,952,828
	2099	5,921,952,828	285,438,126	(99,105,680)	-	6,108,285,274
	2100	6,108,285,274	294,419,350	(103,113,576)	-	6,299,591,048
	2101	6,299,591,048	303,640,289	(106,700,764)	-	6,496,530,572
	2102	6,496,530,572	313,132,774	(110,717,892)	-	6,698,945,453

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2103	6,698,945,453	322,889,171	(114,888,871)	-	6,906,945,753
2104	6,906,945,753	332,914,785	(119,546,315)	-	7,120,314,223
2105	7,120,314,223	343,199,146	(123,717,087)	-	7,339,796,282
2106	7,339,796,282	353,778,181	(128,387,108)	-	7,565,187,355
2107	7,565,187,355	364,642,031	(354,661,844)	-	7,575,167,542
2108	7,575,167,542	365,123,076	(1,340,861,441)	-	6,599,429,176
2109	6,599,429,176	318,092,486	(2,076,067,200)	-	4,841,454,463
2110	4,841,454,463	233,358,105	(1,872,417,744)	-	3,202,394,824
2111	3,202,394,824	154,355,431	(1,422,943,812)	-	1,933,806,442
2112	1,933,806,442	93,209,471	(546,793,735)	-	1,480,222,178
2113	1,480,222,178	71,346,709	(668,957,109)	-	882,611,778
2114	882,611,778	42,541,888	(539,015,148)	-	386,138,518
2115	386,138,518	18,611,877	(404,750,394)	-	(0)

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EXTERNAL FUND CALCULATION

Prairie Island Unit 2

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	420,208,967	10,803,157	-	294,670	431,306,795
2018	431,306,795	22,184,315	-	589,341	454,080,451
2019	454,080,451	23,197,963	-	(5,516,417)	471,761,997
2020	471,761,997	24,106,795	-	(5,516,417)	490,352,374
2021	490,352,374	25,062,340	-	(5,516,417)	509,898,297
2022	509,898,297	26,067,001	-	(5,516,417)	530,448,881
2023	530,448,881	27,123,301	-	(5,516,417)	552,055,764
2024	552,055,764	28,233,894	-	(5,516,417)	574,773,241
2025	574,773,241	29,401,573	-	(5,516,417)	598,658,397
2026	598,658,397	30,629,270	-	(5,516,417)	623,771,250
2027	623,771,250	31,920,070	-	(5,516,417)	650,174,903
2028	650,174,903	33,277,218	-	(5,516,417)	677,935,704
2029	677,935,704	34,704,123	-	(5,516,417)	707,123,410
2030	707,123,410	36,204,371	-	(5,516,417)	737,811,364
2031	737,811,364	37,781,732	-	(5,516,417)	770,076,679
2032	770,076,679	39,440,169	-	(5,516,417)	804,000,431
2033	804,000,431	41,183,850	-	(5,516,417)	839,667,864
2034	839,667,864	43,017,156	-	(5,516,417)	877,168,603
2035	877,168,603	44,944,694	-	(5,516,417)	916,596,881
2036	916,596,881	46,971,308	-	(5,516,417)	958,051,771
2037	958,051,771	49,102,089	-	(5,516,417)	1,001,637,443
2038	1,001,637,443	51,342,393	-	(5,516,417)	1,047,463,419
2039	1,047,463,419	53,697,848	-	(5,516,417)	1,095,644,849
2040	1,095,644,849	56,174,373	-	(5,516,417)	1,146,302,805
2041	1,146,302,805	58,778,192	-	(5,516,417)	1,199,564,581
2042	1,199,564,581	61,515,848	-	(5,516,417)	1,255,564,011
2043	1,255,564,011	64,394,218	-	(5,516,417)	1,314,441,812
2044	1,314,441,812	67,420,537	-	(5,516,417)	1,376,345,932
2045	1,376,345,932	70,602,409	-	(5,516,417)	1,441,431,924
2046	1,441,431,924	73,947,829	-	(5,516,417)	1,509,863,336
2047	1,509,863,336	77,465,204	-	(5,516,417)	1,581,812,122
2048	1,581,812,122	81,163,371	-	(5,516,417)	1,657,459,076
2049	1,657,459,076	85,051,625	-	(5,516,417)	1,736,994,284
2050	1,736,994,284	89,139,734	-	(5,516,417)	1,820,617,601
2051	1,820,617,601	93,437,973	-	(5,516,417)	1,908,539,156
2052	1,908,539,156	97,957,141	-	(5,516,417)	2,000,979,880
2053	2,000,979,880	102,708,594	-	(5,516,417)	2,098,172,057
2054	2,098,172,057	101,231,137	($29,938,170)	(4,578,626)	2,164,886,397
2055	2,164,886,397	104,564,013	(218,808,713)	-	2,050,641,696
2056	2,050,641,696	99,045,994	(124,349,207)	-	2,025,338,483

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External Levelized	2057	2,025,338,483	97,823,849	(67,639,969)	-	2,055,522,362
	2058	2,055,522,362	99,281,730	(99,798,689)	-	2,055,005,404
	2059	2,055,005,404	99,256,761	(302,666,816)	-	1,851,595,349
	2060	1,851,595,349	89,432,055	(30,834,593)	-	1,910,192,811
	2061	1,910,192,811	92,262,313	(31,820,406)	-	1,970,634,717
	2062	1,970,634,717	95,181,657	(32,935,968)	-	2,032,880,406
	2063	2,032,880,406	98,188,124	(34,093,157)	-	2,096,975,373
	2064	2,096,975,373	101,283,911	(35,396,963)	-	2,162,862,321
	2065	2,162,862,321	104,466,250	(36,537,896)	-	2,230,790,675
	2066	2,230,790,675	107,747,190	(37,828,493)	-	2,300,709,372
	2067	2,300,709,372	111,124,263	(39,166,838)	-	2,372,666,797
	2068	2,372,666,797	114,599,806	(40,674,788)	-	2,446,591,815
	2069	2,446,591,815	118,170,385	(41,995,577)	-	2,522,766,623
	2070	2,522,766,623	121,849,628	(43,489,044)	-	2,601,127,207
	2071	2,601,127,207	125,634,444	(45,038,390)	-	2,681,723,260
	2072	2,681,723,260	129,527,233	(46,782,756)	-	2,764,467,738
	2073	2,764,467,738	133,523,792	(49,979,873)	-	2,848,011,657
	2074	2,848,011,657	137,558,963	(53,487,390)	-	2,932,083,229
	2075	2,932,083,229	141,619,620	(55,395,404)	-	3,018,307,445
	2076	3,018,307,445	145,784,250	(58,452,083)	-	3,105,639,611
	2077	3,105,639,611	150,002,393	(58,477,603)	-	3,197,164,401
	2078	3,197,164,401	154,423,041	(63,520,802)	-	3,288,066,639
	2079	3,288,066,639	158,813,619	(62,751,743)	-	3,384,128,514
	2080	3,384,128,514	163,453,407	(64,142,659)	-	3,483,439,262
	2081	3,483,439,262	168,250,116	(68,434,212)	-	3,583,255,166
	2082	3,583,255,166	173,071,225	(70,900,147)	-	3,685,426,244
	2083	3,685,426,244	178,006,088	(72,300,787)	-	3,791,131,545
	2084	3,791,131,545	183,111,654	(76,321,393)	-	3,897,921,805
	2085	3,897,921,805	188,269,623	(78,864,979)	-	4,007,326,449
	2086	4,007,326,449	193,553,867	(80,443,419)	-	4,120,436,898
	2087	4,120,436,898	199,017,102	(84,684,234)	-	4,234,769,766
	2088	4,234,769,766	204,539,380	(88,000,167)	-	4,351,308,978
	2089	4,351,308,978	210,168,224	(89,537,771)	-	4,471,939,431
	2090	4,471,939,431	215,994,675	(94,258,382)	-	4,593,675,724
	2091	4,593,675,724	221,874,537	(97,692,545)	-	4,717,857,716
	2092	4,717,857,716	227,872,528	(101,534,546)	-	4,844,195,698
	2093	4,844,195,698	233,974,652	(104,953,464)	-	4,973,216,886
	2094	4,973,216,886	240,206,376	(108,790,590)	-	5,104,632,672
	2095	5,104,632,672	246,553,758	(124,716,733)	-	5,226,469,697
	2096	5,226,469,697	252,438,486	(117,225,711)	-	5,361,682,472
	2097	5,361,682,472	258,969,263	(121,192,278)	-	5,499,459,457
	2098	5,499,459,457	265,623,892	(38,503,792)	-	5,726,579,557
	2099	5,726,579,557	276,593,793	(39,781,913)	-	5,963,391,437
	2100	5,963,391,437	288,031,806	(41,216,634)	-	6,210,206,609
	2101	6,210,206,609	299,952,979	(42,471,564)	-	6,467,688,024
	2102	6,467,688,024	312,389,332	(43,885,874)	-	6,736,191,482

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2103	6,736,191,482	325,358,049	(45,348,698)	-	7,016,200,832
2104	7,016,200,832	338,882,500	(46,990,057)	-	7,308,093,275
2105	7,308,093,275	352,980,905	(48,426,958)	-	7,612,647,222
2106	7,612,647,222	367,690,861	(50,046,016)	-	7,930,292,067
2107	7,930,292,067	383,033,107	(51,721,076)	-	8,261,604,098
2108	8,261,604,098	399,035,478	(363,913,701)	-	8,296,725,875
2109	8,296,725,875	400,731,860	(930,185,861)	-	7,767,271,873
2110	7,767,271,873	375,159,231	(2,608,600,062)	-	5,533,831,043
2111	5,533,831,043	267,284,039	(2,139,806,354)	-	3,661,308,729
2112	3,661,308,729	176,841,212	(1,987,223,886)	-	1,850,926,054
2113	1,850,926,054	89,399,728	(861,472,551)	-	1,078,853,232
2114	1,078,853,232	52,108,611	(659,104,503)	-	471,857,340
2115	471,857,340	22,790,710	(494,648,050)	-	0

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2021 ACCRUAL COMPARISON

	Present	Proposed	Difference
Monticello	$13,392,226	$9,230,535	($4,161,691)
Prairie Island Unit 1	49,264	14,706,995	14,657,730
Prairie Island Unit 2	589,341	7,523,104	6,933,763
TOTAL	$14,030,831	$31,460,634	$17,429,803

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2021 MN RETAIL SUMMARY

	Remaining Life (yrs)	Operational Earnings Rate	Post-Shutdown Earnings Rate	Market Value Balance 6/30/2017	Book Value 6/30/2017	Unrealized Gain/Loss 6/30/2017	Tax-Effect Adjustment	Tax-Adjusted Fund Balance 6/30/2017	2021 Decommissioning Accrual
Monticello	13.75	4.99%	3.90%	$660,140,345	$529,148,381	$130,991,964	$36,468,163	$623,672,182	**9,230,535**
Prairie Island Unit 1	16.67	4.98%	3.85%	399,941,696	308,078,761	91,862,935	25,574,641	374,367,055	**14,706,995**
Prairie Island Unit 2	17.83	5.03%	3.76%	448,597,551	346,627,064	101,970,487	28,388,583	420,208,967	**7,523,104**
TOTAL DECOMMISSIONING ACCRUAL				**$1,508,679,592**	**$1,183,854,206**	**$324,825,386**	**$90,431,387**	**$1,418,248,204**	**$31,460,634**

INPUT DATA

Escalation Rate (Labor)	4.05%
Escalation Rate (Non-Labor)	2.85%
Escalation Rate (PIIC)	0.00%
Jurisdictional Factor	73.4886%
Tax Rate for tax-effect adjustment	27.84%

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AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
Monticello															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2030	$22,828,619	$16,776,422	1.6755	$28,108,895	$14,110,561	$10,369,648	1.4410	$14,942,662	$0	$0	1.0000	$0	$36,939,181	$27,146,070	$43,051,557
2031	72,399,645	53,205,452	1.7434	92,758,385	42,911,573	31,535,094	1.4820	46,735,010	0	0	1.0000	0	115,311,218	84,740,546	139,493,395
2032	78,459,767	57,658,948	1.8140	104,593,332	102,213,410	75,115,157	1.5243	114,498,034	0	0	1.0000	0	180,673,177	132,774,105	219,091,366
2033	78,071,622	57,373,706	1.8874	108,287,132	98,380,888	72,298,692	1.5677	113,342,659	0	0	1.0000	0	176,452,509	129,672,397	221,629,791
2034	66,363,782	48,769,784	1.9639	95,778,979	38,844,898	28,546,554	1.6124	46,028,463	0	0	1.0000	0	105,208,680	77,316,338	141,807,442
2035	86,863,179	63,834,494	2.0434	130,439,405	113,097,318	83,113,583	1.6584	137,835,567	0	0	1.0000	0	199,960,497	146,948,077	268,274,971
2036	50,290,909	36,958,062	2.1262	78,580,231	20,638,561	15,166,980	1.7056	25,868,801	0	0	1.0000	0	70,929,470	52,125,042	104,449,032
2037	34,606,532	25,431,840	2.2123	56,262,860	14,147,109	10,396,506	1.7542	18,237,551	0	0	1.0000	0	48,753,642	35,828,346	74,500,411
2038	29,564,886	21,726,807	2.3019	50,012,937	15,064,303	11,070,538	1.8042	19,973,465	0	0	1.0000	0	44,629,189	32,797,345	69,986,402
2039	5,908,428	4,342,018	2.3951	10,399,568	2,334,187	1,715,360	1.8556	3,183,022	0	0	1.0000	0	8,242,615	6,057,378	13,582,590
2040	5,924,615	4,353,914	2.4921	10,850,389	2,340,582	1,720,060	1.9085	3,282,734	0	0	1.0000	0	8,265,197	6,073,973	14,133,123
2041	5,908,428	4,342,018	2.5930	11,258,853	2,334,187	1,715,360	1.9629	3,367,080	0	0	1.0000	0	8,242,615	6,057,378	14,625,934
2042	6,004,114	4,412,337	2.6981	11,904,925	2,621,246	1,926,316	2.0189	3,889,038	0	0	1.0000	0	8,625,360	6,338,652	15,793,964
2043	6,195,487	4,552,974	2.8073	12,781,563	3,195,364	2,348,227	2.0764	4,875,858	0	0	1.0000	0	9,390,851	6,901,200	17,657,421
2044	6,115,988	4,494,551	2.9210	13,128,584	2,914,700	2,141,971	2.1356	4,574,392	0	0	1.0000	0	9,030,688	6,636,522	17,702,976
2045	6,099,800	4,482,655	3.0393	13,624,133	2,908,305	2,137,271	2.1964	4,694,302	0	0	1.0000	0	9,008,105	6,619,926	18,318,435
2046	6,482,546	4,763,929	3.1624	15,065,450	4,056,542	2,981,094	2.2590	6,734,291	0	0	1.0000	0	10,539,088	7,745,023	21,799,741
2047	6,386,860	4,693,611	3.2905	15,444,327	3,769,483	2,770,138	2.3234	6,436,139	0	0	1.0000	0	10,156,343	7,463,749	21,880,466
2048	7,066,692	5,193,210	3.4238	17,780,512	5,766,812	4,237,946	2.3896	10,126,997	0	0	1.0000	0	12,833,504	9,431,156	27,907,509
2049	6,386,860	4,693,611	3.5624	16,720,520	3,769,483	2,770,138	2.4577	6,808,169	0	0	1.0000	0	10,156,343	7,463,749	23,528,689
2050	6,195,487	4,552,974	3.7067	16,876,508	3,195,364	2,348,227	2.5278	5,935,847	0	0	1.0000	0	9,390,851	6,901,200	22,812,355
2051	6,099,800	4,482,655	3.8568	17,288,703	2,908,305	2,137,271	2.5998	5,556,477	0	0	1.0000	0	9,008,105	6,619,926	22,845,180
2052	6,211,674	4,564,869	4.0130	18,318,821	3,201,759	2,352,926	2.6739	6,291,489	0	0	1.0000	0	9,413,433	6,917,796	24,610,310
2053	6,099,800	4,482,655	4.1756	18,717,773	2,908,305	2,137,271	2.7501	5,877,709	0	0	1.0000	0	9,008,105	6,619,926	24,595,482
2054	6,099,800	4,482,655	4.3447	19,475,790	2,908,305	2,137,271	2.8285	6,045,271	0	0	1.0000	0	9,008,105	6,619,926	25,521,061
2055	6,195,487	4,552,974	4.5206	20,582,173	3,195,364	2,348,227	2.9091	6,831,226	0	0	1.0000	0	9,390,851	6,901,200	27,413,399
2056	6,115,988	4,494,551	4.7037	21,141,020	2,914,700	2,141,971	2.9920	6,408,776	0	0	1.0000	0	9,030,688	6,636,522	27,549,796
2057	6,099,800	4,482,655	4.8942	21,939,009	2,908,305	2,137,271	3.0773	6,577,024	0	0	1.0000	0	9,008,105	6,619,926	28,516,033
2058	6,195,487	4,552,974	5.0924	23,185,564	3,195,364	2,348,227	3.1650	7,432,137	0	0	1.0000	0	9,390,851	6,901,200	30,617,701
2059	6,291,173	4,623,292	5.2987	24,497,438	3,482,424	2,559,183	3.2552	8,330,652	0	0	1.0000	0	9,773,597	7,182,475	32,828,089
2060	6,115,988	4,494,551	5.5133	24,779,809	2,914,700	2,141,971	3.3480	7,171,318	0	0	1.0000	0	9,030,688	6,636,522	31,951,126
2061	6,291,173	4,623,292	5.7366	26,521,977	3,482,424	2,559,183	3.4434	8,812,290	0	0	1.0000	0	9,773,597	7,182,475	35,334,267
2062	6,291,173	4,623,292	5.9689	27,595,968	3,482,424	2,559,183	3.5415	9,063,346	0	0	1.0000	0	9,773,597	7,182,475	36,659,314
2063	2,248,102	1,652,098	6.2106	10,260,519	24,955,221	18,339,231	3.6425	66,800,650	0	0	1.0000	0	27,203,324	19,991,329	77,061,169
	$670,479,691	$492,725,829		$1,184,962,052	$561,072,469	$412,324,043		$752,568,447	$0	$0		$0	$1,231,552,159	$905,049,872	$1,937,530,499

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	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
Prairie Island Unit 1															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2033	$22,324,352	$16,405,843	1.8874	$30,964,388	$9,448,311	$6,943,427	1.5677	$10,885,211	$1,250,000	$918,607	1.0000	$918,607	$33,022,663	$24,267,877	$42,768,206
2034	63,582,249	46,725,675	1.9639	91,764,553	32,971,807	24,230,504	1.6124	39,069,265	1,250,000	918,607	1.0000	918,607	97,804,055	71,874,786	131,752,425
2035	66,068,657	48,552,900	2.0434	99,212,997	81,814,054	60,123,965	1.6584	99,709,584	1,250,000	918,607	1.0000	918,607	149,132,711	109,595,473	199,841,188
2036	57,950,689	42,587,123	2.1262	90,548,742	66,169,136	48,626,741	1.7056	82,937,770	1,250,000	918,607	1.0000	918,607	125,369,825	92,132,471	174,405,118
2037	38,254,474	28,112,660	2.2123	62,193,638	37,320,257	27,426,117	1.7542	48,110,895	1,250,000	918,607	1.0000	918,607	76,824,731	56,457,384	111,223,139
2038	10,524,282	7,734,143	2.3019	17,803,224	10,943,807	8,042,445	1.8042	14,510,180	1,250,000	918,607	1.0000	918,607	22,718,089	16,695,195	33,232,010
2039	35,901,875	26,383,769	2.3951	63,191,765	76,077,529	55,908,276	1.8556	103,743,397	1,250,000	918,607	1.0000	918,607	113,229,405	83,210,652	167,853,770
2040	32,068,444	23,566,636	2.4921	58,730,414	13,813,311	10,151,203	1.9085	19,373,570	1,250,000	918,607	1.0000	918,607	47,131,756	34,636,446	79,022,591
2041	19,800,405	14,551,031	2.5930	37,730,823	10,002,203	7,350,474	1.9629	14,428,246	1,250,000	918,607	1.0000	918,607	31,052,607	22,820,112	53,077,676
2042	14,925,482	10,968,521	2.6981	29,594,165	12,099,028	8,891,401	2.0189	17,950,849	1,250,000	918,607	1.0000	918,607	28,274,510	20,778,529	48,463,622
2043	8,672,291	6,373,141	2.8073	17,891,320	6,853,529	5,036,559	2.0764	10,457,912	1,250,000	918,607	1.0000	918,607	16,775,820	12,328,308	29,267,838
2044	3,150,484	2,315,245	2.9210	6,762,831	2,315,654	1,701,741	2.1356	3,634,237	1,250,000	918,607	1.0000	918,607	6,716,138	4,935,593	11,315,675
2045	3,142,137	2,309,111	3.0393	7,018,081	2,306,696	1,695,158	2.1964	3,723,244	1,250,000	918,607	1.0000	918,607	6,698,833	4,922,875	11,659,932
2046	3,046,451	2,238,793	3.1624	7,079,958	2,019,637	1,484,202	2.2590	3,352,812	1,250,000	918,607	1.0000	918,607	6,316,088	4,641,602	11,351,378
2047	3,046,451	2,238,793	3.2905	7,366,748	2,019,637	1,484,202	2.3234	3,448,395	1,250,000	918,607	1.0000	918,607	6,316,088	4,641,602	11,733,750
2048	3,054,797	2,244,926	3.4238	7,686,178	2,028,595	1,490,785	2.3896	3,562,380	1,250,000	918,607	1.0000	918,607	6,333,392	4,654,318	12,167,165
2049	3,046,451	2,238,793	3.5624	7,975,475	2,019,637	1,484,202	2.4577	3,647,723	1,250,000	918,607	1.0000	918,607	6,316,088	4,641,602	12,541,806
2050	3,142,137	2,309,111	3.7067	8,559,182	2,306,696	1,695,158	2.5278	4,285,019	1,250,000	918,607	1.0000	918,607	6,698,833	4,922,875	13,762,808
2051	3,142,137	2,309,111	3.8568	8,905,779	2,306,696	1,695,158	2.5998	4,407,071	1,250,000	918,607	1.0000	918,607	6,698,833	4,922,875	14,231,457
2052	3,150,484	2,315,245	4.0130	9,291,079	2,315,654	1,701,741	2.6739	4,550,284	1,250,000	918,607	1.0000	918,607	6,716,138	4,935,593	14,759,970
2053	3,142,137	2,309,111	4.1756	9,641,924	2,306,696	1,695,158	2.7501	4,661,853	1,250,000	918,607	1.0000	918,607	6,698,833	4,922,875	15,222,384
2054	3,142,137	2,309,111	4.3447	10,032,395	2,306,696	1,695,158	2.8285	4,794,753	1,250,000	918,607	1.0000	918,607	6,698,833	4,922,875	15,745,755
2055	3,142,137	2,309,111	4.5206	10,438,567	2,306,696	1,695,158	2.9091	4,931,383	1,250,000	918,607	1.0000	918,607	6,698,833	4,922,875	16,288,557
2056	3,150,484	2,315,245	4.7037	10,890,219	2,315,654	1,701,741	2.9920	5,091,608	1,250,000	918,607	1.0000	918,607	6,716,138	4,935,593	16,900,433
2057	3,142,137	2,309,111	4.8942	11,301,251	2,306,696	1,695,158	3.0773	5,216,508	1,250,000	918,607	1.0000	918,607	6,698,833	4,922,875	17,436,366
2058	3,142,137	2,309,111	5.0924	11,758,917	2,306,696	1,695,158	3.1650	5,365,174	1,250,000	918,607	1.0000	918,607	6,698,833	4,922,875	18,042,698
2059	3,142,137	2,309,111	5.2987	12,235,287	2,306,696	1,695,158	3.2552	5,518,077	1,250,000	918,607	1.0000	918,607	6,698,833	4,922,875	18,671,970
2060	3,150,484	2,315,245	5.5133	12,764,641	2,315,654	1,701,741	3.3480	5,697,427	1,250,000	918,607	1.0000	918,607	6,716,138	4,935,593	19,380,675
2061	3,142,137	2,309,111	5.7366	13,246,446	2,306,696	1,695,158	3.4434	5,837,105	1,250,000	918,607	1.0000	918,607	6,698,833	4,922,875	20,002,159
2062	3,142,137	2,309,111	5.9689	13,782,853	2,306,696	1,695,158	3.5415	6,003,400	1,250,000	918,607	1.0000	918,607	6,698,833	4,922,875	20,704,860
2063	3,142,137	2,309,111	6.2106	14,340,965	2,306,696	1,695,158	3.6425	6,174,611	1,250,000	918,607	1.0000	918,607	6,698,833	4,922,875	21,434,183
2064	3,146,606	2,312,395	6.4622	14,943,162	13,948,599	10,250,624	3.7463	38,401,913	1,250,000	918,607	1.0000	918,607	18,345,206	13,481,626	54,263,681
2065	795,605	584,679	6.7239	3,931,322	4,510,695	3,314,844	3.8531	12,772,427	0	0	1.0000	0	5,306,300	3,899,523	16,703,749
	$436,517,141	$320,790,135		$819,579,289	$421,002,740	$309,388,826		$606,254,283	$40,000,000	$29,395,422		$29,395,422	$897,519,882	$659,574,382	$1,455,228,994

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	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
Prairie Island Unit 2															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2034	$7,760,266	$5,702,908	1.9639	$11,199,940	$4,479,535	$3,291,946	1.6124	$5,307,933	$1,250,000	$918,607	1.0000	$918,607	$13,489,801	$9,913,460	$17,426,480
2035	47,102,812	34,615,176	2.0434	70,732,650	36,175,458	26,584,821	1.6584	44,088,268	1,250,000	918,607	1.0000	918,607	84,528,271	62,118,604	115,739,524
2036	67,705,423	49,755,737	2.1262	105,790,647	86,872,951	63,841,675	1.7056	108,888,362	1,250,000	918,607	1.0000	918,607	155,828,374	114,516,019	215,597,616
2037	71,039,578	52,205,958	2.2123	115,495,242	70,988,753	52,168,608	1.7542	91,514,172	1,250,000	918,607	1.0000	918,607	143,278,331	105,293,173	207,928,021
2038	43,919,901	32,276,100	2.3019	74,296,356	34,731,268	25,523,507	1.8042	46,049,511	1,250,000	918,607	1.0000	918,607	79,901,170	58,718,214	121,264,473
2039	40,527,011	29,782,714	2.3951	71,332,578	77,052,498	56,624,767	1.8556	105,072,917	1,250,000	918,607	1.0000	918,607	118,829,509	87,326,087	177,324,102
2040	37,548,754	27,594,036	2.4921	68,767,098	14,641,371	10,759,732	1.9085	20,534,948	1,250,000	918,607	1.0000	918,607	53,440,125	39,272,375	90,220,653
2041	23,571,483	17,322,342	2.5930	44,916,834	13,611,612	10,002,977	1.9629	19,634,844	1,250,000	918,607	1.0000	918,607	38,433,096	28,243,926	65,470,284
2042	16,800,451	12,346,409	2.6981	33,311,845	17,608,969	12,940,577	2.0189	26,125,730	1,250,000	918,607	1.0000	918,607	35,659,420	26,205,592	60,356,182
2043	9,555,838	7,022,447	2.8073	19,714,117	9,449,994	6,944,664	2.0764	14,419,900	1,250,000	918,607	1.0000	918,607	20,255,832	14,885,718	35,052,624
2044	3,150,484	2,315,245	2.9210	6,762,831	2,315,654	1,701,741	2.1356	3,634,237	1,250,000	918,607	1.0000	918,607	6,716,138	4,935,593	11,315,675
2045	3,142,137	2,309,111	3.0393	7,018,081	2,306,696	1,695,158	2.1964	3,723,244	1,250,000	918,607	1.0000	918,607	6,698,833	4,922,875	11,659,932
2046	3,046,451	2,238,793	3.1624	7,079,958	2,019,637	1,484,202	2.2590	3,352,812	1,250,000	918,607	1.0000	918,607	6,316,088	4,641,602	11,351,378
2047	3,046,451	2,238,793	3.2905	7,366,748	2,019,637	1,484,202	2.3234	3,448,395	1,250,000	918,607	1.0000	918,607	6,316,088	4,641,602	11,733,750
2048	3,054,797	2,244,926	3.4238	7,686,178	2,028,595	1,490,785	2.3896	3,562,380	1,250,000	918,607	1.0000	918,607	6,333,392	4,654,318	12,167,165
2049	3,046,451	2,238,793	3.5624	7,975,475	2,019,637	1,484,202	2.4577	3,647,723	1,250,000	918,607	1.0000	918,607	6,316,088	4,641,602	12,541,806
2050	3,142,137	2,309,111	3.7067	8,559,182	2,306,696	1,695,158	2.5278	4,285,019	1,250,000	918,607	1.0000	918,607	6,698,833	4,922,875	13,762,808
2051	3,142,137	2,309,111	3.8568	8,905,779	2,306,696	1,695,158	2.5998	4,407,071	1,250,000	918,607	1.0000	918,607	6,698,833	4,922,875	14,231,457
2052	3,150,484	2,315,245	4.0130	9,291,079	2,315,654	1,701,741	2.6739	4,550,284	1,250,000	918,607	1.0000	918,607	6,716,138	4,935,593	14,759,970
2053	3,142,137	2,309,111	4.1756	9,641,924	2,306,696	1,695,158	2.7501	4,661,853	1,250,000	918,607	1.0000	918,607	6,698,833	4,922,875	15,222,384
2054	3,142,137	2,309,111	4.3447	10,032,395	2,306,696	1,695,158	2.8285	4,794,753	1,250,000	918,607	1.0000	918,607	6,698,833	4,922,875	15,745,755
2055	3,142,137	2,309,111	4.5206	10,438,567	2,306,696	1,695,158	2.9091	4,931,383	1,250,000	918,607	1.0000	918,607	6,698,833	4,922,875	16,288,557
2056	3,150,484	2,315,245	4.7037	10,890,219	2,315,654	1,701,741	2.9920	5,091,608	1,250,000	918,607	1.0000	918,607	6,716,138	4,935,593	16,900,433
2057	3,142,137	2,309,111	4.8942	11,301,251	2,306,696	1,695,158	3.0773	5,216,508	1,250,000	918,607	1.0000	918,607	6,698,833	4,922,875	17,436,366
2058	3,142,137	2,309,111	5.0924	11,758,917	2,306,696	1,695,158	3.1650	5,365,174	1,250,000	918,607	1.0000	918,607	6,698,833	4,922,875	18,042,698
2059	3,142,137	2,309,111	5.2987	12,235,287	2,306,696	1,695,158	3.2552	5,518,077	1,250,000	918,607	1.0000	918,607	6,698,833	4,922,875	18,671,970
2060	3,150,484	2,315,245	5.5133	12,764,641	2,315,654	1,701,741	3.3480	5,697,427	1,250,000	918,607	1.0000	918,607	6,716,138	4,935,593	19,380,675
2061	3,142,137	2,309,111	5.7366	13,246,446	2,306,696	1,695,158	3.4434	5,837,105	1,250,000	918,607	1.0000	918,607	6,698,833	4,922,875	20,002,159
2062	3,142,137	2,309,111	5.9689	13,782,853	2,306,696	1,695,158	3.5415	6,003,400	1,250,000	918,607	1.0000	918,607	6,698,833	4,922,875	20,704,860
2063	3,142,137	2,309,111	6.2106	14,340,965	2,306,696	1,695,158	3.6425	6,174,611	1,250,000	918,607	1.0000	918,607	6,698,833	4,922,875	21,434,183
2064	3,146,606	2,312,395	6.4622	14,943,162	13,948,599	10,250,624	3.7463	38,401,913	1,250,000	918,607	1.0000	918,607	18,345,206	13,481,626	54,263,681
2065	795,605	584,679	6.7239	3,931,322	4,510,695	3,314,844	3.8531	12,772,427	0	-	1.0000	-	5,306,300	3,899,523	16,703,749
	$431,975,460	$317,452,519		$835,510,566	$429,102,177	$315,340,985		$626,713,989	$38,750,000	$28,476,815		$28,476,815	$899,827,638	$661,270,318	$1,490,701,369
	$1,538,972,292	$1,130,968,482		$2,840,051,907	$1,411,177,386	$1,037,053,854		$1,985,536,718	$78,750,000	$57,872,236		$57,872,236	$3,028,899,678	$2,225,894,572	$4,883,460,862

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EXTERNAL FUND CALCULATION

Monticello

External Levelized

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	623,672,182	15,644,155	-	6,696,113	646,012,450
2018	646,012,450	32,570,157	-	13,392,226	691,974,833
2019	691,974,833	34,863,680	-	13,392,226	740,230,740
2020	740,230,740	37,271,650	-	13,392,226	790,894,616
2021	790,894,616	39,695,943	-	9,230,535	839,821,094
2022	839,821,094	42,137,374	-	9,230,535	891,189,004
2023	891,189,004	44,700,633	-	9,230,535	945,120,173
2024	945,120,173	47,391,798	-	9,230,535	1,001,742,507
2025	1,001,742,507	50,217,253	-	9,230,535	1,061,190,295
2026	1,061,190,295	53,183,698	-	9,230,535	1,123,604,528
2027	1,123,604,528	56,298,168	-	9,230,535	1,189,133,231
2028	1,189,133,231	59,568,050	-	9,230,535	1,257,931,817
2029	1,257,931,817	63,001,100	-	9,230,535	1,330,163,452
2030	1,330,163,452	52,011,371	(43,051,557)	6,922,902	1,346,046,167
2031	1,346,046,167	52,495,801	(139,493,395)	-	1,259,048,573
2032	1,259,048,573	49,102,894	(219,091,366)	-	1,089,060,101
2033	1,089,060,101	42,473,344	(221,629,791)	-	909,903,654
2034	909,903,654	35,486,243	(141,807,442)	-	803,582,455
2035	803,582,455	31,339,716	(268,274,971)	-	566,647,199
2036	566,647,199	22,099,241	(104,449,032)	-	484,297,407
2037	484,297,407	18,887,599	(74,500,411)	-	428,684,596
2038	428,684,596	16,718,699	(69,986,402)	-	375,416,892
2039	375,416,892	14,641,259	(13,582,590)	-	376,475,561
2040	376,475,561	14,682,547	(14,133,123)	-	377,024,986
2041	377,024,986	14,703,974	(14,625,934)	-	377,103,026
2042	377,103,026	14,707,018	(15,793,964)	-	376,016,081
2043	376,016,081	14,664,627	(17,657,421)	-	373,023,287
2044	373,023,287	14,547,908	(17,702,976)	-	369,868,219
2045	369,868,219	14,424,861	(18,318,435)	-	365,974,645
2046	365,974,645	14,273,011	(21,799,741)	-	358,447,915
2047	358,447,915	13,979,469	(21,880,466)	-	350,546,917
2048	350,546,917	13,671,330	(27,907,509)	-	336,310,738
2049	336,310,738	13,116,119	(23,528,689)	-	325,898,168
2050	325,898,168	12,710,029	(22,812,355)	-	315,795,842
2051	315,795,842	12,316,038	(22,845,180)	-	305,266,700
2052	305,266,700	11,905,401	(24,610,310)	-	292,561,791
2053	292,561,791	11,409,910	(24,595,482)	-	279,376,218
2054	279,376,218	10,895,673	(25,521,061)	-	264,750,829
2055	264,750,829	10,325,282	(27,413,399)	-	247,662,713
2056	247,662,713	9,658,846	(27,549,796)	-	229,771,762

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2057	229,771,762	8,961,099	(28,516,033)	-	210,216,827
2058	210,216,827	8,198,456	(30,617,701)	-	187,797,583
2059	187,797,583	7,324,106	(32,828,089)	-	162,293,599
2060	162,293,599	6,329,450	(31,951,126)	-	136,671,923
2061	136,671,923	5,330,205	(35,334,267)	-	106,667,861
2062	106,667,861	4,160,047	(36,659,314)	-	74,168,594
2063	74,168,594	2,892,575	(77,061,169)	-	(0)

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EXTERNAL FUND CALCULATION

Prairie Island Unit 1

External Levelized

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	374,367,055	9,322,046	-	24,632	383,713,733
2018	383,713,733	19,110,171	-	49,264	402,873,168
2019	402,873,168	20,064,310	-	49,264	422,986,743
2020	422,986,743	21,065,966	-	49,264	444,101,974
2021	444,101,974	22,482,482	-	14,706,995	481,291,451
2022	481,291,451	24,334,518	-	14,706,995	520,332,964
2023	520,332,964	26,278,786	-	14,706,995	561,318,744
2024	561,318,744	28,319,878	-	14,706,995	604,345,617
2025	604,345,617	30,462,616	-	14,706,995	649,515,227
2026	649,515,227	32,712,062	-	14,706,995	696,934,284
2027	696,934,284	35,073,532	-	14,706,995	746,714,811
2028	746,714,811	37,552,602	-	14,706,995	798,974,407
2029	798,974,407	40,155,130	-	14,706,995	853,836,531
2030	853,836,531	42,887,263	-	14,706,995	911,430,789
2031	911,430,789	45,755,457	-	14,706,995	971,893,242
2032	971,893,242	48,766,488	-	14,706,995	1,035,366,724
2033	1,035,366,724	40,051,302	(42,768,206)	9,853,686	1,042,503,507
2034	1,042,503,507	40,136,385	(131,752,425)	-	950,887,467
2035	950,887,467	36,609,167	(199,841,188)	-	787,655,446
2036	787,655,446	30,324,735	(174,405,118)	-	643,575,063
2037	643,575,063	24,777,640	(111,223,139)	-	557,129,563
2038	557,129,563	21,449,488	(33,232,010)	-	545,347,041
2039	545,347,041	20,995,861	(167,853,770)	-	398,489,132
2040	398,489,132	15,341,832	(79,022,591)	-	334,808,373
2041	334,808,373	12,890,122	(53,077,676)	-	294,620,819
2042	294,620,819	11,342,902	(48,463,622)	-	257,500,099
2043	257,500,099	9,913,754	(29,267,838)	-	238,146,014
2044	238,146,014	9,168,622	(11,315,675)	-	235,998,961
2045	235,998,961	9,085,960	(11,659,932)	-	233,424,989
2046	233,424,989	8,986,862	(11,351,378)	-	231,060,473
2047	231,060,473	8,895,828	(11,733,750)	-	228,222,552
2048	228,222,552	8,786,568	(12,167,165)	-	224,841,955
2049	224,841,955	8,656,415	(12,541,806)	-	220,956,565
2050	220,956,565	8,506,828	(13,762,808)	-	215,700,585
2051	215,700,585	8,304,473	(14,231,457)	-	209,773,600
2052	209,773,600	8,076,284	(14,759,970)	-	203,089,914
2053	203,089,914	7,818,962	(15,222,384)	-	195,686,492
2054	195,686,492	7,533,930	(15,745,755)	-	187,474,667
2055	187,474,667	7,217,775	(16,288,557)	-	178,403,885
2056	178,403,885	6,868,550	(16,900,433)	-	168,372,001

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2057	168,372,001	6,482,322	(17,436,366)	-	157,417,957
2058	157,417,957	6,060,591	(18,042,698)	-	145,435,851
2059	145,435,851	5,599,280	(18,671,970)	-	132,363,161
2060	132,363,161	5,095,982	(19,380,675)	-	118,078,467
2061	118,078,467	4,546,021	(20,002,159)	-	102,622,329
2062	102,622,329	3,950,960	(20,704,860)	-	85,868,429
2063	85,868,429	3,305,935	(21,434,183)	-	67,740,180
2064	67,740,180	2,607,997	(54,263,681)	-	16,084,496
2065	16,084,496	619,253	(16,703,749)	-	(0)

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EXTERNAL FUND CALCULATION

Prairie Island Unit 2

External Levelized

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	420,208,967	10,571,961	-	294,670	431,075,599
2018	431,075,599	21,697,925	-	589,341	453,362,864
2019	453,362,864	22,818,974	-	589,341	476,771,179
2020	476,771,179	23,996,412	-	589,341	501,356,932
2021	501,356,932	25,407,460	-	7,523,104	534,287,496
2022	534,287,496	27,063,867	-	7,523,104	568,874,467
2023	568,874,467	28,803,592	-	7,523,104	605,201,164
2024	605,201,164	30,630,825	-	7,523,104	643,355,092
2025	643,355,092	32,549,967	-	7,523,104	683,428,164
2026	683,428,164	34,565,643	-	7,523,104	725,516,911
2027	725,516,911	36,682,707	-	7,523,104	769,722,722
2028	769,722,722	38,906,259	-	7,523,104	816,152,085
2029	816,152,085	41,241,656	-	7,523,104	864,916,846
2030	864,916,846	43,694,523	-	7,523,104	916,134,473
2031	916,134,473	46,270,770	-	7,523,104	969,928,348
2032	969,928,348	48,976,602	-	7,523,104	1,026,428,054
2033	1,026,428,054	51,818,537	-	7,523,104	1,085,769,695
2034	1,085,769,695	40,942,331	(17,426,480)	6,244,177	1,115,529,723
2035	1,115,529,723	41,943,918	(115,739,524)	-	1,041,734,116
2036	1,041,734,116	39,169,203	(215,597,616)	-	865,305,704
2037	865,305,704	32,535,494	(207,928,021)	-	689,913,177
2038	689,913,177	25,940,735	(121,264,473)	-	594,589,439
2039	594,589,439	22,356,563	(177,324,102)	-	439,621,900
2040	439,621,900	16,529,783	(90,220,653)	-	365,931,031
2041	365,931,031	13,759,007	(65,470,284)	-	314,219,753
2042	314,219,753	11,814,663	(60,356,182)	-	265,678,234
2043	265,678,234	9,989,502	(35,052,624)	-	240,615,112
2044	240,615,112	9,047,128	(11,315,675)	-	238,346,565
2045	238,346,565	8,961,831	(11,659,932)	-	235,648,464
2046	235,648,464	8,860,382	(11,351,378)	-	233,157,468
2047	233,157,468	8,766,721	(11,733,750)	-	230,190,439
2048	230,190,439	8,655,161	(12,167,165)	-	226,678,435
2049	226,678,435	8,523,109	(12,541,806)	-	222,659,739
2050	222,659,739	8,372,006	(13,762,808)	-	217,268,937
2051	217,268,937	8,169,312	(14,231,457)	-	211,206,792
2052	211,206,792	7,941,375	(14,759,970)	-	204,388,197
2053	204,388,197	7,684,996	(15,222,384)	-	196,850,810
2054	196,850,810	7,401,590	(15,745,755)	-	188,506,646
2055	188,506,646	7,087,850	(16,288,557)	-	179,305,938
2056	179,305,938	6,741,903	(16,900,433)	-	169,147,409

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2057	169,147,409	6,359,943	(17,436,366)	-	158,070,985
2058	158,070,985	5,943,469	(18,042,698)	-	145,971,756
2059	145,971,756	5,488,538	(18,671,970)	-	132,788,324
2060	132,788,324	4,992,841	(19,380,675)	-	118,400,489
2061	118,400,489	4,451,858	(20,002,159)	-	102,850,189
2062	102,850,189	3,867,167	(20,704,860)	-	86,012,496
2063	86,012,496	3,234,070	(21,434,183)	-	67,812,383
2064	67,812,383	2,549,746	(54,263,681)	-	16,098,447
2065	16,098,447	605,302	(16,703,749)	-	(0)

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2019 ACCRUAL COMPARISON

	Present	Proposed	Difference
Monticello	$13,392,226	$23,708,908	$10,316,682
Prairie Island Unit 1	49,264	18,400,907	18,351,643
Prairie Island Unit 2	589,341	10,909,487	10,320,146
TOTAL	$14,030,831	$53,019,302	$38,988,471

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2019 MN RETAIL SUMMARY

	Remaining Life (yrs)	Operational Earnings Rate	Post-Shutdown Earnings Rate	Market Value Balance 6/30/2017	Book Value 6/30/2017	Unrealized Gain/Loss 6/30/2017	Tax-Effect Adjustment	Tax-Adjusted Fund Balance 6/30/2017	2021 Decommissioning Accrual
Monticello	13.75	5.00%	4.43%	$660,140,345	$529,148,381	$130,991,964	$36,468,163	$623,672,182	**23,708,908**
Prairie Island Unit 1	16.67	4.99%	4.15%	399,941,696	308,078,761	91,862,935	25,574,641	374,367,055	**18,400,907**
Prairie Island Unit 2	17.83	5.04%	4.09%	448,597,551	346,627,064	101,970,487	28,388,583	420,208,967	**10,909,487**
TOTAL DECOMMISSIONING ACCRUAL				**$1,508,679,592**	**$1,183,854,206**	**$324,825,386**	**$90,431,387**	**$1,418,248,204**	**$53,019,302**

INPUT DATA

Escalation Rate (Labor)	4.05%
Escalation Rate (Non-Labor)	2.85%
Escalation Rate (PIIC)	0.00%
Jurisdictional Factor	73.4886%
Tax Rate for tax-effect adjustment	27.84%

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AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
Monticello															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2030	$21,103,620	$15,508,745	1.6755	$25,984,903	$8,935,561	$6,566,615	1.4410	$9,462,492	$0	$0	1.0000	$0	$30,039,182	$22,075,360	$35,447,395
2031	72,416,242	53,217,649	1.7434	92,779,649	42,961,353	31,571,677	1.4820	46,789,225	0	0	1.0000	0	115,377,595	84,789,326	139,568,874
2032	78,476,357	57,671,140	1.8140	104,615,448	102,263,189	75,151,739	1.5243	114,553,795	0	0	1.0000	0	180,739,546	132,822,879	219,169,243
2033	78,663,227	57,808,468	1.8874	109,107,702	100,155,666	73,602,950	1.5677	115,387,345	0	0	1.0000	0	178,818,892	131,411,418	224,495,047
2034	66,380,423	48,782,013	1.9639	95,802,994	38,894,671	28,583,132	1.6124	46,087,441	0	0	1.0000	0	105,275,094	77,365,144	141,890,436
2035	86,879,803	63,846,711	2.0434	130,464,369	113,147,091	83,150,161	1.6584	137,896,227	0	0	1.0000	0	200,026,894	146,996,872	268,360,596
2036	50,307,504	36,970,257	2.1262	78,606,161	20,688,337	15,203,559	1.7056	25,931,191	0	0	1.0000	0	70,995,841	52,173,817	104,537,352
2037	34,623,126	25,444,035	2.2123	56,289,838	14,196,883	10,433,084	1.7542	18,301,716	0	0	1.0000	0	48,820,010	35,877,119	74,591,555
2038	29,581,478	21,739,000	2.3019	50,041,005	15,098,979	11,096,021	1.8042	20,019,442	0	0	1.0000	0	44,680,457	32,835,022	70,060,446
2039	5,925,016	4,354,209	2.3951	10,428,765	2,187,162	1,607,314	1.8556	2,982,532	0	0	1.0000	0	8,112,178	5,961,523	13,411,297
2040	5,941,203	4,366,104	2.4921	10,880,768	2,193,018	1,611,617	1.9085	3,075,772	0	0	1.0000	0	8,134,221	5,977,722	13,956,540
2041	5,925,016	4,354,209	2.5930	11,290,463	2,187,162	1,607,314	1.9629	3,154,997	0	0	1.0000	0	8,112,178	5,961,523	14,445,460
2042	5,925,016	4,354,209	2.6981	11,748,090	2,187,162	1,607,314	2.0189	3,245,006	0	0	1.0000	0	8,112,178	5,961,523	14,993,096
2043	5,925,016	4,354,209	2.8073	12,223,570	2,187,162	1,607,314	2.0764	3,337,427	0	0	1.0000	0	8,112,178	5,961,523	15,560,997
2044	5,941,203	4,366,104	2.9210	12,753,390	2,193,018	1,611,617	2.1356	3,441,770	0	0	1.0000	0	8,134,221	5,977,722	16,195,160
2045	5,925,016	4,354,209	3.0393	13,233,746	2,187,162	1,607,314	2.1964	3,530,305	0	0	1.0000	0	8,112,178	5,961,523	16,764,051
2046	5,925,016	4,354,209	3.1624	13,769,749	2,187,162	1,607,314	2.2590	3,630,922	0	0	1.0000	0	8,112,178	5,961,523	17,400,672
2047	5,925,016	4,354,209	3.2905	14,327,523	2,187,162	1,607,314	2.3234	3,734,433	0	0	1.0000	0	8,112,178	5,961,523	18,061,957
2048	6,604,848	4,853,807	3.4238	16,618,465	4,183,953	3,074,727	2.3896	7,347,367	0	0	1.0000	0	10,788,801	7,928,534	23,965,832
2049	5,925,016	4,354,209	3.5624	15,511,433	2,187,162	1,607,314	2.4577	3,950,296	0	0	1.0000	0	8,112,178	5,961,523	19,461,728
2050	7,418,217	5,451,540	3.7067	20,207,225	6,666,766	4,899,310	2.5278	12,384,476	0	0	1.0000	0	14,084,983	10,350,851	32,591,701
2051	7,418,217	5,451,540	3.8568	21,025,501	6,666,766	4,899,310	2.5998	12,737,227	0	0	1.0000	0	14,084,983	10,350,851	33,762,728
2052	8,296,904	6,097,275	4.0130	24,468,364	9,260,122	6,805,130	2.6739	18,196,237	0	0	1.0000	0	17,557,026	12,902,405	42,664,601
2053	8,927,592	6,560,758	4.1756	27,395,102	11,194,891	8,226,964	2.7501	22,624,973	0	0	1.0000	0	20,122,483	14,787,722	50,020,075
2054	7,633,842	5,610,000	4.3447	24,373,767	7,313,641	5,374,689	2.8285	15,202,309	0	0	1.0000	0	14,947,483	10,984,689	39,576,076
2055	8,711,967	6,402,299	4.5206	28,942,231	10,548,016	7,751,585	2.9091	22,550,135	0	0	1.0000	0	19,259,983	14,153,883	51,492,366
2056	9,159,404	6,731,114	4.7037	31,661,139	11,847,622	8,706,646	2.9920	26,050,286	0	0	1.0000	0	21,007,026	15,437,760	57,711,424
2057	5,908,425	4,342,016	4.8942	21,250,695	2,137,389	1,570,737	3.0773	4,833,628	0	0	1.0000	0	8,045,814	5,912,753	26,084,323
2058	5,908,425	4,342,016	5.0924	22,111,283	2,137,389	1,570,737	3.1650	4,971,381	0	0	1.0000	0	8,045,814	5,912,753	27,082,664
2059	5,908,425	4,342,016	5.2987	23,007,041	2,137,389	1,570,737	3.2552	5,113,062	0	0	1.0000	0	8,045,814	5,912,753	28,120,102
2060	5,924,612	4,353,912	5.5133	24,004,421	2,143,245	1,575,040	3.3480	5,273,234	0	0	1.0000	0	8,067,857	5,928,952	29,277,655
2061	5,908,425	4,342,016	5.7366	24,908,410	2,137,389	1,570,737	3.4434	5,408,674	0	0	1.0000	0	8,045,814	5,912,753	30,317,084
2062	5,908,425	4,342,016	5.9689	25,917,060	2,137,389	1,570,737	3.5415	5,562,764	0	0	1.0000	0	8,045,814	5,912,753	31,479,823
2063	5,908,425	4,342,016	6.2106	26,966,525	2,137,389	1,570,737	3.6425	5,721,408	0	0	1.0000	0	8,045,814	5,912,753	32,687,933
2064	5,924,612	4,353,912	6.4622	28,135,848	2,143,245	1,575,040	3.7463	5,900,572	0	0	1.0000	0	8,067,857	5,928,952	34,036,420
2065	5,908,425	4,342,016	6.7239	29,195,282	2,137,389	1,570,737	3.8531	6,052,205	0	0	1.0000	0	8,045,814	5,912,753	35,247,487
2066	5,908,425	4,342,016	6.9962	30,377,613	2,137,389	1,570,737	3.9629	6,224,672	0	0	1.0000	0	8,045,814	5,912,753	36,602,285
2067	5,908,425	4,342,016	7.2795	31,607,706	2,137,389	1,570,737	4.0758	6,402,008	0	0	1.0000	0	8,045,814	5,912,753	38,009,714
2068	5,924,612	4,353,912	7.5744	32,978,269	2,143,245	1,575,040	4.1920	6,602,568	0	0	1.0000	0	8,067,857	5,928,952	39,580,836
2069	5,908,425	4,342,016	7.8811	34,219,863	2,137,389	1,570,737	4.3115	6,772,231	0	0	1.0000	0	8,045,814	5,912,753	40,992,094
2070	5,908,425	4,342,016	8.2003	35,605,835	2,137,389	1,570,737	4.4343	6,965,117	0	0	1.0000	0	8,045,814	5,912,753	42,570,952
2071	5,908,425	4,342,016	8.5324	37,047,818	2,137,389	1,570,737	4.5607	7,163,658	0	0	1.0000	0	8,045,814	5,912,753	44,211,476
2072	5,924,612	4,353,912	8.8780	38,654,028	2,143,245	1,575,040	4.6907	7,388,040	0	0	1.0000	0	8,067,857	5,928,952	46,042,068
2073	5,908,425	4,342,016	9.2375	40,109,374	2,137,389	1,570,737	4.8244	7,577,862	0	0	1.0000	0	8,045,814	5,912,753	47,687,235
2074	5,908,425	4,342,016	9.6117	41,734,156	2,137,389	1,570,737	4.9619	7,793,838	0	0	1.0000	0	8,045,814	5,912,753	49,527,994
2075	5,908,425	4,342,016	10.0009	43,424,069	2,137,389	1,570,737	5.1033	8,015,940	0	0	1.0000	0	8,045,814	5,912,753	51,440,009
2076	5,924,612	4,353,912	10.4060	45,306,805	2,143,245	1,575,040	5.2487	8,266,912	0	0	1.0000	0	8,067,857	5,928,952	53,573,717
2077	5,908,425	4,342,016	10.8274	47,012,745	2,137,389	1,570,737	5.3983	8,479,307	0	0	1.0000	0	8,045,814	5,912,753	55,492,052
2078	6,386,857	4,693,609	11.2659	52,877,728	3,557,353	2,614,247	5.5522	14,514,823	0	0	1.0000	0	9,944,210	7,307,856	67,392,551
2079	6,482,543	4,763,927	11.7222	55,843,706	3,844,412	2,825,203	5.7104	16,133,037	0	0	1.0000	0	10,326,955	7,589,130	71,976,743
2080	6,403,045	4,705,505	12.1970	57,393,047	3,563,167	2,618,520	5.8731	15,378,828	0	0	1.0000	0	9,966,212	7,324,025	72,771,874
2081	6,386,857	4,693,609	12.6909	59,566,121	3,557,353	2,614,247	6.0405	15,791,360	0	0	1.0000	0	9,944,210	7,307,856	75,357,480
2082	6,386,857	4,693,609	13.2049	61,978,635	3,557,353	2,614,247	6.2127	16,241,533	0	0	1.0000	0	9,944,210	7,307,856	78,220,169
2083	6,482,543	4,763,927	13.7397	65,454,929	3,844,412	2,825,203	6.3897	18,052,197	0	0	1.0000	0	10,326,955	7,589,130	83,507,127
2084	6,403,045	4,705,505	14.2962	67,270,843	3,563,167	2,618,520	6.5719	17,208,649	0	0	1.0000	0	9,966,212	7,324,025	84,479,492

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	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
2085	6,386,857	4,693,609	14.8752	69,818,370	3,557,353	2,614,247	6.7592	17,670,219	0	0	1.0000	0	9,944,210	7,307,856	87,488,590
2086	6,386,857	4,693,609	15.4776	72,645,800	3,557,353	2,614,247	6.9518	18,173,723	0	0	1.0000	0	9,944,210	7,307,856	90,819,524
2087	6,482,543	4,763,927	16.1045	76,720,664	3,844,412	2,825,203	7.1499	20,199,916	0	0	1.0000	0	10,326,955	7,589,130	96,920,580
2088	7,066,689	5,193,208	16.7567	87,021,021	5,554,101	4,081,628	7.3537	30,015,070	0	0	1.0000	0	12,620,790	9,274,836	117,036,091
2089	6,386,857	4,693,609	17.4353	81,834,478	3,557,353	2,614,247	7.5633	19,772,335	0	0	1.0000	0	9,944,210	7,307,856	101,606,814
2090	6,099,798	4,482,653	18.1415	81,322,056	2,696,175	1,981,380	7.7788	15,412,758	0	0	1.0000	0	8,795,973	6,464,033	96,734,813
2091	2,034,890	1,495,411	18.8762	28,227,679	24,955,010	18,339,076	8.0005	146,721,776	0	0	1.0000	0	26,989,900	19,834,487	174,949,455
	$851,819,402	$625,989,760		$2,666,101,282	$664,030,274	$487,986,246		$1,223,380,650	$0	$0		$0	$1,515,849,676	$1,113,976,006	$3,889,481,932

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	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
Prairie Island Unit 1															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2033	$22,324,352	$16,405,843	1.8874	$30,964,388	$9,728,959	$7,149,672	1.5677	$11,208,540	$1,250,000	$918,607	1.0000	$918,607	$33,303,311	$24,474,122	$43,091,536
2034	63,582,247	46,725,674	1.9639	91,764,550	33,397,619	24,543,427	1.6124	39,573,822	1,250,000	918,607	1.0000	918,607	98,229,866	72,187,708	132,256,979
2035	65,877,290	48,412,268	2.0434	98,925,629	81,239,936	59,702,054	1.6584	99,009,886	1,250,000	918,607	1.0000	918,607	148,367,226	109,032,929	198,854,122
2036	57,759,315	42,446,486	2.1262	90,249,718	65,595,019	48,204,831	1.7056	82,218,159	1,250,000	918,607	1.0000	918,607	124,604,334	91,569,923	173,386,484
2037	38,110,947	28,007,184	2.2123	61,960,292	36,889,671	27,109,686	1.7542	47,555,811	1,250,000	918,607	1.0000	918,607	76,250,618	56,035,476	110,434,710
2038	13,207,914	9,706,305	2.3019	22,342,944	18,994,691	13,958,924	1.8042	25,184,690	1,250,000	918,607	1.0000	918,607	33,452,605	24,583,836	48,446,241
2039	36,035,855	26,482,229	2.3951	63,427,586	76,476,728	56,201,641	1.8556	104,287,765	1,250,000	918,607	1.0000	918,607	113,762,582	83,602,477	168,633,958
2040	31,919,556	23,457,220	2.4921	58,457,738	13,365,606	9,822,190	1.9085	18,745,650	1,250,000	918,607	1.0000	918,607	46,535,162	34,198,017	78,121,996
2041	19,571,318	14,382,679	2.5930	37,294,286	9,445,873	6,941,635	1.9629	13,625,736	1,250,000	918,607	1.0000	918,607	30,267,191	22,242,921	51,838,628
2042	14,781,952	10,863,043	2.6981	29,309,575	11,668,700	8,575,159	2.0189	17,312,388	1,250,000	918,607	1.0000	918,607	27,700,652	20,356,808	47,540,570
2043	8,544,452	6,279,195	2.8073	17,627,583	6,492,672	4,771,371	2.0764	9,907,275	1,250,000	918,607	1.0000	918,607	16,287,125	11,969,172	28,453,465
2044	3,054,798	2,244,927	2.9210	6,557,431	1,939,011	1,424,951	2.1356	3,043,125	1,250,000	918,607	1.0000	918,607	6,243,809	4,588,485	10,519,163
2045	3,046,451	2,238,793	3.0393	6,804,363	1,930,298	1,418,548	2.1964	3,115,698	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	10,838,668
2046	3,046,451	2,238,793	3.1624	7,079,958	1,930,298	1,418,548	2.2590	3,204,499	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	11,203,065
2047	3,046,451	2,238,793	3.2905	7,366,748	1,930,298	1,418,548	2.3234	3,295,854	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	11,581,208
2048	3,054,798	2,244,927	3.4238	7,686,181	1,939,011	1,424,951	2.3896	3,405,063	1,250,000	918,607	1.0000	918,607	6,243,809	4,588,485	12,009,850
2049	3,046,451	2,238,793	3.5624	7,975,475	1,930,298	1,418,548	2.4577	3,486,365	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	12,380,447
2050	3,046,451	2,238,793	3.7067	8,298,533	1,930,298	1,418,548	2.5278	3,585,805	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	12,802,945
2051	3,046,451	2,238,793	3.8568	8,634,576	1,930,298	1,418,548	2.5998	3,687,940	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	13,241,123
2052	3,054,798	2,244,927	4.0130	9,008,892	1,939,011	1,424,951	2.6739	3,810,176	1,250,000	918,607	1.0000	918,607	6,243,809	4,588,485	13,737,675
2053	3,142,138	2,309,112	4.1756	9,641,927	2,217,357	1,629,503	2.7501	4,481,297	1,250,000	918,607	1.0000	918,607	6,609,495	4,857,222	15,041,831
2054	3,237,824	2,379,430	4.3447	10,337,910	2,504,416	1,840,459	2.8285	5,205,738	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	16,462,254
2055	3,237,824	2,379,430	4.5206	10,756,451	2,504,416	1,840,459	2.9091	5,354,079	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	17,029,137
2056	3,294,014	2,420,723	4.7037	11,386,356	2,656,659	1,952,340	2.9920	5,841,401	1,250,000	918,607	1.0000	918,607	7,200,673	5,291,670	18,146,364
2057	3,189,981	2,344,271	4.8942	11,473,331	2,360,887	1,734,981	3.0773	5,339,058	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	17,730,996
2058	3,333,510	2,449,748	5.0924	12,475,098	2,791,475	2,051,414	3.1650	6,492,726	1,250,000	918,607	1.0000	918,607	7,374,985	5,419,769	19,886,431
2059	3,189,981	2,344,271	5.2987	12,421,588	2,360,887	1,734,981	3.2552	5,647,711	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	18,987,907
2060	3,150,484	2,315,245	5.5133	12,764,641	2,226,070	1,635,906	3.3480	5,477,015	1,250,000	918,607	1.0000	918,607	6,626,554	4,869,758	19,160,263
2061	3,237,824	2,379,430	5.7366	13,649,838	2,504,416	1,840,459	3.4434	6,337,436	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	20,905,881
2062	3,237,824	2,379,430	5.9689	14,202,580	2,504,416	1,840,459	3.5415	6,517,985	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	21,639,172
2063	3,189,981	2,344,271	6.2106	14,559,329	2,360,887	1,734,981	3.6425	6,319,670	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	21,797,605
2064	3,246,170	2,385,563	6.4622	15,415,988	2,513,129	1,846,862	3.7463	6,918,899	1,250,000	918,607	1.0000	918,607	7,009,299	5,151,032	23,253,493
2065	3,237,824	2,379,430	6.7239	15,999,050	2,504,416	1,840,459	3.8531	7,091,472	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	24,009,128
2066	3,189,981	2,344,271	6.9962	16,400,988	2,360,887	1,734,981	3.9629	6,875,558	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	24,195,153
2067	3,237,824	2,379,430	7.2795	17,321,061	2,504,416	1,840,459	4.0758	7,501,342	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	25,741,010
2068	3,246,170	2,385,563	7.5744	18,069,211	2,513,129	1,846,862	4.1920	7,742,045	1,250,000	918,607	1.0000	918,607	7,009,299	5,151,032	26,729,863
2069	3,189,981	2,344,271	7.8811	18,475,433	2,360,887	1,734,981	4.3115	7,480,372	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	26,874,413
2070	3,237,824	2,379,430	8.2003	19,512,040	2,504,416	1,840,459	4.4343	8,161,146	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	28,591,793
2071	3,237,824	2,379,430	8.5324	20,302,249	2,504,416	1,840,459	4.5607	8,393,780	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	29,614,636
2072	3,246,170	2,385,563	8.8780	21,179,032	2,513,129	1,846,862	4.6907	8,663,075	1,250,000	918,607	1.0000	918,607	7,009,299	5,151,032	30,760,714
2073	3,237,824	2,379,430	9.2375	21,979,985	2,504,416	1,840,459	4.8244	8,879,109	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	31,777,701
2074	3,237,824	2,379,430	9.6117	22,870,368	2,504,416	1,840,459	4.9619	9,132,172	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	32,921,147
2075	3,569,646	2,623,281	10.0009	26,235,173	3,499,884	2,572,014	5.1033	13,125,758	1,250,000	918,607	1.0000	918,607	8,319,530	6,113,902	40,279,538
2076	3,246,170	2,385,563	10.4060	24,824,173	2,513,129	1,846,862	5.2487	9,693,624	1,250,000	918,607	1.0000	918,607	7,009,299	5,151,032	35,436,404
2077	3,237,974	2,379,540	10.8274	25,764,234	14,152,775	10,400,669	5.3983	56,145,933	1,250,000	918,607	1.0000	918,607	18,640,749	13,698,817	82,828,774
2078	832,743	611,971	11.2659	6,894,405	4,620,063	3,395,217	5.5522	18,850,925	0	0	1.0000	0	5,452,806	4,007,188	25,745,329
	$481,031,633	$353,503,191		$1,096,648,885	$459,759,673	$337,870,735		$746,933,573	$56,250,000	$41,337,312		$41,337,312	$997,041,305	$732,711,237	$1,884,919,770

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	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
Prairie Island Unit 2															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2034	$7,760,265	$5,702,906	1.9639	$11,199,938	$4,479,535	$3,291,946	1.6124	$5,307,933	$1,250,000	$918,607	1.0000	$918,607	$13,489,800	$9,913,459	$17,426,478
2035	46,911,429	34,474,531	2.0434	70,445,256	35,601,339	26,162,909	1.6584	43,388,568	1,250,000	918,607	1.0000	918,607	83,762,768	61,556,047	114,752,431
2036	67,514,044	49,615,094	2.1262	105,491,613	86,298,832	63,419,763	1.7056	108,168,748	1,250,000	918,607	1.0000	918,607	155,062,875	113,953,465	214,578,969
2037	70,896,041	52,100,475	2.2123	115,261,881	70,558,163	51,852,174	1.7542	90,959,083	1,250,000	918,607	1.0000	918,607	142,704,204	104,871,256	207,139,571
2038	46,603,528	34,248,259	2.3019	78,836,068	42,782,149	31,439,982	1.8042	56,724,016	1,250,000	918,607	1.0000	918,607	90,635,677	66,606,848	136,478,691
2039	40,663,625	29,883,110	2.3951	71,573,036	77,452,618	56,918,809	1.8556	105,618,542	1,250,000	918,607	1.0000	918,607	119,366,242	87,720,525	178,110,184
2040	37,417,177	27,497,343	2.4921	68,526,127	14,193,501	10,430,599	1.9085	19,906,798	1,250,000	918,607	1.0000	918,607	52,860,679	38,846,548	89,351,532
2041	23,327,583	17,143,103	2.5930	44,452,067	13,070,130	9,605,049	1.9629	18,853,752	1,250,000	918,607	1.0000	918,607	37,647,713	27,666,760	64,224,426
2042	16,656,921	12,240,930	2.6981	33,027,253	17,178,640	12,624,334	2.0189	25,487,268	1,250,000	918,607	1.0000	918,607	35,085,561	25,783,871	59,433,129
2043	9,422,862	6,924,725	2.8073	19,439,782	9,074,042	6,668,382	2.0764	13,846,228	1,250,000	918,607	1.0000	918,607	19,746,904	14,511,714	34,204,617
2044	3,054,798	2,244,927	2.9210	6,557,431	1,939,011	1,424,951	2.1356	3,043,125	1,250,000	918,607	1.0000	918,607	6,243,809	4,588,485	10,519,163
2045	3,046,451	2,238,793	3.0393	6,804,363	1,930,298	1,418,548	2.1964	3,115,698	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	10,838,668
2046	3,046,451	2,238,793	3.1624	7,079,958	1,930,298	1,418,548	2.2590	3,204,499	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	11,203,065
2047	3,046,451	2,238,793	3.2905	7,366,748	1,930,298	1,418,548	2.3234	3,295,854	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	11,581,208
2048	3,054,798	2,244,927	3.4238	7,686,181	1,939,011	1,424,951	2.3896	3,405,063	1,250,000	918,607	1.0000	918,607	6,243,809	4,588,485	12,009,850
2049	3,046,451	2,238,793	3.5624	7,975,475	1,930,298	1,418,548	2.4577	3,486,365	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	12,380,447
2050	3,046,451	2,238,793	3.7067	8,298,533	1,930,298	1,418,548	2.5278	3,585,805	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	12,802,945
2051	3,046,451	2,238,793	3.8568	8,634,576	1,930,298	1,418,548	2.5998	3,687,940	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	13,241,123
2052	3,054,798	2,244,927	4.0130	9,008,892	1,939,011	1,424,951	2.6739	3,810,176	1,250,000	918,607	1.0000	918,607	6,243,809	4,588,485	13,737,675
2053	3,142,138	2,309,112	4.1756	9,641,927	2,217,358	1,629,504	2.7501	4,481,299	1,250,000	918,607	1.0000	918,607	6,609,496	4,857,223	15,041,833
2054	3,237,824	2,379,430	4.3447	10,337,910	2,504,416	1,840,459	2.8285	5,205,738	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	16,462,254
2055	3,237,824	2,379,430	4.5206	10,756,451	2,504,416	1,840,459	2.9091	5,354,079	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	17,029,137
2056	3,294,014	2,420,723	4.7037	11,386,356	2,656,659	1,952,340	2.9920	5,841,401	1,250,000	918,607	1.0000	918,607	7,200,673	5,291,670	18,146,364
2057	3,189,981	2,344,271	4.8942	11,473,331	2,360,887	1,734,981	3.0773	5,339,058	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	17,730,996
2058	3,333,510	2,449,748	5.0924	12,475,098	2,791,475	2,051,414	3.1650	6,492,726	1,250,000	918,607	1.0000	918,607	7,374,985	5,419,769	19,886,431
2059	3,189,981	2,344,271	5.2987	12,421,588	2,360,887	1,734,981	3.2552	5,647,711	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	18,987,907
2060	3,150,484	2,315,245	5.5133	12,764,641	2,226,070	1,635,906	3.3480	5,477,015	1,250,000	918,607	1.0000	918,607	6,626,554	4,869,758	19,160,263
2061	3,237,824	2,379,430	5.7366	13,649,838	2,504,416	1,840,459	3.4434	6,337,436	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	20,905,881
2062	3,237,824	2,379,430	5.9689	14,202,580	2,504,416	1,840,459	3.5415	6,517,985	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	21,639,172
2063	3,189,981	2,344,271	6.2106	14,559,329	2,360,887	1,734,981	3.6425	6,319,670	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	21,797,605
2064	3,246,170	2,385,563	6.4622	15,415,988	2,513,129	1,846,862	3.7463	6,918,899	1,250,000	918,607	1.0000	918,607	7,009,299	5,151,032	23,253,493
2065	3,237,824	2,379,430	6.7239	15,999,050	2,504,416	1,840,459	3.8531	7,091,472	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	24,009,128
2066	3,189,981	2,344,271	6.9962	16,400,988	2,360,887	1,734,981	3.9629	6,875,558	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	24,195,153
2067	3,237,824	2,379,430	7.2795	17,321,061	2,504,416	1,840,459	4.0758	7,501,342	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	25,741,010
2068	3,246,170	2,385,563	7.5744	18,069,211	2,513,129	1,846,862	4.1920	7,742,045	1,250,000	918,607	1.0000	918,607	7,009,299	5,151,032	26,729,863
2069	3,189,981	2,344,271	7.8811	18,475,433	2,360,887	1,734,981	4.3115	7,480,372	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	26,874,413
2070	3,237,824	2,379,430	8.2003	19,512,040	2,504,416	1,840,459	4.4343	8,161,146	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	28,591,793
2071	3,237,824	2,379,430	8.5324	20,302,249	2,504,416	1,840,459	4.5607	8,393,780	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	29,614,636
2072	3,246,170	2,385,563	8.8780	21,179,032	2,513,129	1,846,862	4.6907	8,663,075	1,250,000	918,607	1.0000	918,607	7,009,299	5,151,032	30,760,714
2073	3,237,824	2,379,430	9.2375	21,979,985	2,504,416	1,840,459	4.8244	8,879,109	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	31,777,701
2074	3,237,824	2,379,430	9.6117	22,870,368	2,504,416	1,840,459	4.9619	9,132,172	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	32,921,147
2075	3,569,646	2,623,281	10.0009	26,235,173	3,499,884	2,572,014	5.1033	13,125,758	1,250,000	918,607	1.0000	918,607	8,319,530	6,113,902	40,279,538
2076	3,246,170	2,385,563	10.4060	24,824,173	2,513,129	1,846,862	5.2487	9,693,624	1,250,000	918,607	1.0000	918,607	7,009,299	5,151,032	35,436,404
2077	3,237,824	2,379,430	10.8274	25,763,042	14,152,675	10,400,596	5.3983	56,145,536	1,250,000	918,607	1.0000	918,607	18,640,499	13,698,633	82,827,186
2078	832,743	611,971	11.2659	6,894,405	4,620,063	3,395,217	5.5522	18,850,925	0	-	1.0000	-	5,452,806	4,007,188	25,745,329
	$476,489,759	$350,165,433		$1,112,576,425	$467,153,049	$343,304,020		$766,564,392	$55,000,000	$40,418,705		$40,418,705	$998,642,807	$733,888,158	$1,919,559,522
	$1,809,340,794	$1,329,658,384		$4,875,326,592	$1,590,942,995	$1,169,161,000		$2,736,878,615	$111,250,000	$81,756,016		$81,756,016	$3,511,533,789	$2,580,575,401	$7,693,961,224

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EXTERNAL FUND CALCULATION

Monticello

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	623,672,182	15,675,506	-	6,696,113	646,043,801
2018	646,043,801	32,636,996	-	13,392,226	692,073,023
2019	692,073,023	34,938,457	-	13,392,226	740,403,706
2020	740,403,706	37,354,991	-	13,392,226	791,150,922
2021	791,150,922	40,150,269	-	23,708,908	855,010,100
2022	855,010,100	43,343,228	-	23,708,908	922,062,236
2023	922,062,236	46,695,835	-	23,708,908	992,466,979
2024	992,466,979	50,216,072	-	23,708,908	1,066,391,959
2025	1,066,391,959	53,912,321	-	23,708,908	1,144,013,188
2026	1,144,013,188	57,793,382	-	23,708,908	1,225,515,479
2027	1,225,515,479	61,868,497	-	23,708,908	1,311,092,884
2028	1,311,092,884	66,147,367	-	23,708,908	1,400,949,159
2029	1,400,949,159	70,640,181	-	23,708,908	1,495,298,248
2030	1,495,298,248	66,635,577	(35,447,395)	17,781,681	1,544,268,112
2031	1,544,268,112	68,411,077	(139,568,874)	-	1,473,110,315
2032	1,473,110,315	65,258,787	(219,169,243)	-	1,319,199,858
2033	1,319,199,858	58,440,554	(224,495,047)	-	1,153,145,365
2034	1,153,145,365	51,084,340	(141,890,436)	-	1,062,339,269
2035	1,062,339,269	47,061,630	(268,360,596)	-	841,040,302
2036	841,040,302	37,258,085	(104,537,352)	-	773,761,036
2037	773,761,036	34,277,614	(74,591,555)	-	733,447,095
2038	733,447,095	32,491,706	(70,060,446)	-	695,878,355
2039	695,878,355	30,827,411	(13,411,297)	-	713,294,470
2040	713,294,470	31,598,945	(13,956,540)	-	730,936,875
2041	730,936,875	32,380,504	(14,445,460)	-	748,871,919
2042	748,871,919	33,175,026	(14,993,096)	-	767,053,848
2043	767,053,848	33,980,485	(15,560,997)	-	785,473,337
2044	785,473,337	34,796,469	(16,195,160)	-	804,074,645
2045	804,074,645	35,620,507	(16,764,051)	-	822,931,101
2046	822,931,101	36,455,848	(17,400,672)	-	841,986,278
2047	841,986,278	37,299,992	(18,061,957)	-	861,224,313
2048	861,224,313	38,152,237	(23,965,832)	-	875,410,718
2049	875,410,718	38,780,695	(19,461,728)	-	894,729,684
2050	894,729,684	39,636,525	(32,591,701)	-	901,774,508
2051	901,774,508	39,948,611	(33,762,728)	-	907,960,391
2052	907,960,391	40,222,645	(42,664,601)	-	905,518,436
2053	905,518,436	40,114,467	(50,020,075)	-	895,612,827
2054	895,612,827	39,675,648	(39,576,076)	-	895,712,399

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EXTERNAL FUND CALCULATION

2055	895,712,399	39,680,059	(51,492,366)	-	883,900,092
2056	883,900,092	39,156,774	(57,711,424)	-	865,345,442
2057	865,345,442	38,334,803	(26,084,323)	-	877,595,922
2058	877,595,922	38,877,499	(27,082,664)	-	889,390,758
2059	889,390,758	39,400,011	(28,120,102)	-	900,670,666
2060	900,670,666	39,899,710	(29,277,655)	-	911,292,721
2061	911,292,721	40,370,268	(30,317,084)	-	921,345,905
2062	921,345,905	40,815,624	(31,479,823)	-	930,681,705
2063	930,681,705	41,229,200	(32,687,933)	-	939,222,972
2064	939,222,972	41,607,578	(34,036,420)	-	946,794,129
2065	946,794,129	41,942,980	(35,247,487)	-	953,489,622
2066	953,489,622	42,239,590	(36,602,285)	-	959,126,927
2067	959,126,927	42,489,323	(38,009,714)	-	963,606,536
2068	963,606,536	42,687,770	(39,580,836)	-	966,713,469
2069	966,713,469	42,825,407	(40,992,094)	-	968,546,782
2070	968,546,782	42,906,622	(42,570,952)	-	968,882,453
2071	968,882,453	42,921,493	(44,211,476)	-	967,592,469
2072	967,592,469	42,864,346	(46,042,068)	-	964,414,747
2073	964,414,747	42,723,573	(47,687,235)	-	959,451,086
2074	959,451,086	42,503,683	(49,527,994)	-	952,426,775
2075	952,426,775	42,192,506	(51,440,009)	-	943,179,272
2076	943,179,272	41,782,842	(53,573,717)	-	931,388,397
2077	931,388,397	41,260,506	(55,492,052)	-	917,156,851
2078	917,156,851	40,630,048	(67,392,551)	-	890,394,348
2079	890,394,348	39,444,470	(71,976,743)	-	857,862,074
2080	857,862,074	38,003,290	(72,771,874)	-	823,093,490
2081	823,093,490	36,463,042	(75,357,480)	-	784,199,051
2082	784,199,051	34,740,018	(78,220,169)	-	740,718,900
2083	740,718,900	32,813,847	(83,507,127)	-	690,025,621
2084	690,025,621	30,568,135	(84,479,492)	-	636,114,264
2085	636,114,264	28,179,862	(87,488,590)	-	576,805,536
2086	576,805,536	25,552,485	(90,819,524)	-	511,538,498
2087	511,538,498	22,661,155	(96,920,580)	-	437,279,073
2088	437,279,073	19,371,463	(117,036,091)	-	339,614,445
2089	339,614,445	15,044,920	(101,606,814)	-	253,052,551
2090	253,052,551	11,210,228	(96,734,813)	-	167,527,966
2091	167,527,966	7,421,489	(174,949,455)	-	(0)

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EXTERNAL FUND CALCULATION

Prairie Island Unit 1

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	374,367,055	9,340,765	-	24,632	383,732,452
2018	383,732,452	19,149,479	-	49,264	402,931,195
2019	402,931,195	20,107,496	-	49,264	423,087,955
2020	423,087,955	21,113,318	-	49,264	444,250,538
2021	444,250,538	22,627,204	-	18,400,907	485,278,649
2022	485,278,649	24,674,507	-	18,400,907	528,354,063
2023	528,354,063	26,823,970	-	18,400,907	573,578,940
2024	573,578,940	29,080,692	-	18,400,907	621,060,539
2025	621,060,539	31,450,024	-	18,400,907	670,911,469
2026	670,911,469	33,937,585	-	18,400,907	723,249,961
2027	723,249,961	36,549,276	-	18,400,907	778,200,143
2028	778,200,143	39,291,290	-	18,400,907	835,892,340
2029	835,892,340	42,170,130	-	18,400,907	896,463,377
2030	896,463,377	45,192,625	-	18,400,907	960,056,909
2031	960,056,909	48,365,942	-	18,400,907	1,026,823,758
2032	1,026,823,758	51,697,608	-	18,400,907	1,096,922,273
2033	1,096,922,273	45,778,093	(43,091,536)	12,328,608	1,111,937,438
2034	1,111,937,438	46,145,404	(132,256,979)	-	1,025,825,863
2035	1,025,825,863	42,571,773	(198,854,122)	-	869,543,514
2036	869,543,514	36,086,056	(173,386,484)	-	732,243,086
2037	732,243,086	30,388,088	(110,434,710)	-	652,196,464
2038	652,196,464	27,066,153	(48,446,241)	-	630,816,377
2039	630,816,377	26,178,880	(168,633,958)	-	488,361,298
2040	488,361,298	20,266,994	(78,121,996)	-	430,506,296
2041	430,506,296	17,866,011	(51,838,628)	-	396,533,679
2042	396,533,679	16,456,148	(47,540,570)	-	365,449,257
2043	365,449,257	15,166,144	(28,453,465)	-	352,161,936
2044	352,161,936	14,614,720	(10,519,163)	-	356,257,493
2045	356,257,493	14,784,686	(10,838,668)	-	360,203,511
2046	360,203,511	14,948,446	(11,203,065)	-	363,948,892
2047	363,948,892	15,103,879	(11,581,208)	-	367,471,563
2048	367,471,563	15,250,070	(12,009,850)	-	370,711,783
2049	370,711,783	15,384,539	(12,380,447)	-	373,715,875
2050	373,715,875	15,509,209	(12,802,945)	-	376,422,138
2051	376,422,138	15,621,519	(13,241,123)	-	378,802,534
2052	378,802,534	15,720,305	(13,737,675)	-	380,785,164
2053	380,785,164	15,802,584	(15,041,831)	-	381,545,917
2054	381,545,917	15,834,156	(16,462,254)	-	380,917,819
2055	380,917,819	15,808,089	(17,029,137)	-	379,696,771

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2056	379,696,771	15,757,416	(18,146,364)	-	377,307,823
2057	377,307,823	15,658,275	(17,730,996)	-	375,235,102
2058	375,235,102	15,572,257	(19,886,431)	-	370,920,928
2059	370,920,928	15,393,218	(18,987,907)	-	367,326,240
2060	367,326,240	15,244,039	(19,160,263)	-	363,410,016
2061	363,410,016	15,081,516	(20,905,881)	-	357,585,651
2062	357,585,651	14,839,805	(21,639,172)	-	350,786,284
2063	350,786,284	14,557,631	(21,797,605)	-	343,546,309
2064	343,546,309	14,257,172	(23,253,493)	-	334,549,987
2065	334,549,987	13,883,824	(24,009,128)	-	324,424,684
2066	324,424,684	13,463,624	(24,195,153)	-	313,693,155
2067	313,693,155	13,018,266	(25,741,010)	-	300,970,412
2068	300,970,412	12,490,272	(26,729,863)	-	286,730,820
2069	286,730,820	11,899,329	(26,874,413)	-	271,755,737
2070	271,755,737	11,277,863	(28,591,793)	-	254,441,807
2071	254,441,807	10,559,335	(29,614,636)	-	235,386,506
2072	235,386,506	9,768,540	(30,760,714)	-	214,394,332
2073	214,394,332	8,897,365	(31,777,701)	-	191,513,995
2074	191,513,995	7,947,831	(32,921,147)	-	166,540,679
2075	166,540,679	6,911,438	(40,279,538)	-	133,172,579
2076	133,172,579	5,526,662	(35,436,404)	-	103,262,838
2077	103,262,838	4,285,408	(82,828,774)	-	24,719,471
2078	24,719,471	1,025,858	(25,745,329)	-	0

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EXTERNAL FUND CALCULATION

Prairie Island Unit 2

External Levelized

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	420,208,967	10,592,979	-	294,670	431,096,616
2018	431,096,616	21,742,121	-	589,341	453,428,078
2019	453,428,078	22,867,627	-	589,341	476,885,046
2020	476,885,046	24,049,858	-	589,341	501,524,244
2021	501,524,244	25,551,741	-	10,909,487	537,985,472
2022	537,985,472	27,389,387	-	10,909,487	576,284,346
2023	576,284,346	29,319,650	-	10,909,487	616,513,483
2024	616,513,483	31,347,199	-	10,909,487	658,770,168
2025	658,770,168	33,476,936	-	10,909,487	703,156,591
2026	703,156,591	35,714,011	-	10,909,487	749,780,089
2027	749,780,089	38,063,836	-	10,909,487	798,753,411
2028	798,753,411	40,532,091	-	10,909,487	850,194,989
2029	850,194,989	43,124,747	-	10,909,487	904,229,222
2030	904,229,222	45,848,072	-	10,909,487	960,986,781
2031	960,986,781	48,708,653	-	10,909,487	1,020,604,921
2032	1,020,604,921	51,713,407	-	10,909,487	1,083,227,815
2033	1,083,227,815	54,869,601	-	10,909,487	1,149,006,903
2034	1,149,006,903	47,179,554	(17,426,478)	9,054,874	1,187,814,854
2035	1,187,814,854	48,581,628	(114,752,431)	-	1,121,644,050
2036	1,121,644,050	45,875,242	(214,578,969)	-	952,940,323
2037	952,940,323	38,975,259	(207,139,571)	-	784,776,011
2038	784,776,011	32,097,339	(136,478,691)	-	680,394,659
2039	680,394,659	27,828,142	(178,110,184)	-	530,112,616
2040	530,112,616	21,681,606	(89,351,532)	-	462,442,690
2041	462,442,690	18,913,906	(64,224,426)	-	417,132,170
2042	417,132,170	17,060,706	(59,433,129)	-	374,759,747
2043	374,759,747	15,327,674	(34,204,617)	-	355,882,804
2044	355,882,804	14,555,607	(10,519,163)	-	359,919,247
2045	359,919,247	14,720,697	(10,838,668)	-	363,801,277
2046	363,801,277	14,879,472	(11,203,065)	-	367,477,684
2047	367,477,684	15,029,837	(11,581,208)	-	370,926,313
2048	370,926,313	15,170,886	(12,009,850)	-	374,087,349
2049	374,087,349	15,300,173	(12,380,447)	-	377,007,075
2050	377,007,075	15,419,589	(12,802,945)	-	379,623,719
2051	379,623,719	15,526,610	(13,241,123)	-	381,909,206
2052	381,909,206	15,620,087	(13,737,675)	-	383,791,617
2053	383,791,617	15,697,077	(15,041,833)	-	384,446,862
2054	384,446,862	15,723,877	(16,462,254)	-	383,708,484

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2055	383,708,484	15,693,677	(17,029,137)	-	382,373,024
2056	382,373,024	15,639,057	(18,146,364)	-	379,865,717
2057	379,865,717	15,536,508	(17,730,996)	-	377,671,229
2058	377,671,229	15,446,753	(19,886,431)	-	373,231,551
2059	373,231,551	15,265,170	(18,987,907)	-	369,508,815
2060	369,508,815	15,112,911	(19,160,263)	-	365,461,463
2061	365,461,463	14,947,374	(20,905,881)	-	359,502,955
2062	359,502,955	14,703,671	(21,639,172)	-	352,567,455
2063	352,567,455	14,420,009	(21,797,605)	-	345,189,858
2064	345,189,858	14,118,265	(23,253,493)	-	336,054,630
2065	336,054,630	13,744,634	(24,009,128)	-	325,790,136
2066	325,790,136	13,324,817	(24,195,153)	-	314,919,800
2067	314,919,800	12,880,220	(25,741,010)	-	302,059,010
2068	302,059,010	12,354,214	(26,729,863)	-	287,683,360
2069	287,683,360	11,766,249	(26,874,413)	-	272,575,197
2070	272,575,197	11,148,326	(28,591,793)	-	255,131,730
2071	255,131,730	10,434,888	(29,614,636)	-	235,951,981
2072	235,951,981	9,650,436	(30,760,714)	-	214,841,703
2073	214,841,703	8,787,026	(31,777,701)	-	191,851,028
2074	191,851,028	7,846,707	(32,921,147)	-	166,776,588
2075	166,776,588	6,821,162	(40,279,538)	-	133,318,213
2076	133,318,213	5,452,715	(35,436,404)	-	103,334,524
2077	103,334,524	4,226,382	(82,827,186)	-	24,733,720
2078	24,733,720	1,011,609	(25,745,329)	-	0

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2021 ACCRUAL COMPARISON

	Present	Proposed	Difference
Monticello	$13,392,226	$59,441,865	$46,049,639
Prairie Island Unit 1	49,264	34,479,626	34,430,362
Prairie Island Unit 2	589,341	21,951,682	21,362,341
TOTAL	$14,030,831	$115,873,173	$101,842,342

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5-Year Early Shutdown

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2021 MN RETAIL SUMMARY

	Remaining Life (yrs)	Operational Earnings Rate	Post-Shutdown Earnings Rate	Market Value Balance 6/30/2017	Book Value 6/30/2017	Unrealized Gain/Loss 6/30/2017	Tax-Effect Adjustment	Tax-Adjusted Fund Balance 6/30/2017	2021 Decommissioning Accrual
Monticello	8.75	5.00%	4.43%	$660,140,345	$529,148,381	$130,991,964	$36,468,163	$623,672,182	**59,441,865**
Prairie Island Unit 1	11.67	4.99%	4.15%	399,941,696	308,078,761	91,862,935	25,574,641	374,367,055	**34,479,626**
Prairie Island Unit 2	12.83	5.04%	4.09%	448,597,551	346,627,064	101,970,487	28,388,583	420,208,967	**21,951,682**
TOTAL DECOMMISSIONING ACCRUAL				**$1,508,679,592**	**$1,183,854,206**	**$324,825,386**	**$90,431,387**	**$1,418,248,204**	**$115,873,173**

INPUT DATA

Escalation Rate (Labor)	4.05%
Escalation Rate (Non-Labor)	2.85%
Escalation Rate (PIIC)	0.00%
Jurisdictional Factor	73.4886%
Tax Rate for tax-effect adjustment	27.84%

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AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Monticello															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2025	$21,103,620	$15,508,745	1.3738	$21,305,914	$8,935,561	$6,566,615	1.2521	$8,222,059	$0	$0	1.0000	$0	$30,039,182	$22,075,360	$29,527,973
2026	72,416,242	53,217,649	1.4295	76,074,629	42,961,353	31,571,677	1.2878	40,658,006	0	0	1.0000	0	115,377,595	84,789,326	116,732,635
2027	78,476,357	57,671,140	1.4874	85,780,054	102,263,189	75,151,739	1.3245	99,538,478	0	0	1.0000	0	180,739,546	132,822,879	185,318,532
2028	78,663,227	57,808,468	1.5476	89,464,385	100,155,666	73,602,950	1.3622	100,261,939	0	0	1.0000	0	178,818,892	131,411,418	189,726,324
2029	66,380,423	48,782,013	1.6103	78,553,675	38,894,671	28,583,132	1.4010	40,044,967	0	0	1.0000	0	105,275,094	77,365,144	118,598,642
2030	86,879,803	63,846,711	1.6755	106,975,164	113,147,091	83,150,161	1.4410	119,819,382	0	0	1.0000	0	200,026,894	146,996,872	226,794,546
2031	50,307,504	36,970,257	1.7434	64,453,946	20,688,337	15,203,559	1.4820	22,531,675	0	0	1.0000	0	70,995,841	52,173,817	86,985,621
2032	34,623,126	25,444,035	1.8140	46,155,479	14,196,883	10,433,084	1.5243	15,903,150	0	0	1.0000	0	48,820,010	35,877,119	62,058,629
2033	29,581,478	21,739,000	1.8874	41,030,189	15,098,979	11,096,021	1.5677	17,395,233	0	0	1.0000	0	44,680,457	32,835,022	58,425,422
2034	5,925,016	4,354,209	1.9639	8,551,230	2,187,162	1,607,314	1.6124	2,591,633	0	0	1.0000	0	8,112,178	5,961,523	11,142,863
2035	5,941,203	4,366,104	2.0434	8,921,697	2,193,018	1,611,617	1.6584	2,672,706	0	0	1.0000	0	8,134,221	5,977,722	11,594,404
2036	5,925,016	4,354,209	2.1262	9,257,918	2,187,162	1,607,314	1.7056	2,741,435	0	0	1.0000	0	8,112,178	5,961,523	11,999,353
2037	5,925,016	4,354,209	2.2123	9,632,816	2,187,162	1,607,314	1.7542	2,819,550	0	0	1.0000	0	8,112,178	5,961,523	12,452,366
2038	5,925,016	4,354,209	2.3019	10,022,953	2,187,162	1,607,314	1.8042	2,899,916	0	0	1.0000	0	8,112,178	5,961,523	12,922,869
2039	5,941,203	4,366,104	2.3951	10,457,256	2,193,018	1,611,617	1.8556	2,990,517	0	0	1.0000	0	8,134,221	5,977,722	13,447,773
2040	5,925,016	4,354,209	2.4921	10,851,123	2,187,162	1,607,314	1.9085	3,067,559	0	0	1.0000	0	8,112,178	5,961,523	13,918,682
2041	5,925,016	4,354,209	2.5930	11,290,463	2,187,162	1,607,314	1.9629	3,154,997	0	0	1.0000	0	8,112,178	5,961,523	14,445,460
2042	5,925,016	4,354,209	2.6981	11,748,090	2,187,162	1,607,314	2.0189	3,245,006	0	0	1.0000	0	8,112,178	5,961,523	14,993,096
2043	6,604,848	4,853,807	2.8073	13,626,093	4,183,953	3,074,727	2.0764	6,384,363	0	0	1.0000	0	10,788,801	7,928,534	20,010,456
2044	5,925,016	4,354,209	2.9210	12,718,643	2,187,162	1,607,314	2.1356	3,432,580	0	0	1.0000	0	8,112,178	5,961,523	16,151,223
2045	7,418,217	5,451,540	3.0393	16,568,867	6,666,766	4,899,310	2.1964	10,760,845	0	0	1.0000	0	14,084,983	10,350,851	27,329,712
2046	7,418,217	5,451,540	3.1624	17,239,951	6,666,766	4,899,310	2.2590	11,067,542	0	0	1.0000	0	14,084,983	10,350,851	28,307,493
2047	8,296,904	6,097,275	3.2905	20,063,083	9,260,122	6,805,130	2.3234	15,811,039	0	0	1.0000	0	17,557,026	12,902,405	35,874,122
2048	8,927,592	6,560,758	3.4238	22,462,724	11,194,891	8,226,964	2.3896	19,659,153	0	0	1.0000	0	20,122,483	14,787,722	42,121,877
2049	7,633,842	5,610,000	3.5624	19,985,064	7,313,641	5,374,689	2.4577	13,209,374	0	0	1.0000	0	14,947,483	10,984,689	33,194,438
2050	8,711,967	6,402,299	3.7067	23,731,400	10,548,016	7,751,585	2.5278	19,594,456	0	0	1.0000	0	19,259,983	14,153,883	43,325,856
2051	9,159,404	6,731,114	3.8568	25,960,559	11,847,622	8,706,646	2.5998	22,635,539	0	0	1.0000	0	21,007,026	15,437,760	48,596,098
2052	5,908,425	4,342,016	4.0130	17,424,511	2,137,389	1,570,737	2.6739	4,199,993	0	0	1.0000	0	8,045,814	5,912,753	21,624,503
2053	5,908,425	4,342,016	4.1756	18,130,522	2,137,389	1,570,737	2.7501	4,319,683	0	0	1.0000	0	8,045,814	5,912,753	22,450,205
2054	5,908,425	4,342,016	4.3447	18,864,757	2,137,389	1,570,737	2.8285	4,442,828	0	0	1.0000	0	8,045,814	5,912,753	23,307,586
2055	5,924,612	4,353,912	4.5206	19,682,293	2,143,245	1,575,040	2.9091	4,581,949	0	0	1.0000	0	8,067,857	5,928,952	24,264,242
2056	5,908,425	4,342,016	4.7037	20,423,541	2,137,389	1,570,737	2.9920	4,699,644	0	0	1.0000	0	8,045,814	5,912,753	25,123,185
2057	5,908,425	4,342,016	4.8942	21,250,695	2,137,389	1,570,737	3.0773	4,833,628	0	0	1.0000	0	8,045,814	5,912,753	26,084,323
2058	5,908,425	4,342,016	5.0924	22,111,283	2,137,389	1,570,737	3.1650	4,971,381	0	0	1.0000	0	8,045,814	5,912,753	27,082,664
2059	5,924,612	4,353,912	5.2987	23,070,072	2,143,245	1,575,040	3.2552	5,127,070	0	0	1.0000	0	8,067,857	5,928,952	28,197,142
2060	5,908,425	4,342,016	5.5133	23,938,837	2,137,389	1,570,737	3.3480	5,258,826	0	0	1.0000	0	8,045,814	5,912,753	29,197,663
2061	5,908,425	4,342,016	5.7366	24,908,410	2,137,389	1,570,737	3.4434	5,408,674	0	0	1.0000	0	8,045,814	5,912,753	30,317,084
2062	5,908,425	4,342,016	5.9689	25,917,060	2,137,389	1,570,737	3.5415	5,562,764	0	0	1.0000	0	8,045,814	5,912,753	31,479,823
2063	5,924,612	4,353,912	6.2106	27,040,404	2,143,245	1,575,040	3.6425	5,737,083	0	0	1.0000	0	8,067,857	5,928,952	32,777,487
2064	5,908,425	4,342,016	6.4622	28,058,976	2,137,389	1,570,737	3.7463	5,884,450	0	0	1.0000	0	8,045,814	5,912,753	33,943,427
2065	5,908,425	4,342,016	6.7239	29,195,282	2,137,389	1,570,737	3.8531	6,052,205	0	0	1.0000	0	8,045,814	5,912,753	35,247,487
2066	5,908,425	4,342,016	6.9962	30,377,613	2,137,389	1,570,737	3.9629	6,224,672	0	0	1.0000	0	8,045,814	5,912,753	36,602,285
2067	5,924,612	4,353,912	7.2795	31,694,300	2,143,245	1,575,040	4.0758	6,419,548	0	0	1.0000	0	8,067,857	5,928,952	38,113,848
2068	5,908,425	4,342,016	7.5744	32,888,167	2,137,389	1,570,737	4.1920	6,584,528	0	0	1.0000	0	8,045,814	5,912,753	39,472,694
2069	5,908,425	4,342,016	7.8811	34,219,863	2,137,389	1,570,737	4.3115	6,772,231	0	0	1.0000	0	8,045,814	5,912,753	40,992,094
2070	5,908,425	4,342,016	8.2003	35,605,835	2,137,389	1,570,737	4.4343	6,965,117	0	0	1.0000	0	8,045,814	5,912,753	42,570,952
2071	5,924,612	4,353,912	8.5324	37,149,316	2,143,245	1,575,040	4.5607	7,183,285	0	0	1.0000	0	8,067,857	5,928,952	44,332,601
2072	5,908,425	4,342,016	8.8780	38,548,419	2,137,389	1,570,737	4.6907	7,367,854	0	0	1.0000	0	8,045,814	5,912,753	45,916,273
2073	6,386,857	4,693,609	9.2375	43,357,212	3,557,353	2,614,247	4.8244	12,612,174	0	0	1.0000	0	9,944,210	7,307,856	55,969,386
2074	6,482,543	4,763,927	9.6117	45,789,438	3,844,412	2,825,203	4.9619	14,018,373	0	0	1.0000	0	10,326,955	7,589,130	59,807,811
2075	6,403,045	4,705,505	10.0009	47,059,287	3,563,167	2,618,520	5.1033	13,363,091	0	0	1.0000	0	9,966,212	7,324,025	60,422,378
2076	6,386,857	4,693,609	10.4060	48,841,694	3,557,353	2,614,247	5.2487	13,721,399	0	0	1.0000	0	9,944,210	7,307,856	62,563,093
2077	6,386,857	4,693,609	10.8274	50,819,580	3,557,353	2,614,247	5.3983	14,112,490	0	0	1.0000	0	9,944,210	7,307,856	64,932,071
2078	6,482,543	4,763,927	11.2659	53,669,926	3,844,412	2,825,203	5.5522	15,686,090	0	0	1.0000	0	10,326,955	7,589,130	69,356,016

Xcel Energy
Nuclear Decommissioning Accrual
60-Year Decommissioning Period
DECON Method - No Recasking
5-Year Early Shutdown

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AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
2079	6,403,045	4,705,505	11.7222	55,158,873	3,563,167	2,618,520	5.7104	14,952,795	0	0	1.0000	0	9,966,212	7,324,025	70,111,667
2080	6,386,857	4,693,609	12.1970	57,247,947	3,557,353	2,614,247	5.8731	15,353,735	0	0	1.0000	0	9,944,210	7,307,856	72,601,682
2081	6,386,857	4,693,609	12.6909	59,566,121	3,557,353	2,614,247	6.0405	15,791,360	0	0	1.0000	0	9,944,210	7,307,856	75,357,480
2082	6,482,543	4,763,927	13.2049	62,907,181	3,844,412	2,825,203	6.2127	17,552,136	0	0	1.0000	0	10,326,955	7,589,130	80,459,317
2083	7,066,689	5,193,208	13.7397	71,353,114	5,554,101	4,081,628	6.3897	26,080,380	0	0	1.0000	0	12,620,790	9,274,836	97,433,494
2084	6,386,857	4,693,609	14.2962	67,100,771	3,557,353	2,614,247	6.5719	17,180,571	0	0	1.0000	0	9,944,210	7,307,856	84,281,342
2085	6,099,798	4,482,653	14.8752	66,680,365	2,696,175	1,981,380	6.7592	13,392,543	0	0	1.0000	0	8,795,973	6,464,033	80,072,908
2086	2,034,890	1,495,411	15.4776	23,145,375	24,955,010	18,339,076	6.9518	127,489,587	0	0	1.0000	0	26,989,900	19,834,487	150,634,962
	$851,819,402	$625,989,760		$2,186,080,404	$664,030,274	$487,986,246		$1,063,017,234	$0	$0		$0	$1,515,849,676	$1,113,976,006	$3,249,097,637

Xcel Energy
Nuclear Decommissioning Accrual
60-Year Decommissioning Period
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5-Year Early Shutdown

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AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Prairie Island Unit 1															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2028	$22,324,352	$16,405,843	1.5476	$25,389,683	$9,728,959	$7,149,672	1.3622	$9,739,283	$1,250,000	$918,607	1.0000	$918,607	$33,303,311	$24,474,122	$36,047,572
2029	63,582,247	46,725,674	1.6103	75,242,352	33,397,619	24,543,427	1.4010	34,385,342	1,250,000	918,607	1.0000	918,607	98,229,866	72,187,708	110,546,301
2030	65,877,290	48,412,268	1.6755	81,114,755	81,239,936	59,702,054	1.4410	86,030,660	1,250,000	918,607	1.0000	918,607	148,367,226	109,032,929	168,064,022
2031	57,759,315	42,446,486	1.7434	74,001,203	65,595,019	48,204,831	1.4820	71,439,559	1,250,000	918,607	1.0000	918,607	124,604,334	91,569,923	146,359,369
2032	38,110,947	28,007,184	1.8140	50,805,031	36,889,671	27,109,686	1.5243	41,323,294	1,250,000	918,607	1.0000	918,607	76,250,618	56,035,476	93,046,932
2033	13,207,914	9,706,305	1.8874	18,319,680	18,994,691	13,958,924	1.5677	21,883,405	1,250,000	918,607	1.0000	918,607	33,452,605	24,583,836	41,121,692
2034	36,035,855	26,482,229	1.9639	52,008,449	76,476,728	56,201,641	1.6124	90,619,526	1,250,000	918,607	1.0000	918,607	113,762,582	83,602,477	143,546,582
2035	31,919,556	23,457,220	2.0434	47,932,484	13,365,606	9,822,190	1.6584	16,289,120	1,250,000	918,607	1.0000	918,607	46,535,162	34,198,017	65,140,211
2036	19,571,318	14,382,679	2.1262	30,580,451	9,445,873	6,941,635	1.7056	11,839,653	1,250,000	918,607	1.0000	918,607	30,267,191	22,242,921	43,338,711
2037	14,781,952	10,863,043	2.2123	24,032,309	11,668,700	8,575,159	1.7542	15,042,543	1,250,000	918,607	1.0000	918,607	27,700,652	20,356,808	39,993,460
2038	8,544,452	6,279,195	2.3019	14,454,078	6,492,672	4,771,371	1.8042	8,608,507	1,250,000	918,607	1.0000	918,607	16,287,125	11,969,172	23,981,192
2039	3,054,798	2,244,927	2.3951	5,376,824	1,939,011	1,424,951	1.8556	2,644,139	1,250,000	918,607	1.0000	918,607	6,243,809	4,588,485	8,939,570
2040	3,046,451	2,238,793	2.4921	5,579,295	1,930,298	1,418,548	1.9085	2,707,298	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	9,205,201
2041	3,046,451	2,238,793	2.5930	5,805,190	1,930,298	1,418,548	1.9629	2,784,467	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	9,508,264
2042	3,046,451	2,238,793	2.6981	6,040,487	1,930,298	1,418,548	2.0189	2,863,906	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	9,823,000
2043	3,054,798	2,244,927	2.8073	6,302,183	1,939,011	1,424,951	2.0764	2,958,768	1,250,000	918,607	1.0000	918,607	6,243,809	4,588,485	10,179,558
2044	3,046,451	2,238,793	2.9210	6,539,514	1,930,298	1,418,548	2.1356	3,029,451	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	10,487,571
2045	3,046,451	2,238,793	3.0393	6,804,363	1,930,298	1,418,548	2.1964	3,115,698	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	10,838,668
2046	3,046,451	2,238,793	3.1624	7,079,958	1,930,298	1,418,548	2.2590	3,204,499	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	11,203,065
2047	3,054,798	2,244,927	3.2905	7,386,932	1,939,011	1,424,951	2.3234	3,310,731	1,250,000	918,607	1.0000	918,607	6,243,809	4,588,485	11,616,270
2048	3,142,138	2,309,112	3.4238	7,905,937	2,217,357	1,629,503	2.3896	3,893,861	1,250,000	918,607	1.0000	918,607	6,609,495	4,857,222	12,718,405
2049	3,237,824	2,379,430	3.5624	8,476,482	2,504,416	1,840,459	2.4577	4,523,295	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	13,918,384
2050	3,237,824	2,379,430	3.7067	8,819,833	2,504,416	1,840,459	2.5278	4,652,312	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	14,390,752
2051	3,294,014	2,420,723	3.8568	9,336,245	2,656,659	1,952,340	2.5998	5,075,694	1,250,000	918,607	1.0000	918,607	7,200,673	5,291,670	15,330,546
2052	3,189,981	2,344,271	4.0130	9,407,559	2,360,887	1,734,981	2.6739	4,639,167	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	14,965,333
2053	3,333,510	2,449,748	4.1756	10,229,169	2,791,475	2,051,414	2.7501	5,641,594	1,250,000	918,607	1.0000	918,607	7,374,985	5,419,769	16,789,370
2054	3,189,981	2,344,271	4.3447	10,185,154	2,360,887	1,734,981	2.8285	4,907,395	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	16,011,156
2055	3,150,484	2,315,245	4.5206	10,466,297	2,226,070	1,635,906	2.9091	4,759,015	1,250,000	918,607	1.0000	918,607	6,626,554	4,869,758	16,143,919
2056	3,237,824	2,379,430	4.7037	11,192,125	2,504,416	1,840,459	2.9920	5,506,653	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	17,617,385
2057	3,237,824	2,379,430	4.8942	11,645,406	2,504,416	1,840,459	3.0773	5,663,644	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	18,227,657
2058	3,189,981	2,344,271	5.0924	11,937,965	2,360,887	1,734,981	3.1650	5,491,216	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	18,347,788
2059	3,246,170	2,385,563	5.2987	12,640,385	2,513,129	1,846,862	3.2552	6,011,905	1,250,000	918,607	1.0000	918,607	7,009,299	5,151,032	19,570,897
2060	3,237,824	2,379,430	5.5133	13,118,512	2,504,416	1,840,459	3.3480	6,161,856	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	20,198,974
2061	3,189,981	2,344,271	5.7366	13,448,144	2,360,887	1,734,981	3.4434	5,974,235	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	20,340,986
2062	3,237,824	2,379,430	5.9689	14,202,580	2,504,416	1,840,459	3.5415	6,517,985	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	21,639,172
2063	3,246,170	2,385,563	6.2106	14,815,780	2,513,129	1,846,862	3.6425	6,727,195	1,250,000	918,607	1.0000	918,607	7,009,299	5,151,032	22,461,581
2064	3,189,981	2,344,271	6.4622	15,149,147	2,360,887	1,734,981	3.7463	6,499,761	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	22,567,515
2065	3,237,824	2,379,430	6.7239	15,999,050	2,504,416	1,840,459	3.8531	7,091,472	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	24,009,128
2066	3,237,824	2,379,430	6.9962	16,646,968	2,504,416	1,840,459	3.9629	7,293,554	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	24,859,129
2067	3,246,170	2,385,563	7.2795	17,365,709	2,513,129	1,846,862	4.0758	7,527,440	1,250,000	918,607	1.0000	918,607	7,009,299	5,151,032	25,811,755
2068	3,237,824	2,379,430	7.5744	18,022,755	2,504,416	1,840,459	4.1920	7,715,203	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	26,656,565
2069	3,237,824	2,379,430	7.8811	18,752,526	2,504,416	1,840,459	4.3115	7,935,138	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	27,606,271
2070	3,569,646	2,623,281	8.2003	21,511,693	3,499,884	2,572,014	4.4343	11,405,081	1,250,000	918,607	1.0000	918,607	8,319,530	6,113,902	33,835,381
2071	3,246,170	2,385,563	8.5324	20,354,581	2,513,129	1,846,862	4.5607	8,422,983	1,250,000	918,607	1.0000	918,607	7,009,299	5,151,032	29,696,171
2072	3,237,974	2,379,540	8.8780	21,125,558	14,152,775	10,400,669	4.6907	48,786,420	1,250,000	918,607	1.0000	918,607	18,640,749	13,698,817	70,830,585
2073	832,743	611,971	9.2375	5,653,083	4,620,063	3,395,217	4.8244	16,379,886	0	0	1.0000	0	5,452,806	4,007,188	22,032,968
	$481,031,633	$353,503,191		$899,203,866	$459,759,673	$337,870,735		$649,023,806	$56,250,000	$41,337,312		$41,337,312	$997,041,305	$732,711,237	$1,589,564,984

Xcel Energy
Nuclear Decommissioning Accrual
60-Year Decommissioning Period
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AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Prairie Island Unit 2															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2029	$7,760,265	$5,702,906	1.6103	$9,183,390	$4,479,535	$3,291,946	1.4010	$4,612,016	$1,250,000	$918,607	1.0000	$918,607	$13,489,800	$9,913,459	$14,714,013
2030	46,911,429	34,474,531	1.6755	57,762,076	35,601,339	26,162,909	1.4410	37,700,752	1,250,000	918,607	1.0000	918,607	83,762,768	61,556,047	96,381,435
2031	67,514,044	49,615,094	1.7434	86,498,955	86,298,832	63,419,763	1.4820	93,988,089	1,250,000	918,607	1.0000	918,607	155,062,875	113,953,465	181,405,652
2032	70,896,041	52,100,475	1.8140	94,510,262	70,558,163	51,852,174	1.5243	79,038,268	1,250,000	918,607	1.0000	918,607	142,704,204	104,871,256	174,467,137
2033	46,603,528	34,248,259	1.8874	64,640,164	42,782,149	31,439,982	1.5677	49,288,460	1,250,000	918,607	1.0000	918,607	90,635,677	66,606,848	114,847,231
2034	40,663,625	29,883,110	1.9639	58,687,439	77,452,618	56,918,809	1.6124	91,775,887	1,250,000	918,607	1.0000	918,607	119,366,242	87,720,525	151,381,933
2035	37,417,177	27,497,343	2.0434	56,188,070	14,193,501	10,430,599	1.6584	17,298,105	1,250,000	918,607	1.0000	918,607	52,860,679	38,846,548	74,404,782
2036	23,327,583	17,143,103	2.1262	36,449,666	13,070,130	9,605,049	1.7056	16,382,372	1,250,000	918,607	1.0000	918,607	37,647,713	27,666,760	53,750,646
2037	16,656,921	12,240,930	2.2123	27,080,609	17,178,640	12,624,334	1.7542	22,145,607	1,250,000	918,607	1.0000	918,607	35,085,561	25,783,871	50,144,824
2038	9,422,862	6,924,725	2.3019	15,940,025	9,074,042	6,668,382	1.8042	12,031,095	1,250,000	918,607	1.0000	918,607	19,746,904	14,511,714	28,889,727
2039	3,054,798	2,244,927	2.3951	5,376,824	1,939,011	1,424,951	1.8556	2,644,139	1,250,000	918,607	1.0000	918,607	6,243,809	4,588,485	8,939,570
2040	3,046,451	2,238,793	2.4921	5,579,295	1,930,298	1,418,548	1.9085	2,707,298	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	9,205,201
2041	3,046,451	2,238,793	2.5930	5,805,190	1,930,298	1,418,548	1.9629	2,784,467	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	9,508,264
2042	3,046,451	2,238,793	2.6981	6,040,487	1,930,298	1,418,548	2.0189	2,863,906	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	9,823,000
2043	3,054,798	2,244,927	2.8073	6,302,183	1,939,011	1,424,951	2.0764	2,958,768	1,250,000	918,607	1.0000	918,607	6,243,809	4,588,485	10,179,558
2044	3,046,451	2,238,793	2.9210	6,539,514	1,930,298	1,418,548	2.1356	3,029,451	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	10,487,571
2045	3,046,451	2,238,793	3.0393	6,804,363	1,930,298	1,418,548	2.1964	3,115,698	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	10,838,668
2046	3,046,451	2,238,793	3.1624	7,079,958	1,930,298	1,418,548	2.2590	3,204,499	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	11,203,065
2047	3,054,798	2,244,927	3.2905	7,386,932	1,939,011	1,424,951	2.3234	3,310,731	1,250,000	918,607	1.0000	918,607	6,243,809	4,588,485	11,616,270
2048	3,142,138	2,309,112	3.4238	7,905,937	2,217,358	1,629,504	2.3896	3,893,863	1,250,000	918,607	1.0000	918,607	6,609,496	4,857,223	12,718,407
2049	3,237,824	2,379,430	3.5624	8,476,482	2,504,416	1,840,459	2.4577	4,523,295	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	13,918,384
2050	3,237,824	2,379,430	3.7067	8,819,833	2,504,416	1,840,459	2.5278	4,652,312	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	14,390,752
2051	3,294,014	2,420,723	3.8568	9,336,245	2,656,659	1,952,340	2.5998	5,075,694	1,250,000	918,607	1.0000	918,607	7,200,673	5,291,670	15,330,546
2052	3,189,981	2,344,271	4.0130	9,407,559	2,360,887	1,734,981	2.6739	4,639,167	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	14,965,333
2053	3,333,510	2,449,748	4.1756	10,229,169	2,791,475	2,051,414	2.7501	5,641,594	1,250,000	918,607	1.0000	918,607	7,374,985	5,419,769	16,789,370
2054	3,189,981	2,344,271	4.3447	10,185,154	2,360,887	1,734,981	2.8285	4,907,395	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	16,011,156
2055	3,150,484	2,315,245	4.5206	10,466,297	2,226,070	1,635,906	2.9091	4,759,015	1,250,000	918,607	1.0000	918,607	6,626,554	4,869,758	16,143,919
2056	3,237,824	2,379,430	4.7037	11,192,125	2,504,416	1,840,459	2.9920	5,506,653	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	17,617,385
2057	3,237,824	2,379,430	4.8942	11,645,406	2,504,416	1,840,459	3.0773	5,663,644	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	18,227,657
2058	3,189,981	2,344,271	5.0924	11,937,965	2,360,887	1,734,981	3.1650	5,491,216	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	18,347,788
2059	3,246,170	2,385,563	5.2987	12,640,385	2,513,129	1,846,862	3.2552	6,011,905	1,250,000	918,607	1.0000	918,607	7,009,299	5,151,032	19,570,897
2060	3,237,824	2,379,430	5.5133	13,118,512	2,504,416	1,840,459	3.3480	6,161,856	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	20,198,974
2061	3,189,981	2,344,271	5.7366	13,448,144	2,360,887	1,734,981	3.4434	5,974,235	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	20,340,986
2062	3,237,824	2,379,430	5.9689	14,202,580	2,504,416	1,840,459	3.5415	6,517,985	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	21,639,172
2063	3,246,170	2,385,563	6.2106	14,815,780	2,513,129	1,846,862	3.6425	6,727,195	1,250,000	918,607	1.0000	918,607	7,009,299	5,151,032	22,461,581
2064	3,189,981	2,344,271	6.4622	15,149,147	2,360,887	1,734,981	3.7463	6,499,761	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	22,567,515
2065	3,237,824	2,379,430	6.7239	15,999,050	2,504,416	1,840,459	3.8531	7,091,472	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	24,009,128
2066	3,237,824	2,379,430	6.9962	16,646,968	2,504,416	1,840,459	3.9629	7,293,554	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	24,859,129
2067	3,246,170	2,385,563	7.2795	17,365,709	2,513,129	1,846,862	4.0758	7,527,440	1,250,000	918,607	1.0000	918,607	7,009,299	5,151,032	25,811,755
2068	3,237,824	2,379,430	7.5744	18,022,755	2,504,416	1,840,459	4.1920	7,715,203	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	26,656,565
2069	3,237,824	2,379,430	7.8811	18,752,526	2,504,416	1,840,459	4.3115	7,935,138	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	27,606,271
2070	3,569,646	2,623,281	8.2003	21,511,693	3,499,884	2,572,014	4.4343	11,405,081	1,250,000	918,607	1.0000	918,607	8,319,530	6,113,902	33,835,381
2071	3,246,170	2,385,563	8.5324	20,354,581	2,513,129	1,846,862	4.5607	8,422,983	1,250,000	918,607	1.0000	918,607	7,009,299	5,151,032	29,696,171
2072	3,237,824	2,379,430	8.8780	21,124,581	14,152,675	10,400,596	4.6907	48,786,075	1,250,000	918,607	1.0000	918,607	18,640,499	13,698,633	70,829,263
2073	832,743	611,971	9.2375	5,653,083	4,620,063	3,395,217	4.8244	16,379,886	0	-	1.0000	-	5,452,806	4,007,188	22,032,968
	$476,489,759	$350,165,433		$912,263,071	$467,153,049	$343,304,020		$666,083,223	$55,000,000	$40,418,705		$40,418,705	$998,642,807	$733,888,158	$1,618,764,999
	$1,809,340,794	$1,329,658,384		$3,997,547,341	$1,590,942,995	$1,169,161,000		$2,378,124,263	$111,250,000	$81,756,016		$81,756,016	$3,511,533,789	$2,580,575,401	$6,457,427,620

Xcel Energy
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EXTERNAL FUND CALCULATION

Monticello

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	623,672,182	15,675,506	-	6,696,113	646,043,801
2018	646,043,801	32,636,996	-	13,392,226	692,073,023
2019	692,073,023	34,938,457	-	13,392,226	740,403,706
2020	740,403,706	37,354,991	-	13,392,226	791,150,922
2021	791,150,922	41,043,593	-	59,441,865	891,636,380
2022	891,636,380	46,067,866	-	59,441,865	997,146,110
2023	997,146,110	51,343,352	-	59,441,865	1,107,931,327
2024	1,107,931,327	56,882,613	-	59,441,865	1,224,255,805
2025	1,224,255,805	55,222,010	(29,527,973)	44,581,398	1,294,531,240
2026	1,294,531,240	57,347,734	(116,732,635)	-	1,235,146,340
2027	1,235,146,340	54,716,983	(185,318,532)	-	1,104,544,791
2028	1,104,544,791	48,931,334	(189,726,324)	-	963,749,802
2029	963,749,802	42,694,116	(118,598,642)	-	887,845,276
2030	887,845,276	39,331,546	(226,794,546)	-	700,382,276
2031	700,382,276	31,026,935	(86,985,621)	-	644,423,589
2032	644,423,589	28,547,965	(62,058,629)	-	610,912,925
2033	610,912,925	27,063,443	(58,425,422)	-	579,550,945
2034	579,550,945	25,674,107	(11,142,863)	-	594,082,189
2035	594,082,189	26,317,841	(11,594,404)	-	608,805,626
2036	608,805,626	26,970,089	(11,999,353)	-	623,776,362
2037	623,776,362	27,633,293	(12,452,366)	-	638,957,289
2038	638,957,289	28,305,808	(12,922,869)	-	654,340,229
2039	654,340,229	28,987,272	(13,447,773)	-	669,879,727
2040	669,879,727	29,675,672	(13,918,682)	-	685,636,717
2041	685,636,717	30,373,707	(14,445,460)	-	701,564,964
2042	701,564,964	31,079,328	(14,993,096)	-	717,651,196
2043	717,651,196	31,791,948	(20,010,456)	-	729,432,688
2044	729,432,688	32,313,868	(16,151,223)	-	745,595,333
2045	745,595,333	33,029,873	(27,329,712)	-	751,295,494
2046	751,295,494	33,282,390	(28,307,493)	-	756,270,391
2047	756,270,391	33,502,778	(35,874,122)	-	753,899,048
2048	753,899,048	33,397,728	(42,121,877)	-	745,174,899
2049	745,174,899	33,011,248	(33,194,438)	-	744,991,709
2050	744,991,709	33,003,133	(43,325,856)	-	734,668,986
2051	734,668,986	32,545,836	(48,596,098)	-	718,618,724
2052	718,618,724	31,834,809	(21,624,503)	-	728,829,031
2053	728,829,031	32,287,126	(22,450,205)	-	738,665,952
2054	738,665,952	32,722,902	(23,307,586)	-	748,081,267

External Levelized

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EXTERNAL FUND CALCULATION

2055	748,081,267	33,140,000	(24,264,242)	-	756,957,026
2056	756,957,026	33,533,196	(25,123,185)	-	765,367,037
2057	765,367,037	33,905,760	(26,084,323)	-	773,188,474
2058	773,188,474	34,252,249	(27,082,664)	-	780,358,059
2059	780,358,059	34,569,862	(28,197,142)	-	786,730,780
2060	786,730,780	34,852,174	(29,197,663)	-	792,385,290
2061	792,385,290	35,102,668	(30,317,084)	-	797,170,874
2062	797,170,874	35,314,670	(31,479,823)	-	801,005,721
2063	801,005,721	35,484,553	(32,777,487)	-	803,712,787
2064	803,712,787	35,604,476	(33,943,427)	-	805,373,837
2065	805,373,837	35,678,061	(35,247,487)	-	805,804,411
2066	805,804,411	35,697,135	(36,602,285)	-	804,899,261
2067	804,899,261	35,657,037	(38,113,848)	-	802,442,450
2068	802,442,450	35,548,201	(39,472,694)	-	798,517,956
2069	798,517,956	35,374,345	(40,992,094)	-	792,900,208
2070	792,900,208	35,125,479	(42,570,952)	-	785,454,736
2071	785,454,736	34,795,645	(44,332,601)	-	775,917,780
2072	775,917,780	34,373,158	(45,916,273)	-	764,374,664
2073	764,374,664	33,861,798	(55,969,386)	-	742,267,076
2074	742,267,076	32,882,431	(59,807,811)	-	715,341,697
2075	715,341,697	31,689,637	(60,422,378)	-	686,608,956
2076	686,608,956	30,416,777	(62,563,093)	-	654,462,640
2077	654,462,640	28,992,695	(64,932,071)	-	618,523,264
2078	618,523,264	27,400,581	(69,356,016)	-	576,567,828
2079	576,567,828	25,541,955	(70,111,667)	-	531,998,116
2080	531,998,116	23,567,517	(72,601,682)	-	482,963,950
2081	482,963,950	21,395,303	(75,357,480)	-	429,001,773
2082	429,001,773	19,004,779	(80,459,317)	-	367,547,234
2083	367,547,234	16,282,342	(97,433,494)	-	286,396,083
2084	286,396,083	12,687,346	(84,281,342)	-	214,802,088
2085	214,802,088	9,515,732	(80,072,908)	-	144,244,912
2086	144,244,912	6,390,050	(150,634,962)	-	0

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60-Year Decommissioning Period **Page 9 of 12**
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5-Year Early Shutdown **Proposed**

EXTERNAL FUND CALCULATION

Prairie Island Unit 1

External Levelized

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	374,367,055	9,340,765	-	24,632	383,732,452
2018	383,732,452	19,149,479	-	49,264	402,931,195
2019	402,931,195	20,107,496	-	49,264	423,087,955
2020	423,087,955	21,113,318	-	49,264	444,250,538
2021	444,250,538	23,028,369	-	34,479,626	501,758,533
2022	501,758,533	25,898,017	-	34,479,626	562,136,177
2023	562,136,177	28,910,862	-	34,479,626	625,526,665
2024	625,526,665	32,074,047	-	34,479,626	692,080,339
2025	692,080,339	35,395,076	-	34,479,626	761,955,041
2026	761,955,041	38,881,823	-	34,479,626	835,316,491
2027	835,316,491	42,542,560	-	34,479,626	912,338,677
2028	912,338,677	38,341,408	(36,047,572)	23,101,350	937,733,862
2029	937,733,862	38,915,955	(110,546,301)	-	866,103,517
2030	866,103,517	35,943,296	(168,064,022)	-	733,982,791
2031	733,982,791	30,460,286	(146,359,369)	-	618,083,707
2032	618,083,707	25,650,474	(93,046,932)	-	550,687,249
2033	550,687,249	22,853,521	(41,121,692)	-	532,419,078
2034	532,419,078	22,095,392	(143,546,582)	-	410,967,888
2035	410,967,888	17,055,167	(65,140,211)	-	362,882,844
2036	362,882,844	15,059,638	(43,338,711)	-	334,603,771
2037	334,603,771	13,886,057	(39,993,460)	-	308,496,368
2038	308,496,368	12,802,599	(23,981,192)	-	297,317,775
2039	297,317,775	12,338,688	(8,939,570)	-	300,716,892
2040	300,716,892	12,479,751	(9,205,201)	-	303,991,443
2041	303,991,443	12,615,645	(9,508,264)	-	307,098,823
2042	307,098,823	12,744,601	(9,823,000)	-	310,020,425
2043	310,020,425	12,865,848	(10,179,558)	-	312,706,714
2044	312,706,714	12,977,329	(10,487,571)	-	315,196,472
2045	315,196,472	13,080,654	(10,838,668)	-	317,438,457
2046	317,438,457	13,173,696	(11,203,065)	-	319,409,089
2047	319,409,089	13,255,477	(11,616,270)	-	321,048,296
2048	321,048,296	13,323,504	(12,718,405)	-	321,653,396
2049	321,653,396	13,348,616	(13,918,384)	-	321,083,628
2050	321,083,628	13,324,971	(14,390,752)	-	320,017,846
2051	320,017,846	13,280,741	(15,330,546)	-	317,968,041
2052	317,968,041	13,195,674	(14,965,333)	-	316,198,382
2053	316,198,382	13,122,233	(16,789,370)	-	312,531,245
2054	312,531,245	12,970,047	(16,011,156)	-	309,490,136
2055	309,490,136	12,843,841	(16,143,919)	-	306,190,057

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EXTERNAL FUND CALCULATION

2056	306,190,057	12,706,887	(17,617,385)	-	301,279,560
2057	301,279,560	12,503,102	(18,227,657)	-	295,555,004
2058	295,555,004	12,265,533	(18,347,788)	-	289,472,749
2059	289,472,749	12,013,119	(19,570,897)	-	281,914,971
2060	281,914,971	11,699,471	(20,198,974)	-	273,415,468
2061	273,415,468	11,346,742	(20,340,986)	-	264,421,224
2062	264,421,224	10,973,481	(21,639,172)	-	253,755,533
2063	253,755,533	10,530,855	(22,461,581)	-	241,824,806
2064	241,824,806	10,035,729	(22,567,515)	-	229,293,021
2065	229,293,021	9,515,660	(24,009,128)	-	214,799,553
2066	214,799,553	8,914,181	(24,859,129)	-	198,854,605
2067	198,854,605	8,252,466	(25,811,755)	-	181,295,316
2068	181,295,316	7,523,756	(26,656,565)	-	162,162,507
2069	162,162,507	6,729,744	(27,606,271)	-	141,285,980
2070	141,285,980	5,863,368	(33,835,381)	-	113,313,967
2071	113,313,967	4,702,530	(29,696,171)	-	88,320,326
2072	88,320,326	3,665,294	(70,830,585)	-	21,155,034
2073	21,155,034	877,934	(22,032,968)	-	(0)

Xcel Energy
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5-Year Early Shutdown

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Proposed

EXTERNAL FUND CALCULATION

Prairie Island Unit 2

External Levelized

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	420,208,967	10,592,979	-	294,670	431,096,616
2018	431,096,616	21,742,121	-	589,341	453,428,078
2019	453,428,078	22,867,627	-	589,341	476,885,046
2020	476,885,046	24,049,858	-	589,341	501,524,244
2021	501,524,244	25,830,004	-	21,951,682	549,305,931
2022	549,305,931	28,238,201	-	21,951,682	599,495,814
2023	599,495,814	30,767,771	-	21,951,682	652,215,268
2024	652,215,268	33,424,832	-	21,951,682	707,591,782
2025	707,591,782	36,215,808	-	21,951,682	765,759,273
2026	765,759,273	39,147,450	-	21,951,682	826,858,405
2027	826,858,405	42,226,846	-	21,951,682	891,036,933
2028	891,036,933	45,461,444	-	21,951,682	958,450,059
2029	958,450,059	39,573,204	(14,714,013)	18,219,896	1,001,529,147
2030	1,001,529,147	40,962,542	(96,381,435)	-	946,110,254
2031	946,110,254	38,695,909	(181,405,652)	-	803,400,512
2032	803,400,512	32,859,081	(174,467,137)	-	661,792,456
2033	661,792,456	27,067,311	(114,847,231)	-	574,012,536
2034	574,012,536	23,477,113	(151,381,933)	-	446,107,716
2035	446,107,716	18,245,806	(74,404,782)	-	389,948,739
2036	389,948,739	15,948,903	(53,750,646)	-	352,146,997
2037	352,146,997	14,402,812	(50,144,824)	-	316,404,985
2038	316,404,985	12,940,964	(28,889,727)	-	300,456,222
2039	300,456,222	12,288,659	(8,939,570)	-	303,805,312
2040	303,805,312	12,425,637	(9,205,201)	-	307,025,748
2041	307,025,748	12,557,353	(9,508,264)	-	310,074,837
2042	310,074,837	12,682,061	(9,823,000)	-	312,933,898
2043	312,933,898	12,798,996	(10,179,558)	-	315,553,337
2044	315,553,337	12,906,131	(10,487,571)	-	317,971,897
2045	317,971,897	13,005,051	(10,838,668)	-	320,138,279
2046	320,138,279	13,093,656	(11,203,065)	-	322,028,870
2047	322,028,870	13,170,981	(11,616,270)	-	323,583,582
2048	323,583,582	13,234,568	(12,718,407)	-	324,099,744
2049	324,099,744	13,255,680	(13,918,384)	-	323,437,039
2050	323,437,039	13,228,575	(14,390,752)	-	322,274,862
2051	322,274,862	13,181,042	(15,330,546)	-	320,125,358
2052	320,125,358	13,093,127	(14,965,333)	-	318,253,152
2053	318,253,152	13,016,554	(16,789,370)	-	314,480,336
2054	314,480,336	12,862,246	(16,011,156)	-	311,331,426

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EXTERNAL FUND CALCULATION

2055	311,331,426	12,733,455	(16,143,919)	-	307,920,962
2056	307,920,962	12,593,967	(17,617,385)	-	302,897,545
2057	302,897,545	12,388,510	(18,227,657)	-	297,058,397
2058	297,058,397	12,149,688	(18,347,788)	-	290,860,298
2059	290,860,298	11,896,186	(19,570,897)	-	283,185,587
2060	283,185,587	11,582,291	(20,198,974)	-	274,568,904
2061	274,568,904	11,229,868	(20,340,986)	-	265,457,785
2062	265,457,785	10,857,223	(21,639,172)	-	254,675,837
2063	254,675,837	10,416,242	(22,461,581)	-	242,630,498
2064	242,630,498	9,923,587	(22,567,515)	-	229,986,570
2065	229,986,570	9,406,451	(24,009,128)	-	215,383,892
2066	215,383,892	8,809,201	(24,859,129)	-	199,333,964
2067	199,333,964	8,152,759	(25,811,755)	-	181,674,968
2068	181,674,968	7,430,506	(26,656,565)	-	162,448,909
2069	162,448,909	6,644,160	(27,606,271)	-	141,486,799
2070	141,486,799	5,786,810	(33,835,381)	-	113,438,228
2071	113,438,228	4,639,624	(29,696,171)	-	88,381,681
2072	88,381,681	3,614,811	(70,829,263)	-	21,167,228
2073	21,167,228	865,740	(22,032,968)	-	(0)

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2021 ACCRUAL COMPARISON

	Present	Proposed	Difference
Monticello	$13,392,226	($2,594,535)	($15,986,761)
Prairie Island Unit 1	49,264	1,440,489	1,391,225
Prairie Island Unit 2	589,341	(2,660,472)	(3,249,812)
TOTAL	$14,030,831	($3,814,517)	($17,845,349)

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2021 MN RETAIL SUMMARY

	Remaining Life (yrs)	Operational Earnings Rate	Post-Shutdown Earnings Rate	Market Value Balance 6/30/2017	Book Value 6/30/2017	Unrealized Gain/Loss 6/30/2017	Tax-Effect Adjustment	Tax-Adjusted Fund Balance 6/30/2017	2021 Decommissioning Accrual
Monticello	33.75	5.00%	4.43%	$660,140,345	$529,148,381	$130,991,964	$36,468,163	$623,672,182	**(2,594,535)**
Prairie Island Unit 1	36.67	4.99%	4.15%	399,941,696	308,078,761	91,862,935	25,574,641	374,367,055	**1,440,489**
Prairie Island Unit 2	37.83	5.04%	4.09%	448,597,551	346,627,064	101,970,487	28,388,583	420,208,967	**(2,660,472)**
TOTAL DECOMMISSIONING ACCRUAL				**$1,508,679,592**	**$1,183,854,206**	**$324,825,386**	**$90,431,387**	**$1,418,248,204**	**($3,814,517)**

INPUT DATA

Escalation Rate (Labor)	4.05%
Escalation Rate (Non-Labor)	2.85%
Escalation Rate (PIIC)	0.00%
Jurisdictional Factor	73.4886%
Tax Rate for tax-effect adjustment	27.84%

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	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
Monticello															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2050	$21,103,620	$15,508,745	3.7067	$57,486,266	$8,935,561	$6,566,615	2.5278	$16,599,089	$0	$0	1.0000	$0	$30,039,182	$22,075,360	$74,085,355
2051	72,416,242	53,217,649	3.8568	205,249,828	42,961,353	31,571,677	2.5998	82,080,046	0	0	1.0000	0	115,377,595	84,789,326	287,329,874
2052	78,476,357	57,671,140	4.0130	231,434,285	102,263,189	75,151,739	2.6739	200,948,234	0	0	1.0000	0	180,739,546	132,822,879	432,382,519
2053	78,663,227	57,808,468	4.1756	241,385,038	100,155,666	73,602,950	2.7501	202,415,473	0	0	1.0000	0	178,818,892	131,411,418	443,800,512
2054	66,380,423	48,782,013	4.3447	211,943,210	38,894,671	28,583,132	2.8285	80,847,388	0	0	1.0000	0	105,275,094	77,365,144	292,790,598
2055	86,879,803	63,846,711	4.5206	288,625,441	113,147,091	83,150,161	2.9091	241,892,133	0	0	1.0000	0	200,026,894	146,996,872	530,517,574
2056	50,307,504	36,970,257	4.7037	173,896,999	20,688,337	15,203,559	2.9920	45,489,050	0	0	1.0000	0	70,995,841	52,173,817	219,386,048
2057	34,623,126	25,444,035	4.8942	124,528,195	14,196,883	10,433,084	3.0773	32,105,730	0	0	1.0000	0	48,820,010	35,877,119	156,633,925
2058	29,581,478	21,739,000	5.0924	110,703,685	15,098,979	11,096,021	3.1650	35,118,908	0	0	1.0000	0	44,680,457	32,835,022	145,822,593
2059	5,925,016	4,354,209	5.2987	23,071,645	2,187,162	1,607,314	3.2552	5,232,129	0	0	1.0000	0	8,112,178	5,961,523	28,303,774
2060	5,941,203	4,366,104	5.5133	24,071,642	2,193,018	1,611,617	3.3480	5,395,695	0	0	1.0000	0	8,134,221	5,977,722	29,467,337
2061	5,925,016	4,354,209	5.7366	24,978,353	2,187,162	1,607,314	3.4434	5,534,625	0	0	1.0000	0	8,112,178	5,961,523	30,512,978
2062	5,925,016	4,354,209	5.9689	25,989,836	2,187,162	1,607,314	3.5415	5,692,303	0	0	1.0000	0	8,112,178	5,961,523	31,682,138
2063	5,925,016	4,354,209	6.2106	27,042,248	2,187,162	1,607,314	3.6425	5,854,641	0	0	1.0000	0	8,112,178	5,961,523	32,896,889
2064	5,941,203	4,366,104	6.4622	28,214,638	2,193,018	1,611,617	3.7463	6,037,602	0	0	1.0000	0	8,134,221	5,977,722	34,252,241
2065	5,925,016	4,354,209	6.7239	29,277,263	2,187,162	1,607,314	3.8531	6,193,142	0	0	1.0000	0	8,112,178	5,961,523	35,470,405
2066	5,925,016	4,354,209	6.9962	30,462,914	2,187,162	1,607,314	3.9629	6,369,625	0	0	1.0000	0	8,112,178	5,961,523	36,832,539
2067	5,925,016	4,354,209	7.2795	31,696,461	2,187,162	1,607,314	4.0758	6,551,091	0	0	1.0000	0	8,112,178	5,961,523	38,247,552
2068	6,604,848	4,853,807	7.5744	36,764,678	4,183,953	3,074,727	4.1920	12,889,255	0	0	1.0000	0	10,788,801	7,928,534	49,653,932
2069	5,925,016	4,354,209	7.8811	34,315,953	2,187,162	1,607,314	4.3115	6,929,934	0	0	1.0000	0	8,112,178	5,961,523	41,245,888
2070	7,418,217	5,451,540	8.2003	44,704,267	6,666,766	4,899,310	4.4343	21,725,011	0	0	1.0000	0	14,084,983	10,350,851	66,429,278
2071	7,418,217	5,451,540	8.5324	46,514,723	6,666,766	4,899,310	4.5607	22,344,284	0	0	1.0000	0	14,084,983	10,350,851	68,859,007
2072	8,296,904	6,097,275	8.8780	54,131,605	9,260,122	6,805,130	4.6907	31,920,823	0	0	1.0000	0	17,557,026	12,902,405	86,052,428
2073	8,927,592	6,560,758	9.2375	60,605,004	11,194,891	8,226,964	4.8244	39,690,164	0	0	1.0000	0	20,122,483	14,787,722	100,295,169
2074	7,633,842	5,610,000	9.6117	53,921,638	7,313,641	5,374,689	4.9619	26,668,671	0	0	1.0000	0	14,947,483	10,984,689	80,590,309
2075	8,711,967	6,402,299	10.0009	64,028,748	10,548,016	7,751,585	5.1033	39,558,662	0	0	1.0000	0	19,259,983	14,153,883	103,587,410
2076	9,159,404	6,731,114	10.4060	70,043,968	11,847,622	8,706,646	5.2487	45,698,574	0	0	1.0000	0	21,007,026	15,437,760	115,742,542
2077	5,908,425	4,342,016	10.8274	47,012,745	2,137,389	1,570,737	5.3983	8,479,307	0	0	1.0000	0	8,045,814	5,912,753	55,492,052
2078	5,908,425	4,342,016	11.2659	48,916,719	2,137,389	1,570,737	5.5522	8,721,044	0	0	1.0000	0	8,045,814	5,912,753	57,637,763
2079	5,908,425	4,342,016	11.7222	50,897,981	2,137,389	1,570,737	5.7104	8,969,534	0	0	1.0000	0	8,045,814	5,912,753	59,867,515
2080	5,924,612	4,353,912	12.1970	53,104,661	2,143,245	1,575,040	5.8731	9,250,367	0	0	1.0000	0	8,067,857	5,928,952	62,355,028
2081	5,908,425	4,342,016	12.6909	55,104,092	2,137,389	1,570,737	6.0405	9,488,034	0	0	1.0000	0	8,045,814	5,912,753	64,592,126
2082	5,908,425	4,342,016	13.2049	57,335,888	2,137,389	1,570,737	6.2127	9,758,515	0	0	1.0000	0	8,045,814	5,912,753	67,094,403
2083	5,908,425	4,342,016	13.7397	59,657,998	2,137,389	1,570,737	6.3897	10,036,535	0	0	1.0000	0	8,045,814	5,912,753	69,694,534
2084	5,924,612	4,353,912	14.2962	62,244,392	2,143,245	1,575,040	6.5719	10,351,005	0	0	1.0000	0	8,067,857	5,928,952	72,595,397
2085	5,908,425	4,342,016	14.8752	64,588,358	2,137,389	1,570,737	6.7592	10,616,923	0	0	1.0000	0	8,045,814	5,912,753	75,205,280
2086	5,908,425	4,342,016	15.4776	67,203,988	2,137,389	1,570,737	6.9518	10,919,447	0	0	1.0000	0	8,045,814	5,912,753	78,123,435
2087	5,908,425	4,342,016	16.1045	69,925,998	2,137,389	1,570,737	7.1499	11,230,609	0	0	1.0000	0	8,045,814	5,912,753	81,156,608
2088	5,924,612	4,353,912	16.7567	72,957,192	2,143,245	1,575,040	7.3537	11,582,371	0	0	1.0000	0	8,067,857	5,928,952	84,539,563
2089	5,908,425	4,342,016	17.4353	75,704,353	2,137,389	1,570,737	7.5633	11,879,952	0	0	1.0000	0	8,045,814	5,912,753	87,584,305
2090	5,908,425	4,342,016	18.1415	78,770,685	2,137,389	1,570,737	7.7788	12,218,446	0	0	1.0000	0	8,045,814	5,912,753	90,989,131
2091	5,908,425	4,342,016	18.8762	81,960,764	2,137,389	1,570,737	8.0005	12,566,678	0	0	1.0000	0	8,045,814	5,912,753	94,527,442
2092	5,924,612	4,353,912	19.6407	85,513,873	2,143,245	1,575,040	8.2285	12,960,216	0	0	1.0000	0	8,067,857	5,928,952	98,474,090
2093	5,908,425	4,342,016	20.4361	88,733,875	2,137,389	1,570,737	8.4630	13,293,144	0	0	1.0000	0	8,045,814	5,912,753	102,027,019
2094	5,908,425	4,342,016	21.2638	92,327,762	2,137,389	1,570,737	8.7042	13,672,005	0	0	1.0000	0	8,045,814	5,912,753	105,999,767
2095	5,908,425	4,342,016	22.1250	96,067,106	2,137,389	1,570,737	8.9523	14,061,705	0	0	1.0000	0	8,045,814	5,912,753	110,128,811
2096	5,924,612	4,353,912	23.0210	100,231,401	2,143,245	1,575,040	9.2075	14,502,180	0	0	1.0000	0	8,067,857	5,928,952	114,733,581
2097	5,908,425	4,342,016	23.9534	104,006,048	2,137,389	1,570,737	9.4699	14,874,718	0	0	1.0000	0	8,045,814	5,912,753	118,880,766
2098	6,386,857	4,693,609	24.9235	116,981,160	3,557,353	2,614,247	9.7398	25,462,244	0	0	1.0000	0	9,944,210	7,307,856	142,443,404
2099	6,482,543	4,763,927	25.9329	123,542,445	3,844,412	2,825,203	10.0173	28,300,902	0	0	1.0000	0	10,326,955	7,589,130	151,843,348
2100	6,403,045	4,705,505	26.9832	126,969,587	3,563,167	2,618,520	10.3028	26,978,084	0	0	1.0000	0	9,966,212	7,324,025	153,947,671
2101	6,386,857	4,693,609	28.0760	131,777,762	3,557,353	2,614,247	10.5965	27,701,870	0	0	1.0000	0	9,944,210	7,307,856	159,479,632
2102	6,386,857	4,693,609	29.2131	137,114,865	3,557,353	2,614,247	10.8985	28,491,372	0	0	1.0000	0	9,944,210	7,307,856	165,606,237
2103	6,482,543	4,763,927	30.3962	144,805,281	3,844,412	2,825,203	11.2091	31,667,979	0	0	1.0000	0	10,326,955	7,589,130	176,473,260
2104	6,403,045	4,705,505	31.6272	148,821,953	3,563,167	2,618,520	11.5285	30,187,604	0	0	1.0000	0	9,966,212	7,324,025	179,009,557

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AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
2105	6,386,857	4,693,609	32.9081	154,457,749	3,557,353	2,614,247	11.8571	30,997,390	0	0	1.0000	0	9,944,210	7,307,856	185,455,139
2106	6,386,857	4,693,609	34.2409	160,713,391	3,557,353	2,614,247	12.1950	31,880,744	0	0	1.0000	0	9,944,210	7,307,856	192,594,135
2107	6,482,543	4,763,927	35.6277	169,727,766	3,844,412	2,825,203	12.5426	35,435,387	0	0	1.0000	0	10,326,955	7,589,130	205,163,152
2108	7,066,689	5,193,208	37.0706	192,515,320	5,554,101	4,081,628	12.9000	52,653,004	0	0	1.0000	0	12,620,790	9,274,836	245,168,324
2109	6,386,857	4,693,609	38.5720	181,041,880	3,557,353	2,614,247	13.2677	34,685,047	0	0	1.0000	0	9,944,210	7,307,856	215,726,927
2110	6,099,798	4,482,653	40.1341	179,907,257	2,696,175	1,981,380	13.6458	27,037,513	0	0	1.0000	0	8,795,973	6,464,033	206,944,771
2111	2,034,890	1,495,411	41.7596	62,447,769	24,955,010	18,339,076	14.0347	257,383,427	0	0	1.0000	0	26,989,900	19,834,487	319,831,196
	$851,819,402	$625,989,760		$5,898,178,598	$664,030,274	$487,986,246		$2,146,077,587	$0	$0		$0	$1,515,849,676	$1,113,976,006	$8,044,256,184

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AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
Prairie Island Unit 1															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2053	$22,324,352	$16,405,843	4.1756	$68,504,239	$9,728,959	$7,149,672	2.7501	$19,662,312	$1,250,000	$918,607	1.0000	$918,607	$33,303,311	$24,474,122	$89,085,158
2054	63,582,247	46,725,674	4.3447	203,009,034	33,397,619	24,543,427	2.8285	69,421,084	1,250,000	918,607	1.0000	918,607	98,229,866	72,187,708	273,348,725
2055	65,877,290	48,412,268	4.5206	218,852,499	81,239,936	59,702,054	2.9091	173,679,245	1,250,000	918,607	1.0000	918,607	148,367,226	109,032,929	393,450,351
2056	57,759,315	42,446,486	4.7037	199,655,534	65,595,019	48,204,831	2.9920	144,228,854	1,250,000	918,607	1.0000	918,607	124,604,334	91,569,923	344,802,995
2057	38,110,947	28,007,184	4.8942	137,072,758	36,889,671	27,109,686	3.0773	83,424,636	1,250,000	918,607	1.0000	918,607	76,250,618	56,035,476	221,416,001
2058	13,207,914	9,706,305	5.0924	49,428,388	18,994,691	13,958,924	3.1650	44,179,994	1,250,000	918,607	1.0000	918,607	33,452,605	24,583,836	94,526,988
2059	36,035,855	26,482,229	5.2987	140,321,385	76,476,728	56,201,641	3.2552	182,947,582	1,250,000	918,607	1.0000	918,607	113,762,582	83,602,477	324,187,574
2060	31,919,556	23,457,220	5.5133	129,326,692	13,365,606	9,822,190	3.3480	32,884,693	1,250,000	918,607	1.0000	918,607	46,535,162	34,198,017	163,129,992
2061	19,571,318	14,382,679	5.7366	82,507,674	9,445,873	6,941,635	3.4434	23,902,826	1,250,000	918,607	1.0000	918,607	30,267,191	22,242,921	107,329,108
2062	14,781,952	10,863,043	5.9689	64,840,415	11,668,700	8,575,159	3.5415	30,368,925	1,250,000	918,607	1.0000	918,607	27,700,652	20,356,808	96,127,947
2063	8,544,452	6,279,195	6.2106	38,997,566	6,492,672	4,771,371	3.6425	17,379,719	1,250,000	918,607	1.0000	918,607	16,287,125	11,969,172	57,295,891
2064	3,054,798	2,244,927	6.4622	14,507,166	1,939,011	1,424,951	3.7463	5,338,294	1,250,000	918,607	1.0000	918,607	6,243,809	4,588,485	20,764,067
2065	3,046,451	2,238,793	6.7239	15,053,419	1,930,298	1,418,548	3.8531	5,465,806	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	21,437,832
2066	3,046,451	2,238,793	6.9962	15,663,042	1,930,298	1,418,548	3.9629	5,621,563	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	22,203,212
2067	3,046,451	2,238,793	7.2795	16,297,292	1,930,298	1,418,548	4.0758	5,781,717	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	22,997,616
2068	3,054,798	2,244,927	7.5744	17,003,974	1,939,011	1,424,951	4.1920	5,973,394	1,250,000	918,607	1.0000	918,607	6,243,809	4,588,485	23,895,975
2069	3,046,451	2,238,793	7.8811	17,644,150	1,930,298	1,418,548	4.3115	6,116,069	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	24,678,825
2070	3,046,451	2,238,793	8.2003	18,358,772	1,930,298	1,418,548	4.4343	6,290,266	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	25,567,646
2071	3,046,451	2,238,793	8.5324	19,102,276	1,930,298	1,418,548	4.5607	6,469,571	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	26,490,453
2072	3,054,798	2,244,927	8.8780	19,930,461	1,939,011	1,424,951	4.6907	6,684,017	1,250,000	918,607	1.0000	918,607	6,243,809	4,588,485	27,533,085
2073	3,142,138	2,309,112	9.2375	21,330,420	2,217,357	1,629,503	4.8244	7,861,375	1,250,000	918,607	1.0000	918,607	6,609,495	4,857,222	30,110,402
2074	3,237,824	2,379,430	9.6117	22,870,368	2,504,416	1,840,459	4.9619	9,132,172	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	32,921,147
2075	3,237,824	2,379,430	10.0009	23,796,442	2,504,416	1,840,459	5.1033	9,392,413	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	34,107,462
2076	3,294,014	2,420,723	10.4060	25,190,046	2,656,659	1,952,340	5.2487	10,247,247	1,250,000	918,607	1.0000	918,607	7,200,673	5,291,670	36,355,900
2077	3,189,981	2,344,271	10.8274	25,382,359	2,360,887	1,734,981	5.3983	9,365,950	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	35,666,916
2078	3,333,510	2,449,748	11.2659	27,598,619	2,791,475	2,051,414	5.5522	11,389,862	1,250,000	918,607	1.0000	918,607	7,374,985	5,419,769	39,907,088
2079	3,189,981	2,344,271	11.7222	27,480,012	2,360,887	1,734,981	5.7104	9,907,438	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	38,306,057
2080	3,150,484	2,315,245	12.1970	28,239,045	2,226,070	1,635,906	5.8731	9,607,842	1,250,000	918,607	1.0000	918,607	6,626,554	4,869,758	38,765,494
2081	3,237,824	2,379,430	12.6909	30,197,109	2,504,416	1,840,459	6.0405	11,117,291	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	42,233,007
2082	3,237,824	2,379,430	13.2049	31,420,136	2,504,416	1,840,459	6.2127	11,434,218	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	43,772,961
2083	3,189,981	2,344,271	13.7397	32,209,579	2,360,887	1,734,981	6.3897	11,086,010	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	44,214,196
2084	3,246,170	2,385,563	14.2962	34,104,491	2,513,129	1,846,862	6.5719	12,137,392	1,250,000	918,607	1.0000	918,607	7,009,299	5,151,032	47,160,490
2085	3,237,824	2,379,430	14.8752	35,394,498	2,504,416	1,840,459	6.7592	12,440,029	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	48,753,133
2086	3,189,981	2,344,271	15.4776	36,283,687	2,360,887	1,734,981	6.9518	12,061,243	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	49,263,538
2087	3,237,824	2,379,430	16.1045	38,319,531	2,504,416	1,840,459	7.1499	13,159,096	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	52,397,234
2088	3,246,170	2,385,563	16.7567	39,974,170	2,513,129	1,846,862	7.3537	13,581,268	1,250,000	918,607	1.0000	918,607	7,009,299	5,151,032	54,474,045
2089	3,189,981	2,344,271	17.4353	40,873,067	2,360,887	1,734,981	7.5633	13,122,185	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	54,913,858
2090	3,237,824	2,379,430	18.1415	43,166,430	2,504,416	1,840,459	7.7788	14,316,561	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	58,401,597
2091	3,237,824	2,379,430	18.8762	44,914,597	2,504,416	1,840,459	8.0005	14,724,590	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	60,557,794
2092	3,246,170	2,385,563	19.6407	46,854,135	2,513,129	1,846,862	8.2285	15,196,903	1,250,000	918,607	1.0000	918,607	7,009,299	5,151,032	62,969,645
2093	3,237,824	2,379,430	20.4361	48,626,270	2,504,416	1,840,459	8.4630	15,575,802	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	65,120,679
2094	3,237,824	2,379,430	21.2638	50,595,724	2,504,416	1,840,459	8.7042	16,019,721	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	67,534,052
2095	3,569,646	2,623,281	22.1250	58,040,097	3,499,884	2,572,014	8.9523	23,025,439	1,250,000	918,607	1.0000	918,607	8,319,530	6,113,902	81,984,143
2096	3,246,170	2,385,563	23.0210	54,918,055	2,513,129	1,846,862	9.2075	17,004,981	1,250,000	918,607	1.0000	918,607	7,009,299	5,151,032	72,841,643
2097	3,237,974	2,379,540	23.9534	56,998,080	14,152,775	10,400,669	9.4699	98,493,298	1,250,000	918,607	1.0000	918,607	18,640,749	13,698,817	156,409,985
2098	832,743	611,971	24.9235	15,252,461	4,620,063	3,395,217	9.7398	33,068,736	0	0	1.0000	0	5,452,806	4,007,188	48,321,196
	$481,031,633	$353,503,191		$2,426,106,164	$459,759,673	$337,870,735		$1,310,289,630	$56,250,000	$41,337,312		$41,337,312	$997,041,305	$732,711,237	$3,777,733,106

Xcel Energy
Nuclear Decommissioning Accrual
60-Year Decommissioning Period
DECON Method - No Recasking
20-Year Life Extension

Docket No. E002/M-17-828
Schedule F.14
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Proposed

AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
Prairie Island Unit 2															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2054	$7,760,265	$5,702,906	4.3447	$24,777,417	$4,479,535	$3,291,946	2.8285	$9,311,268	$1,250,000	$918,607	1.0000	$918,607	$13,489,800	$9,913,459	$35,007,292
2055	46,911,429	34,474,531	4.5206	155,845,564	35,601,339	26,162,909	2.9091	76,110,519	1,250,000	918,607	1.0000	918,607	83,762,768	61,556,047	232,874,689
2056	67,514,044	49,615,094	4.7037	233,374,519	86,298,832	63,419,763	2.9920	189,751,932	1,250,000	918,607	1.0000	918,607	155,062,875	113,953,465	424,045,058
2057	70,896,041	52,100,475	4.8942	254,990,145	70,558,163	51,852,174	3.0773	159,564,694	1,250,000	918,607	1.0000	918,607	142,704,204	104,871,256	415,473,446
2058	46,603,528	34,248,259	5.0924	174,405,835	42,782,149	31,439,982	3.1650	99,507,544	1,250,000	918,607	1.0000	918,607	90,635,677	66,606,848	274,831,986
2059	40,663,625	29,883,110	5.2987	158,341,633	77,452,618	56,918,809	3.2552	185,282,106	1,250,000	918,607	1.0000	918,607	119,366,242	87,720,525	344,542,346
2060	37,417,177	27,497,343	5.5133	151,601,099	14,193,501	10,430,599	3.3480	34,921,645	1,250,000	918,607	1.0000	918,607	52,860,679	38,846,548	187,441,351
2061	23,327,583	17,143,103	5.7366	98,343,127	13,070,130	9,605,049	3.4434	33,074,027	1,250,000	918,607	1.0000	918,607	37,647,713	27,666,760	132,335,761
2062	16,656,921	12,240,930	5.9689	73,064,887	17,178,640	12,624,334	3.5415	44,709,080	1,250,000	918,607	1.0000	918,607	35,085,561	25,783,871	118,692,574
2063	9,422,862	6,924,725	6.2106	43,006,699	9,074,042	6,668,382	3.6425	24,289,581	1,250,000	918,607	1.0000	918,607	19,746,904	14,511,714	68,214,888
2064	3,054,798	2,244,927	6.4622	14,507,166	1,939,011	1,424,951	3.7463	5,338,294	1,250,000	918,607	1.0000	918,607	6,243,809	4,588,485	20,764,067
2065	3,046,451	2,238,793	6.7239	15,053,419	1,930,298	1,418,548	3.8531	5,465,806	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	21,437,832
2066	3,046,451	2,238,793	6.9962	15,663,042	1,930,298	1,418,548	3.9629	5,621,563	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	22,203,212
2067	3,046,451	2,238,793	7.2795	16,297,292	1,930,298	1,418,548	4.0758	5,781,717	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	22,997,616
2068	3,054,798	2,244,927	7.5744	17,003,974	1,939,011	1,424,951	4.1920	5,973,394	1,250,000	918,607	1.0000	918,607	6,243,809	4,588,485	23,895,975
2069	3,046,451	2,238,793	7.8811	17,644,150	1,930,298	1,418,548	4.3115	6,116,069	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	24,678,825
2070	3,046,451	2,238,793	8.2003	18,358,772	1,930,298	1,418,548	4.4343	6,290,266	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	25,567,646
2071	3,046,451	2,238,793	8.5324	19,102,276	1,930,298	1,418,548	4.5607	6,469,571	1,250,000	918,607	1.0000	918,607	6,226,749	4,575,947	26,490,453
2072	3,054,798	2,244,927	8.8780	19,930,461	1,939,011	1,424,951	4.6907	6,684,017	1,250,000	918,607	1.0000	918,607	6,243,809	4,588,485	27,533,085
2073	3,142,138	2,309,112	9.2375	21,330,420	2,217,358	1,629,504	4.8244	7,861,379	1,250,000	918,607	1.0000	918,607	6,609,496	4,857,223	30,110,406
2074	3,237,824	2,379,430	9.6117	22,870,368	2,504,416	1,840,459	4.9619	9,132,172	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	32,921,147
2075	3,237,824	2,379,430	10.0009	23,796,442	2,504,416	1,840,459	5.1033	9,392,413	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	34,107,462
2076	3,294,014	2,420,723	10.4060	25,190,046	2,656,659	1,952,340	5.2487	10,247,247	1,250,000	918,607	1.0000	918,607	7,200,673	5,291,670	36,355,900
2077	3,189,981	2,344,271	10.8274	25,382,359	2,360,887	1,734,981	5.3983	9,365,950	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	35,666,916
2078	3,333,510	2,449,748	11.2659	27,598,619	2,791,475	2,051,414	5.5522	11,389,862	1,250,000	918,607	1.0000	918,607	7,374,985	5,419,769	39,907,088
2079	3,189,981	2,344,271	11.7222	27,480,012	2,360,887	1,734,981	5.7104	9,907,438	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	38,306,057
2080	3,150,484	2,315,245	12.1970	28,239,045	2,226,070	1,635,906	5.8731	9,607,842	1,250,000	918,607	1.0000	918,607	6,626,554	4,869,758	38,765,494
2081	3,237,824	2,379,430	12.6909	30,197,109	2,504,416	1,840,459	6.0405	11,117,291	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	42,233,007
2082	3,237,824	2,379,430	13.2049	31,420,136	2,504,416	1,840,459	6.2127	11,434,218	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	43,772,961
2083	3,189,981	2,344,271	13.7397	32,209,579	2,360,887	1,734,981	6.3897	11,086,010	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	44,214,196
2084	3,246,170	2,385,563	14.2962	34,104,491	2,513,129	1,846,862	6.5719	12,137,392	1,250,000	918,607	1.0000	918,607	7,009,299	5,151,032	47,160,490
2085	3,237,824	2,379,430	14.8752	35,394,498	2,504,416	1,840,459	6.7592	12,440,029	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	48,753,133
2086	3,189,981	2,344,271	15.4776	36,283,687	2,360,887	1,734,981	6.9518	12,061,243	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	49,263,538
2087	3,237,824	2,379,430	16.1045	38,319,531	2,504,416	1,840,459	7.1499	13,159,096	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	52,397,234
2088	3,246,170	2,385,563	16.7567	39,974,170	2,513,129	1,846,862	7.3537	13,581,268	1,250,000	918,607	1.0000	918,607	7,009,299	5,151,032	54,474,045
2089	3,189,981	2,344,271	17.4353	40,873,067	2,360,887	1,734,981	7.5633	13,122,185	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	54,913,858
2090	3,237,824	2,379,430	18.1415	43,166,430	2,504,416	1,840,459	7.7788	14,316,561	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	58,401,597
2091	3,237,824	2,379,430	18.8762	44,914,597	2,504,416	1,840,459	8.0005	14,724,590	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	60,557,794
2092	3,246,170	2,385,563	19.6407	46,854,135	2,513,129	1,846,862	8.2285	15,196,903	1,250,000	918,607	1.0000	918,607	7,009,299	5,151,032	62,969,645
2093	3,237,824	2,379,430	20.4361	48,626,270	2,504,416	1,840,459	8.4630	15,575,802	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	65,120,679
2094	3,237,824	2,379,430	21.2638	50,595,724	2,504,416	1,840,459	8.7042	16,019,721	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	67,534,052
2095	3,569,646	2,623,281	22.1250	58,040,097	3,499,884	2,572,014	8.9523	23,025,439	1,250,000	918,607	1.0000	918,607	8,319,530	6,113,902	81,984,143
2096	3,246,170	2,385,563	23.0210	54,918,055	2,513,129	1,846,862	9.2075	17,004,981	1,250,000	918,607	1.0000	918,607	7,009,299	5,151,032	72,841,643
2097	3,237,824	2,379,430	23.9534	56,995,443	14,152,675	10,400,596	9.4699	98,492,602	1,250,000	918,607	1.0000	918,607	18,640,499	13,698,633	156,406,652
2098	832,743	611,971	24.9235	15,252,461	4,620,063	3,395,217	9.7398	33,068,736	0	-	1.0000	-	5,452,806	4,007,188	48,321,196
	$476,489,759	$350,165,433		$2,461,338,267	$467,153,049	$343,304,020		$1,344,731,465	$55,000,000	$40,418,705		$40,418,705	$998,642,807	$733,888,158	$3,846,488,437
	$1,809,340,794	$1,329,658,384		$10,785,623,029	$1,590,942,995	$1,169,161,000		$4,801,098,682	$111,250,000	$81,756,016		$81,756,016	$3,511,533,789	$2,580,575,401	$15,668,477,727

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Monticello

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	623,672,182	15,675,506	-	6,696,113	646,043,801
2018	646,043,801	32,636,996	-	13,392,226	692,073,023
2019	692,073,023	34,938,457	-	13,392,226	740,403,706
2020	740,403,706	37,354,991	-	13,392,226	791,150,922
2021	791,150,922	39,492,683	-	(2,594,535)	828,049,070
2022	828,049,070	41,337,590	-	(2,594,535)	866,792,125
2023	866,792,125	43,274,743	-	(2,594,535)	907,472,333
2024	907,472,333	45,308,753	-	(2,594,535)	950,186,552
2025	950,186,552	47,444,464	-	(2,594,535)	995,036,481
2026	995,036,481	49,686,961	-	(2,594,535)	1,042,128,907
2027	1,042,128,907	52,041,582	-	(2,594,535)	1,091,575,954
2028	1,091,575,954	54,513,934	-	(2,594,535)	1,143,495,353
2029	1,143,495,353	57,109,904	-	(2,594,535)	1,198,010,722
2030	1,198,010,722	59,835,673	-	(2,594,535)	1,255,251,860
2031	1,255,251,860	62,697,730	-	(2,594,535)	1,315,355,055
2032	1,315,355,055	65,702,889	-	(2,594,535)	1,378,463,409
2033	1,378,463,409	68,858,307	-	(2,594,535)	1,444,727,181
2034	1,444,727,181	72,171,496	-	(2,594,535)	1,514,304,142
2035	1,514,304,142	75,650,344	-	(2,594,535)	1,587,359,951
2036	1,587,359,951	79,303,134	-	(2,594,535)	1,664,068,550
2037	1,664,068,550	83,138,564	-	(2,594,535)	1,744,612,579
2038	1,744,612,579	87,165,766	-	(2,594,535)	1,829,183,810
2039	1,829,183,810	91,394,327	-	(2,594,535)	1,917,983,602
2040	1,917,983,602	95,834,317	-	(2,594,535)	2,011,223,384
2041	2,011,223,384	100,496,306	-	(2,594,535)	2,109,125,154
2042	2,109,125,154	105,391,394	-	(2,594,535)	2,211,922,014
2043	2,211,922,014	110,531,237	-	(2,594,535)	2,319,858,716
2044	2,319,858,716	115,928,072	-	(2,594,535)	2,433,192,254
2045	2,433,192,254	121,594,749	-	(2,594,535)	2,552,192,468
2046	2,552,192,468	127,544,760	-	(2,594,535)	2,677,142,693
2047	2,677,142,693	133,792,271	-	(2,594,535)	2,808,340,429
2048	2,808,340,429	140,352,158	-	(2,594,535)	2,946,098,052
2049	2,946,098,052	147,240,039	-	(2,594,535)	3,090,743,557
2050	3,090,743,557	136,876,838	(74,085,355)	(1,945,901)	3,151,589,138
2051	3,151,589,138	139,615,399	(287,329,874)	-	3,003,874,664
2052	3,003,874,664	133,071,648	(432,382,519)	-	2,704,563,792
2053	2,704,563,792	119,812,176	(443,800,512)	-	2,380,575,456
2054	2,380,575,456	105,459,493	(292,790,598)	-	2,193,244,352
2055	2,193,244,352	97,160,725	(530,517,574)	-	1,759,887,502

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External Levelized	2056	1,759,887,502	77,963,016	(219,386,048)	-	1,618,464,470
	2057	1,618,464,470	71,697,976	(156,633,925)	-	1,533,528,521
	2058	1,533,528,521	67,935,313	(145,822,593)	-	1,455,641,241
	2059	1,455,641,241	64,484,907	(28,303,774)	-	1,491,822,375
	2060	1,491,822,375	66,087,731	(29,467,337)	-	1,528,442,769
	2061	1,528,442,769	67,710,015	(30,512,978)	-	1,565,639,805
	2062	1,565,639,805	69,357,843	(31,682,138)	-	1,603,315,511
	2063	1,603,315,511	71,026,877	(32,896,889)	-	1,641,445,499
	2064	1,641,445,499	72,716,036	(34,252,241)	-	1,679,909,293
	2065	1,679,909,293	74,419,982	(35,470,405)	-	1,718,858,870
	2066	1,718,858,870	76,145,448	(36,832,539)	-	1,758,171,780
	2067	1,758,171,780	77,887,010	(38,247,552)	-	1,797,811,238
	2068	1,797,811,238	79,643,038	(49,653,932)	-	1,827,800,343
	2069	1,827,800,343	80,971,555	(41,245,888)	-	1,867,526,010
	2070	1,867,526,010	82,731,402	(66,429,278)	-	1,883,828,135
	2071	1,883,828,135	83,453,586	(68,859,007)	-	1,898,422,713
	2072	1,898,422,713	84,100,126	(86,052,428)	-	1,896,470,411
	2073	1,896,470,411	84,013,639	(100,295,169)	-	1,880,188,882
	2074	1,880,188,882	83,292,367	(80,590,309)	-	1,882,890,941
	2075	1,882,890,941	83,412,069	(103,587,410)	-	1,862,715,599
	2076	1,862,715,599	82,518,301	(115,742,542)	-	1,829,491,358
	2077	1,829,491,358	81,046,467	(55,492,052)	-	1,855,045,773
	2078	1,855,045,773	82,178,528	(57,637,763)	-	1,879,586,538
	2079	1,879,586,538	83,265,684	(59,867,515)	-	1,902,984,707
	2080	1,902,984,707	84,302,223	(62,355,028)	-	1,924,931,901
	2081	1,924,931,901	85,274,483	(64,592,126)	-	1,945,614,258
	2082	1,945,614,258	86,190,712	(67,094,403)	-	1,964,710,567
	2083	1,964,710,567	87,036,678	(69,694,534)	-	1,982,052,711
	2084	1,982,052,711	87,804,935	(72,595,397)	-	1,997,262,248
	2085	1,997,262,248	88,478,718	(75,205,280)	-	2,010,535,686
	2086	2,010,535,686	89,066,731	(78,123,435)	-	2,021,478,982
	2087	2,021,478,982	89,551,519	(81,156,608)	-	2,029,873,893
	2088	2,029,873,893	89,923,413	(84,539,563)	-	2,035,257,743
	2089	2,035,257,743	90,161,918	(87,584,305)	-	2,037,835,356
	2090	2,037,835,356	90,276,106	(90,989,131)	-	2,037,122,332
	2091	2,037,122,332	90,244,519	(94,527,442)	-	2,032,839,409
	2092	2,032,839,409	90,054,786	(98,474,090)	-	2,024,420,106
	2093	2,024,420,106	89,681,811	(102,027,019)	-	2,012,074,898
	2094	2,012,074,898	89,134,918	(105,999,767)	-	1,995,210,049
	2095	1,995,210,049	88,387,805	(110,128,811)	-	1,973,469,043
	2096	1,973,469,043	87,424,679	(114,733,581)	-	1,946,160,140
	2097	1,946,160,140	86,214,894	(118,880,766)	-	1,913,494,268
	2098	1,913,494,268	84,767,796	(142,443,404)	-	1,855,818,659
	2099	1,855,818,659	82,212,767	(151,843,348)	-	1,786,188,078
	2100	1,786,188,078	79,128,132	(153,947,671)	-	1,711,368,539

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2101	1,711,368,539	75,813,626	(159,479,632)	-	1,627,702,533
2102	1,627,702,533	72,107,222	(165,606,237)	-	1,534,203,519
2103	1,534,203,519	67,965,216	(176,473,260)	-	1,425,695,474
2104	1,425,695,474	63,158,310	(179,009,557)	-	1,309,844,227
2105	1,309,844,227	58,026,099	(185,455,139)	-	1,182,415,187
2106	1,182,415,187	52,380,993	(192,594,135)	-	1,042,202,045
2107	1,042,202,045	46,169,551	(205,163,152)	-	883,208,443
2108	883,208,443	39,126,134	(245,168,324)	-	677,166,253
2109	677,166,253	29,998,465	(215,726,927)	-	491,437,791
2110	491,437,791	21,770,694	(206,944,771)	-	306,263,714
2111	306,263,714	13,567,483	(319,831,196)	-	(0)

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EXTERNAL FUND CALCULATION

Prairie Island Unit 1

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	374,367,055	9,340,765	-	24,632	383,732,452
2018	383,732,452	19,149,479	-	49,264	402,931,195
2019	402,931,195	20,107,496	-	49,264	423,087,955
2020	423,087,955	21,113,318	-	49,264	444,250,538
2021	444,250,538	22,204,042	-	1,440,489	467,895,069
2022	467,895,069	23,383,904	-	1,440,489	492,719,462
2023	492,719,462	24,622,641	-	1,440,489	518,782,593
2024	518,782,593	25,923,192	-	1,440,489	546,146,273
2025	546,146,273	27,288,639	-	1,440,489	574,875,402
2026	574,875,402	28,722,223	-	1,440,489	605,038,114
2027	605,038,114	30,227,342	-	1,440,489	636,705,945
2028	636,705,945	31,807,567	-	1,440,489	669,954,001
2029	669,954,001	33,466,645	-	1,440,489	704,861,135
2030	704,861,135	35,208,511	-	1,440,489	741,510,135
2031	741,510,135	37,037,296	-	1,440,489	779,987,920
2032	779,987,920	38,957,337	-	1,440,489	820,385,747
2033	820,385,747	40,973,189	-	1,440,489	862,799,425
2034	862,799,425	43,089,631	-	1,440,489	907,329,545
2035	907,329,545	45,311,685	-	1,440,489	954,081,719
2036	954,081,719	47,644,618	-	1,440,489	1,003,166,826
2037	1,003,166,826	50,093,965	-	1,440,489	1,054,701,280
2038	1,054,701,280	52,665,534	-	1,440,489	1,108,807,303
2039	1,108,807,303	55,365,425	-	1,440,489	1,165,613,217
2040	1,165,613,217	58,200,040	-	1,440,489	1,225,253,746
2041	1,225,253,746	61,176,102	-	1,440,489	1,287,870,337
2042	1,287,870,337	64,300,670	-	1,440,489	1,353,611,496
2043	1,353,611,496	67,581,154	-	1,440,489	1,422,633,139
2044	1,422,633,139	71,025,334	-	1,440,489	1,495,098,962
2045	1,495,098,962	74,641,378	-	1,440,489	1,571,180,830
2046	1,571,180,830	78,437,864	-	1,440,489	1,651,059,183
2047	1,651,059,183	82,423,793	-	1,440,489	1,734,923,465
2048	1,734,923,465	86,608,621	-	1,440,489	1,822,972,576
2049	1,822,972,576	91,002,272	-	1,440,489	1,915,415,337
2050	1,915,415,337	95,615,165	-	1,440,489	2,012,470,991
2051	2,012,470,991	100,458,243	-	1,440,489	2,114,369,723
2052	2,114,369,723	105,542,989	-	1,440,489	2,221,353,202
2053	2,221,353,202	92,206,184	(89,085,158)	965,128	2,225,439,356
2054	2,225,439,356	92,355,733	(273,348,725)	-	2,044,446,364
2055	2,044,446,364	84,844,524	(393,450,351)	-	1,735,840,537

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2056	1,735,840,537	72,037,382	(344,802,995)	-	1,463,074,925
2057	1,463,074,925	60,717,609	(221,416,001)	-	1,302,376,533
2058	1,302,376,533	54,048,626	(94,526,988)	-	1,261,898,170
2059	1,261,898,170	52,368,774	(324,187,574)	-	990,079,371
2060	990,079,371	41,088,294	(163,129,992)	-	868,037,672
2061	868,037,672	36,023,563	(107,329,108)	-	796,732,128
2062	796,732,128	33,064,383	(96,127,947)	-	733,668,564
2063	733,668,564	30,447,245	(57,295,891)	-	706,819,918
2064	706,819,918	29,333,027	(20,764,067)	-	715,388,878
2065	715,388,878	29,688,638	(21,437,832)	-	723,639,684
2066	723,639,684	30,031,047	(22,203,212)	-	731,467,519
2067	731,467,519	30,355,902	(22,997,616)	-	738,825,805
2068	738,825,805	30,661,271	(23,895,975)	-	745,591,101
2069	745,591,101	30,942,031	(24,678,825)	-	751,854,306
2070	751,854,306	31,201,954	(25,567,646)	-	757,488,615
2071	757,488,615	31,435,778	(26,490,453)	-	762,433,939
2072	762,433,939	31,641,008	(27,533,085)	-	766,541,863
2073	766,541,863	31,811,487	(30,110,402)	-	768,242,947
2074	768,242,947	31,882,082	(32,921,147)	-	767,203,883
2075	767,203,883	31,838,961	(34,107,462)	-	764,935,382
2076	764,935,382	31,744,818	(36,355,900)	-	760,324,300
2077	760,324,300	31,553,458	(35,666,916)	-	756,210,843
2078	756,210,843	31,382,750	(39,907,088)	-	747,686,505
2079	747,686,505	31,028,990	(38,306,057)	-	740,409,438
2080	740,409,438	30,726,992	(38,765,494)	-	732,370,935
2081	732,370,935	30,393,394	(42,233,007)	-	720,531,323
2082	720,531,323	29,902,050	(43,772,961)	-	706,660,412
2083	706,660,412	29,326,407	(44,214,196)	-	691,772,623
2084	691,772,623	28,708,564	(47,160,490)	-	673,320,696
2085	673,320,696	27,942,809	(48,753,133)	-	652,510,372
2086	652,510,372	27,079,180	(49,263,538)	-	630,326,015
2087	630,326,015	26,158,530	(52,397,234)	-	604,087,310
2088	604,087,310	25,069,623	(54,474,045)	-	574,682,888
2089	574,682,888	23,849,340	(54,913,858)	-	543,618,370
2090	543,618,370	22,560,162	(58,401,597)	-	507,776,935
2091	507,776,935	21,072,743	(60,557,794)	-	468,291,883
2092	468,291,883	19,434,113	(62,969,645)	-	424,756,351
2093	424,756,351	17,627,389	(65,120,679)	-	377,263,061
2094	377,263,061	15,656,417	(67,534,052)	-	325,385,425
2095	325,385,425	13,503,495	(81,984,143)	-	256,904,777
2096	256,904,777	10,661,548	(72,841,643)	-	194,724,683
2097	194,724,683	8,081,074	(156,409,985)	-	46,395,772
2098	46,395,772	1,925,425	(48,321,196)	-	(0)

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Prairie Island Unit 2

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	420,208,967	10,592,979	-	294,670	431,096,616
2018	431,096,616	21,742,121	-	589,341	453,428,078
2019	453,428,078	22,867,627	-	589,341	476,885,046
2020	476,885,046	24,049,858	-	589,341	501,524,244
2021	501,524,244	25,209,778	-	(2,660,472)	524,073,551
2022	524,073,551	26,346,263	-	(2,660,472)	547,759,342
2023	547,759,342	27,540,027	-	(2,660,472)	572,638,898
2024	572,638,898	28,793,957	-	(2,660,472)	598,772,383
2025	598,772,383	30,111,084	-	(2,660,472)	626,222,995
2026	626,222,995	31,494,595	-	(2,660,472)	655,057,119
2027	655,057,119	32,947,835	-	(2,660,472)	685,344,482
2028	685,344,482	34,474,318	-	(2,660,472)	717,158,328
2029	717,158,328	36,077,736	-	(2,660,472)	750,575,593
2030	750,575,593	37,761,966	-	(2,660,472)	785,677,087
2031	785,677,087	39,531,081	-	(2,660,472)	822,547,697
2032	822,547,697	41,389,360	-	(2,660,472)	861,276,585
2033	861,276,585	43,341,296	-	(2,660,472)	901,957,410
2034	901,957,410	45,391,610	-	(2,660,472)	944,688,548
2035	944,688,548	47,545,259	-	(2,660,472)	989,573,335
2036	989,573,335	49,807,452	-	(2,660,472)	1,036,720,316
2037	1,036,720,316	52,183,660	-	(2,660,472)	1,086,243,505
2038	1,086,243,505	54,679,629	-	(2,660,472)	1,138,262,662
2039	1,138,262,662	57,301,394	-	(2,660,472)	1,192,903,584
2040	1,192,903,584	60,055,297	-	(2,660,472)	1,250,298,410
2041	1,250,298,410	62,947,996	-	(2,660,472)	1,310,585,934
2042	1,310,585,934	65,986,487	-	(2,660,472)	1,373,911,950
2043	1,373,911,950	69,178,118	-	(2,660,472)	1,440,429,597
2044	1,440,429,597	72,530,608	-	(2,660,472)	1,510,299,733
2045	1,510,299,733	76,052,063	-	(2,660,472)	1,583,691,324
2046	1,583,691,324	79,750,999	-	(2,660,472)	1,660,781,851
2047	1,660,781,851	83,636,361	-	(2,660,472)	1,741,757,741
2048	1,741,757,741	87,717,546	-	(2,660,472)	1,826,814,816
2049	1,826,814,816	92,004,423	-	(2,660,472)	1,916,158,767
2050	1,916,158,767	96,507,358	-	(2,660,472)	2,010,005,653
2051	2,010,005,653	101,237,241	-	(2,660,472)	2,108,582,423
2052	2,108,582,423	106,205,510	-	(2,660,472)	2,212,127,461
2053	2,212,127,461	111,424,180	-	(2,660,472)	2,320,891,170
2054	2,320,891,170	94,879,291	(35,007,292)	(2,208,191)	2,378,554,978
2055	2,378,554,978	97,282,899	(232,874,689)	-	2,242,963,188

External Levelized

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EXTERNAL FUND CALCULATION

2056	2,242,963,188	91,737,194	(424,045,058)	-	1,910,655,324
2057	1,910,655,324	78,145,803	(415,473,446)	-	1,573,327,681
2058	1,573,327,681	64,349,102	(274,831,986)	-	1,362,844,797
2059	1,362,844,797	55,740,352	(344,542,346)	-	1,074,042,803
2060	1,074,042,803	43,928,351	(187,441,351)	-	930,529,803
2061	930,529,803	38,058,669	(132,335,761)	-	836,252,711
2062	836,252,711	34,202,736	(118,692,574)	-	751,762,873
2063	751,762,873	30,747,101	(68,214,888)	-	714,295,087
2064	714,295,087	29,214,669	(20,764,067)	-	722,745,689
2065	722,745,689	29,560,299	(21,437,832)	-	730,868,155
2066	730,868,155	29,892,508	(22,203,212)	-	738,557,451
2067	738,557,451	30,207,000	(22,997,616)	-	745,766,835
2068	745,766,835	30,501,864	(23,895,975)	-	752,372,723
2069	752,372,723	30,772,044	(24,678,825)	-	758,465,942
2070	758,465,942	31,021,257	(25,567,646)	-	763,919,554
2071	763,919,554	31,244,310	(26,490,453)	-	768,673,410
2072	768,673,410	31,438,742	(27,533,085)	-	772,579,068
2073	772,579,068	31,598,484	(30,110,406)	-	774,067,146
2074	774,067,146	31,659,346	(32,921,147)	-	772,805,345
2075	772,805,345	31,607,739	(34,107,462)	-	770,305,622
2076	770,305,622	31,505,500	(36,355,900)	-	765,455,222
2077	765,455,222	31,307,119	(35,666,916)	-	761,095,425
2078	761,095,425	31,128,803	(39,907,088)	-	752,317,139
2079	752,317,139	30,769,771	(38,306,057)	-	744,780,853
2080	744,780,853	30,461,537	(38,765,494)	-	736,476,896
2081	736,476,896	30,121,905	(42,233,007)	-	724,365,795
2082	724,365,795	29,626,561	(43,772,961)	-	710,219,395
2083	710,219,395	29,047,973	(44,214,196)	-	695,053,172
2084	695,053,172	28,427,675	(47,160,490)	-	676,320,357
2085	676,320,357	27,661,503	(48,753,133)	-	655,228,726
2086	655,228,726	26,798,855	(49,263,538)	-	632,764,043
2087	632,764,043	25,880,049	(52,397,234)	-	606,246,858
2088	606,246,858	24,795,497	(54,474,045)	-	576,568,309
2089	576,568,309	23,581,644	(54,913,858)	-	545,236,095
2090	545,236,095	22,300,156	(58,401,597)	-	509,134,654
2091	509,134,654	20,823,607	(60,557,794)	-	469,400,467
2092	469,400,467	19,198,479	(62,969,645)	-	425,629,301
2093	425,629,301	17,408,238	(65,120,679)	-	377,916,860
2094	377,916,860	15,456,800	(67,534,052)	-	325,839,607
2095	325,839,607	13,326,840	(81,984,143)	-	257,182,304
2096	257,182,304	10,518,756	(72,841,643)	-	194,859,418
2097	194,859,418	7,969,750	(156,406,652)	-	46,422,516
2098	46,422,516	1,898,681	(48,321,196)	-	(0)

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2021 ACCRUAL COMPARISON

	Present	Proposed	Difference
Monticello	$13,392,226	$28,665,382	$15,273,156
Prairie Island Unit 1	49,264	23,051,488	23,002,224
Prairie Island Unit 2	589,341	15,399,724	14,810,383
TOTAL	$14,030,831	$67,116,594	$53,085,763

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2021 MN RETAIL SUMMARY

	Remaining Life (yrs)	Operational Earnings Rate	Post-Shutdown Earnings Rate	Market Value Balance 6/30/2017	Book Value 6/30/2017	Unrealized Gain/Loss 6/30/2017	Tax-Effect Adjustment	Tax-Adjusted Fund Balance 6/30/2017	2021 Decommissioning Accrual
Monticello	13.75	5.00%	4.46%	$660,140,345	$529,148,381	$130,991,964	$36,468,163	$623,672,182	**28,665,382**
Prairie Island Unit 1	16.67	5.00%	4.19%	399,941,696	308,078,761	91,862,935	25,574,641	374,367,055	**23,051,488**
Prairie Island Unit 2	17.83	5.04%	4.13%	448,597,551	346,627,064	101,970,487	28,388,583	420,208,967	**15,399,724**
TOTAL DECOMMISSIONING ACCRUAL				**$1,508,679,592**	**$1,183,854,206**	**$324,825,386**	**$90,431,387**	**$1,418,248,204**	**$67,116,594**

INPUT DATA

Escalation Rate (Labor)	4.05%
Escalation Rate (Non-Labor)	2.85%
Escalation Rate (PIIC)	0.00%
Jurisdictional Factor	73.4886%
Tax Rate for tax-effect adjustment	27.84%

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	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
Monticello															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2030	$21,103,620	$15,508,745	1.6755	$25,984,903	$8,935,561	$6,566,615	1.4410	$9,462,492	$0	$0	1.0000	$0	$30,039,182	$22,075,360	$35,447,395
2031	72,416,235	53,217,644	1.7434	92,779,641	42,961,344	31,571,670	1.4820	46,789,215	0	0	1.0000	0	115,377,579	84,789,314	139,568,856
2032	81,871,153	60,165,927	1.8140	109,140,991	112,447,587	82,636,106	1.5243	125,962,216	0	0	1.0000	0	194,318,741	142,802,033	235,103,207
2033	78,663,227	57,808,468	1.8874	109,107,702	100,155,666	73,602,950	1.5677	115,387,345	0	0	1.0000	0	178,818,892	131,411,418	224,495,047
2034	66,380,423	48,782,013	1.9639	95,802,994	38,894,671	28,583,132	1.6124	46,087,441	0	0	1.0000	0	105,275,094	77,365,144	141,890,436
2035	86,879,803	63,846,711	2.0434	130,464,369	113,147,091	83,150,161	1.6584	137,896,227	0	0	1.0000	0	200,026,894	146,996,872	268,360,596
2036	50,307,504	36,970,257	2.1262	78,606,161	20,688,337	15,203,559	1.7056	25,931,191	0	0	1.0000	0	70,995,841	52,173,817	104,537,352
2037	34,623,126	25,444,035	2.2123	56,289,838	14,196,883	10,433,084	1.7542	18,301,716	0	0	1.0000	0	48,820,010	35,877,119	74,591,555
2038	29,581,478	21,739,000	2.3019	50,041,005	15,098,979	11,096,021	1.8042	20,019,442	0	0	1.0000	0	44,680,457	32,835,022	70,060,446
2039	5,925,017	4,354,209	2.3951	10,428,767	2,187,162	1,607,314	1.8556	2,982,532	0	0	1.0000	0	8,112,179	5,961,523	13,411,299
2040	5,941,204	4,366,105	2.4921	10,880,770	2,193,018	1,611,617	1.9085	3,075,772	0	0	1.0000	0	8,134,222	5,977,722	13,956,542
2041	5,925,017	4,354,209	2.5930	11,290,465	2,187,162	1,607,314	1.9629	3,154,997	0	0	1.0000	0	8,112,179	5,961,523	14,445,461
2042	5,925,017	4,354,209	2.6981	11,748,092	2,187,162	1,607,314	2.0189	3,245,006	0	0	1.0000	0	8,112,179	5,961,523	14,993,098
2043	5,925,017	4,354,209	2.8073	12,223,572	2,187,162	1,607,314	2.0764	3,337,427	0	0	1.0000	0	8,112,179	5,961,523	15,560,999
2044	5,941,204	4,366,105	2.9210	12,753,392	2,193,018	1,611,617	2.1356	3,441,770	0	0	1.0000	0	8,134,222	5,977,722	16,195,163
2045	5,925,017	4,354,209	3.0393	13,233,748	2,187,162	1,607,314	2.1964	3,530,305	0	0	1.0000	0	8,112,179	5,961,523	16,764,053
2046	5,925,017	4,354,209	3.1624	13,769,752	2,187,162	1,607,314	2.2590	3,630,922	0	0	1.0000	0	8,112,179	5,961,523	17,400,674
2047	5,925,017	4,354,209	3.2905	14,327,526	2,187,162	1,607,314	2.3234	3,734,433	0	0	1.0000	0	8,112,179	5,961,523	18,061,959
2048	6,604,849	4,853,808	3.4238	16,618,468	4,183,955	3,074,728	2.3896	7,347,371	0	0	1.0000	0	10,788,804	7,928,536	23,965,838
2049	5,925,017	4,354,209	3.5624	15,511,435	2,187,159	1,607,312	2.4577	3,950,290	0	0	1.0000	0	8,112,176	5,961,521	19,461,726
2050	7,418,218	5,451,541	3.7067	20,207,228	6,666,765	4,899,309	2.5278	12,384,475	0	0	1.0000	0	14,084,983	10,350,851	32,591,702
2051	7,418,218	5,451,541	3.8568	21,025,504	6,666,765	4,899,309	2.5998	12,737,225	0	0	1.0000	0	14,084,983	10,350,851	33,762,729
2052	8,296,905	6,097,276	4.0130	24,468,367	9,260,121	6,805,129	2.6739	18,196,235	0	0	1.0000	0	17,557,026	12,902,405	42,664,602
2053	8,927,593	6,560,759	4.1756	27,395,105	11,194,890	8,226,963	2.7501	22,624,971	0	0	1.0000	0	20,122,483	14,787,722	50,020,076
2054	7,633,843	5,610,001	4.3447	24,373,771	7,313,640	5,374,689	2.8285	15,202,307	0	0	1.0000	0	14,947,483	10,984,689	39,576,077
2055	8,711,968	6,402,299	4.5206	28,942,234	10,548,015	7,751,584	2.9091	22,550,133	0	0	1.0000	0	19,259,983	14,153,883	51,492,367
2056	9,159,405	6,731,114	4.7037	31,661,142	11,847,621	8,706,646	2.9920	26,050,283	0	0	1.0000	0	21,007,026	15,437,760	57,711,426
2057	5,908,426	4,342,017	4.8942	21,250,699	2,137,389	1,570,737	3.0773	4,833,628	0	0	1.0000	0	8,045,815	5,912,753	26,084,326
2058	12,004,811	8,822,162	5.0924	44,925,978	20,426,543	15,011,171	3.1650	47,510,357	0	0	1.0000	0	32,431,354	23,833,333	92,436,335
2059	5,908,426	4,342,017	5.2987	23,007,045	2,137,389	1,570,737	3.2552	5,113,062	0	0	1.0000	0	8,045,815	5,912,753	28,120,106
2060	5,924,613	4,353,912	5.5133	24,004,425	2,143,245	1,575,040	3.3480	5,273,234	0	0	1.0000	0	8,067,858	5,928,952	29,277,659
2061	5,908,426	4,342,017	5.7366	24,908,414	2,137,389	1,570,737	3.4434	5,408,674	0	0	1.0000	0	8,045,815	5,912,753	30,317,088
2062	5,908,426	4,342,017	5.9689	25,917,064	2,137,389	1,570,737	3.5415	5,562,764	0	0	1.0000	0	8,045,815	5,912,753	31,479,828
2063	5,908,426	4,342,017	6.2106	26,966,530	2,137,389	1,570,737	3.6425	5,721,408	0	0	1.0000	0	8,045,815	5,912,753	32,687,938
2064	5,924,613	4,353,912	6.4622	28,135,853	2,143,245	1,575,040	3.7463	5,900,572	0	0	1.0000	0	8,067,858	5,928,952	34,036,425
2065	5,908,426	4,342,017	6.7239	29,195,287	2,137,389	1,570,737	3.8531	6,052,205	0	0	1.0000	0	8,045,815	5,912,753	35,247,492
2066	9,566,257	7,030,104	6.9962	49,184,013	13,110,882	9,634,998	3.9629	38,182,533	0	0	1.0000	0	22,677,139	16,665,102	87,366,546
2067	5,908,426	4,342,017	7.2795	31,607,711	2,137,389	1,570,737	4.0758	6,402,008	0	0	1.0000	0	8,045,815	5,912,753	38,009,720
2068	14,459,552	10,626,116	7.5744	80,486,450	27,748,061	20,391,649	4.1920	85,481,792	0	0	1.0000	0	42,207,613	31,017,765	165,968,243
2069	5,908,426	4,342,017	7.8811	34,219,869	2,137,389	1,570,737	4.3115	6,772,231	0	0	1.0000	0	8,045,815	5,912,753	40,992,100
2070	5,908,426	4,342,017	8.2003	35,605,841	2,137,389	1,570,737	4.4343	6,965,117	0	0	1.0000	0	8,045,815	5,912,753	42,570,958
2071	5,908,426	4,342,017	8.5324	37,047,824	2,137,389	1,570,737	4.5607	7,163,658	0	0	1.0000	0	8,045,815	5,912,753	44,211,483
2072	5,924,613	4,353,912	8.8780	38,654,034	2,143,245	1,575,040	4.6907	7,388,040	0	0	1.0000	0	8,067,858	5,928,952	46,042,074
2073	5,908,426	4,342,017	9.2375	40,109,380	2,137,389	1,570,737	4.8244	7,577,862	0	0	1.0000	0	8,045,815	5,912,753	47,687,242
2074	5,908,426	4,342,017	9.6117	41,734,163	2,137,389	1,570,737	4.9619	7,793,838	0	0	1.0000	0	8,045,815	5,912,753	49,528,001
2075	5,908,426	4,342,017	10.0009	43,424,076	2,137,389	1,570,737	5.1033	8,015,940	0	0	1.0000	0	8,045,815	5,912,753	51,440,016
2076	5,924,613	4,353,912	10.4060	45,306,813	2,143,245	1,575,040	5.2487	8,266,912	0	0	1.0000	0	8,067,858	5,928,952	53,573,725
2077	5,908,426	4,342,017	10.8274	47,012,753	2,137,389	1,570,737	5.3983	8,479,307	0	0	1.0000	0	8,045,815	5,912,753	55,492,060
2078	6,386,857	4,693,609	11.2659	52,877,728	3,557,353	2,614,247	5.5522	14,514,823	0	0	1.0000	0	9,944,210	7,307,856	67,392,551
2079	6,482,543	4,763,927	11.7222	55,843,706	3,844,412	2,825,203	5.7104	16,133,037	0	0	1.0000	0	10,326,955	7,589,130	71,976,743
2080	6,403,045	4,705,505	12.1970	57,393,047	3,563,167	2,618,520	5.8731	15,378,828	0	0	1.0000	0	9,966,212	7,324,025	72,771,874
2081	6,386,857	4,693,609	12.6909	59,566,121	3,557,353	2,614,247	6.0405	15,791,360	0	0	1.0000	0	9,944,210	7,307,856	75,357,480
2082	6,386,857	4,693,609	13.2049	61,978,635	3,557,353	2,614,247	6.2127	16,241,533	0	0	1.0000	0	9,944,210	7,307,856	78,220,169
2083	6,482,543	4,763,927	13.7397	65,454,929	3,844,412	2,825,203	6.3897	18,052,197	0	0	1.0000	0	10,326,955	7,589,130	83,507,127
2084	6,403,045	4,705,505	14.2962	67,270,843	3,563,167	2,618,520	6.5719	17,208,649	0	0	1.0000	0	9,966,212	7,324,025	84,479,492

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	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
2085	6,386,857	4,693,609	14.8752	69,818,370	3,557,353	2,614,247	6.7592	17,670,219	0	0	1.0000	0	9,944,210	7,307,856	87,488,590
2086	6,386,857	4,693,609	15.4776	72,645,800	3,557,353	2,614,247	6.9518	18,173,723	0	0	1.0000	0	9,944,210	7,307,856	90,819,524
2087	6,482,543	4,763,927	16.1045	76,720,664	3,844,412	2,825,203	7.1499	20,199,916	0	0	1.0000	0	10,326,955	7,589,130	96,920,580
2088	7,066,689	5,193,208	16.7567	87,021,021	5,554,101	4,081,628	7.3537	30,015,070	0	0	1.0000	0	12,620,790	9,274,836	117,036,091
2089	6,386,857	4,693,609	17.4353	81,834,478	3,557,353	2,614,247	7.5633	19,772,335	0	0	1.0000	0	9,944,210	7,307,856	101,606,814
2090	6,099,798	4,482,653	18.1415	81,322,056	11,895,081	8,741,523	7.7788	67,998,558	0	0	1.0000	0	17,994,879	13,224,176	149,320,614
2091	2,067,326	1,519,248	18.8762	28,677,630	15,798,591	11,610,156	8.0005	92,887,054	0	0	1.0000	0	17,865,917	13,129,404	121,564,684
	$873,535,822	$641,948,844		$2,760,206,192	$729,124,605	$535,823,128		$1,386,916,184	$0	$0		$0	$1,602,660,427	$1,177,771,972	$4,147,122,376

Xcel Energy
Nuclear Decommissioning Accrual
60-Year Decommissioning Period
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AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
Prairie Island Unit 1															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2033	$22,324,352	$16,405,843	1.8874	$30,964,388	$9,448,311	$6,943,427	1.5677	$10,885,211	$1,250,000	$918,607	1.0000	$918,607	$33,022,663	$24,267,877	$42,768,206
2034	63,582,247	46,725,674	1.9639	91,764,550	32,971,808	24,230,505	1.6124	39,069,266	1,250,000	918,607	1.0000	918,607	97,804,054	71,874,785	131,752,423
2035	65,877,290	48,412,268	2.0434	98,925,629	81,239,936	59,702,054	1.6584	99,009,886	1,250,000	918,607	1.0000	918,607	148,367,226	109,032,929	198,854,122
2036	57,759,315	42,446,486	2.1262	90,249,718	65,595,018	48,204,830	1.7056	82,218,158	1,250,000	918,607	1.0000	918,607	124,604,333	91,569,923	173,386,483
2037	39,808,345	29,254,577	2.2123	64,719,901	41,981,871	30,851,870	1.7542	54,120,350	1,250,000	918,607	1.0000	918,607	83,040,216	61,025,054	119,758,858
2038	13,207,909	9,706,302	2.3019	22,342,936	18,994,691	13,958,923	1.8042	25,184,690	1,250,000	918,607	1.0000	918,607	33,452,600	24,583,832	48,446,232
2039	36,035,851	26,482,226	2.3951	63,427,579	76,476,727	56,201,641	1.8556	104,287,765	1,250,000	918,607	1.0000	918,607	113,762,578	83,602,474	168,633,951
2040	31,919,556	23,457,220	2.4921	58,457,738	13,365,606	9,822,190	1.9085	18,745,650	1,250,000	918,607	1.0000	918,607	46,535,162	34,198,017	78,121,996
2041	19,571,318	14,382,679	2.5930	37,294,286	9,445,873	6,941,635	1.9629	13,625,736	1,250,000	918,607	1.0000	918,607	30,267,191	22,242,921	51,838,628
2042	14,781,952	10,863,043	2.6981	29,309,575	11,668,700	8,575,159	2.0189	17,312,388	1,250,000	918,607	1.0000	918,607	27,700,652	20,356,808	47,540,570
2043	8,544,452	6,279,195	2.8073	17,627,583	6,492,672	4,771,371	2.0764	9,907,275	1,250,000	918,607	1.0000	918,607	16,287,125	11,969,172	28,453,465
2044	3,054,798	2,244,927	2.9210	6,557,431	1,939,011	1,424,951	2.1356	3,043,125	1,250,000	918,607	1.0000	918,607	6,243,809	4,588,485	10,519,163
2045	5,353,318	3,934,076	3.0393	11,956,837	8,850,896	6,504,395	2.1964	14,286,253	1,250,000	918,607	1.0000	918,607	15,454,214	11,357,078	27,161,698
2046	4,584,362	3,368,981	3.1624	10,654,067	6,544,030	4,809,113	2.2590	10,863,786	1,250,000	918,607	1.0000	918,607	12,378,392	9,096,701	22,436,459
2047	4,584,362	3,368,981	3.2905	11,085,633	6,544,030	4,809,113	2.3234	11,173,492	1,250,000	918,607	1.0000	918,607	12,378,392	9,096,701	23,177,732
2048	3,054,798	2,244,927	3.4238	7,686,181	1,939,011	1,424,951	2.3896	3,405,063	1,250,000	918,607	1.0000	918,607	6,243,809	4,588,485	12,009,850
2049	4,584,362	3,368,981	3.5624	12,001,659	6,544,030	4,809,113	2.4577	11,819,356	1,250,000	918,607	1.0000	918,607	12,378,392	9,096,701	24,739,622
2050	5,353,318	3,934,076	3.7067	14,582,439	8,850,896	6,504,395	2.5278	16,441,810	1,250,000	918,607	1.0000	918,607	15,454,214	11,357,078	31,942,856
2051	5,159,362	3,791,541	3.8568	14,623,213	8,269,028	6,076,789	2.5998	15,798,435	1,250,000	918,607	1.0000	918,607	14,678,390	10,786,936	31,340,256
2052	5,361,664	3,940,209	4.0130	15,812,060	8,859,611	6,510,800	2.6739	17,409,227	1,250,000	918,607	1.0000	918,607	15,471,275	11,369,616	34,139,894
2053	3,142,138	2,309,112	4.1756	9,641,927	2,217,357	1,629,503	2.7501	4,481,297	1,250,000	918,607	1.0000	918,607	6,609,495	4,857,222	15,041,831
2054	3,237,824	2,379,430	4.3447	10,337,910	2,504,416	1,840,459	2.8285	5,205,738	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	16,462,254
2055	5,544,690	4,074,712	4.5206	18,420,145	9,425,014	6,926,306	2.9091	20,149,317	1,250,000	918,607	1.0000	918,607	16,219,704	11,919,626	39,488,069
2056	4,831,925	3,550,912	4.7037	16,702,424	7,270,391	5,342,905	2.9920	15,985,972	1,250,000	918,607	1.0000	918,607	13,352,316	9,812,424	33,607,002
2057	5,302,892	3,897,019	4.8942	19,072,789	8,699,619	6,393,224	3.0773	19,673,868	1,250,000	918,607	1.0000	918,607	15,252,511	11,208,849	39,665,263
2058	3,333,511	2,449,749	5.0924	12,475,102	2,791,475	2,051,414	3.1650	6,492,726	1,250,000	918,607	1.0000	918,607	7,374,986	5,419,770	19,886,435
2059	3,189,981	2,344,271	5.2987	12,421,588	2,360,887	1,734,981	3.2552	5,647,711	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	18,987,907
2060	3,150,484	2,315,245	5.5133	12,764,641	2,226,070	1,635,906	3.3480	5,477,015	1,250,000	918,607	1.0000	918,607	6,626,554	4,869,758	19,160,263
2061	3,237,824	2,379,430	5.7366	13,649,838	2,504,416	1,840,459	3.4434	6,337,436	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	20,905,881
2062	3,237,824	2,379,430	5.9689	14,202,580	2,504,416	1,840,459	3.5415	6,517,985	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	21,639,172
2063	3,189,981	2,344,271	6.2106	14,559,329	2,360,887	1,734,981	3.6425	6,319,670	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	21,797,605
2064	3,246,171	2,385,564	6.4622	15,415,992	2,513,129	1,846,862	3.7463	6,918,899	1,250,000	918,607	1.0000	918,607	7,009,300	5,151,033	23,253,498
2065	3,237,824	2,379,430	6.7239	15,999,050	2,504,416	1,840,459	3.8531	7,091,472	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	24,009,128
2066	3,189,981	2,344,271	6.9962	16,400,988	2,360,887	1,734,981	3.9629	6,875,558	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	24,195,153
2067	3,237,824	2,379,430	7.2795	17,321,061	2,504,416	1,840,459	4.0758	7,501,342	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	25,741,010
2068	3,246,171	2,385,564	7.5744	18,069,217	2,513,129	1,846,862	4.1920	7,742,045	1,250,000	918,607	1.0000	918,607	7,009,300	5,151,033	26,729,869
2069	3,189,981	2,344,271	7.8811	18,475,433	2,360,887	1,734,981	4.3115	7,480,372	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	26,874,413
2070	3,237,824	2,379,430	8.2003	19,512,040	2,504,416	1,840,459	4.4343	8,161,146	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	28,591,793
2071	3,237,824	2,379,430	8.5324	20,302,249	2,504,416	1,840,459	4.5607	8,393,780	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	29,614,636
2072	3,246,171	2,385,564	8.8780	21,179,038	2,513,129	1,846,862	4.6907	8,663,075	1,250,000	918,607	1.0000	918,607	7,009,300	5,151,033	30,760,720
2073	3,237,824	2,379,430	9.2375	21,979,985	2,504,416	1,840,459	4.8244	8,879,109	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	31,777,701
2074	3,237,824	2,379,430	9.6117	22,870,368	2,504,416	1,840,459	4.9619	9,132,172	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	32,921,147
2075	3,569,647	2,623,282	10.0009	26,235,181	3,499,884	2,572,014	5.1033	13,125,758	1,250,000	918,607	1.0000	918,607	8,319,531	6,113,903	40,279,545
2076	3,246,171	2,385,564	10.4060	24,824,180	2,513,129	1,846,862	5.2487	9,693,624	1,250,000	918,607	1.0000	918,607	7,009,300	5,151,033	35,436,411
2077	3,237,824	2,379,430	10.8274	25,763,042	14,152,682	10,400,601	5.3983	56,145,565	1,250,000	918,607	1.0000	918,607	18,640,506	13,698,638	82,827,215
2078	982,878	722,303	11.2659	8,137,390	5,148,901	3,783,853	5.5522	21,008,709	0	0	1.0000	0	6,131,779	4,506,156	29,146,099
	$502,483,945	$369,268,185		$1,156,776,892	$523,488,941	$384,704,452		$867,708,282	$56,250,000	$41,337,312		$41,337,312	$1,082,222,886	$795,309,949	$2,065,822,485

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	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
Prairie Island Unit 2															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2034	$7,760,265	$5,702,906	1.9639	$11,199,938	$4,479,535	$3,291,946	1.6124	$5,307,933	$1,250,000	$918,607	1.0000	$918,607	$13,489,800	$9,913,459	$17,426,478
2035	46,911,429	34,474,531	2.0434	70,445,256	35,601,339	26,162,909	1.6584	43,388,568	1,250,000	918,607	1.0000	918,607	83,762,768	61,556,047	114,752,431
2036	67,514,013	49,615,071	2.1262	105,491,565	86,298,834	63,419,765	1.7056	108,168,751	1,250,000	918,607	1.0000	918,607	155,062,846	113,953,443	214,578,923
2037	72,593,441	53,347,870	2.2123	118,021,492	75,650,366	55,594,360	1.7542	97,523,626	1,250,000	918,607	1.0000	918,607	149,493,807	109,860,837	216,463,726
2038	46,603,527	34,248,258	2.3019	78,836,066	42,782,151	31,439,984	1.8042	56,724,019	1,250,000	918,607	1.0000	918,607	90,635,678	66,606,849	136,478,692
2039	40,663,625	29,883,110	2.3951	71,573,036	77,452,618	56,918,809	1.8556	105,618,542	1,250,000	918,607	1.0000	918,607	119,366,242	87,720,525	178,110,184
2040	37,417,177	27,497,343	2.4921	68,526,127	14,193,501	10,430,599	1.9085	19,906,798	1,250,000	918,607	1.0000	918,607	52,860,679	38,846,548	89,351,532
2041	23,327,583	17,143,103	2.5930	44,452,067	13,070,130	9,605,049	1.9629	18,853,752	1,250,000	918,607	1.0000	918,607	37,647,713	27,666,760	64,224,426
2042	16,656,921	12,240,930	2.6981	33,027,253	17,178,640	12,624,334	2.0189	25,487,268	1,250,000	918,607	1.0000	918,607	35,085,561	25,783,871	59,433,129
2043	9,422,862	6,924,725	2.8073	19,439,782	9,074,042	6,668,382	2.0764	13,846,228	1,250,000	918,607	1.0000	918,607	19,746,904	14,511,714	34,204,617
2044	3,054,798	2,244,927	2.9210	6,557,431	1,939,011	1,424,951	2.1356	3,043,125	1,250,000	918,607	1.0000	918,607	6,243,809	4,588,485	10,519,163
2045	5,353,318	3,934,076	3.0393	11,956,837	8,850,896	6,504,395	2.1964	14,286,253	1,250,000	918,607	1.0000	918,607	15,454,214	11,357,078	27,161,698
2046	4,584,362	3,368,981	3.1624	10,654,067	6,544,030	4,809,113	2.2590	10,863,786	1,250,000	918,607	1.0000	918,607	12,378,392	9,096,701	22,436,459
2047	4,584,362	3,368,981	3.2905	11,085,633	6,544,030	4,809,113	2.3234	11,173,492	1,250,000	918,607	1.0000	918,607	12,378,392	9,096,701	23,177,732
2048	3,054,798	2,244,927	3.4238	7,686,181	1,939,011	1,424,951	2.3896	3,405,063	1,250,000	918,607	1.0000	918,607	6,243,809	4,588,485	12,009,850
2049	4,584,362	3,368,981	3.5624	12,001,659	6,544,030	4,809,113	2.4577	11,819,356	1,250,000	918,607	1.0000	918,607	12,378,392	9,096,701	24,739,622
2050	5,353,318	3,934,076	3.7067	14,582,439	8,850,896	6,504,395	2.5278	16,441,810	1,250,000	918,607	1.0000	918,607	15,454,214	11,357,078	31,942,856
2051	5,159,362	3,791,541	3.8568	14,623,213	8,269,030	6,076,790	2.5998	15,798,439	1,250,000	918,607	1.0000	918,607	14,678,392	10,786,938	31,340,260
2052	5,361,664	3,940,209	4.0130	15,812,060	8,859,609	6,510,798	2.6739	17,409,224	1,250,000	918,607	1.0000	918,607	15,471,273	11,369,615	34,139,891
2053	3,142,138	2,309,112	4.1756	9,641,927	2,217,357	1,629,503	2.7501	4,481,297	1,250,000	918,607	1.0000	918,607	6,609,495	4,857,222	15,041,831
2054	3,237,824	2,379,430	4.3447	10,337,910	2,504,416	1,840,459	2.8285	5,205,738	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	16,462,254
2055	5,544,690	4,074,712	4.5206	18,420,145	9,425,014	6,926,306	2.9091	20,149,317	1,250,000	918,607	1.0000	918,607	16,219,704	11,919,626	39,488,069
2056	4,831,925	3,550,912	4.7037	16,702,424	7,270,391	5,342,905	2.9920	15,985,972	1,250,000	918,607	1.0000	918,607	13,352,316	9,812,424	33,607,002
2057	5,302,892	3,897,019	4.8942	19,072,789	8,699,619	6,393,224	3.0773	19,673,868	1,250,000	918,607	1.0000	918,607	15,252,511	11,208,849	39,665,263
2058	3,333,511	2,449,749	5.0924	12,475,102	2,791,475	2,051,414	3.1650	6,492,726	1,250,000	918,607	1.0000	918,607	7,374,986	5,419,770	19,886,435
2059	3,189,981	2,344,271	5.2987	12,421,588	2,360,887	1,734,981	3.2552	5,647,711	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	18,987,907
2060	3,150,484	2,315,245	5.5133	12,764,641	2,226,070	1,635,906	3.3480	5,477,015	1,250,000	918,607	1.0000	918,607	6,626,554	4,869,758	19,160,263
2061	3,237,824	2,379,430	5.7366	13,649,838	2,504,416	1,840,459	3.4434	6,337,436	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	20,905,881
2062	3,237,824	2,379,430	5.9689	14,202,580	2,504,416	1,840,459	3.5415	6,517,985	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	21,639,172
2063	3,189,981	2,344,271	6.2106	14,559,329	2,360,887	1,734,981	3.6425	6,319,670	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	21,797,605
2064	3,246,171	2,385,564	6.4622	15,415,992	2,513,129	1,846,862	3.7463	6,918,899	1,250,000	918,607	1.0000	918,607	7,009,300	5,151,033	23,253,498
2065	3,237,824	2,379,430	6.7239	15,999,050	2,504,416	1,840,459	3.8531	7,091,472	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	24,009,128
2066	3,189,981	2,344,271	6.9962	16,400,988	2,360,887	1,734,981	3.9629	6,875,558	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	24,195,153
2067	3,237,824	2,379,430	7.2795	17,321,061	2,504,416	1,840,459	4.0758	7,501,342	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	25,741,010
2068	3,246,171	2,385,564	7.5744	18,069,217	2,513,129	1,846,862	4.1920	7,742,045	1,250,000	918,607	1.0000	918,607	7,009,300	5,151,033	26,729,869
2069	3,189,981	2,344,271	7.8811	18,475,433	2,360,887	1,734,981	4.3115	7,480,372	1,250,000	918,607	1.0000	918,607	6,800,868	4,997,859	26,874,413
2070	3,237,824	2,379,430	8.2003	19,512,040	2,504,416	1,840,459	4.4343	8,161,146	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	28,591,793
2071	3,237,824	2,379,430	8.5324	20,302,249	2,504,416	1,840,459	4.5607	8,393,780	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	29,614,636
2072	3,246,171	2,385,564	8.8780	21,179,038	2,513,129	1,846,862	4.6907	8,663,075	1,250,000	918,607	1.0000	918,607	7,009,300	5,151,033	30,760,720
2073	3,237,824	2,379,430	9.2375	21,979,985	2,504,416	1,840,459	4.8244	8,879,109	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	31,777,701
2074	3,237,824	2,379,430	9.6117	22,870,368	2,504,416	1,840,459	4.9619	9,132,172	1,250,000	918,607	1.0000	918,607	6,992,240	5,138,496	32,921,147
2075	3,569,647	2,623,282	10.0009	26,235,181	3,499,884	2,572,014	5.1033	13,125,758	1,250,000	918,607	1.0000	918,607	8,319,531	6,113,903	40,279,545
2076	3,246,171	2,385,564	10.4060	24,824,180	2,513,129	1,846,862	5.2487	9,693,624	1,250,000	918,607	1.0000	918,607	7,009,300	5,151,033	35,436,411
2077	3,237,824	2,379,430	10.8274	25,763,042	14,152,682	10,400,601	5.3983	56,145,565	1,250,000	918,607	1.0000	918,607	18,640,506	13,698,638	82,827,215
2078	982,878	722,303	11.2659	8,137,389	5,148,901	3,783,853	5.5522	21,008,709	0	-	1.0000	-	6,131,779	4,506,156	29,146,099
	$497,942,199	$365,930,521		$1,172,705,590	$531,588,885	$390,656,984		$888,167,393	$55,000,000	$40,418,705		$40,418,705	$1,084,531,084	$797,006,210	$2,101,291,688
	$1,873,961,967	$1,377,147,550		$5,089,688,674	$1,784,202,430	$1,311,184,564		$3,142,791,860	$111,250,000	$81,756,016		$81,756,016	$3,769,414,397	$2,770,088,131	$8,314,236,550

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Monticello

External Levelized

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	623,672,182	15,675,506	-	6,696,113	646,043,801
2018	646,043,801	32,636,996	-	13,392,226	692,073,023
2019	692,073,023	34,938,457	-	13,392,226	740,403,706
2020	740,403,706	37,354,991	-	13,392,226	791,150,922
2021	791,150,922	40,274,181	-	28,665,382	860,090,485
2022	860,090,485	43,721,159	-	28,665,382	932,477,026
2023	932,477,026	47,340,486	-	28,665,382	1,008,482,893
2024	1,008,482,893	51,140,779	-	28,665,382	1,088,289,054
2025	1,088,289,054	55,131,087	-	28,665,382	1,172,085,523
2026	1,172,085,523	59,320,911	-	28,665,382	1,260,071,816
2027	1,260,071,816	63,720,225	-	28,665,382	1,352,457,423
2028	1,352,457,423	68,339,506	-	28,665,382	1,449,462,310
2029	1,449,462,310	73,189,750	-	28,665,382	1,551,317,442
2030	1,551,317,442	69,668,186	(35,447,395)	21,499,036	1,607,037,270
2031	1,607,037,270	71,673,862	(139,568,856)	-	1,539,142,277
2032	1,539,142,277	68,645,746	(235,103,207)	-	1,372,684,815
2033	1,372,684,815	61,221,743	(224,495,047)	-	1,209,411,511
2034	1,209,411,511	53,939,753	(141,890,436)	-	1,121,460,828
2035	1,121,460,828	50,017,153	(268,360,596)	-	903,117,385
2036	903,117,385	40,279,035	(104,537,352)	-	838,859,069
2037	838,859,069	37,413,114	(74,591,555)	-	801,680,629
2038	801,680,629	35,754,956	(70,060,446)	-	767,375,138
2039	767,375,138	34,224,931	(13,411,299)	-	788,188,771
2040	788,188,771	35,153,219	(13,956,542)	-	809,385,448
2041	809,385,448	36,098,591	(14,445,461)	-	831,038,578
2042	831,038,578	37,064,321	(14,993,098)	-	853,109,800
2043	853,109,800	38,048,697	(15,560,999)	-	875,597,498
2044	875,597,498	39,051,648	(16,195,163)	-	898,453,984
2045	898,453,984	40,071,048	(16,764,053)	-	921,760,979
2046	921,760,979	41,110,540	(17,400,674)	-	945,470,845
2047	945,470,845	42,168,000	(18,061,959)	-	969,576,885
2048	969,576,885	43,243,129	(23,965,838)	-	988,854,176
2049	988,854,176	44,102,896	(19,461,726)	-	1,013,495,347
2050	1,013,495,347	45,201,892	(32,591,702)	-	1,026,105,537
2051	1,026,105,537	45,764,307	(33,762,729)	-	1,038,107,115
2052	1,038,107,115	46,299,577	(42,664,602)	-	1,041,742,091
2053	1,041,742,091	46,461,697	(50,020,076)	-	1,038,183,712
2054	1,038,183,712	46,302,994	(39,576,077)	-	1,044,910,628

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2055	1,044,910,628	46,603,014	(51,492,367)	-	1,040,021,275
2056	1,040,021,275	46,384,949	(57,711,426)	-	1,028,694,798
2057	1,028,694,798	45,879,788	(26,084,326)	-	1,048,490,260
2058	1,048,490,260	46,762,666	(92,436,335)	-	1,002,816,590
2059	1,002,816,590	44,725,620	(28,120,106)	-	1,019,422,104
2060	1,019,422,104	45,466,226	(29,277,659)	-	1,035,610,671
2061	1,035,610,671	46,188,236	(30,317,088)	-	1,051,481,818
2062	1,051,481,818	46,896,089	(31,479,828)	-	1,066,898,080
2063	1,066,898,080	47,583,654	(32,687,938)	-	1,081,793,796
2064	1,081,793,796	48,248,003	(34,036,425)	-	1,096,005,375
2065	1,096,005,375	48,881,840	(35,247,492)	-	1,109,639,722
2066	1,109,639,722	49,489,932	(87,366,546)	-	1,071,763,108
2067	1,071,763,108	47,800,635	(38,009,720)	-	1,081,554,023
2068	1,081,554,023	48,237,309	(165,968,243)	-	963,823,089
2069	963,823,089	42,986,510	(40,992,100)	-	965,817,499
2070	965,817,499	43,075,460	(42,570,958)	-	966,322,002
2071	966,322,002	43,097,961	(44,211,483)	-	965,208,481
2072	965,208,481	43,048,298	(46,042,074)	-	962,214,705
2073	962,214,705	42,914,776	(47,687,242)	-	957,442,239
2074	957,442,239	42,701,924	(49,528,001)	-	950,616,161
2075	950,616,161	42,397,481	(51,440,016)	-	941,573,626
2076	941,573,626	41,994,184	(53,573,725)	-	929,994,085
2077	929,994,085	41,477,736	(55,492,060)	-	915,979,761
2078	915,979,761	40,852,697	(67,392,551)	-	889,439,908
2079	889,439,908	39,669,020	(71,976,743)	-	857,132,184
2080	857,132,184	38,228,095	(72,771,874)	-	822,588,405
2081	822,588,405	36,687,443	(75,357,480)	-	783,918,367
2082	783,918,367	34,962,759	(78,220,169)	-	740,660,958
2083	740,660,958	33,033,479	(83,507,127)	-	690,187,310
2084	690,187,310	30,782,354	(84,479,492)	-	636,490,172
2085	636,490,172	28,387,462	(87,488,590)	-	577,389,044
2086	577,389,044	25,751,551	(90,819,524)	-	512,321,072
2087	512,321,072	22,849,520	(96,920,580)	-	438,250,011
2088	438,250,011	19,545,951	(117,036,091)	-	340,759,871
2089	340,759,871	15,197,890	(101,606,814)	-	254,350,948
2090	254,350,948	11,344,052	(149,320,614)	-	116,374,386
2091	116,374,386	5,190,298	(121,564,684)	-	(0)

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Prairie Island Unit 1

External Levelized

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	374,367,055	9,359,484	-	24,632	383,751,171
2018	383,751,171	19,188,790	-	49,264	402,989,226
2019	402,989,226	20,150,693	-	49,264	423,189,183
2020	423,189,183	21,160,691	-	49,264	444,399,138
2021	444,399,138	22,796,244	-	23,051,488	490,246,870
2022	490,246,870	25,088,631	-	23,051,488	538,386,989
2023	538,386,989	27,495,637	-	23,051,488	588,934,114
2024	588,934,114	30,022,993	-	23,051,488	642,008,595
2025	642,008,595	32,676,717	-	23,051,488	697,736,800
2026	697,736,800	35,463,127	-	23,051,488	756,251,416
2027	756,251,416	38,388,858	-	23,051,488	817,691,762
2028	817,691,762	41,460,875	-	23,051,488	882,204,125
2029	882,204,125	44,686,493	-	23,051,488	949,942,107
2030	949,942,107	48,073,393	-	23,051,488	1,021,066,988
2031	1,021,066,988	51,629,637	-	23,051,488	1,095,748,113
2032	1,095,748,113	55,363,693	-	23,051,488	1,174,163,294
2033	1,174,163,294	49,521,004	(42,768,206)	15,444,497	1,196,360,589
2034	1,196,360,589	50,127,509	(131,752,423)	-	1,114,735,675
2035	1,114,735,675	46,707,425	(198,854,122)	-	962,588,978
2036	962,588,978	40,332,478	(173,386,483)	-	829,534,973
2037	829,534,973	34,757,515	(119,758,858)	-	744,533,631
2038	744,533,631	31,195,959	(48,446,232)	-	727,283,357
2039	727,283,357	30,473,173	(168,633,951)	-	589,122,579
2040	589,122,579	24,684,236	(78,121,996)	-	535,684,820
2041	535,684,820	22,445,194	(51,838,628)	-	506,291,385
2042	506,291,385	21,213,609	(47,540,570)	-	479,964,424
2043	479,964,424	20,110,509	(28,453,465)	-	471,621,469
2044	471,621,469	19,760,940	(10,519,163)	-	480,863,245
2045	480,863,245	20,148,170	(27,161,698)	-	473,849,717
2046	473,849,717	19,854,303	(22,436,459)	-	471,267,562
2047	471,267,562	19,746,111	(23,177,732)	-	467,835,940
2048	467,835,940	19,602,326	(12,009,850)	-	475,428,416
2049	475,428,416	19,920,451	(24,739,622)	-	470,609,244
2050	470,609,244	19,718,527	(31,942,856)	-	458,384,915
2051	458,384,915	19,206,328	(31,340,256)	-	446,250,987
2052	446,250,987	18,697,916	(34,139,894)	-	430,809,009
2053	430,809,009	18,050,897	(15,041,831)	-	433,818,076
2054	433,818,076	18,176,977	(16,462,254)	-	435,532,799
2055	435,532,799	18,248,824	(39,488,069)	-	414,293,554

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2056	414,293,554	17,358,900	(33,607,002)	-	398,045,451
2057	398,045,451	16,678,104	(39,665,263)	-	375,058,292
2058	375,058,292	15,714,942	(19,886,435)	-	370,886,800
2059	370,886,800	15,540,157	(18,987,907)	-	367,439,050
2060	367,439,050	15,395,696	(19,160,263)	-	363,674,484
2061	363,674,484	15,237,961	(20,905,881)	-	358,006,564
2062	358,006,564	15,000,475	(21,639,172)	-	351,367,867
2063	351,367,867	14,722,314	(21,797,605)	-	344,292,575
2064	344,292,575	14,425,859	(23,253,498)	-	335,464,936
2065	335,464,936	14,055,981	(24,009,128)	-	325,511,789
2066	325,511,789	13,638,944	(24,195,153)	-	314,955,580
2067	314,955,580	13,196,639	(25,741,010)	-	302,411,209
2068	302,411,209	12,671,030	(26,729,869)	-	288,352,370
2069	288,352,370	12,081,964	(26,874,413)	-	273,559,921
2070	273,559,921	11,462,161	(28,591,793)	-	256,430,289
2071	256,430,289	10,744,429	(29,614,636)	-	237,560,082
2072	237,560,082	9,953,767	(30,760,720)	-	216,753,129
2073	216,753,129	9,081,956	(31,777,701)	-	194,057,384
2074	194,057,384	8,131,004	(32,921,147)	-	169,267,242
2075	169,267,242	7,092,297	(40,279,545)	-	136,079,994
2076	136,079,994	5,701,752	(35,436,411)	-	106,345,334
2077	106,345,334	4,455,869	(82,827,215)	-	27,973,989
2078	27,973,989	1,172,110	(29,146,099)	-	0

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EXTERNAL FUND CALCULATION

Prairie Island Unit 2

External Levelized

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	420,208,967	10,592,979	-	294,670	431,096,616
2018	431,096,616	21,742,121	-	589,341	453,428,078
2019	453,428,078	22,867,627	-	589,341	476,885,046
2020	476,885,046	24,049,858	-	589,341	501,524,244
2021	501,524,244	25,664,895	-	15,399,724	542,588,863
2022	542,588,863	27,734,552	-	15,399,724	585,723,139
2023	585,723,139	29,908,519	-	15,399,724	631,031,382
2024	631,031,382	32,192,055	-	15,399,724	678,623,161
2025	678,623,161	34,590,680	-	15,399,724	728,613,565
2026	728,613,565	37,110,197	-	15,399,724	781,123,486
2027	781,123,486	39,756,697	-	15,399,724	836,279,906
2028	836,279,906	42,536,580	-	15,399,724	894,216,211
2029	894,216,211	45,456,570	-	15,399,724	955,072,505
2030	955,072,505	48,523,727	-	15,399,724	1,018,995,956
2031	1,018,995,956	51,745,469	-	15,399,724	1,086,141,149
2032	1,086,141,149	55,129,587	-	15,399,724	1,156,670,460
2033	1,156,670,460	58,684,264	-	15,399,724	1,230,754,448
2034	1,230,754,448	51,094,102	(17,426,478)	12,781,771	1,277,203,844
2035	1,277,203,844	52,748,519	(114,752,431)	-	1,215,199,931
2036	1,215,199,931	50,187,757	(214,578,923)	-	1,050,808,766
2037	1,050,808,766	43,398,402	(216,463,726)	-	877,743,442
2038	877,743,442	36,250,804	(136,478,692)	-	777,515,555
2039	777,515,555	32,111,392	(178,110,184)	-	631,516,763
2040	631,516,763	26,081,642	(89,351,532)	-	568,246,873
2041	568,246,873	23,468,596	(64,224,426)	-	527,491,043
2042	527,491,043	21,785,380	(59,433,129)	-	489,843,294
2043	489,843,294	20,230,528	(34,204,617)	-	475,869,206
2044	475,869,206	19,653,398	(10,519,163)	-	485,003,440
2045	485,003,440	20,030,642	(27,161,698)	-	477,872,385
2046	477,872,385	19,736,129	(22,436,459)	-	475,172,055
2047	475,172,055	19,624,606	(23,177,732)	-	471,618,929
2048	471,618,929	19,477,862	(12,009,850)	-	479,086,941
2049	479,086,941	19,786,291	(24,739,622)	-	474,133,609
2050	474,133,609	19,581,718	(31,942,856)	-	461,772,471
2051	461,772,471	19,071,203	(31,340,260)	-	449,503,414
2052	449,503,414	18,564,491	(34,139,891)	-	433,928,014
2053	433,928,014	17,921,227	(15,041,831)	-	436,807,411
2054	436,807,411	18,040,146	(16,462,254)	-	438,385,302

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2055	438,385,302	18,105,313	(39,488,069)	-	417,002,546
2056	417,002,546	17,222,205	(33,607,002)	-	400,617,749
2057	400,617,749	16,545,513	(39,665,263)	-	377,497,998
2058	377,497,998	15,590,667	(19,886,435)	-	373,202,231
2059	373,202,231	15,413,252	(18,987,907)	-	369,627,576
2060	369,627,576	15,265,619	(19,160,263)	-	365,732,933
2061	365,732,933	15,104,770	(20,905,881)	-	359,931,822
2062	359,931,822	14,865,184	(21,639,172)	-	353,157,835
2063	353,157,835	14,585,419	(21,797,605)	-	345,945,648
2064	345,945,648	14,287,555	(23,253,498)	-	336,979,705
2065	336,979,705	13,917,262	(24,009,128)	-	326,887,838
2066	326,887,838	13,500,468	(24,195,153)	-	316,193,153
2067	316,193,153	13,058,777	(25,741,010)	-	303,510,921
2068	303,510,921	12,535,001	(26,729,869)	-	289,316,053
2069	289,316,053	11,948,753	(26,874,413)	-	274,390,394
2070	274,390,394	11,332,323	(28,591,793)	-	257,130,923
2071	257,130,923	10,619,507	(29,614,636)	-	238,135,795
2072	238,135,795	9,835,008	(30,760,720)	-	217,210,083
2073	217,210,083	8,970,776	(31,777,701)	-	194,403,158
2074	194,403,158	8,028,850	(32,921,147)	-	169,510,861
2075	169,510,861	7,000,799	(40,279,545)	-	136,232,115
2076	136,232,115	5,626,386	(35,436,411)	-	106,422,090
2077	106,422,090	4,395,232	(82,827,215)	-	27,990,107
2078	27,990,107	1,155,991	(29,146,099)	-	0

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2021 ACCRUAL COMPARISON

	Present	Proposed	Difference
Monticello	$13,392,226	$58,502,632	$45,110,406
Prairie Island Unit 1	49,264	39,989,727	39,940,463
Prairie Island Unit 2	589,341	31,249,066	30,659,725
TOTAL	$14,030,831	$129,741,425	$115,710,594

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2021 MN RETAIL SUMMARY

	Remaining Life (yrs)	Operational Earnings Rate	Post-Shutdown Earnings Rate	Market Value Balance 6/30/2017	Book Value 6/30/2017	Unrealized Gain/Loss 6/30/2017	Tax-Effect Adjustment	Tax-Adjusted Fund Balance 6/30/2017	2021 Decommissioning Accrual
Monticello	13.75	5.03%	4.79%	$660,140,345	$529,148,381	$130,991,964	$36,468,163	$623,672,182	**58,502,632**
Prairie Island Unit 1	16.67	5.03%	4.71%	399,941,696	308,078,761	91,862,935	25,574,641	374,367,055	**39,989,727**
Prairie Island Unit 2	17.83	5.07%	4.69%	448,597,551	346,627,064	101,970,487	28,388,583	420,208,967	**31,249,066**
TOTAL DECOMMISSIONING ACCRUAL				**$1,508,679,592**	**$1,183,854,206**	**$324,825,386**	**$90,431,387**	**$1,418,248,204**	**$129,741,425**

INPUT DATA

Escalation Rate (Labor)	4.05%
Escalation Rate (Non-Labor)	2.85%
Escalation Rate (PIIC)	0.00%
Jurisdictional Factor	73.4886%
Tax Rate for tax-effect adjustment	27.84%

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	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
Monticello															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2030	$21,103,620	$15,508,745	1.6755	$25,984,903	$8,935,561	$6,566,615	1.4410	$9,462,492	$0	$0	1.0000	$0	$30,039,182	$22,075,360	$35,447,395
2031	72,416,235	53,217,644	1.7434	92,779,641	42,961,344	31,571,670	1.4820	46,789,215	0	0	1.0000	0	115,377,579	84,789,314	139,568,856
2032	81,871,153	60,165,927	1.8140	109,140,991	112,447,587	82,636,106	1.5243	125,962,216	0	0	1.0000	0	194,318,741	142,802,033	235,103,207
2033	78,663,227	57,808,468	1.8874	109,107,702	100,155,666	73,602,950	1.5677	115,387,345	0	0	1.0000	0	178,818,892	131,411,418	224,495,047
2034	66,380,423	48,782,013	1.9639	95,802,994	38,894,671	28,583,132	1.6124	46,087,441	0	0	1.0000	0	105,275,094	77,365,144	141,890,436
2035	86,879,803	63,846,711	2.0434	130,464,369	113,147,091	83,150,161	1.6584	137,896,227	0	0	1.0000	0	200,026,894	146,996,872	268,360,596
2036	50,307,504	36,970,257	2.1262	78,606,161	20,688,337	15,203,559	1.7056	25,931,191	0	0	1.0000	0	70,995,841	52,173,817	104,537,352
2037	34,755,723	25,541,478	2.2123	56,505,412	14,196,883	10,433,084	1.7542	18,301,716	0	0	1.0000	0	48,952,606	35,974,562	74,807,128
2038	29,827,529	21,919,820	2.3019	50,457,233	15,094,222	11,092,525	1.8042	20,013,134	0	0	1.0000	0	44,921,751	33,012,345	70,470,367
2039	7,164,563	5,265,134	2.3951	12,610,522	2,125,149	1,561,742	1.8556	2,897,968	0	0	1.0000	0	9,289,712	6,826,875	15,508,490
2040	7,184,147	5,279,526	2.4921	13,157,106	2,130,835	1,565,920	1.9085	2,988,559	0	0	1.0000	0	9,314,982	6,845,446	16,145,665
2041	7,164,563	5,265,134	2.5930	13,652,492	2,125,149	1,561,742	1.9629	3,065,543	0	0	1.0000	0	9,289,712	6,826,875	16,718,034
2042	7,164,563	5,265,134	2.6981	14,205,857	2,125,149	1,561,742	2.0189	3,153,000	0	0	1.0000	0	9,289,712	6,826,875	17,358,857
2043	7,164,563	5,265,134	2.8073	14,780,810	2,125,149	1,561,742	2.0764	3,242,800	0	0	1.0000	0	9,289,712	6,826,875	18,023,610
2044	7,184,147	5,279,526	2.9210	15,421,495	2,130,835	1,565,920	2.1356	3,344,179	0	0	1.0000	0	9,314,982	6,845,446	18,765,674
2045	7,164,563	5,265,134	3.0393	16,002,321	2,125,149	1,561,742	2.1964	3,430,209	0	0	1.0000	0	9,289,712	6,826,875	19,432,530
2046	7,164,563	5,265,134	3.1624	16,650,459	2,125,149	1,561,742	2.2590	3,527,974	0	0	1.0000	0	9,289,712	6,826,875	20,178,433
2047	7,164,563	5,265,134	3.2905	17,324,923	2,125,149	1,561,742	2.3234	3,628,550	0	0	1.0000	0	9,289,712	6,826,875	20,953,473
2048	7,847,792	5,767,229	3.4238	19,745,838	4,121,769	3,029,029	2.3896	7,238,167	0	0	1.0000	0	11,969,561	8,796,258	26,984,005
2049	7,164,563	5,265,134	3.5624	18,756,512	2,125,149	1,561,742	2.4577	3,838,292	0	0	1.0000	0	9,289,712	6,826,875	22,594,805
2050	8,657,764	6,362,466	3.7067	23,583,751	6,604,752	4,853,737	2.5278	12,269,277	0	0	1.0000	0	15,262,516	11,216,203	35,853,028
2051	8,657,764	6,362,466	3.8568	24,538,757	6,604,752	4,853,737	2.5998	12,618,746	0	0	1.0000	0	15,262,516	11,216,203	37,157,503
2052	8,677,348	6,376,858	4.0130	25,590,329	6,610,438	4,857,916	2.6739	12,989,580	0	0	1.0000	0	15,287,786	11,234,773	38,579,910
2053	8,657,764	6,362,466	4.1756	26,567,111	6,604,752	4,853,737	2.7501	13,348,262	0	0	1.0000	0	15,262,516	11,216,203	39,915,373
2054	8,657,764	6,362,466	4.3447	27,643,004	6,604,752	4,853,737	2.8285	13,728,795	0	0	1.0000	0	15,262,516	11,216,203	41,371,799
2055	8,657,764	6,362,466	4.5206	28,762,162	6,604,752	4,853,737	2.9091	14,120,006	0	0	1.0000	0	15,262,516	11,216,203	42,882,168
2056	8,677,348	6,376,858	4.7037	29,994,825	6,610,438	4,857,916	2.9920	14,534,883	0	0	1.0000	0	15,287,786	11,234,773	44,529,708
2057	8,657,764	6,362,466	4.8942	31,139,179	6,604,752	4,853,737	3.0773	14,936,405	0	0	1.0000	0	15,262,516	11,216,203	46,075,584
2058	14,754,149	10,842,611	5.0924	55,214,911	24,893,906	18,294,172	3.1650	57,901,054	0	0	1.0000	0	39,648,055	29,136,783	113,115,965
2059	8,657,764	6,362,466	5.2987	33,712,796	6,604,752	4,853,737	3.2552	15,799,885	0	0	1.0000	0	15,262,516	11,216,203	49,512,681
2060	8,677,348	6,376,858	5.5133	35,157,529	6,610,438	4,857,916	3.3480	16,264,301	0	0	1.0000	0	15,287,786	11,234,773	51,421,830
2061	8,657,764	6,362,466	5.7366	36,498,920	6,604,752	4,853,737	3.4434	16,713,358	0	0	1.0000	0	15,262,516	11,216,203	53,212,278
2062	8,657,764	6,362,466	5.9689	37,976,921	6,604,752	4,853,737	3.5415	17,189,510	0	0	1.0000	0	15,262,516	11,216,203	55,166,430
2063	8,657,764	6,362,466	6.2106	39,514,729	6,604,752	4,853,737	3.6425	17,679,737	0	0	1.0000	0	15,262,516	11,216,203	57,194,466
2064	8,677,348	6,376,858	6.4622	41,208,529	6,610,438	4,857,916	3.7463	18,199,209	0	0	1.0000	0	15,287,786	11,234,773	59,407,738
2065	8,657,764	6,362,466	6.7239	42,780,582	6,604,752	4,853,737	3.8531	18,701,934	0	0	1.0000	0	15,262,516	11,216,203	61,482,516
2066	12,315,595	9,050,553	6.9962	63,319,477	17,578,245	12,917,998	3.9629	51,192,736	0	0	1.0000	0	29,893,840	21,968,551	114,512,212
2067	8,657,764	6,362,466	7.2795	46,315,568	6,604,752	4,853,737	4.0758	19,782,861	0	0	1.0000	0	15,262,516	11,216,203	66,098,430
2068	17,212,287	12,649,061	7.5744	95,809,046	32,215,254	23,674,525	4.1920	99,243,607	0	0	1.0000	0	49,427,541	36,323,585	195,052,653
2069	8,657,764	6,362,466	7.8811	50,143,227	6,604,752	4,853,737	4.3115	20,926,887	0	0	1.0000	0	15,262,516	11,216,203	71,070,115
2070	8,657,764	6,362,466	8.2003	52,174,126	6,604,752	4,853,737	4.4343	21,522,926	0	0	1.0000	0	15,262,516	11,216,203	73,697,053
2071	8,657,764	6,362,466	8.5324	54,287,101	6,604,752	4,853,737	4.5607	22,136,439	0	0	1.0000	0	15,262,516	11,216,203	76,423,540
2072	8,677,348	6,376,858	8.8780	56,613,741	6,610,438	4,857,916	4.6907	22,787,025	0	0	1.0000	0	15,287,786	11,234,773	79,400,766
2073	8,657,764	6,362,466	9.2375	58,773,276	6,604,752	4,853,737	4.8244	23,416,369	0	0	1.0000	0	15,262,516	11,216,203	82,189,645
2074	8,657,764	6,362,466	9.6117	61,154,110	6,604,752	4,853,737	4.9619	24,083,758	0	0	1.0000	0	15,262,516	11,216,203	85,237,868
2075	8,657,764	6,362,466	10.0009	63,630,382	6,604,752	4,853,737	5.1033	24,770,076	0	0	1.0000	0	15,262,516	11,216,203	88,400,458
2076	8,677,348	6,376,858	10.4060	66,357,580	6,610,438	4,857,916	5.2487	25,497,742	0	0	1.0000	0	15,287,786	11,234,773	91,855,321
2077	8,657,764	6,362,466	10.8274	68,888,960	6,604,752	4,853,737	5.3983	26,201,929	0	0	1.0000	0	15,262,516	11,216,203	95,090,888
2078	8,657,764	6,362,466	11.2659	71,678,901	6,604,752	4,853,737	5.5522	26,948,919	0	0	1.0000	0	15,262,516	11,216,203	98,627,820
2079	8,657,764	6,362,466	11.7222	74,582,094	6,604,752	4,853,737	5.7104	27,716,780	0	0	1.0000	0	15,262,516	11,216,203	102,298,874
2080	8,677,348	6,376,858	12.1970	77,778,532	6,610,438	4,857,916	5.8731	28,531,024	0	0	1.0000	0	15,287,786	11,234,773	106,309,556
2081	8,657,764	6,362,466	12.6909	80,745,414	6,604,752	4,853,737	6.0405	29,318,999	0	0	1.0000	0	15,262,516	11,216,203	110,064,413
2082	8,657,764	6,362,466	13.2049	84,015,722	6,604,752	4,853,737	6.2127	30,154,812	0	0	1.0000	0	15,262,516	11,216,203	114,170,534
2083	8,657,764	6,362,466	13.7397	87,418,368	6,604,752	4,853,737	6.3897	31,013,924	0	0	1.0000	0	15,262,516	11,216,203	118,432,292
2084	8,677,348	6,376,858	14.2962	91,164,831	6,610,438	4,857,916	6.5719	31,925,735	0	0	1.0000	0	15,287,786	11,234,773	123,090,567

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	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
2085	8,657,764	6,362,466	14.8752	94,642,948	6,604,752	4,853,737	6.7592	32,807,380	0	0	1.0000	0	15,262,516	11,216,203	127,450,327
2086	8,657,764	6,362,466	15.4776	98,475,697	6,604,752	4,853,737	6.9518	33,742,209	0	0	1.0000	0	15,262,516	11,216,203	132,217,906
2087	8,657,764	6,362,466	16.1045	102,464,327	6,604,752	4,853,737	7.1499	34,703,735	0	0	1.0000	0	15,262,516	11,216,203	137,168,061
2088	9,340,993	6,864,561	16.7567	115,027,384	8,601,373	6,321,025	7.3537	46,482,921	0	0	1.0000	0	17,942,366	13,185,586	161,510,305
2089	8,657,764	6,362,466	17.4353	110,931,496	6,604,752	4,853,737	7.5633	36,710,269	0	0	1.0000	0	15,262,516	11,216,203	147,641,765
2090	8,657,764	6,362,466	18.1415	115,424,669	6,604,752	4,853,737	7.7788	37,756,250	0	0	1.0000	0	15,262,516	11,216,203	153,180,919
2091	8,657,764	6,362,466	18.8762	120,099,172	6,604,752	4,853,737	8.0005	38,832,323	0	0	1.0000	0	15,262,516	11,216,203	158,931,496
2092	9,539,848	7,010,696	19.6407	137,694,984	9,197,938	6,759,432	8.2285	55,619,986	0	0	1.0000	0	18,737,786	13,770,128	193,314,969
2093	10,167,139	7,471,683	20.4361	152,692,070	11,132,877	8,181,391	8.4630	69,239,109	0	0	1.0000	0	21,300,016	15,653,074	221,931,179
2094	8,873,389	6,520,925	21.2638	138,659,650	7,251,627	5,329,116	8.7042	46,385,693	0	0	1.0000	0	16,125,016	11,850,041	185,045,343
2095	31,288,861	22,993,731	22.1250	508,736,309	83,569,860	61,414,281	8.9523	549,799,071	0	0	1.0000	0	114,858,721	84,408,013	1,058,535,380
2096	10,402,348	7,644,535	23.0210	175,984,843	11,785,438	8,660,948	9.2075	79,745,681	0	0	1.0000	0	22,187,786	16,305,483	255,730,524
2097	7,147,972	5,252,941	23.9534	125,825,803	2,075,375	1,525,163	9.4699	14,443,145	0	0	1.0000	0	9,223,347	6,778,105	140,268,948
2098	7,147,972	5,252,941	24.9235	130,921,681	2,075,375	1,525,163	9.7398	14,854,786	0	0	1.0000	0	9,223,347	6,778,105	145,776,468
2099	7,147,972	5,252,941	25.9329	136,224,000	2,075,375	1,525,163	10.0173	15,278,019	0	0	1.0000	0	9,223,347	6,778,105	151,502,020
2100	7,147,972	5,252,941	26.9832	141,741,164	2,075,375	1,525,163	10.3028	15,713,453	0	0	1.0000	0	9,223,347	6,778,105	157,454,618
2101	7,147,972	5,252,941	28.0760	147,481,579	2,075,375	1,525,163	10.5965	16,161,394	0	0	1.0000	0	9,223,347	6,778,105	163,642,973
2102	7,147,972	5,252,941	29.2131	153,454,698	2,075,375	1,525,163	10.8985	16,621,993	0	0	1.0000	0	9,223,347	6,778,105	170,076,691
2103	7,147,972	5,252,941	30.3962	159,669,453	2,075,375	1,525,163	11.2091	17,095,709	0	0	1.0000	0	9,223,347	6,778,105	176,765,162
2104	7,167,556	5,267,333	31.6272	166,591,002	2,081,061	1,529,342	11.5285	17,631,018	0	0	1.0000	0	9,248,617	6,796,675	184,222,021
2105	7,147,972	5,252,941	32.9081	172,864,316	2,075,375	1,525,163	11.8571	18,084,015	0	0	1.0000	0	9,223,347	6,778,105	190,948,331
2106	7,147,972	5,252,941	34.2409	179,865,436	2,075,375	1,525,163	12.1950	18,599,368	0	0	1.0000	0	9,223,347	6,778,105	198,464,804
2107	7,147,972	5,252,941	35.6277	187,150,215	2,075,375	1,525,163	12.5426	19,129,514	0	0	1.0000	0	9,223,347	6,778,105	206,279,730
2108	13,263,941	9,747,478	37.0706	361,344,874	20,370,216	14,969,777	12.9000	193,110,129	0	0	1.0000	0	33,634,157	24,717,256	554,455,003
2109	7,147,972	5,252,941	38.5720	202,616,450	2,075,375	1,525,163	13.2677	20,235,410	0	0	1.0000	0	9,223,347	6,778,105	222,851,861
2110	7,147,972	5,252,941	40.1341	210,822,070	2,075,375	1,525,163	13.6458	20,812,075	0	0	1.0000	0	9,223,347	6,778,105	231,634,144
2111	7,147,972	5,252,941	41.7596	219,360,726	2,075,375	1,525,163	14.0347	21,405,211	0	0	1.0000	0	9,223,347	6,778,105	240,765,936
2112	7,167,556	5,267,333	43.4508	228,869,844	2,081,061	1,529,342	14.4347	22,075,592	0	0	1.0000	0	9,248,617	6,796,675	250,945,436
2113	7,147,972	5,252,941	45.2106	237,488,626	11,274,281	8,285,306	14.8461	123,004,487	0	0	1.0000	0	18,422,253	13,538,248	360,493,113
2114	7,147,972	5,252,941	47.0416	247,106,761	2,075,375	1,525,163	15.2692	23,288,025	0	0	1.0000	0	9,223,347	6,778,105	270,394,786
2115	7,147,972	5,252,941	48.9468	257,114,665	2,075,375	1,525,163	15.7044	23,951,776	0	0	1.0000	0	9,223,347	6,778,105	281,066,441
2116	10,825,387	7,955,420	50.9291	405,162,399	13,054,554	9,593,603	16.1520	154,955,880	0	0	1.0000	0	23,879,941	17,549,024	560,118,279
2117	7,147,972	5,252,941	52.9918	278,362,812	2,075,375	1,525,163	16.6123	25,336,472	0	0	1.0000	0	9,223,347	6,778,105	303,699,284
2118	14,921,796	10,965,812	55.1379	604,631,851	29,162,169	21,430,856	17.0857	366,161,179	0	0	1.0000	0	44,083,965	32,396,668	970,793,029
2119	6,482,543	4,763,927	57.3710	273,311,262	3,844,412	2,825,203	17.5727	49,646,438	0	0	1.0000	0	10,326,955	7,589,130	322,957,700
2120	6,403,045	4,705,505	59.6946	280,893,249	3,563,167	2,618,520	18.0735	47,325,815	0	0	1.0000	0	9,966,212	7,324,025	328,219,064
2121	6,386,857	4,693,609	62.1122	291,530,372	3,557,353	2,614,247	18.5886	48,595,194	0	0	1.0000	0	9,944,210	7,307,856	340,125,566
2122	6,386,857	4,693,609	64.6277	303,337,145	3,557,353	2,614,247	19.1184	49,980,222	0	0	1.0000	0	9,944,210	7,307,856	353,317,367
2123	6,482,543	4,763,927	67.2451	320,350,755	3,844,412	2,825,203	19.6633	55,552,807	0	0	1.0000	0	10,326,955	7,589,130	375,903,562
2124	6,403,045	4,705,505	69.9686	329,237,609	3,563,167	2,618,520	20.2237	52,956,156	0	0	1.0000	0	9,966,212	7,324,025	382,193,765
2125	6,386,857	4,693,609	72.8023	341,705,519	3,557,353	2,614,247	20.8000	54,376,340	0	0	1.0000	0	9,944,210	7,307,856	396,081,860
2126	6,386,857	4,693,609	75.7508	355,544,625	3,557,353	2,614,247	21.3928	55,926,066	0	0	1.0000	0	9,944,210	7,307,856	411,470,691
2127	6,482,543	4,763,927	78.8187	375,486,541	3,844,412	2,825,203	22.0025	62,161,521	0	0	1.0000	0	10,326,955	7,589,130	437,648,062
2128	7,066,689	5,193,208	82.0109	425,899,625	5,554,101	4,081,628	22.6296	92,365,615	0	0	1.0000	0	12,620,790	9,274,836	518,265,240
2129	6,386,857	4,693,609	85.3323	400,516,438	3,557,353	2,614,247	23.2745	60,845,295	0	0	1.0000	0	9,944,210	7,307,856	461,361,733
2130	6,099,798	4,482,653	88.7883	398,007,170	2,696,175	1,981,380	23.9379	47,430,073	0	0	1.0000	0	8,795,973	6,464,033	445,437,243
2131	2,028,079	1,490,406	92.3842	137,689,966	5,022,573	3,691,016	24.6201	90,873,191	0	0	1.0000	0	7,050,652	5,181,422	228,563,157
	$1,309,028,449	$961,986,078		$13,824,906,481	$1,110,107,131	$815,801,677		$4,468,161,723	$0	$0		$0	$2,419,135,581	$1,777,787,755	$18,293,068,204

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	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
Prairie Island Unit 1															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2033	$22,324,352	$16,405,843	1.8874	$30,964,388	$9,448,311	$6,943,427	1.5677	$10,885,211	$1,250,000	$918,607	1.0000	$918,607	$33,022,663	$24,267,877	$42,768,206
2034	63,582,247	46,725,674	1.9639	91,764,550	32,971,808	24,230,505	1.6124	39,069,266	1,250,000	918,607	1.0000	918,607	97,804,054	71,874,785	131,752,423
2035	65,877,290	48,412,268	2.0434	98,925,629	81,239,936	59,702,054	1.6584	99,009,886	1,250,000	918,607	1.0000	918,607	148,367,226	109,032,929	198,854,122
2036	57,759,315	42,446,486	2.1262	90,249,718	65,595,018	48,204,830	1.7056	82,218,158	1,250,000	918,607	1.0000	918,607	124,604,333	91,569,923	173,386,483
2037	39,808,345	29,254,577	2.2123	64,719,901	41,981,870	30,851,869	1.7542	54,120,349	1,250,000	918,607	1.0000	918,607	83,040,216	61,025,054	119,758,858
2038	13,207,909	9,706,302	2.3019	22,342,936	18,994,690	13,958,923	1.8042	25,184,688	1,250,000	918,607	1.0000	918,607	33,452,599	24,583,831	48,446,231
2039	35,713,289	26,245,180	2.3951	62,859,831	75,509,036	55,490,499	1.8556	102,968,170	1,250,000	918,607	1.0000	918,607	112,472,326	82,654,286	166,746,607
2040	31,919,562	23,457,225	2.4921	58,457,750	13,365,605	9,822,190	1.9085	18,745,649	1,250,000	918,607	1.0000	918,607	46,535,167	34,198,022	78,122,006
2041	19,624,628	14,421,855	2.5930	37,395,870	9,445,873	6,941,635	1.9629	13,625,736	1,250,000	918,607	1.0000	918,607	30,320,500	22,282,097	51,940,213
2042	14,863,703	10,923,120	2.6981	29,471,671	11,668,700	8,575,159	2.0189	17,312,388	1,250,000	918,607	1.0000	918,607	27,782,403	20,416,886	47,702,666
2043	8,912,167	6,549,423	2.8073	18,386,194	6,470,357	4,754,972	2.0764	9,873,223	1,250,000	918,607	1.0000	918,607	16,632,524	12,223,001	29,178,024
2044	3,676,270	2,701,638	2.9210	7,891,484	1,896,910	1,394,012	2.1356	2,977,052	1,250,000	918,607	1.0000	918,607	6,823,180	5,014,256	11,787,142
2045	5,973,091	4,389,538	3.0393	13,341,123	8,808,910	6,473,541	2.1964	14,218,485	1,250,000	918,607	1.0000	918,607	16,032,001	11,781,686	28,478,215
2046	5,204,136	3,824,444	3.1624	12,094,423	6,502,044	4,778,258	2.2590	10,794,085	1,250,000	918,607	1.0000	918,607	12,956,180	9,521,309	23,807,115
2047	5,204,136	3,824,444	3.2905	12,584,334	6,502,044	4,778,258	2.3234	11,101,805	1,250,000	918,607	1.0000	918,607	12,956,180	9,521,309	24,604,746
2048	3,676,270	2,701,638	3.4238	9,249,867	1,896,910	1,394,012	2.3896	3,331,131	1,250,000	918,607	1.0000	918,607	6,823,180	5,014,256	13,499,605
2049	5,204,136	3,824,444	3.5624	13,624,200	6,502,044	4,778,258	2.4577	11,743,525	1,250,000	918,607	1.0000	918,607	12,956,180	9,521,309	26,286,332
2050	5,973,091	4,389,538	3.7067	16,270,701	8,808,910	6,473,541	2.5278	16,363,816	1,250,000	918,607	1.0000	918,607	16,032,001	11,781,686	33,553,124
2051	5,779,136	4,247,003	3.8568	16,379,843	8,227,044	6,045,936	2.5998	15,718,224	1,250,000	918,607	1.0000	918,607	15,256,180	11,211,546	33,016,674
2052	5,983,136	4,396,920	4.0130	17,644,840	8,817,508	6,479,859	2.6739	17,326,496	1,250,000	918,607	1.0000	918,607	16,050,644	11,795,386	35,889,943
2053	3,666,225	2,694,256	4.1756	11,250,134	1,888,312	1,387,693	2.7501	3,816,295	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	15,985,036
2054	3,666,225	2,694,256	4.3447	11,705,733	1,888,312	1,387,693	2.8285	3,925,090	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	16,549,430
2055	5,973,091	4,389,538	4.5206	19,843,346	8,808,910	6,473,541	2.9091	18,832,177	1,250,000	918,607	1.0000	918,607	16,032,001	11,781,686	39,594,130
2056	5,214,180	3,831,825	4.7037	18,023,758	6,510,642	4,784,577	2.9920	14,315,454	1,250,000	918,607	1.0000	918,607	12,974,822	9,535,009	33,257,818
2057	5,204,136	3,824,444	4.8942	18,717,595	6,502,044	4,778,258	3.0773	14,704,134	1,250,000	918,607	1.0000	918,607	12,956,180	9,521,309	34,340,336
2058	3,666,225	2,694,256	5.0924	13,720,228	1,888,312	1,387,693	3.1650	4,392,049	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	19,030,884
2059	5,010,180	3,681,909	5.2987	19,509,330	5,920,178	4,350,653	3.2552	14,162,246	1,250,000	918,607	1.0000	918,607	12,180,358	8,951,169	34,590,184
2060	5,214,180	3,831,825	5.5133	21,126,003	6,510,642	4,784,577	3.3480	16,018,763	1,250,000	918,607	1.0000	918,607	12,974,822	9,535,009	38,063,373
2061	5,204,136	3,824,444	5.7366	21,939,307	6,502,044	4,778,258	3.4434	16,453,454	1,250,000	918,607	1.0000	918,607	12,956,180	9,521,309	39,311,368
2062	3,666,225	2,694,256	5.9689	16,081,743	1,888,312	1,387,693	3.5415	4,914,516	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	21,914,866
2063	8,279,957	6,084,821	6.2106	37,790,387	15,729,508	11,559,388	3.6425	42,105,071	1,250,000	918,607	1.0000	918,607	25,259,465	18,562,816	80,814,065
2064	6,558,136	4,819,479	6.4622	31,144,439	10,542,508	7,747,537	3.7463	29,024,597	1,250,000	918,607	1.0000	918,607	18,350,644	13,485,623	61,087,643
2065	5,204,136	3,824,444	6.7239	25,715,181	6,502,044	4,778,258	3.8531	18,411,107	1,250,000	918,607	1.0000	918,607	12,956,180	9,521,309	45,044,894
2066	3,666,225	2,694,256	6.9962	18,849,552	1,888,312	1,387,693	3.9629	5,499,289	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	25,267,448
2067	3,666,225	2,694,256	7.2795	19,612,835	1,888,312	1,387,693	4.0758	5,655,960	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	26,187,402
2068	6,752,091	4,962,014	7.5744	37,584,279	11,124,374	8,175,142	4.1920	34,270,194	1,250,000	918,607	1.0000	918,607	19,126,465	14,055,763	72,773,080
2069	5,973,091	4,389,538	7.8811	34,594,389	8,808,910	6,473,541	4.3115	27,910,670	1,250,000	918,607	1.0000	918,607	16,032,001	11,781,686	63,423,667
2070	3,666,225	2,694,256	8.2003	22,093,705	1,888,312	1,387,693	4.4343	6,153,448	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	29,165,760
2071	3,666,225	2,694,256	8.5324	22,988,468	1,888,312	1,387,693	4.5607	6,328,853	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	30,235,927
2072	7,327,091	5,384,573	8.8780	47,804,241	12,849,374	9,442,819	4.6907	44,293,432	1,250,000	918,607	1.0000	918,607	21,426,465	15,745,999	93,016,280
2073	3,666,225	2,694,256	9.2375	24,888,187	1,888,312	1,387,693	4.8244	6,694,787	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	32,501,581
2074	3,666,225	2,694,256	9.6117	25,896,378	1,888,312	1,387,693	4.9619	6,885,595	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	33,700,580
2075	7,842,824	5,763,578	10.0009	57,640,967	14,418,110	10,595,661	5.1033	54,072,835	1,250,000	918,607	1.0000	918,607	23,510,934	17,277,845	112,632,408
2076	3,676,270	2,701,638	10.4060	28,113,241	1,896,910	1,394,012	5.2487	7,316,750	1,250,000	918,607	1.0000	918,607	6,823,180	5,014,256	36,348,598
2077	3,666,225	2,694,256	10.8274	29,171,785	1,888,312	1,387,693	5.3983	7,491,184	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	37,581,576
2078	7,511,002	5,519,727	11.2659	62,184,690	13,422,642	9,864,106	5.5522	54,767,487	1,250,000	918,607	1.0000	918,607	22,183,644	16,302,439	117,870,783
2079	3,666,225	2,694,256	11.7222	31,582,605	1,888,312	1,387,693	5.7104	7,924,283	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	40,425,495
2080	3,676,270	2,701,638	12.1970	32,951,875	1,896,910	1,394,012	5.8731	8,187,171	1,250,000	918,607	1.0000	918,607	6,823,180	5,014,256	42,057,653
2081	3,666,225	2,694,256	12.6909	34,192,530	1,888,312	1,387,693	6.0405	8,382,361	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	43,493,498
2082	7,123,091	5,234,657	13.2049	69,123,117	12,258,910	9,008,896	6.2127	55,969,566	1,250,000	918,607	1.0000	918,607	20,632,001	15,162,159	126,011,290
2083	3,666,225	2,694,256	13.7397	37,018,266	1,888,312	1,387,693	6.3897	8,866,943	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	46,803,816
2084	3,676,270	2,701,638	14.2962	38,623,152	1,896,910	1,394,012	6.5719	9,161,307	1,250,000	918,607	1.0000	918,607	6,823,180	5,014,256	48,703,066
2085	3,666,225	2,694,256	14.8752	40,077,593	1,888,312	1,387,693	6.7592	9,379,696	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	50,375,896
2086	3,666,225	2,694,256	15.4776	41,700,613	1,888,312	1,387,693	6.9518	9,646,966	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	52,266,185
2087	3,666,225	2,694,256	16.1045	43,389,641	1,888,312	1,387,693	7.1499	9,921,868	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	54,230,116

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	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
2088	3,676,270	2,701,638	16.7567	45,270,532	1,896,910	1,394,012	7.3537	10,251,145	1,250,000	918,607	1.0000	918,607	6,823,180	5,014,256	56,440,284
2089	26,815,724	19,706,488	17.4353	343,588,526	73,271,240	53,845,975	7.5633	407,253,263	1,250,000	918,607	1.0000	918,607	101,336,964	74,471,070	751,760,396
2090	3,666,225	2,694,256	18.1415	48,877,840	1,888,312	1,387,693	7.7788	10,794,588	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	60,591,035
2091	3,666,225	2,694,256	18.8762	50,857,310	1,888,312	1,387,693	8.0005	11,102,240	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	62,878,157
2092	3,676,270	2,701,638	19.6407	53,062,055	1,896,910	1,394,012	8.2285	11,470,627	1,250,000	918,607	1.0000	918,607	6,823,180	5,014,256	65,451,288
2093	3,050,095	2,241,471	20.4361	45,806,920	1,970,565	1,448,140	8.4630	12,255,605	1,250,000	918,607	1.0000	918,607	6,270,660	4,608,217	58,981,132
2094	3,145,781	2,311,789	21.2638	49,157,418	2,257,624	1,659,095	8.7042	14,441,095	1,250,000	918,607	1.0000	918,607	6,653,405	4,889,491	64,517,121
2095	5,452,647	4,007,071	22.1250	88,656,455	9,178,222	6,744,942	8.9523	60,382,748	1,250,000	918,607	1.0000	918,607	15,880,869	11,670,621	149,957,811
2096	4,739,629	3,483,085	23.0210	80,184,095	7,022,923	5,161,044	9.2075	47,520,316	1,250,000	918,607	1.0000	918,607	13,012,552	9,562,736	128,623,019
2097	4,635,849	3,406,818	23.9534	81,604,884	6,727,827	4,944,183	9.4699	46,820,915	1,250,000	918,607	1.0000	918,607	12,613,676	9,269,608	129,344,406
2098	3,241,467	2,382,107	24.9235	59,370,449	2,544,683	1,870,051	9.7398	18,213,919	1,250,000	918,607	1.0000	918,607	7,036,150	5,170,765	78,502,975
2099	3,097,938	2,276,630	25.9329	59,039,614	2,114,095	1,553,618	10.0173	15,563,055	1,250,000	918,607	1.0000	918,607	6,462,033	4,748,854	75,521,275
2100	5,356,961	3,936,753	26.9832	106,226,198	8,891,163	6,533,987	10.3028	67,318,361	1,250,000	918,607	1.0000	918,607	15,498,124	11,389,347	174,463,166
2101	5,452,647	4,007,071	28.0760	112,502,537	9,178,222	6,744,942	10.5965	71,472,783	1,250,000	918,607	1.0000	918,607	15,880,869	11,670,621	184,893,927
2102	5,452,647	4,007,071	29.2131	117,058,978	9,178,222	6,744,942	10.8985	73,509,756	1,250,000	918,607	1.0000	918,607	15,880,869	11,670,621	191,487,341
2103	3,097,938	2,276,630	30.3962	69,200,896	2,114,095	1,553,618	11.2091	17,414,656	1,250,000	918,607	1.0000	918,607	6,462,033	4,748,854	87,534,159
2104	3,153,875	2,317,737	31.6272	73,303,536	2,265,661	1,665,001	11.5285	19,194,968	1,250,000	918,607	1.0000	918,607	6,669,536	4,901,345	93,417,111
2105	5,452,647	4,007,071	32.9081	131,865,107	9,178,222	6,744,942	11.8571	79,975,457	1,250,000	918,607	1.0000	918,607	15,880,869	11,670,621	212,759,172
2106	4,635,849	3,406,818	34.2409	116,652,528	6,727,827	4,944,183	12.1950	60,294,307	1,250,000	918,607	1.0000	918,607	12,613,676	9,269,608	177,865,442
2107	4,683,692	3,441,978	35.6277	122,629,742	6,871,356	5,049,660	12.5426	63,335,866	1,250,000	918,607	1.0000	918,607	12,805,048	9,410,244	186,884,215
2108	3,153,875	2,317,737	37.0706	85,919,906	2,265,661	1,665,001	12.9000	21,478,518	1,250,000	918,607	1.0000	918,607	6,669,536	4,901,345	108,317,031
2109	4,635,849	3,406,818	38.5720	131,407,799	6,727,827	4,944,183	13.2677	65,597,932	1,250,000	918,607	1.0000	918,607	12,613,676	9,269,608	197,924,338
2110	4,676,515	3,436,703	40.1341	137,928,992	6,849,827	5,033,839	13.6458	68,690,756	1,250,000	918,607	1.0000	918,607	12,776,342	9,389,149	207,538,354
2111	4,669,339	3,431,430	41.7596	143,295,132	6,828,297	5,018,017	14.0347	70,426,357	1,250,000	918,607	1.0000	918,607	12,747,636	9,368,053	214,640,096
2112	3,139,522	2,307,189	43.4508	100,249,222	2,222,602	1,633,358	14.4347	23,577,032	1,250,000	918,607	1.0000	918,607	6,612,124	4,859,154	124,744,860
2113	7,745,160	5,691,806	45.2106	257,329,968	16,055,761	11,799,146	14.8461	175,171,308	1,250,000	918,607	1.0000	918,607	25,050,921	18,409,559	433,419,883
2114	6,207,249	4,561,618	47.0416	214,585,787	11,442,029	8,408,581	15.2692	128,392,313	1,250,000	918,607	1.0000	918,607	18,899,278	13,888,806	343,896,707
2115	5,001,161	3,675,281	48.9468	179,893,239	7,823,765	5,749,572	15.7044	90,293,572	1,250,000	918,607	1.0000	918,607	14,074,926	10,343,459	271,105,418
2116	3,139,522	2,307,189	50.9291	117,503,075	13,878,680	10,199,241	16.1520	164,738,142	1,250,000	918,607	1.0000	918,607	18,268,202	13,425,037	283,159,824
2117	3,127,840	2,298,604	52.9918	121,807,184	2,203,801	1,619,541	16.6123	26,904,307	1,250,000	918,607	1.0000	918,607	6,581,641	4,836,753	149,630,097
2118	1,058,128	777,603	55.1379	42,875,395	2,284,593	1,678,914	17.0857	28,685,429	0	0	1.0000	0	3,342,721	2,456,517	71,560,824
	$740,716,704	$544,341,994		$5,178,979,867	$854,501,635	$627,960,894		$3,154,984,274	$106,250,000	$78,081,589		$78,081,589	$1,701,468,338	$1,250,384,477	$8,412,045,730

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	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
Prairie Island Unit 2															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2034	$7,760,265	$5,702,906	1.9639	$11,199,938	$4,479,535	$3,291,946	1.6124	$5,307,933	$1,250,000	$918,607	1.0000	$918,607	$13,489,800	$9,913,459	$17,426,478
2035	46,911,429	34,474,531	2.0434	70,445,256	35,601,339	26,162,909	1.6584	43,388,568	1,250,000	918,607	1.0000	918,607	83,762,768	61,556,047	114,752,431
2036	67,514,041	49,615,092	2.1262	105,491,609	86,298,834	63,419,765	1.7056	108,168,751	1,250,000	918,607	1.0000	918,607	155,062,874	113,953,464	214,578,967
2037	72,593,441	53,347,870	2.2123	118,021,492	75,650,363	55,594,358	1.7542	97,523,623	1,250,000	918,607	1.0000	918,607	149,493,804	109,860,835	216,463,722
2038	46,603,525	34,248,257	2.3019	78,836,063	42,782,150	31,439,983	1.8042	56,724,017	1,250,000	918,607	1.0000	918,607	90,635,675	66,606,847	136,478,687
2039	40,341,063	29,646,064	2.3951	71,005,287	76,484,927	56,207,667	1.8556	104,298,947	1,250,000	918,607	1.0000	918,607	118,075,990	86,772,338	176,222,841
2040	37,417,178	27,497,343	2.4921	68,526,129	14,193,500	10,430,598	1.9085	19,906,796	1,250,000	918,607	1.0000	918,607	52,860,678	38,846,548	89,351,532
2041	23,380,886	17,182,275	2.5930	44,553,639	13,070,130	9,605,049	1.9629	18,853,752	1,250,000	918,607	1.0000	918,607	37,701,016	27,705,931	64,325,998
2042	16,738,669	12,301,006	2.6981	33,189,343	17,178,640	12,624,334	2.0189	25,487,268	1,250,000	918,607	1.0000	918,607	35,167,309	25,843,947	59,595,219
2043	9,790,576	7,194,952	2.8073	20,198,390	9,051,726	6,651,983	2.0764	13,812,177	1,250,000	918,607	1.0000	918,607	20,092,302	14,765,542	34,929,174
2044	3,676,270	2,701,638	2.9210	7,891,484	1,896,910	1,394,012	2.1356	2,977,052	1,250,000	918,607	1.0000	918,607	6,823,180	5,014,256	11,787,142
2045	5,973,091	4,389,538	3.0393	13,341,123	8,808,910	6,473,541	2.1964	14,218,485	1,250,000	918,607	1.0000	918,607	16,032,001	11,781,686	28,478,215
2046	5,204,136	3,824,444	3.1624	12,094,423	6,502,044	4,778,258	2.2590	10,794,085	1,250,000	918,607	1.0000	918,607	12,956,180	9,521,309	23,807,115
2047	5,204,136	3,824,444	3.2905	12,584,334	6,502,044	4,778,258	2.3234	11,101,805	1,250,000	918,607	1.0000	918,607	12,956,180	9,521,309	24,604,746
2048	3,676,270	2,701,638	3.4238	9,249,867	1,896,910	1,394,012	2.3896	3,331,131	1,250,000	918,607	1.0000	918,607	6,823,180	5,014,256	13,499,605
2049	5,204,136	3,824,444	3.5624	13,624,200	6,502,044	4,778,258	2.4577	11,743,525	1,250,000	918,607	1.0000	918,607	12,956,180	9,521,309	26,286,332
2050	5,973,091	4,389,538	3.7067	16,270,701	8,808,910	6,473,541	2.5278	16,363,816	1,250,000	918,607	1.0000	918,607	16,032,001	11,781,686	33,553,124
2051	5,779,136	4,247,003	3.8568	16,379,843	8,227,044	6,045,936	2.5998	15,718,224	1,250,000	918,607	1.0000	918,607	15,256,180	11,211,546	33,016,674
2052	5,983,136	4,396,920	4.0130	17,644,840	8,817,508	6,479,859	2.6739	17,326,496	1,250,000	918,607	1.0000	918,607	16,050,644	11,795,386	35,889,943
2053	3,666,225	2,694,256	4.1756	11,250,134	1,888,312	1,387,693	2.7501	3,816,295	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	15,985,036
2054	3,666,225	2,694,256	4.3447	11,705,733	1,888,312	1,387,693	2.8285	3,925,090	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	16,549,430
2055	5,973,091	4,389,538	4.5206	19,843,346	8,808,910	6,473,541	2.9091	18,832,177	1,250,000	918,607	1.0000	918,607	16,032,001	11,781,686	39,594,130
2056	5,214,180	3,831,825	4.7037	18,023,758	6,510,642	4,784,577	2.9920	14,315,454	1,250,000	918,607	1.0000	918,607	12,974,822	9,535,009	33,257,818
2057	5,204,136	3,824,444	4.8942	18,717,595	6,502,044	4,778,258	3.0773	14,704,134	1,250,000	918,607	1.0000	918,607	12,956,180	9,521,309	34,340,336
2058	3,666,225	2,694,256	5.0924	13,720,228	1,888,312	1,387,693	3.1650	4,392,049	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	19,030,884
2059	5,010,180	3,681,909	5.2987	19,509,330	5,920,178	4,350,653	3.2552	14,162,246	1,250,000	918,607	1.0000	918,607	12,180,358	8,951,169	34,590,184
2060	5,214,180	3,831,825	5.5133	21,126,003	6,510,642	4,784,577	3.3480	16,018,763	1,250,000	918,607	1.0000	918,607	12,974,822	9,535,009	38,063,373
2061	5,204,136	3,824,444	5.7366	21,939,307	6,502,044	4,778,258	3.4434	16,453,454	1,250,000	918,607	1.0000	918,607	12,956,180	9,521,309	39,311,368
2062	3,666,225	2,694,256	5.9689	16,081,743	1,888,312	1,387,693	3.5415	4,914,516	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	21,914,866
2063	8,279,957	6,084,821	6.2106	37,790,387	15,729,508	11,559,388	3.6425	42,105,071	1,250,000	918,607	1.0000	918,607	25,259,465	18,562,816	80,814,065
2064	6,558,136	4,819,479	6.4622	31,144,439	10,542,508	7,747,537	3.7463	29,024,597	1,250,000	918,607	1.0000	918,607	18,350,644	13,485,623	61,087,643
2065	5,204,136	3,824,444	6.7239	25,715,181	6,502,044	4,778,258	3.8531	18,411,107	1,250,000	918,607	1.0000	918,607	12,956,180	9,521,309	45,044,894
2066	3,666,225	2,694,256	6.9962	18,849,552	1,888,312	1,387,693	3.9629	5,499,289	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	25,267,448
2067	3,666,225	2,694,256	7.2795	19,612,835	1,888,312	1,387,693	4.0758	5,655,960	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	26,187,402
2068	6,752,091	4,962,014	7.5744	37,584,279	11,124,374	8,175,142	4.1920	34,270,194	1,250,000	918,607	1.0000	918,607	19,126,465	14,055,763	72,773,080
2069	5,973,091	4,389,538	7.8811	34,594,389	8,808,910	6,473,541	4.3115	27,910,670	1,250,000	918,607	1.0000	918,607	16,032,001	11,781,686	63,423,667
2070	3,666,225	2,694,256	8.2003	22,093,705	1,888,312	1,387,693	4.4343	6,153,448	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	29,165,760
2071	3,666,225	2,694,256	8.5324	22,988,468	1,888,312	1,387,693	4.5607	6,328,853	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	30,235,927
2072	7,327,091	5,384,573	8.8780	47,804,241	12,849,374	9,442,819	4.6907	44,293,432	1,250,000	918,607	1.0000	918,607	21,426,465	15,745,999	93,016,280
2073	3,666,225	2,694,256	9.2375	24,888,187	1,888,312	1,387,693	4.8244	6,694,787	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	32,501,581
2074	3,666,225	2,694,256	9.6117	25,896,378	1,888,312	1,387,693	4.9619	6,885,595	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	33,700,580
2075	7,842,824	5,763,578	10.0009	57,640,967	14,418,110	10,595,661	5.1033	54,072,835	1,250,000	918,607	1.0000	918,607	23,510,934	17,277,845	112,632,408
2076	3,676,270	2,701,638	10.4060	28,113,241	1,896,910	1,394,012	5.2487	7,316,750	1,250,000	918,607	1.0000	918,607	6,823,180	5,014,256	36,348,598
2077	3,666,225	2,694,256	10.8274	29,171,785	1,888,312	1,387,693	5.3983	7,491,184	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	37,581,576
2078	7,511,002	5,519,727	11.2659	62,184,690	13,422,642	9,864,106	5.5522	54,767,487	1,250,000	918,607	1.0000	918,607	22,183,644	16,302,439	117,870,783
2079	3,666,225	2,694,256	11.7222	31,582,605	1,888,312	1,387,693	5.7104	7,924,283	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	40,425,495
2080	3,676,270	2,701,638	12.1970	32,951,875	1,896,910	1,394,012	5.8731	8,187,171	1,250,000	918,607	1.0000	918,607	6,823,180	5,014,256	42,057,653
2081	3,666,225	2,694,256	12.6909	34,192,530	1,888,312	1,387,693	6.0405	8,382,361	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	43,493,498
2082	7,123,091	5,234,657	13.2049	69,123,117	12,258,910	9,008,896	6.2127	55,969,566	1,250,000	918,607	1.0000	918,607	20,632,001	15,162,159	126,011,290
2083	3,666,225	2,694,256	13.7397	37,018,266	1,888,312	1,387,693	6.3897	8,866,943	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	46,803,816
2084	3,676,270	2,701,638	14.2962	38,623,152	1,896,910	1,394,012	6.5719	9,161,307	1,250,000	918,607	1.0000	918,607	6,823,180	5,014,256	48,703,066
2085	3,666,225	2,694,256	14.8752	40,077,593	1,888,312	1,387,693	6.7592	9,379,696	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	50,375,896
2086	3,666,225	2,694,256	15.4776	41,700,613	1,888,312	1,387,693	6.9518	9,646,966	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	52,266,185
2087	3,666,225	2,694,256	16.1045	43,389,641	1,888,312	1,387,693	7.1499	9,921,868	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	54,230,116
2088	3,676,270	2,701,638	16.7567	45,270,532	1,896,910	1,394,012	7.3537	10,251,145	1,250,000	918,607	1.0000	918,607	6,823,180	5,014,256	56,440,284

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	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
2089	26,815,724	19,706,488	17.4353	343,588,526	71,336,809	52,424,389	7.5633	396,501,384	1,250,000	918,607	1.0000	918,607	99,402,533	73,049,484	741,008,517
2090	3,666,225	2,694,256	18.1415	48,877,840	3,822,743	2,809,279	7.7788	21,852,819	1,250,000	918,607	1.0000	918,607	8,738,968	6,422,142	71,649,266
2091	3,666,225	2,694,256	18.8762	50,857,310	1,888,312	1,387,693	8.0005	11,102,240	1,250,000	918,607	1.0000	918,607	6,804,537	5,000,556	62,878,157
2092	3,676,270	2,701,638	19.6407	53,062,055	1,896,910	1,394,012	8.2285	11,470,627	1,250,000	918,607	1.0000	918,607	6,823,180	5,014,256	65,451,288
2093	3,050,095	2,241,471	20.4361	45,806,920	1,970,568	1,448,142	8.4630	12,255,624	1,250,000	918,607	1.0000	918,607	6,270,663	4,608,219	58,981,150
2094	3,145,781	2,311,789	21.2638	49,157,418	2,257,624	1,659,095	8.7042	14,441,095	1,250,000	918,607	1.0000	918,607	6,653,405	4,889,491	64,517,121
2095	5,452,647	4,007,071	22.1250	88,656,455	9,178,222	6,744,942	8.9523	60,382,748	1,250,000	918,607	1.0000	918,607	15,880,869	11,670,621	149,957,811
2096	4,739,629	3,483,085	23.0210	80,184,095	7,022,923	5,161,044	9.2075	47,520,316	1,250,000	918,607	1.0000	918,607	13,012,552	9,562,736	128,623,019
2097	4,635,849	3,406,818	23.9534	81,604,884	6,727,827	4,944,183	9.4699	46,820,915	1,250,000	918,607	1.0000	918,607	12,613,676	9,269,608	129,344,406
2098	3,241,467	2,382,107	24.9235	59,370,449	2,544,683	1,870,051	9.7398	18,213,919	1,250,000	918,607	1.0000	918,607	7,036,150	5,170,765	78,502,975
2099	3,097,938	2,276,630	25.9329	59,039,614	2,114,095	1,553,618	10.0173	15,563,055	1,250,000	918,607	1.0000	918,607	6,462,033	4,748,854	75,521,275
2100	5,356,961	3,936,753	26.9832	106,226,198	8,891,163	6,533,987	10.3028	67,318,361	1,250,000	918,607	1.0000	918,607	15,498,124	11,389,347	174,463,166
2101	5,452,647	4,007,071	28.0760	112,502,537	9,178,222	6,744,942	10.5965	71,472,783	1,250,000	918,607	1.0000	918,607	15,880,869	11,670,621	184,893,927
2102	5,452,647	4,007,071	29.2131	117,058,978	9,178,222	6,744,942	10.8985	73,509,756	1,250,000	918,607	1.0000	918,607	15,880,869	11,670,621	191,487,341
2103	3,097,938	2,276,630	30.3962	69,200,896	2,114,095	1,553,618	11.2091	17,414,656	1,250,000	918,607	1.0000	918,607	6,462,033	4,748,854	87,534,159
2104	3,153,875	2,317,737	31.6272	73,303,536	2,265,661	1,665,001	11.5285	19,194,968	1,250,000	918,607	1.0000	918,607	6,669,536	4,901,345	93,417,111
2105	5,452,647	4,007,071	32.9081	131,865,107	9,178,222	6,744,942	11.8571	79,975,457	1,250,000	918,607	1.0000	918,607	15,880,869	11,670,621	212,759,172
2106	4,635,849	3,406,818	34.2409	116,652,528	6,727,827	4,944,183	12.1950	60,294,307	1,250,000	918,607	1.0000	918,607	12,613,676	9,269,608	177,865,442
2107	4,683,692	3,441,978	35.6277	122,629,742	6,871,356	5,049,660	12.5426	63,335,866	1,250,000	918,607	1.0000	918,607	12,805,048	9,410,244	186,884,215
2108	3,153,875	2,317,737	37.0706	85,919,906	2,265,661	1,665,001	12.9000	21,478,518	1,250,000	918,607	1.0000	918,607	6,669,536	4,901,345	108,317,031
2109	4,635,849	3,406,818	38.5720	131,407,799	6,727,827	4,944,183	13.2677	65,597,932	1,250,000	918,607	1.0000	918,607	12,613,676	9,269,608	197,924,338
2110	4,676,515	3,436,703	40.1341	137,928,992	6,849,827	5,033,839	13.6458	68,690,756	1,250,000	918,607	1.0000	918,607	12,776,342	9,389,149	207,538,354
2111	4,669,339	3,431,430	41.7596	143,295,132	6,828,297	5,018,017	14.0347	70,426,357	1,250,000	918,607	1.0000	918,607	12,747,636	9,368,053	214,640,096
2112	3,139,522	2,307,189	43.4508	100,249,222	2,222,602	1,633,358	14.4347	23,577,032	1,250,000	918,607	1.0000	918,607	6,612,124	4,859,154	124,744,860
2113	7,745,160	5,691,806	45.2106	257,329,968	16,055,761	11,799,146	14.8461	175,171,308	1,250,000	918,607	1.0000	918,607	25,050,921	18,409,559	433,419,883
2114	6,207,249	4,561,618	47.0416	214,585,787	11,442,029	8,408,581	15.2692	128,392,313	1,250,000	918,607	1.0000	918,607	18,899,278	13,888,806	343,896,707
2115	5,001,161	3,675,281	48.9468	179,893,239	7,823,765	5,749,572	15.7044	90,293,572	1,250,000	918,607	1.0000	918,607	14,074,926	10,343,459	271,105,418
2116	3,139,522	2,307,189	50.9291	117,503,075	13,878,680	10,199,241	16.1520	164,738,142	1,250,000	918,607	1.0000	918,607	18,268,202	13,425,037	283,159,824
2117	3,127,840	2,298,604	52.9918	121,807,184	2,203,801	1,619,541	16.6123	26,904,307	1,250,000	918,607	1.0000	918,607	6,581,641	4,836,753	149,630,097
2118	1,058,128	777,603	55.1379	42,875,395	2,284,593	1,678,914	17.0857	28,685,429	0	-	1.0000	-	3,342,721	2,456,517	71,560,824
	$736,174,967	$541,004,338		$5,194,908,576	$862,601,579	$633,913,426		$3,175,749,753	$105,000,000	$77,162,982		$77,162,982	$1,703,776,546	$1,252,080,745	$8,447,821,310
	$2,785,920,120	$2,047,332,409		$24,198,794,924	$2,827,210,344	$2,077,675,998		$10,798,895,750	$211,250,000	$155,244,570		$155,244,570	$5,824,380,465	$4,280,252,977	$35,152,935,244

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Monticello

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	623,672,182	15,769,559	-	6,696,113	646,137,854
2018	646,137,854	32,837,549	-	13,392,226	692,367,629
2019	692,367,629	35,162,906	-	13,392,226	740,922,761
2020	740,922,761	37,605,229	-	13,392,226	791,920,216
2021	791,920,216	41,304,928	-	58,502,632	891,727,776
2022	891,727,776	46,325,248	-	58,502,632	996,555,657
2023	996,555,657	51,598,091	-	58,502,632	1,106,656,380
2024	1,106,656,380	57,136,157	-	58,502,632	1,222,295,169
2025	1,222,295,169	62,952,788	-	58,502,632	1,343,750,589
2026	1,343,750,589	69,061,996	-	58,502,632	1,471,315,217
2027	1,471,315,217	75,478,497	-	58,502,632	1,605,296,346
2028	1,605,296,346	82,217,747	-	58,502,632	1,746,016,726
2029	1,746,016,726	89,295,982	-	58,502,632	1,893,815,340
2030	1,893,815,340	91,764,608	(35,447,395)	43,876,974	1,994,009,528
2031	1,994,009,528	95,513,056	(139,568,856)	-	1,949,953,728
2032	1,949,953,728	93,402,784	(235,103,207)	-	1,808,253,305
2033	1,808,253,305	86,615,333	(224,495,047)	-	1,670,373,591
2034	1,670,373,591	80,010,895	(141,890,436)	-	1,608,494,050
2035	1,608,494,050	77,046,865	(268,360,596)	-	1,417,180,319
2036	1,417,180,319	67,882,937	(104,537,352)	-	1,380,525,905
2037	1,380,525,905	66,127,191	(74,807,128)	-	1,371,845,968
2038	1,371,845,968	65,711,422	(70,470,367)	-	1,367,087,023
2039	1,367,087,023	65,483,468	(15,508,490)	-	1,417,062,002
2040	1,417,062,002	67,877,270	(16,145,665)	-	1,468,793,607
2041	1,468,793,607	70,355,214	(16,718,034)	-	1,522,430,787
2042	1,522,430,787	72,924,435	(17,358,857)	-	1,577,996,364
2043	1,577,996,364	75,586,026	(18,023,610)	-	1,635,558,779
2044	1,635,558,779	78,343,266	(18,765,674)	-	1,695,136,371
2045	1,695,136,371	81,197,032	(19,432,530)	-	1,756,900,873
2046	1,756,900,873	84,155,552	(20,178,433)	-	1,820,877,992
2047	1,820,877,992	87,220,056	(20,953,473)	-	1,887,144,575
2048	1,887,144,575	90,394,225	(26,984,005)	-	1,950,554,795
2049	1,950,554,795	93,431,575	(22,594,805)	-	2,021,391,565
2050	2,021,391,565	96,824,656	(35,853,028)	-	2,082,363,193
2051	2,082,363,193	99,745,197	(37,157,503)	-	2,144,950,887
2052	2,144,950,887	102,743,147	(38,579,910)	-	2,209,114,125
2053	2,209,114,125	105,816,567	(39,915,373)	-	2,275,015,318
2054	2,275,015,318	108,973,234	(41,371,799)	-	2,342,616,752
2055	2,342,616,752	112,211,342	(42,882,168)	-	2,411,945,926
2056	2,411,945,926	115,532,210	(44,529,708)	-	2,482,948,428

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External Levelized	2057	2,482,948,428	118,933,230	(46,075,584)	-	2,555,806,073
	2058	2,555,806,073	122,423,111	(113,115,965)	-	2,565,113,219
	2059	2,565,113,219	122,868,923	(49,512,681)	-	2,638,469,461
	2060	2,638,469,461	126,382,687	(51,421,830)	-	2,713,430,318
	2061	2,713,430,318	129,973,312	(53,212,278)	-	2,790,191,353
	2062	2,790,191,353	133,650,166	(55,166,430)	-	2,868,675,088
	2063	2,868,675,088	137,409,537	(57,194,466)	-	2,948,890,159
	2064	2,948,890,159	141,251,839	(59,407,738)	-	3,030,734,259
	2065	3,030,734,259	145,172,171	(61,482,516)	-	3,114,423,914
	2066	3,114,423,914	149,180,905	(114,512,212)	-	3,149,092,607
	2067	3,149,092,607	150,841,536	(66,098,430)	-	3,233,835,713
	2068	3,233,835,713	154,900,731	(195,052,653)	-	3,193,683,791
	2069	3,193,683,791	152,977,454	(71,070,115)	-	3,275,591,130
	2070	3,275,591,130	156,900,815	(73,697,053)	-	3,358,794,892
	2071	3,358,794,892	160,886,275	(76,423,540)	-	3,443,257,628
	2072	3,443,257,628	164,932,040	(79,400,766)	-	3,528,788,902
	2073	3,528,788,902	169,028,988	(82,189,645)	-	3,615,628,246
	2074	3,615,628,246	173,188,593	(85,237,868)	-	3,703,578,971
	2075	3,703,578,971	177,401,433	(88,400,458)	-	3,792,579,945
	2076	3,792,579,945	181,664,579	(91,855,321)	-	3,882,389,203
	2077	3,882,389,203	185,966,443	(95,090,888)	-	3,973,264,758
	2078	3,973,264,758	190,319,382	(98,627,820)	-	4,064,956,320
	2079	4,064,956,320	194,711,408	(102,298,874)	-	4,157,368,854
	2080	4,157,368,854	199,137,968	(106,309,556)	-	4,250,197,266
	2081	4,250,197,266	203,584,449	(110,064,413)	-	4,343,717,302
	2082	4,343,717,302	208,064,059	(114,170,534)	-	4,437,610,827
	2083	4,437,610,827	212,561,559	(118,432,292)	-	4,531,740,094
	2084	4,531,740,094	217,070,351	(123,090,567)	-	4,625,719,878
	2085	4,625,719,878	221,571,982	(127,450,327)	-	4,719,841,533
	2086	4,719,841,533	226,080,409	(132,217,906)	-	4,813,704,036
	2087	4,813,704,036	230,576,423	(137,168,061)	-	4,907,112,398
	2088	4,907,112,398	235,050,684	(161,510,305)	-	4,980,652,777
	2089	4,980,652,777	238,573,268	(147,641,765)	-	5,071,584,280
	2090	5,071,584,280	242,928,887	(153,180,919)	-	5,161,332,248
	2091	5,161,332,248	247,227,815	(158,931,496)	-	5,249,628,567
	2092	5,249,628,567	251,457,208	(193,314,969)	-	5,307,770,806
	2093	5,307,770,806	254,242,222	(221,931,179)	-	5,340,081,849
	2094	5,340,081,849	255,789,921	(185,045,343)	-	5,410,826,427
	2095	5,410,826,427	259,178,586	(1,058,535,380)	-	4,611,469,633
	2096	4,611,469,633	220,889,395	(255,730,524)	-	4,576,628,504
	2097	4,576,628,504	219,220,505	(140,268,948)	-	4,655,580,062
	2098	4,655,580,062	223,002,285	(145,776,468)	-	4,732,805,879
	2099	4,732,805,879	226,701,402	(151,502,020)	-	4,808,005,261
	2100	4,808,005,261	230,303,452	(157,454,618)	-	4,880,854,095
	2101	4,880,854,095	233,792,911	(163,642,973)	-	4,951,004,033
	2102	4,951,004,033	237,153,093	(170,076,691)	-	5,018,080,435

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2103	5,018,080,435	240,366,053	(176,765,162)	-	5,081,681,326
2104	5,081,681,326	243,412,535	(184,222,021)	-	5,140,871,840
2105	5,140,871,840	246,247,761	(190,948,331)	-	5,196,171,270
2106	5,196,171,270	248,896,604	(198,464,804)	-	5,246,603,070
2107	5,246,603,070	251,312,287	(206,279,730)	-	5,291,635,628
2108	5,291,635,628	253,469,347	(554,455,003)	-	4,990,649,971
2109	4,990,649,971	239,052,134	(222,851,861)	-	5,006,850,244
2110	5,006,850,244	239,828,127	(231,634,144)	-	5,015,044,227
2111	5,015,044,227	240,220,618	(240,765,936)	-	5,014,498,909
2112	5,014,498,909	240,194,498	(250,945,436)	-	5,003,747,971
2113	5,003,747,971	239,679,528	(360,493,113)	-	4,882,934,386
2114	4,882,934,386	233,892,557	(270,394,786)	-	4,846,432,156
2115	4,846,432,156	232,144,100	(281,066,441)	-	4,797,509,816
2116	4,797,509,816	229,800,720	(560,118,279)	-	4,467,192,257
2117	4,467,192,257	213,978,509	(303,699,284)	-	4,377,471,482
2118	4,377,471,482	209,680,884	(970,793,029)	-	3,616,359,336
2119	3,616,359,336	173,223,612	(322,957,700)	-	3,466,625,248
2120	3,466,625,248	166,051,349	(328,219,064)	-	3,304,457,533
2121	3,304,457,533	158,283,516	(340,125,566)	-	3,122,615,484
2122	3,122,615,484	149,573,282	(353,317,367)	-	2,918,871,398
2123	2,918,871,398	139,813,940	(375,903,562)	-	2,682,781,777
2124	2,682,781,777	128,505,247	(382,193,765)	-	2,429,093,258
2125	2,429,093,258	116,353,567	(396,081,860)	-	2,149,364,966
2126	2,149,364,966	102,954,582	(411,470,691)	-	1,840,848,856
2127	1,840,848,856	88,176,660	(437,648,062)	-	1,491,377,454
2128	1,491,377,454	71,436,980	(518,265,240)	-	1,044,549,194
2129	1,044,549,194	50,033,906	(461,361,733)	-	633,221,367
2130	633,221,367	30,331,303	(445,437,243)	-	218,115,428
2131	218,115,428	10,447,729	(228,563,157)	-	(0)

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EXTERNAL FUND CALCULATION

Prairie Island Unit 1

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	374,367,055	9,415,641	-	24,632	383,807,328
2018	383,807,328	19,306,748	-	49,264	403,163,340
2019	403,163,340	20,280,355	-	49,264	423,492,960
2020	423,492,960	21,302,935	-	49,264	444,845,159
2021	444,845,159	23,381,453	-	39,989,727	508,216,339
2022	508,216,339	26,569,023	-	39,989,727	574,775,089
2023	574,775,089	29,916,929	-	39,989,727	644,681,745
2024	644,681,745	33,433,233	-	39,989,727	718,104,705
2025	718,104,705	37,126,408	-	39,989,727	795,220,841
2026	795,220,841	41,005,350	-	39,989,727	876,215,918
2027	876,215,918	45,079,402	-	39,989,727	961,285,047
2028	961,285,047	49,358,379	-	39,989,727	1,050,633,153
2029	1,050,633,153	53,852,589	-	39,989,727	1,144,475,470
2030	1,144,475,470	58,572,858	-	39,989,727	1,243,038,054
2031	1,243,038,054	63,530,556	-	39,989,727	1,346,558,337
2032	1,346,558,337	68,737,626	-	39,989,727	1,455,285,690
2033	1,455,285,690	69,174,934	(42,768,206)	26,793,117	1,508,485,535
2034	1,508,485,535	71,049,669	(131,752,423)	-	1,447,782,781
2035	1,447,782,781	68,190,569	(198,854,122)	-	1,317,119,228
2036	1,317,119,228	62,036,316	(173,386,483)	-	1,205,769,061
2037	1,205,769,061	56,791,723	(119,758,858)	-	1,142,801,927
2038	1,142,801,927	53,825,971	(48,446,231)	-	1,148,181,666
2039	1,148,181,666	54,079,356	(166,746,607)	-	1,035,514,416
2040	1,035,514,416	48,772,729	(78,122,006)	-	1,006,165,138
2041	1,006,165,138	47,390,378	(51,940,213)	-	1,001,615,304
2042	1,001,615,304	47,176,081	(47,702,666)	-	1,001,088,718
2043	1,001,088,718	47,151,279	(29,178,024)	-	1,019,061,973
2044	1,019,061,973	47,997,819	(11,787,142)	-	1,055,272,649
2045	1,055,272,649	49,703,342	(28,478,215)	-	1,076,497,776
2046	1,076,497,776	50,703,045	(23,807,115)	-	1,103,393,707
2047	1,103,393,707	51,969,844	(24,604,746)	-	1,130,758,804
2048	1,130,758,804	53,258,740	(13,499,605)	-	1,170,517,939
2049	1,170,517,939	55,131,395	(26,286,332)	-	1,199,363,002
2050	1,199,363,002	56,489,997	(33,553,124)	-	1,222,299,875
2051	1,222,299,875	57,570,324	(33,016,674)	-	1,246,853,526
2052	1,246,853,526	58,726,801	(35,889,943)	-	1,269,690,384
2053	1,269,690,384	59,802,417	(15,985,036)	-	1,313,507,765
2054	1,313,507,765	61,866,216	(16,549,430)	-	1,358,824,550
2055	1,358,824,550	64,000,636	(39,594,130)	-	1,383,231,056
2056	1,383,231,056	65,150,183	(33,257,818)	-	1,415,123,421

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External Levelized	2057	1,415,123,421	66,652,313	(34,340,336)	-	1,447,435,398
	2058	1,447,435,398	68,174,207	(19,030,884)	-	1,496,578,721
	2059	1,496,578,721	70,488,858	(34,590,184)	-	1,532,477,395
	2060	1,532,477,395	72,179,685	(38,063,373)	-	1,566,593,707
	2061	1,566,593,707	73,786,564	(39,311,368)	-	1,601,068,903
	2062	1,601,068,903	75,410,345	(21,914,866)	-	1,654,564,383
	2063	1,654,564,383	77,929,982	(80,814,065)	-	1,651,680,300
	2064	1,651,680,300	77,794,142	(61,087,643)	-	1,668,386,799
	2065	1,668,386,799	78,581,018	(45,044,894)	-	1,701,922,923
	2066	1,701,922,923	80,160,570	(25,267,448)	-	1,756,816,044
	2067	1,756,816,044	82,746,036	(26,187,402)	-	1,813,374,678
	2068	1,813,374,678	85,409,947	(72,773,080)	-	1,826,011,545
	2069	1,826,011,545	86,005,144	(63,423,667)	-	1,848,593,022
	2070	1,848,593,022	87,068,731	(29,165,760)	-	1,906,495,993
	2071	1,906,495,993	89,795,961	(30,235,927)	-	1,966,056,028
	2072	1,966,056,028	92,601,239	(93,016,280)	-	1,965,640,986
	2073	1,965,640,986	92,581,690	(32,501,581)	-	2,025,721,095
	2074	2,025,721,095	95,411,464	(33,700,580)	-	2,087,431,979
	2075	2,087,431,979	98,318,046	(112,632,408)	-	2,073,117,617
	2076	2,073,117,617	97,643,840	(36,348,598)	-	2,134,412,858
	2077	2,134,412,858	100,530,846	(37,581,576)	-	2,197,362,128
	2078	2,197,362,128	103,495,756	(117,870,783)	-	2,182,987,101
	2079	2,182,987,101	102,818,692	(40,425,495)	-	2,245,380,298
	2080	2,245,380,298	105,757,412	(42,057,653)	-	2,309,080,058
	2081	2,309,080,058	108,757,671	(43,493,498)	-	2,374,344,231
	2082	2,374,344,231	111,831,613	(126,011,290)	-	2,360,164,554
	2083	2,360,164,554	111,163,750	(46,803,816)	-	2,424,524,489
	2084	2,424,524,489	114,195,103	(48,703,066)	-	2,490,016,526
	2085	2,490,016,526	117,279,778	(50,375,896)	-	2,556,920,409
	2086	2,556,920,409	120,430,951	(52,266,185)	-	2,625,085,175
	2087	2,625,085,175	123,641,512	(54,230,116)	-	2,694,496,570
	2088	2,694,496,570	126,910,788	(56,440,284)	-	2,764,967,075
	2089	2,764,967,075	130,229,949	(751,760,396)	-	2,143,436,628
	2090	2,143,436,628	100,955,865	(60,591,035)	-	2,183,801,458
	2091	2,183,801,458	102,857,049	(62,878,157)	-	2,223,780,350
	2092	2,223,780,350	104,740,054	(65,451,288)	-	2,263,069,116
	2093	2,263,069,116	106,590,555	(58,981,132)	-	2,310,678,540
	2094	2,310,678,540	108,832,959	(64,517,121)	-	2,354,994,378
	2095	2,354,994,378	110,920,235	(149,957,811)	-	2,315,956,803
	2096	2,315,956,803	109,081,565	(128,623,019)	-	2,296,415,349
	2097	2,296,415,349	108,161,163	(129,344,406)	-	2,275,232,107
	2098	2,275,232,107	107,163,432	(78,502,975)	-	2,303,892,564
	2099	2,303,892,564	108,513,340	(75,521,275)	-	2,336,884,628
	2100	2,336,884,628	110,067,266	(174,463,166)	-	2,272,488,728
	2101	2,272,488,728	107,034,219	(184,893,927)	-	2,194,629,020
	2102	2,194,629,020	103,367,027	(191,487,341)	-	2,106,508,706

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2103	2,106,508,706	99,216,560	(87,534,159)	-	2,118,191,107
2104	2,118,191,107	99,766,801	(93,417,111)	-	2,124,540,798
2105	2,124,540,798	100,065,872	(212,759,172)	-	2,011,847,497
2106	2,011,847,497	94,758,017	(177,865,442)	-	1,928,740,073
2107	1,928,740,073	90,843,657	(186,884,215)	-	1,832,699,515
2108	1,832,699,515	86,320,147	(108,317,031)	-	1,810,702,632
2109	1,810,702,632	85,284,094	(197,924,338)	-	1,698,062,388
2110	1,698,062,388	79,978,738	(207,538,354)	-	1,570,502,772
2111	1,570,502,772	73,970,681	(214,640,096)	-	1,429,833,357
2112	1,429,833,357	67,345,151	(124,744,860)	-	1,372,433,648
2113	1,372,433,648	64,641,625	(433,419,883)	-	1,003,655,390
2114	1,003,655,390	47,272,169	(343,896,707)	-	707,030,852
2115	707,030,852	33,301,153	(271,105,418)	-	469,226,587
2116	469,226,587	22,100,572	(283,159,824)	-	208,167,335
2117	208,167,335	9,804,681	(149,630,097)	-	68,341,919
2118	68,341,919	3,218,904	(71,560,824)	-	0

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EXTERNAL FUND CALCULATION

Prairie Island Unit 2

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	420,208,967	10,656,032	-	294,670	431,159,670
2018	431,159,670	21,874,735	-	589,341	453,623,746
2019	453,623,746	23,013,664	-	589,341	477,226,750
2020	477,226,750	24,210,336	-	589,341	502,026,427
2021	502,026,427	26,244,904	-	31,249,066	559,520,397
2022	559,520,397	29,159,848	-	31,249,066	619,929,312
2023	619,929,312	32,222,580	-	31,249,066	683,400,958
2024	683,400,958	35,440,592	-	31,249,066	750,090,617
2025	750,090,617	38,821,758	-	31,249,066	820,161,441
2026	820,161,441	42,374,349	-	31,249,066	893,784,856
2027	893,784,856	46,107,056	-	31,249,066	971,140,979
2028	971,140,979	50,029,011	-	31,249,066	1,052,419,057
2029	1,052,419,057	54,149,810	-	31,249,066	1,137,817,933
2030	1,137,817,933	58,479,533	-	31,249,066	1,227,546,532
2031	1,227,546,532	63,028,773	-	31,249,066	1,321,824,372
2032	1,321,824,372	67,808,659	-	31,249,066	1,420,882,098
2033	1,420,882,098	72,830,886	-	31,249,066	1,524,962,050
2034	1,524,962,050	72,128,936	(17,426,478)	25,936,725	1,605,601,234
2035	1,605,601,234	75,302,698	(114,752,431)	-	1,566,151,500
2036	1,566,151,500	73,452,505	(214,578,967)	-	1,425,025,039
2037	1,425,025,039	66,833,674	(216,463,722)	-	1,275,394,992
2038	1,275,394,992	59,816,025	(136,478,687)	-	1,198,732,330
2039	1,198,732,330	56,220,546	(176,222,841)	-	1,078,730,035
2040	1,078,730,035	50,592,439	(89,351,532)	-	1,039,970,942
2041	1,039,970,942	48,774,637	(64,325,998)	-	1,024,419,581
2042	1,024,419,581	48,045,278	(59,595,219)	-	1,012,869,641
2043	1,012,869,641	47,503,586	(34,929,174)	-	1,025,444,053
2044	1,025,444,053	48,093,326	(11,787,142)	-	1,061,750,237
2045	1,061,750,237	49,796,086	(28,478,215)	-	1,083,068,108
2046	1,083,068,108	50,795,894	(23,807,115)	-	1,110,056,888
2047	1,110,056,888	52,061,668	(24,604,746)	-	1,137,513,810
2048	1,137,513,810	53,349,398	(13,499,605)	-	1,177,363,603
2049	1,177,363,603	55,218,353	(26,286,332)	-	1,206,295,623
2050	1,206,295,623	56,575,265	(33,553,124)	-	1,229,317,764
2051	1,229,317,764	57,655,003	(33,016,674)	-	1,253,956,094
2052	1,253,956,094	58,810,541	(35,889,943)	-	1,276,876,691
2053	1,276,876,691	59,885,517	(15,985,036)	-	1,320,777,172
2054	1,320,777,172	61,944,449	(16,549,430)	-	1,366,172,191
2055	1,366,172,191	64,073,476	(39,594,130)	-	1,390,651,536
2056	1,390,651,536	65,221,557	(33,257,818)	-	1,422,615,275

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External Levelized	2057	1,422,615,275	66,720,656	(34,340,336)	-	1,454,995,596
	2058	1,454,995,596	68,239,293	(19,030,884)	-	1,504,204,005
	2059	1,504,204,005	70,547,168	(34,590,184)	-	1,540,160,989
	2060	1,540,160,989	72,233,550	(38,063,373)	-	1,574,331,166
	2061	1,574,331,166	73,836,132	(39,311,368)	-	1,608,855,930
	2062	1,608,855,930	75,455,343	(21,914,866)	-	1,662,396,408
	2063	1,662,396,408	77,966,392	(80,814,065)	-	1,659,548,734
	2064	1,659,548,734	77,832,836	(61,087,643)	-	1,676,293,927
	2065	1,676,293,927	78,618,185	(45,044,894)	-	1,709,867,217
	2066	1,709,867,217	80,192,772	(25,267,448)	-	1,764,792,541
	2067	1,764,792,541	82,768,770	(26,187,402)	-	1,821,373,910
	2068	1,821,373,910	85,422,436	(72,773,080)	-	1,834,023,266
	2069	1,834,023,266	86,015,691	(63,423,667)	-	1,856,615,291
	2070	1,856,615,291	87,075,257	(29,165,760)	-	1,914,524,787
	2071	1,914,524,787	89,791,213	(30,235,927)	-	1,974,080,073
	2072	1,974,080,073	92,584,355	(93,016,280)	-	1,973,648,148
	2073	1,973,648,148	92,564,098	(32,501,581)	-	2,033,710,665
	2074	2,033,710,665	95,381,030	(33,700,580)	-	2,095,391,115
	2075	2,095,391,115	98,273,843	(112,632,408)	-	2,081,032,550
	2076	2,081,032,550	97,600,427	(36,348,598)	-	2,142,284,378
	2077	2,142,284,378	100,473,137	(37,581,576)	-	2,205,175,940
	2078	2,205,175,940	103,422,752	(117,870,783)	-	2,190,727,908
	2079	2,190,727,908	102,745,139	(40,425,495)	-	2,253,047,552
	2080	2,253,047,552	105,667,930	(42,057,653)	-	2,316,657,830
	2081	2,316,657,830	108,651,252	(43,493,498)	-	2,381,815,584
	2082	2,381,815,584	111,707,151	(126,011,290)	-	2,367,511,445
	2083	2,367,511,445	111,036,287	(46,803,816)	-	2,431,743,916
	2084	2,431,743,916	114,048,790	(48,703,066)	-	2,497,089,640
	2085	2,497,089,640	117,113,504	(50,375,896)	-	2,563,827,248
	2086	2,563,827,248	120,243,498	(52,266,185)	-	2,631,804,561
	2087	2,631,804,561	123,431,634	(54,230,116)	-	2,701,006,078
	2088	2,701,006,078	126,677,185	(56,440,284)	-	2,771,242,980
	2089	2,771,242,980	129,971,296	(741,008,517)	-	2,160,205,758
	2090	2,160,205,758	101,313,650	(71,649,266)	-	2,189,870,142
	2091	2,189,870,142	102,704,910	(62,878,157)	-	2,229,696,895
	2092	2,229,696,895	104,572,784	(65,451,288)	-	2,268,818,391
	2093	2,268,818,391	106,407,583	(58,981,150)	-	2,316,244,823
	2094	2,316,244,823	108,631,882	(64,517,121)	-	2,360,359,585
	2095	2,360,359,585	110,700,865	(149,957,811)	-	2,321,102,639
	2096	2,321,102,639	108,859,714	(128,623,019)	-	2,301,339,333
	2097	2,301,339,333	107,932,815	(129,344,406)	-	2,279,927,743
	2098	2,279,927,743	106,928,611	(78,502,975)	-	2,308,353,379
	2099	2,308,353,379	108,261,773	(75,521,275)	-	2,341,093,877
	2100	2,341,093,877	109,797,303	(174,463,166)	-	2,276,428,014
	2101	2,276,428,014	106,764,474	(184,893,927)	-	2,198,298,560
	2102	2,198,298,560	103,100,202	(191,487,341)	-	2,109,911,422

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2103	2,109,911,422	98,954,846	(87,534,159)	-	2,121,332,109
2104	2,121,332,109	99,490,476	(93,417,111)	-	2,127,405,474
2105	2,127,405,474	99,775,317	(212,759,172)	-	2,014,421,619
2106	2,014,421,619	94,476,374	(177,865,442)	-	1,931,032,551
2107	1,931,032,551	90,565,427	(186,884,215)	-	1,834,713,763
2108	1,834,713,763	86,048,075	(108,317,031)	-	1,812,444,808
2109	1,812,444,808	85,003,661	(197,924,338)	-	1,699,524,131
2110	1,699,524,131	79,707,682	(207,538,354)	-	1,571,693,459
2111	1,571,693,459	73,712,423	(214,640,096)	-	1,430,765,786
2112	1,430,765,786	67,102,915	(124,744,860)	-	1,373,123,841
2113	1,373,123,841	64,399,508	(433,419,883)	-	1,004,103,467
2114	1,004,103,467	47,092,453	(343,896,707)	-	707,299,213
2115	707,299,213	33,172,333	(271,105,418)	-	469,366,127
2116	469,366,127	22,013,271	(283,159,824)	-	208,219,574
2117	208,219,574	9,765,498	(149,630,097)	-	68,354,975
2118	68,354,975	3,205,848	(71,560,824)	-	0

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2021 ACCRUAL COMPARISON

	Present	Proposed	Difference
Monticello	$13,392,226	$83,850,493	$70,458,267
Prairie Island Unit 1	49,264	52,464,065	52,414,800
Prairie Island Unit 2	589,341	43,013,201	42,423,861
TOTAL	$14,030,831	$179,327,759	$165,296,928

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2021 MN RETAIL SUMMARY

	Remaining Life (yrs)	Operational Earnings Rate	Post-Shutdown Earnings Rate	Market Value Balance 6/30/2017	Book Value 6/30/2017	Unrealized Gain/Loss 6/30/2017	Tax-Effect Adjustment	Tax-Adjusted Fund Balance 6/30/2017	2021 Decommissioning Accrual
Monticello	13.75	5.04%	4.97%	$660,140,345	$529,148,381	$130,991,964	$36,468,163	$623,672,182	**83,850,493**
Prairie Island Unit 1	16.67	5.04%	4.94%	399,941,696	308,078,761	91,862,935	25,574,641	374,367,055	**52,464,065**
Prairie Island Unit 2	17.83	5.08%	4.93%	448,597,551	346,627,064	101,970,487	28,388,583	420,208,967	**43,013,201**
TOTAL DECOMMISSIONING ACCRUAL				**$1,508,679,592**	**$1,183,854,206**	**$324,825,386**	**$90,431,387**	**$1,418,248,204**	**$179,327,759**

INPUT DATA

Escalation Rate (Labor)	4.05%
Escalation Rate (Non-Labor)	2.85%
Escalation Rate (PIIC)	0.00%
Jurisdictional Factor	73.4886%
Tax Rate for tax-effect adjustment	27.84%

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AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
Monticello															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2030	$21,103,620	$15,508,745	1.6755	$25,984,903	$8,935,561	$6,566,615	1.4410	$9,462,492	$0	$0	1.0000	$0	$30,039,182	$22,075,360	$35,447,395
2031	72,416,235	53,217,644	1.7434	92,779,641	42,961,344	31,571,670	1.4820	46,789,215	0	0	1.0000	0	115,377,579	84,789,314	139,568,856
2032	81,871,155	60,165,928	1.8140	109,140,994	112,447,584	82,636,104	1.5243	125,962,213	0	0	1.0000	0	194,318,740	142,802,032	235,103,206
2033	78,663,227	57,808,468	1.8874	109,107,702	100,155,663	73,602,948	1.5677	115,387,342	0	0	1.0000	0	178,818,889	131,411,416	224,495,044
2034	66,380,422	48,782,012	1.9639	95,802,993	38,894,668	28,583,129	1.6124	46,087,438	0	0	1.0000	0	105,275,090	77,365,141	141,890,431
2035	86,879,799	63,846,708	2.0434	130,464,363	113,147,093	83,150,162	1.6584	137,896,229	0	0	1.0000	0	200,026,892	146,996,870	268,360,592
2036	50,307,501	36,970,255	2.1262	78,606,156	20,688,341	15,203,562	1.7056	25,931,196	0	0	1.0000	0	70,995,842	52,173,817	104,537,352
2037	34,755,725	25,541,479	2.2123	56,505,415	14,196,879	10,433,081	1.7542	18,301,711	0	0	1.0000	0	48,952,604	35,974,561	74,807,126
2038	29,827,531	21,919,821	2.3019	50,457,236	15,091,277	11,090,361	1.8042	20,009,230	0	0	1.0000	0	44,918,808	33,010,182	70,466,465
2039	7,164,560	5,265,132	2.3951	12,610,517	2,086,795	1,533,555	1.8556	2,845,665	0	0	1.0000	0	9,251,355	6,798,687	15,456,182
2040	7,184,150	5,279,528	2.4921	13,157,112	2,092,376	1,537,657	1.9085	2,934,618	0	0	1.0000	0	9,276,526	6,817,185	16,091,729
2041	7,164,560	5,265,132	2.5930	13,652,486	2,086,795	1,533,555	1.9629	3,010,216	0	0	1.0000	0	9,251,355	6,798,687	16,662,702
2042	7,164,560	5,265,132	2.6981	14,205,851	2,086,795	1,533,555	2.0189	3,096,095	0	0	1.0000	0	9,251,355	6,798,687	17,301,946
2043	7,164,560	5,265,132	2.8073	14,780,804	2,086,795	1,533,555	2.0764	3,184,274	0	0	1.0000	0	9,251,355	6,798,687	17,965,078
2044	7,184,150	5,279,528	2.9210	15,421,501	2,092,376	1,537,657	2.1356	3,283,820	0	0	1.0000	0	9,276,526	6,817,185	18,705,321
2045	7,164,560	5,265,132	3.0393	16,002,314	2,086,795	1,533,555	2.1964	3,368,301	0	0	1.0000	0	9,251,355	6,798,687	19,370,615
2046	7,164,560	5,265,132	3.1624	16,650,452	2,086,795	1,533,555	2.2590	3,464,302	0	0	1.0000	0	9,251,355	6,798,687	20,114,754
2047	7,164,560	5,265,132	3.2905	17,324,915	2,086,795	1,533,555	2.3234	3,563,063	0	0	1.0000	0	9,251,355	6,798,687	20,887,978
2048	7,847,790	5,767,227	3.4238	19,745,833	4,083,316	3,000,770	2.3896	7,170,639	0	0	1.0000	0	11,931,106	8,767,997	26,916,472
2049	7,164,560	5,265,132	3.5624	18,756,505	2,086,795	1,533,555	2.4577	3,769,019	0	0	1.0000	0	9,251,355	6,798,687	22,525,524
2050	8,657,770	6,362,470	3.7067	23,583,767	6,566,405	4,825,556	2.5278	12,198,040	0	0	1.0000	0	15,224,175	11,188,026	35,781,808
2051	8,657,770	6,362,470	3.8568	24,538,774	6,566,405	4,825,556	2.5998	12,545,480	0	0	1.0000	0	15,224,175	11,188,026	37,084,255
2052	8,677,350	6,376,859	4.0130	25,590,335	6,571,986	4,829,657	2.6739	12,914,021	0	0	1.0000	0	15,249,336	11,206,516	38,504,356
2053	8,657,770	6,362,470	4.1756	26,567,130	6,566,405	4,825,556	2.7501	13,270,762	0	0	1.0000	0	15,224,175	11,188,026	39,837,891
2054	8,657,770	6,362,470	4.3447	27,643,023	6,566,405	4,825,556	2.8285	13,649,085	0	0	1.0000	0	15,224,175	11,188,026	41,292,108
2055	8,657,770	6,362,470	4.5206	28,762,182	6,566,405	4,825,556	2.9091	14,038,025	0	0	1.0000	0	15,224,175	11,188,026	42,800,207
2056	8,677,350	6,376,859	4.7037	29,994,832	6,571,986	4,829,657	2.9920	14,450,335	0	0	1.0000	0	15,249,336	11,206,516	44,445,167
2057	8,657,770	6,362,470	4.8942	31,139,201	6,566,405	4,825,556	3.0773	14,849,683	0	0	1.0000	0	15,224,175	11,188,026	45,988,884
2058	14,754,150	10,842,611	5.0924	55,214,915	24,855,555	18,265,988	3.1650	57,811,852	0	0	1.0000	0	39,609,705	29,108,599	113,026,766
2059	8,657,770	6,362,470	5.2987	33,712,820	6,566,405	4,825,556	3.2552	15,708,150	0	0	1.0000	0	15,224,175	11,188,026	49,420,970
2060	8,677,350	6,376,859	5.5133	35,157,537	6,571,986	4,829,657	3.3480	16,169,693	0	0	1.0000	0	15,249,336	11,206,516	51,327,230
2061	8,657,770	6,362,470	5.7366	36,498,945	6,566,405	4,825,556	3.4434	16,616,320	0	0	1.0000	0	15,224,175	11,188,026	53,115,265
2062	8,657,770	6,362,470	5.9689	37,976,947	6,566,405	4,825,556	3.5415	17,089,707	0	0	1.0000	0	15,224,175	11,188,026	55,066,654
2063	8,657,770	6,362,470	6.2106	39,514,756	6,566,405	4,825,556	3.6425	17,577,088	0	0	1.0000	0	15,224,175	11,188,026	57,091,844
2064	8,677,350	6,376,859	6.4622	41,208,538	6,571,986	4,829,657	3.7463	18,093,345	0	0	1.0000	0	15,249,336	11,206,516	59,301,884
2065	8,657,770	6,362,470	6.7239	42,780,612	6,566,405	4,825,556	3.8531	18,593,350	0	0	1.0000	0	15,224,175	11,188,026	61,373,962
2066	12,315,600	9,050,556	6.9962	63,319,502	17,539,895	12,889,815	3.9629	51,081,048	0	0	1.0000	0	29,855,495	21,940,371	114,400,551
2067	8,657,770	6,362,470	7.2795	46,315,600	6,566,405	4,825,556	4.0758	19,668,001	0	0	1.0000	0	15,224,175	11,188,026	65,983,601
2068	17,212,290	12,649,063	7.5744	95,809,063	32,176,796	23,646,262	4.1920	99,125,130	0	0	1.0000	0	49,389,086	36,295,325	194,934,193
2069	8,657,770	6,362,470	7.8811	50,143,262	6,566,405	4,825,556	4.3115	20,805,385	0	0	1.0000	0	15,224,175	11,188,026	70,948,647
2070	8,657,770	6,362,470	8.2003	52,174,163	6,566,405	4,825,556	4.4343	21,397,963	0	0	1.0000	0	15,224,175	11,188,026	73,572,125
2071	8,657,770	6,362,470	8.5324	54,287,139	6,566,405	4,825,556	4.5607	22,007,913	0	0	1.0000	0	15,224,175	11,188,026	76,295,052
2072	8,677,350	6,376,859	8.8780	56,613,754	6,571,986	4,829,657	4.6907	22,654,474	0	0	1.0000	0	15,249,336	11,206,516	79,268,228
2073	8,657,770	6,362,470	9.2375	58,773,316	6,566,405	4,825,556	4.8244	23,280,412	0	0	1.0000	0	15,224,175	11,188,026	82,053,729
2074	8,657,770	6,362,470	9.6117	61,154,153	6,566,405	4,825,556	4.9619	23,943,926	0	0	1.0000	0	15,224,175	11,188,026	85,098,079
2075	8,657,770	6,362,470	10.0009	63,630,426	6,566,405	4,825,556	5.1033	24,626,260	0	0	1.0000	0	15,224,175	11,188,026	88,256,686
2076	8,677,350	6,376,859	10.4060	66,357,595	6,571,986	4,829,657	5.2487	25,349,422	0	0	1.0000	0	15,249,336	11,206,516	91,707,017
2077	8,657,770	6,362,470	10.8274	68,889,007	6,566,405	4,825,556	5.3983	26,049,799	0	0	1.0000	0	15,224,175	11,188,026	94,938,806
2078	8,657,770	6,362,470	11.2659	71,678,950	6,566,405	4,825,556	5.5522	26,792,452	0	0	1.0000	0	15,224,175	11,188,026	98,471,402
2079	8,657,770	6,362,470	11.7222	74,582,146	6,566,405	4,825,556	5.7104	27,555,855	0	0	1.0000	0	15,224,175	11,188,026	102,138,001
2080	8,677,350	6,376,859	12.1970	77,778,550	6,571,986	4,829,657	5.8731	28,365,060	0	0	1.0000	0	15,249,336	11,206,516	106,143,610
2081	8,657,770	6,362,470	12.6909	80,745,470	6,566,405	4,825,556	6.0405	29,148,771	0	0	1.0000	0	15,224,175	11,188,026	109,894,241
2082	8,657,770	6,362,470	13.2049	84,015,780	6,566,405	4,825,556	6.2127	29,979,732	0	0	1.0000	0	15,224,175	11,188,026	113,995,512
2083	8,657,770	6,362,470	13.7397	87,418,429	6,566,405	4,825,556	6.3897	30,833,855	0	0	1.0000	0	15,224,175	11,188,026	118,252,284
2084	8,677,350	6,376,859	14.2962	91,164,852	6,571,986	4,829,657	6.5719	31,740,025	0	0	1.0000	0	15,249,336	11,206,516	122,904,877

Xcel Energy
Nuclear Decommissioning Accrual
200-Year Decommissioning Period
DECON Method

Docket No. E002/M-17-828
Schedule F.17

Proposed

AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
2085	8,657,770	6,362,470	14.8752	94,643,013	6,566,405	4,825,556	6.7592	32,616,898	0	0	1.0000	0	15,224,175	11,188,026	127,259,911
2086	8,657,770	6,362,470	15.4776	98,475,765	6,566,405	4,825,556	6.9518	33,546,300	0	0	1.0000	0	15,224,175	11,188,026	132,022,065
2087	8,657,770	6,362,470	16.1045	102,464,398	6,566,405	4,825,556	7.1499	34,502,243	0	0	1.0000	0	15,224,175	11,188,026	136,966,641
2088	9,340,990	6,864,558	16.7567	115,027,347	8,562,916	6,292,763	7.3537	46,275,091	0	0	1.0000	0	17,903,906	13,157,321	161,302,438
2089	8,657,770	6,362,470	17.4353	110,931,573	6,566,405	4,825,556	7.5633	36,497,128	0	0	1.0000	0	15,224,175	11,188,026	147,428,700
2090	8,657,770	6,362,470	18.1415	115,424,749	6,566,405	4,825,556	7.7788	37,537,035	0	0	1.0000	0	15,224,175	11,188,026	152,961,784
2091	8,657,770	6,362,470	18.8762	120,099,256	6,566,405	4,825,556	8.0005	38,606,861	0	0	1.0000	0	15,224,175	11,188,026	158,706,116
2092	8,677,350	6,376,859	19.6407	125,245,975	6,571,986	4,829,657	8.2285	39,740,835	0	0	1.0000	0	15,249,336	11,206,516	164,986,810
2093	8,657,770	6,362,470	20.4361	130,024,073	6,566,405	4,825,556	8.4630	40,838,680	0	0	1.0000	0	15,224,175	11,188,026	170,862,753
2094	8,657,770	6,362,470	21.2638	135,290,289	6,566,405	4,825,556	8.7042	42,002,605	0	0	1.0000	0	15,224,175	11,188,026	177,292,894
2095	29,995,110	22,042,973	22.1250	487,700,768	79,650,261	58,533,825	8.9523	524,012,362	0	0	1.0000	0	109,645,371	80,576,798	1,011,713,130
2096	8,677,350	6,376,859	23.0210	146,801,672	6,571,986	4,829,657	9.2075	44,469,070	0	0	1.0000	0	15,249,336	11,206,516	191,270,742
2097	8,657,770	6,362,470	23.9534	152,402,788	6,566,405	4,825,556	9.4699	45,697,533	0	0	1.0000	0	15,224,175	11,188,026	198,100,321
2098	8,657,770	6,362,470	24.9235	158,575,020	6,566,405	4,825,556	9.7398	46,999,950	0	0	1.0000	0	15,224,175	11,188,026	205,574,971
2099	8,657,770	6,362,470	25.9329	164,997,298	6,566,405	4,825,556	10.0173	48,339,042	0	0	1.0000	0	15,224,175	11,188,026	213,336,340
2100	8,657,770	6,362,470	26.9832	171,679,800	6,566,405	4,825,556	10.3028	49,716,738	0	0	1.0000	0	15,224,175	11,188,026	221,396,538
2101	8,657,770	6,362,470	28.0760	178,632,707	6,566,405	4,825,556	10.5965	51,134,004	0	0	1.0000	0	15,224,175	11,188,026	229,766,711
2102	8,657,770	6,362,470	29.2131	185,867,472	6,566,405	4,825,556	10.8985	52,591,322	0	0	1.0000	0	15,224,175	11,188,026	238,458,794
2103	8,657,770	6,362,470	30.3962	193,394,910	6,566,405	4,825,556	11.2091	54,090,140	0	0	1.0000	0	15,224,175	11,188,026	247,485,050
2104	8,677,350	6,376,859	31.6272	201,682,196	6,571,986	4,829,657	11.5285	55,678,704	0	0	1.0000	0	15,249,336	11,206,516	257,360,900
2105	8,657,770	6,362,470	32.9081	209,376,798	6,566,405	4,825,556	11.8571	57,217,100	0	0	1.0000	0	15,224,175	11,188,026	266,593,898
2106	8,657,770	6,362,470	34.2409	217,856,698	6,566,405	4,825,556	12.1950	58,847,655	0	0	1.0000	0	15,224,175	11,188,026	276,704,354
2107	8,657,770	6,362,470	35.6277	226,680,171	6,566,405	4,825,556	12.5426	60,525,019	0	0	1.0000	0	15,224,175	11,188,026	287,205,190
2108	14,773,730	10,857,001	37.0706	402,475,524	24,861,136	18,270,089	12.9000	235,684,150	0	0	1.0000	0	39,634,866	29,127,090	638,159,674
2109	8,657,770	6,362,470	38.5720	245,413,192	6,566,405	4,825,556	13.2677	64,024,029	0	0	1.0000	0	15,224,175	11,188,026	309,437,221
2110	8,657,770	6,362,470	40.1341	255,352,006	6,566,405	4,825,556	13.6458	65,848,572	0	0	1.0000	0	15,224,175	11,188,026	321,200,578
2111	8,657,770	6,362,470	41.7596	265,694,201	6,566,405	4,825,556	14.0347	67,725,231	0	0	1.0000	0	15,224,175	11,188,026	333,419,432
2112	8,677,350	6,376,859	43.4508	277,079,626	6,571,986	4,829,657	14.4347	69,714,654	0	0	1.0000	0	15,249,336	11,206,516	346,794,281
2113	8,657,770	6,362,470	45.2106	287,651,085	6,566,405	4,825,556	14.8461	71,640,687	0	0	1.0000	0	15,224,175	11,188,026	359,291,772
2114	8,657,770	6,362,470	47.0416	299,300,767	6,566,405	4,825,556	15.2692	73,682,380	0	0	1.0000	0	15,224,175	11,188,026	372,983,147
2115	8,657,770	6,362,470	48.9468	311,422,545	6,566,405	4,825,556	15.7044	75,782,462	0	0	1.0000	0	15,224,175	11,188,026	387,205,007
2116	12,335,180	9,064,945	50.9291	461,669,511	17,545,476	12,893,916	16.1520	208,262,538	0	0	1.0000	0	29,880,656	21,958,862	669,932,049
2117	8,657,770	6,362,470	52.9918	337,158,736	6,566,405	4,825,556	16.6123	80,163,584	0	0	1.0000	0	15,224,175	11,188,026	417,322,320
2118	17,192,700	12,634,667	55.1379	696,648,984	32,171,215	23,642,161	17.0857	403,942,863	0	0	1.0000	0	49,363,915	36,276,827	1,100,591,847
2119	8,657,770	6,362,470	57.3710	365,021,265	6,566,405	4,825,556	17.5727	84,798,048	0	0	1.0000	0	15,224,175	11,188,026	449,819,313
2120	8,677,350	6,376,859	59.6946	380,664,049	6,571,986	4,829,657	18.0735	87,288,812	0	0	1.0000	0	15,249,336	11,206,516	467,952,861
2121	8,657,770	6,362,470	62.1122	395,187,007	6,566,405	4,825,556	18.5886	89,700,330	0	0	1.0000	0	15,224,175	11,188,026	484,887,338
2122	8,657,770	6,362,470	64.6277	411,191,801	6,566,405	4,825,556	19.1184	92,256,910	0	0	1.0000	0	15,224,175	11,188,026	503,448,710
2123	8,657,770	6,362,470	67.2451	427,844,930	6,566,405	4,825,556	19.6633	94,886,355	0	0	1.0000	0	15,224,175	11,188,026	522,731,285
2124	8,677,350	6,376,859	69.9686	446,179,899	6,571,986	4,829,657	20.2237	97,673,541	0	0	1.0000	0	15,249,336	11,206,516	543,853,439
2125	8,657,770	6,362,470	72.8023	463,202,448	6,566,405	4,825,556	20.8000	100,371,565	0	0	1.0000	0	15,224,175	11,188,026	563,574,012
2126	8,657,770	6,362,470	75.7508	481,962,190	6,566,405	4,825,556	21.3928	103,232,154	0	0	1.0000	0	15,224,175	11,188,026	585,194,345
2127	8,657,770	6,362,470	78.8187	501,481,612	6,566,405	4,825,556	22.0025	106,174,296	0	0	1.0000	0	15,224,175	11,188,026	607,655,908
2128	9,340,990	6,864,558	82.0109	562,968,618	8,562,916	6,292,763	22.6296	142,402,709	0	0	1.0000	0	17,903,906	13,157,321	705,371,327
2129	8,657,770	6,362,470	85.3323	542,924,196	6,566,405	4,825,556	23.2745	112,312,403	0	0	1.0000	0	15,224,175	11,188,026	655,236,600
2130	8,657,770	6,362,470	88.7883	564,912,893	6,566,405	4,825,556	23.9379	115,513,677	0	0	1.0000	0	15,224,175	11,188,026	680,426,570
2131	8,657,770	6,362,470	92.3842	587,791,698	6,566,405	4,825,556	24.6201	118,805,671	0	0	1.0000	0	15,224,175	11,188,026	706,597,370
2132	8,677,350	6,376,859	96.1257	612,980,038	6,571,986	4,829,657	25.3218	122,295,617	0	0	1.0000	0	15,249,336	11,206,516	735,275,655
2133	8,657,770	6,362,470	100.0188	636,366,612	6,566,405	4,825,556	26.0434	125,673,885	0	0	1.0000	0	15,224,175	11,188,026	762,040,497
2134	8,657,770	6,362,470	104.0696	662,139,705	6,566,405	4,825,556	26.7857	129,255,895	0	0	1.0000	0	15,224,175	11,188,026	791,395,600
2135	8,657,770	6,362,470	108.2844	688,956,243	6,566,405	4,825,556	27.5491	132,939,725	0	0	1.0000	0	15,224,175	11,188,026	821,895,968
2136	8,677,350	6,376,859	112.6699	718,480,069	6,571,986	4,829,657	28.3342	136,844,476	0	0	1.0000	0	15,249,336	11,206,516	855,324,546
2137	8,657,770	6,362,470	117.2331	745,892,078	6,566,405	4,825,556	29.1417	140,624,905	0	0	1.0000	0	15,224,175	11,188,026	886,516,984
2138	8,657,770	6,362,470	121.9810	776,100,450	6,566,405	4,825,556	29.9723	144,633,012	0	0	1.0000	0	15,224,175	11,188,026	920,733,462
2139	8,657,770	6,362,470	126.9212	807,532,324	6,566,405	4,825,556	30.8265	148,755,002	0	0	1.0000	0	15,224,175	11,188,026	956,287,326
2140	8,677,350	6,376,859	132.0616	842,138,207	6,571,986	4,829,657	31.7050	153,124,285	0	0	1.0000	0	15,249,336	11,206,516	995,262,492
2141	8,657,770	6,362,470	137.4100	874,266,999	6,566,405	4,825,556	32.6086	157,354,625	0	0	1.0000	0	15,224,175	11,188,026	1,031,621,624

Xcel Energy
Nuclear Decommissioning Accrual
200-Year Decommissioning Period
DECON Method

Docket No. E002/M-17-828
Schedule F.17

Proposed

AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
2142	8,657,770	6,362,470	142.9752	909,675,417	6,566,405	4,825,556	33.5380	161,839,497	0	0	1.0000	0	15,224,175	11,188,026	1,071,514,914
2143	8,657,770	6,362,470	148.7656	946,516,663	6,566,405	4,825,556	34.4938	166,451,764	0	0	1.0000	0	15,224,175	11,188,026	1,112,968,427
2144	8,677,350	6,376,859	154.7907	987,078,473	6,571,986	4,829,657	35.4769	171,341,270	0	0	1.0000	0	15,249,336	11,206,516	1,158,419,743
2145	29,995,110	22,042,973	161.0597	3,550,234,550	70,578,445	51,867,079	36.4880	1,892,525,961	0	0	1.0000	0	100,573,555	73,910,051	5,442,760,511
2146	8,657,770	6,362,470	167.5826	1,066,239,260	6,566,405	4,825,556	37.5279	181,092,983	0	0	1.0000	0	15,224,175	11,188,026	1,247,332,243
2147	8,657,770	6,362,470	174.3697	1,109,421,980	6,566,405	4,825,556	38.5974	186,253,915	0	0	1.0000	0	15,224,175	11,188,026	1,295,675,896
2148	8,677,350	6,376,859	181.4317	1,156,964,375	6,571,986	4,829,657	39.6975	191,725,321	0	0	1.0000	0	15,249,336	11,206,516	1,348,689,696
2149	8,657,770	6,362,470	188.7796	1,201,104,536	6,566,405	4,825,556	40.8288	197,021,661	0	0	1.0000	0	15,224,175	11,188,026	1,398,126,197
2150	8,657,770	6,362,470	196.4252	1,249,749,437	6,566,405	4,825,556	41.9925	202,637,160	0	0	1.0000	0	15,224,175	11,188,026	1,452,386,597
2151	8,657,770	6,362,470	204.3804	1,300,364,158	6,566,405	4,825,556	43.1893	208,412,386	0	0	1.0000	0	15,224,175	11,188,026	1,508,776,544
2152	8,677,350	6,376,859	212.6578	1,356,088,812	6,571,986	4,829,657	44.4201	214,533,861	0	0	1.0000	0	15,249,336	11,206,516	1,570,622,673
2153	8,657,770	6,362,470	221.2705	1,407,826,912	6,566,405	4,825,556	45.6861	220,460,834	0	0	1.0000	0	15,224,175	11,188,026	1,628,287,746
2154	8,657,770	6,362,470	230.2319	1,464,843,550	6,566,405	4,825,556	46.9882	226,744,191	0	0	1.0000	0	15,224,175	11,188,026	1,691,587,741
2155	8,657,770	6,362,470	239.5563	1,524,169,765	6,566,405	4,825,556	48.3273	233,206,093	0	0	1.0000	0	15,224,175	11,188,026	1,757,375,858
2156	8,677,350	6,376,859	249.2584	1,589,485,679	6,571,986	4,829,657	49.7047	240,056,668	0	0	1.0000	0	15,249,336	11,206,516	1,829,542,347
2157	8,657,770	6,362,470	259.3533	1,650,127,583	6,566,405	4,825,556	51.1212	246,688,214	0	0	1.0000	0	15,224,175	11,188,026	1,896,815,797
2158	14,754,150	10,842,611	269.8571	2,925,955,689	24,855,555	18,265,988	52.5782	960,392,763	0	0	1.0000	0	39,609,705	29,108,599	3,886,348,451
2159	8,657,770	6,362,470	280.7864	1,786,495,039	6,566,405	4,825,556	54.0767	260,950,144	0	0	1.0000	0	15,224,175	11,188,026	2,047,445,183
2160	8,677,350	6,376,859	292.1582	1,863,051,656	6,571,986	4,829,657	55.6179	268,615,398	0	0	1.0000	0	15,249,336	11,206,516	2,131,667,054
2161	8,657,770	6,362,470	303.9906	1,934,131,064	6,566,405	4,825,556	57.2030	276,036,280	0	0	1.0000	0	15,224,175	11,188,026	2,210,167,344
2162	8,657,770	6,362,470	316.3022	2,012,463,250	6,566,405	4,825,556	58.8333	283,903,384	0	0	1.0000	0	15,224,175	11,188,026	2,296,366,634
2163	8,657,770	6,362,470	329.1125	2,093,968,399	6,566,405	4,825,556	60.5100	291,994,394	0	0	1.0000	0	15,224,175	11,188,026	2,385,962,792
2164	8,677,350	6,376,859	342.4415	2,183,701,172	6,571,986	4,829,657	62.2345	300,571,308	0	0	1.0000	0	15,249,336	11,206,516	2,484,272,480
2165	8,657,770	6,362,470	356.3104	2,267,014,221	6,566,405	4,825,556	64.0082	308,875,154	0	0	1.0000	0	15,224,175	11,188,026	2,575,889,374
2166	12,315,600	9,050,556	370.7410	3,355,412,309	17,539,895	12,889,815	65.8325	848,568,754	0	0	1.0000	0	29,855,495	21,940,371	4,203,981,063
2167	8,657,770	6,362,470	385.7560	2,454,360,967	6,566,405	4,825,556	67.7087	326,732,124	0	0	1.0000	0	15,224,175	11,188,026	2,781,093,090
2168	17,875,930	13,136,762	401.3791	5,272,821,890	34,167,736	25,109,375	69.6384	1,748,576,695	0	0	1.0000	0	52,043,666	38,246,137	7,021,398,585
2169	8,657,770	6,362,470	417.6350	2,657,190,147	6,566,405	4,825,556	71.6231	345,621,280	0	0	1.0000	0	15,224,175	11,188,026	3,002,811,427
2170	8,657,770	6,362,470	434.5492	2,764,806,236	6,566,405	4,825,556	73.6643	355,471,205	0	0	1.0000	0	15,224,175	11,188,026	3,120,277,441
2171	8,657,770	6,362,470	452.1484	2,876,780,618	6,566,405	4,825,556	75.7638	365,602,460	0	0	1.0000	0	15,224,175	11,188,026	3,242,383,078
2172	8,677,350	6,376,859	470.4604	3,000,059,650	6,571,986	4,829,657	77.9230	376,341,387	0	0	1.0000	0	15,249,336	11,206,516	3,376,401,038
2173	8,657,770	6,362,470	489.5141	3,114,518,762	6,566,405	4,825,556	80.1438	386,738,395	0	0	1.0000	0	15,224,175	11,188,026	3,501,257,157
2174	8,657,770	6,362,470	509.3394	3,240,656,638	6,566,405	4,825,556	82.4279	397,760,448	0	0	1.0000	0	15,224,175	11,188,026	3,638,417,086
2175	8,657,770	6,362,470	529.9676	3,371,902,941	6,566,405	4,825,556	84.7771	409,096,644	0	0	1.0000	0	15,224,175	11,188,026	3,780,999,585
2176	8,677,350	6,376,859	551.4313	3,516,399,665	6,571,986	4,829,657	87.1933	421,113,759	0	0	1.0000	0	15,249,336	11,206,516	3,937,513,425
2177	8,657,770	6,362,470	573.7643	3,650,558,130	6,566,405	4,825,556	89.6783	432,747,659	0	0	1.0000	0	15,224,175	11,188,026	4,083,305,789
2178	8,657,770	6,362,470	597.0018	3,798,406,026	6,566,405	4,825,556	92.2341	445,080,815	0	0	1.0000	0	15,224,175	11,188,026	4,243,486,841
2179	8,657,770	6,362,470	621.1803	3,952,241,006	6,566,405	4,825,556	94.8628	457,765,754	0	0	1.0000	0	15,224,175	11,188,026	4,410,006,760
2180	8,677,350	6,376,859	646.3381	4,121,606,950	6,571,986	4,829,657	97.5664	471,212,278	0	0	1.0000	0	15,249,336	11,206,516	4,592,819,228
2181	8,657,770	6,362,470	672.5148	4,278,855,221	6,566,405	4,825,556	100.3470	484,230,068	0	0	1.0000	0	15,224,175	11,188,026	4,763,085,289
2182	8,657,770	6,362,470	699.7517	4,452,149,179	6,566,405	4,825,556	103.2069	498,030,676	0	0	1.0000	0	15,224,175	11,188,026	4,950,179,855
2183	8,657,770	6,362,470	728.0916	4,632,460,942	6,566,405	4,825,556	106.1483	512,224,566	0	0	1.0000	0	15,224,175	11,188,026	5,144,685,508
2184	8,677,350	6,376,859	757.5793	4,830,976,401	6,571,986	4,829,657	109.1736	527,271,076	0	0	1.0000	0	15,249,336	11,206,516	5,358,247,477
2185	8,657,770	6,362,470	788.2613	5,015,288,851	6,566,405	4,825,556	112.2850	541,837,556	0	0	1.0000	0	15,224,175	11,188,026	5,557,126,407
2186	8,657,770	6,362,470	820.1859	5,218,408,160	6,566,405	4,825,556	115.4851	557,279,817	0	0	1.0000	0	15,224,175	11,188,026	5,775,687,978
2187	8,657,770	6,362,470	853.4034	5,429,753,507	6,566,405	4,825,556	118.7764	573,162,170	0	0	1.0000	0	15,224,175	11,188,026	6,002,915,676
2188	8,677,350	6,376,859	887.9662	5,662,435,282	6,571,986	4,829,657	122.1616	589,998,665	0	0	1.0000	0	15,249,336	11,206,516	6,252,433,947
2189	8,657,770	6,362,470	923.9289	5,878,469,883	6,566,405	4,825,556	125.6432	606,298,298	0	0	1.0000	0	15,224,175	11,188,026	6,484,768,180
2190	8,657,770	6,362,470	961.3480	6,116,547,783	6,566,405	4,825,556	129.2240	623,577,649	0	0	1.0000	0	15,224,175	11,188,026	6,740,125,432
2191	8,657,770	6,362,470	1,000.2826	6,364,268,006	6,566,405	4,825,556	132.9069	641,349,689	0	0	1.0000	0	15,224,175	11,188,026	7,005,617,695
2192	9,539,850	7,010,698	1,040.7940	7,296,692,215	9,159,486	6,731,174	136.6947	920,115,763	0	0	1.0000	0	18,699,336	13,741,871	8,216,807,977
2193	10,167,140	7,471,684	1,082.9462	8,091,431,966	11,094,525	8,153,206	140.5905	1,146,263,295	0	0	1.0000	0	21,261,665	15,624,890	9,237,695,262
2194	8,873,390	6,520,926	1,126.8055	7,347,815,273	7,213,275	5,300,931	144.5974	766,500,900	0	0	1.0000	0	16,086,665	11,821,857	8,114,316,172
2195	31,288,860	22,993,731	1,172.4411	26,958,794,965	74,459,695	54,719,353	148.7184	8,137,774,629	0	0	1.0000	0	105,748,555	77,713,084	35,096,569,593
2196	10,402,350	7,644,537	1,219.9250	9,325,761,294	11,746,986	8,632,690	152.9569	1,320,429,498	0	0	1.0000	0	22,149,336	16,277,227	10,646,190,792
2197	7,147,970	5,252,940	1,269.3320	6,667,724,564	2,037,025	1,496,980	157.3161	235,499,077	0	0	1.0000	0	9,184,995	6,749,920	6,903,223,641
2198	7,147,970	5,252,940	1,320.7399	6,937,767,167	2,037,025	1,496,980	161.7997	242,210,938	0	0	1.0000	0	9,184,995	6,749,920	7,179,978,104

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	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
2199	7,147,970	5,252,940	1,374.2299	7,218,746,916	2,037,025	1,496,980	166.4109	249,113,812	0	0	1.0000	0	9,184,995	6,749,920	7,467,860,728
2200	7,147,970	5,252,940	1,429.8862	7,511,106,109	2,037,025	1,496,980	171.1537	256,213,690	0	0	1.0000	0	9,184,995	6,749,920	7,767,319,798
2201	7,147,970	5,252,940	1,487.7966	7,815,305,953	2,037,025	1,496,980	176.0315	263,515,660	0	0	1.0000	0	9,184,995	6,749,920	8,078,821,612
2202	7,147,970	5,252,940	1,548.0523	8,131,825,517	2,037,025	1,496,980	181.0484	271,025,859	0	0	1.0000	0	9,184,995	6,749,920	8,402,851,376
2203	7,147,970	5,252,940	1,610.7485	8,461,164,880	2,037,025	1,496,980	186.2083	278,750,127	0	0	1.0000	0	9,184,995	6,749,920	8,739,915,007
2204	7,167,560	5,267,336	1,675.9838	8,827,970,129	2,042,606	1,501,081	191.5152	287,479,915	0	0	1.0000	0	9,210,166	6,768,418	9,115,450,044
2205	7,147,970	5,252,940	1,743.8611	9,160,397,352	2,037,025	1,496,980	196.9734	294,865,268	0	0	1.0000	0	9,184,995	6,749,920	9,455,262,620
2206	7,147,970	5,252,940	1,814.4875	9,531,393,579	2,037,025	1,496,980	202.5872	303,269,015	0	0	1.0000	0	9,184,995	6,749,920	9,834,662,594
2207	7,147,970	5,252,940	1,887.9742	9,917,414,789	2,037,025	1,496,980	208.3609	311,912,129	0	0	1.0000	0	9,184,995	6,749,920	10,229,326,918
2208	13,927,590	10,235,184	1,964.4372	20,106,377,146	22,322,696	16,404,626	214.2992	3,515,498,298	0	0	1.0000	0	36,250,286	26,639,811	23,621,875,444
2209	7,147,970	5,252,940	2,043.9969	10,736,992,637	2,037,025	1,496,980	220.4067	329,944,453	0	0	1.0000	0	9,184,995	6,749,920	11,066,937,090
2210	7,147,970	5,252,940	2,126.7788	11,171,840,973	2,037,025	1,496,980	226.6883	339,347,883	0	0	1.0000	0	9,184,995	6,749,920	11,511,188,856
2211	7,147,970	5,252,940	2,212.9133	11,624,300,315	2,037,025	1,496,980	233.1489	349,019,273	0	0	1.0000	0	9,184,995	6,749,920	11,973,319,588
2212	7,167,560	5,267,336	2,302.5363	12,128,232,789	2,042,606	1,501,081	239.7937	359,949,876	0	0	1.0000	0	9,210,166	6,768,418	12,488,182,665
2213	7,147,970	5,252,940	2,395.7890	12,584,935,356	11,235,929	8,257,122	246.6278	2,036,435,750	0	0	1.0000	0	18,383,899	13,510,061	14,621,371,106
2214	7,147,970	5,252,940	2,492.8185	13,094,625,476	2,037,025	1,496,980	253.6567	379,719,042	0	0	1.0000	0	9,184,995	6,749,920	13,474,344,519
2215	7,147,970	5,252,940	2,593.7776	13,624,957,550	2,037,025	1,496,980	260.8859	390,541,011	0	0	1.0000	0	9,184,995	6,749,920	14,015,498,561
2216	10,825,390	7,955,423	2,698.8256	21,470,298,074	13,016,096	9,565,341	268.3212	2,566,583,660	0	0	1.0000	0	23,841,486	17,520,763	24,036,881,734
2217	7,147,970	5,252,940	2,808.1281	14,750,927,819	2,037,025	1,496,980	275.9683	413,119,064	0	0	1.0000	0	9,184,995	6,749,920	15,164,046,883
2218	14,921,800	10,965,815	2,921.8572	32,040,545,612	29,162,168	21,430,855	283.8334	6,082,792,505	0	0	1.0000	0	44,083,968	32,396,670	38,123,338,117
2219	6,482,540	4,763,925	3,040.1925	14,483,248,755	3,844,408	2,825,200	291.9227	824,739,875	0	0	1.0000	0	10,326,948	7,589,124	15,307,988,630
2220	6,403,050	4,705,509	3,163.3203	14,885,031,666	3,563,171	2,618,523	300.2424	786,191,677	0	0	1.0000	0	9,966,221	7,324,032	15,671,223,343
2221	6,386,860	4,693,611	3,291.4347	15,448,714,288	3,557,358	2,614,251	308.7994	807,279,028	0	0	1.0000	0	9,944,218	7,307,862	16,255,993,316
2222	6,386,860	4,693,611	3,424.7378	16,074,387,191	3,557,358	2,614,251	317.6001	830,286,263	0	0	1.0000	0	9,944,218	7,307,862	16,904,673,455
2223	6,482,540	4,763,925	3,563.4397	16,975,959,121	3,844,408	2,825,200	326.6517	922,856,229	0	0	1.0000	0	10,326,948	7,589,124	17,898,815,350
2224	6,403,050	4,705,509	3,707.7590	17,446,892,787	3,563,171	2,618,523	335.9613	879,722,443	0	0	1.0000	0	9,966,221	7,324,032	18,326,615,231
2225	6,386,860	4,693,611	3,857.9233	18,107,591,442	3,557,358	2,614,251	345.5362	903,318,231	0	0	1.0000	0	9,944,218	7,307,862	19,010,909,673
2226	6,386,860	4,693,611	4,014.1692	18,840,948,925	3,557,358	2,614,251	355.3840	929,062,848	0	0	1.0000	0	9,944,218	7,307,862	19,770,011,773
2227	6,482,540	4,763,925	4,176.7430	19,897,689,984	3,844,408	2,825,200	365.5124	1,032,645,461	0	0	1.0000	0	10,326,948	7,589,124	20,930,335,445
2228	6,403,050	4,705,509	4,345.9011	20,449,676,086	3,563,171	2,618,523	375.9295	984,380,100	0	0	1.0000	0	9,966,221	7,324,032	21,434,056,187
2229	6,386,860	4,693,611	4,521.9101	21,224,087,226	3,557,358	2,614,251	386.6435	1,010,783,016	0	0	1.0000	0	9,944,218	7,307,862	22,234,870,241
2230	6,099,800	4,482,655	4,705.0475	21,091,103,808	2,696,178	1,981,382	397.6629	787,922,075	0	0	1.0000	0	8,795,978	6,464,037	21,879,025,883
2231	2,028,079	1,490,406	4,895.6019	7,296,434,457	5,022,573	3,691,016	408.9963	1,509,612,017	0	0	1.0000	0	7,050,652	5,181,422	8,806,046,474
	$2,255,855,813	$1,657,795,815		$717,266,338,345	$2,005,587,868	$1,473,877,521		$73,233,079,006	$0	$0		$0	$4,261,443,682	$3,131,673,337	$790,499,417,350

Xcel Energy
Nuclear Decommissioning Accrual
200-Year Decommissioning Period
DECON Method

Docket No. E002/M-17-828
Schedule F.17

Proposed

AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
Prairie Island Unit 1															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2033	$22,324,352	$16,405,843	1.8874	$30,964,388	$9,448,311	$6,943,427	1.5677	$10,885,211	$1,250,000	$918,607	1.0000	$918,607	$33,022,663	$24,267,877	$42,768,206
2034	63,582,247	46,725,674	1.9639	91,764,550	32,971,808	24,230,505	1.6124	39,069,266	1,250,000	918,607	1.0000	918,607	97,804,054	71,874,785	131,752,423
2035	65,877,294	48,412,271	2.0434	98,925,635	81,239,940	59,702,057	1.6584	99,009,891	1,250,000	918,607	1.0000	918,607	148,367,234	109,032,935	198,854,133
2036	57,759,315	42,446,486	2.1262	90,249,718	65,595,019	48,204,831	1.7056	82,218,159	1,250,000	918,607	1.0000	918,607	124,604,334	91,569,923	173,386,484
2037	39,808,349	29,254,580	2.2123	64,719,908	41,981,869	30,851,869	1.7542	54,120,348	1,250,000	918,607	1.0000	918,607	83,040,219	61,025,056	119,758,863
2038	13,207,909	9,706,302	2.3019	22,342,936	18,994,690	13,958,923	1.8042	25,184,688	1,250,000	918,607	1.0000	918,607	33,452,599	24,583,831	48,446,231
2039	35,713,293	26,245,183	2.3951	62,859,838	75,509,032	55,490,496	1.8556	102,968,164	1,250,000	918,607	1.0000	918,607	112,472,326	82,654,286	166,746,609
2040	31,919,565	23,457,227	2.4921	58,457,756	13,365,605	9,822,190	1.9085	18,745,649	1,250,000	918,607	1.0000	918,607	46,535,170	34,198,024	78,122,012
2041	19,624,629	14,421,856	2.5930	37,395,872	9,445,873	6,941,635	1.9629	13,625,736	1,250,000	918,607	1.0000	918,607	30,320,501	22,282,098	51,940,215
2042	14,863,700	10,923,118	2.6981	29,471,665	11,668,700	8,575,159	2.0189	17,312,388	1,250,000	918,607	1.0000	918,607	27,782,400	20,416,884	47,702,660
2043	8,912,163	6,549,420	2.8073	18,386,186	6,432,175	4,726,912	2.0764	9,814,961	1,250,000	918,607	1.0000	918,607	16,594,338	12,194,939	29,119,754
2044	3,676,270	2,701,638	2.9210	7,891,484	1,824,877	1,341,076	2.1356	2,864,001	1,250,000	918,607	1.0000	918,607	6,751,147	4,961,320	11,674,091
2045	5,973,090	4,389,537	3.0393	13,341,121	8,737,075	6,420,750	2.1964	14,102,536	1,250,000	918,607	1.0000	918,607	15,960,165	11,728,895	28,362,264
2046	5,204,130	3,824,440	3.1624	12,094,409	6,430,205	4,725,465	2.2590	10,674,825	1,250,000	918,607	1.0000	918,607	12,884,335	9,468,512	23,687,841
2047	5,204,130	3,824,440	3.2905	12,584,319	6,430,205	4,725,465	2.3234	10,979,145	1,250,000	918,607	1.0000	918,607	12,884,335	9,468,512	24,482,072
2048	3,676,270	2,701,638	3.4238	9,249,867	1,824,877	1,341,076	2.3896	3,204,634	1,250,000	918,607	1.0000	918,607	6,751,147	4,961,320	13,373,108
2049	5,204,130	3,824,440	3.5624	13,624,185	6,430,205	4,725,465	2.4577	11,613,775	1,250,000	918,607	1.0000	918,607	12,884,335	9,468,512	26,156,567
2050	5,973,090	4,389,537	3.7067	16,270,699	8,737,075	6,420,750	2.5278	16,230,373	1,250,000	918,607	1.0000	918,607	15,960,165	11,728,895	33,419,678
2051	5,779,130	4,246,999	3.8568	16,379,826	8,155,205	5,993,143	2.5998	15,580,972	1,250,000	918,607	1.0000	918,607	15,184,335	11,158,749	32,879,405
2052	5,983,130	4,396,916	4.0130	17,644,823	8,745,477	6,426,924	2.6739	17,184,953	1,250,000	918,607	1.0000	918,607	15,978,607	11,742,447	35,748,383
2053	3,666,220	2,694,252	4.1756	11,250,119	1,816,475	1,334,902	2.7501	3,671,113	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	15,839,839
2054	3,666,220	2,694,252	4.3447	11,705,717	1,816,475	1,334,902	2.8285	3,775,769	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	16,400,093
2055	5,973,090	4,389,537	4.5206	19,843,343	8,737,075	6,420,750	2.9091	18,678,605	1,250,000	918,607	1.0000	918,607	15,960,165	11,728,895	39,440,555
2056	5,214,180	3,831,825	4.7037	18,023,758	6,438,607	4,731,639	2.9920	14,157,064	1,250,000	918,607	1.0000	918,607	12,902,787	9,482,071	33,099,428
2057	5,204,130	3,824,440	4.8942	18,717,574	6,430,205	4,725,465	3.0773	14,541,673	1,250,000	918,607	1.0000	918,607	12,884,335	9,468,512	34,177,854
2058	3,666,220	2,694,252	5.0924	13,720,209	1,816,475	1,334,902	3.1650	4,224,963	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	18,863,779
2059	5,010,180	3,681,909	5.2987	19,509,330	5,848,345	4,297,864	3.2552	13,990,408	1,250,000	918,607	1.0000	918,607	12,108,525	8,898,380	34,418,346
2060	5,214,180	3,831,825	5.5133	21,126,003	6,438,607	4,731,639	3.3480	15,841,527	1,250,000	918,607	1.0000	918,607	12,902,787	9,482,071	37,886,138
2061	5,204,130	3,824,440	5.7366	21,939,282	6,430,205	4,725,465	3.4434	16,271,666	1,250,000	918,607	1.0000	918,607	12,884,335	9,468,512	39,129,555
2062	3,666,220	2,694,252	5.9689	16,081,721	1,816,475	1,334,902	3.5415	4,727,554	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	21,727,882
2063	8,279,960	6,084,823	6.2106	37,790,401	15,657,675	11,506,599	3.6425	41,912,788	1,250,000	918,607	1.0000	918,607	25,187,635	18,510,029	80,621,796
2064	6,558,130	4,819,475	6.4622	31,144,411	10,470,477	7,694,602	3.7463	28,826,287	1,250,000	918,607	1.0000	918,607	18,278,607	13,432,684	60,889,305
2065	5,204,130	3,824,440	6.7239	25,715,151	6,430,205	4,725,465	3.8531	18,207,689	1,250,000	918,607	1.0000	918,607	12,884,335	9,468,512	44,841,447
2066	3,666,220	2,694,252	6.9962	18,849,526	1,816,475	1,334,902	3.9629	5,290,081	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	25,058,214
2067	3,666,220	2,694,252	7.2795	19,612,808	1,816,475	1,334,902	4.0758	5,440,792	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	25,972,206
2068	6,752,090	4,962,013	7.5744	37,584,274	11,052,337	8,122,202	4.1920	34,048,273	1,250,000	918,607	1.0000	918,607	19,054,427	14,002,823	72,551,153
2069	5,973,090	4,389,537	7.8811	34,594,384	8,737,075	6,420,750	4.3115	27,683,065	1,250,000	918,607	1.0000	918,607	15,960,165	11,728,895	63,196,056
2070	3,666,220	2,694,252	8.2003	22,093,675	1,816,475	1,334,902	4.4343	5,919,354	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	28,931,636
2071	3,666,220	2,694,252	8.5324	22,988,436	1,816,475	1,334,902	4.5607	6,088,085	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	29,995,129
2072	7,327,090	5,384,572	8.8780	47,804,235	12,777,337	9,389,880	4.6907	44,045,110	1,250,000	918,607	1.0000	918,607	21,354,427	15,693,059	92,767,952
2073	3,666,220	2,694,252	9.2375	24,888,153	1,816,475	1,334,902	4.8244	6,440,099	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	32,246,859
2074	3,666,220	2,694,252	9.6117	25,896,343	1,816,475	1,334,902	4.9619	6,623,648	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	33,438,597
2075	7,842,820	5,763,575	10.0009	57,640,937	14,346,275	10,542,870	5.1033	53,803,430	1,250,000	918,607	1.0000	918,607	23,439,095	17,225,052	112,362,974
2076	3,676,270	2,701,638	10.4060	28,113,241	1,824,877	1,341,076	5.2487	7,038,903	1,250,000	918,607	1.0000	918,607	6,751,147	4,961,320	36,070,752
2077	3,666,220	2,694,252	10.8274	29,171,745	1,816,475	1,334,902	5.3983	7,206,199	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	37,296,551
2078	7,511,000	5,519,725	11.2659	62,184,673	13,350,805	9,811,314	5.5522	54,474,377	1,250,000	918,607	1.0000	918,607	22,111,805	16,249,646	117,577,657
2079	3,666,220	2,694,252	11.7222	31,582,562	1,816,475	1,334,902	5.7104	7,622,822	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	40,123,990
2080	3,676,270	2,701,638	12.1970	32,951,875	1,824,877	1,341,076	5.8731	7,876,271	1,250,000	918,607	1.0000	918,607	6,751,147	4,961,320	41,746,752
2081	3,666,220	2,694,252	12.6909	34,192,483	1,816,475	1,334,902	6.0405	8,063,473	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	43,174,563
2082	7,123,090	5,234,656	13.2049	69,123,107	12,187,075	8,956,105	6.2127	55,641,597	1,250,000	918,607	1.0000	918,607	20,560,165	15,109,368	125,683,310
2083	3,666,220	2,694,252	13.7397	37,018,215	1,816,475	1,334,902	6.3897	8,529,620	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	46,466,442
2084	3,676,270	2,701,638	14.2962	38,623,152	1,824,877	1,341,076	6.5719	8,813,414	1,250,000	918,607	1.0000	918,607	6,751,147	4,961,320	48,355,173
2085	3,666,220	2,694,252	14.8752	40,077,538	1,816,475	1,334,902	6.7592	9,022,866	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	50,019,012
2086	3,666,220	2,694,252	15.4776	41,700,556	1,816,475	1,334,902	6.9518	9,279,968	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	51,899,131
2087	3,666,220	2,694,252	16.1045	43,389,582	1,816,475	1,334,902	7.1499	9,544,412	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	53,852,602

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	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
2088	3,676,270	2,701,638	16.7567	45,270,532	1,824,877	1,341,076	7.3537	9,861,867	1,250,000	918,607	1.0000	918,607	6,751,147	4,961,320	56,051,006
2089	26,770,050	19,672,923	17.4353	343,003,308	73,210,048	53,801,006	7.5633	406,913,146	1,250,000	918,607	1.0000	918,607	101,230,098	74,392,535	750,835,061
2090	3,666,220	2,694,252	18.1415	48,877,774	1,816,475	1,334,902	7.7788	10,383,932	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	60,180,313
2091	3,666,220	2,694,252	18.8762	50,857,241	1,816,475	1,334,902	8.0005	10,679,880	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	62,455,727
2092	3,676,270	2,701,638	19.6407	53,062,055	1,824,877	1,341,076	8.2285	11,035,040	1,250,000	918,607	1.0000	918,607	6,751,147	4,961,320	65,015,702
2093	3,666,220	2,694,252	20.4361	55,060,005	1,816,475	1,334,902	8.4630	11,297,272	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	67,275,883
2094	3,666,220	2,694,252	21.2638	57,290,037	1,816,475	1,334,902	8.7042	11,619,250	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	69,827,894
2095	5,973,090	4,389,537	22.1250	97,118,516	8,737,075	6,420,750	8.9523	57,480,484	1,250,000	918,607	1.0000	918,607	15,960,165	11,728,895	155,517,607
2096	5,214,180	3,831,825	23.0210	88,212,454	6,438,607	4,731,639	9.2075	43,566,566	1,250,000	918,607	1.0000	918,607	12,902,787	9,482,071	132,697,627
2097	5,204,130	3,824,440	23.9534	91,608,338	6,430,205	4,725,465	9.4699	44,749,681	1,250,000	918,607	1.0000	918,607	12,884,335	9,468,512	137,276,626
2098	3,666,220	2,694,252	24.9235	67,150,191	1,816,475	1,334,902	9.7398	13,001,674	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	81,070,472
2099	3,666,220	2,694,252	25.9329	69,869,769	1,816,475	1,334,902	10.0173	13,372,109	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	84,160,485
2100	5,973,090	4,389,537	26.9832	118,443,767	8,737,075	6,420,750	10.3028	66,151,707	1,250,000	918,607	1.0000	918,607	15,960,165	11,728,895	185,514,081
2101	5,973,090	4,389,537	28.0760	123,240,654	8,737,075	6,420,750	10.5965	68,037,482	1,250,000	918,607	1.0000	918,607	15,960,165	11,728,895	192,196,742
2102	5,973,090	4,389,537	29.2131	128,231,997	8,737,075	6,420,750	10.8985	69,976,548	1,250,000	918,607	1.0000	918,607	15,960,165	11,728,895	199,127,152
2103	3,666,220	2,694,252	30.3962	81,895,024	1,816,475	1,334,902	11.2091	14,963,045	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	97,776,676
2104	3,676,270	2,701,638	31.6272	85,445,235	1,824,877	1,341,076	11.5285	15,460,589	1,250,000	918,607	1.0000	918,607	6,751,147	4,961,320	101,824,431
2105	5,973,090	4,389,537	32.9081	144,451,338	8,737,075	6,420,750	11.8571	76,131,479	1,250,000	918,607	1.0000	918,607	15,960,165	11,728,895	221,501,424
2106	5,204,130	3,824,440	34.2409	130,952,263	6,430,205	4,725,465	12.1950	57,627,046	1,250,000	918,607	1.0000	918,607	12,884,335	9,468,512	189,497,916
2107	5,204,130	3,824,440	35.6277	136,255,997	6,430,205	4,725,465	12.5426	59,269,617	1,250,000	918,607	1.0000	918,607	12,884,335	9,468,512	196,444,221
2108	3,676,270	2,701,638	37.0706	100,151,329	1,824,877	1,341,076	12.9000	17,299,874	1,250,000	918,607	1.0000	918,607	6,751,147	4,961,320	118,369,810
2109	5,204,130	3,824,440	38.5720	147,516,295	6,430,205	4,725,465	13.2677	62,696,052	1,250,000	918,607	1.0000	918,607	12,884,335	9,468,512	211,130,954
2110	5,204,130	3,824,440	40.1341	153,490,453	6,430,205	4,725,465	13.6458	64,482,750	1,250,000	918,607	1.0000	918,607	12,884,335	9,468,512	218,891,810
2111	5,204,130	3,824,440	41.7596	159,707,080	6,430,205	4,725,465	14.0347	66,320,483	1,250,000	918,607	1.0000	918,607	12,884,335	9,468,512	226,946,170
2112	3,676,270	2,701,638	43.4508	117,388,318	1,824,877	1,341,076	14.4347	19,358,023	1,250,000	918,607	1.0000	918,607	6,751,147	4,961,320	137,664,947
2113	8,279,960	6,084,823	45.2106	275,098,493	15,657,675	11,506,599	14.8461	170,828,123	1,250,000	918,607	1.0000	918,607	25,187,635	18,510,029	446,845,223
2114	6,742,050	4,954,635	47.0416	233,073,960	11,043,935	8,116,028	15.2692	123,925,262	1,250,000	918,607	1.0000	918,607	19,035,985	13,989,270	357,917,829
2115	5,535,960	4,068,297	48.9468	199,130,117	7,425,675	5,457,021	15.7044	85,699,248	1,250,000	918,607	1.0000	918,607	14,211,635	10,443,925	285,747,972
2116	3,676,270	2,701,638	50.9291	137,591,975	1,824,877	1,341,076	16.1520	21,661,052	1,250,000	918,607	1.0000	918,607	6,751,147	4,961,320	160,171,633
2117	3,666,220	2,694,252	52.9918	142,773,266	1,816,475	1,334,902	16.6123	22,175,785	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	165,867,658
2118	6,742,050	4,954,635	55.1379	273,188,172	11,043,935	8,116,028	17.0857	138,668,027	1,250,000	918,607	1.0000	918,607	19,035,985	13,989,270	412,774,806
2119	5,973,090	4,389,537	57.3710	251,832,154	8,737,075	6,420,750	17.5727	112,829,920	1,250,000	918,607	1.0000	918,607	15,960,165	11,728,895	365,580,681
2120	3,676,270	2,701,638	59.6946	161,273,179	1,824,877	1,341,076	18.0735	24,237,929	1,250,000	918,607	1.0000	918,607	6,751,147	4,961,320	186,429,715
2121	3,666,220	2,694,252	62.1122	167,345,923	1,816,475	1,334,902	18.5886	24,813,951	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	193,078,480
2122	7,511,000	5,519,725	64.6277	356,727,150	13,350,805	9,811,314	19.1184	187,576,623	1,250,000	918,607	1.0000	918,607	22,111,805	16,249,646	545,222,379
2123	3,666,220	2,694,252	67.2451	181,175,249	1,816,475	1,334,902	19.6633	26,248,569	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	208,342,425
2124	3,676,270	2,701,638	69.9686	189,029,805	1,824,877	1,341,076	20.2237	27,121,509	1,250,000	918,607	1.0000	918,607	6,751,147	4,961,320	217,069,921
2125	7,511,000	5,519,725	72.8023	401,848,696	13,350,805	9,811,314	20.8000	204,075,328	1,250,000	918,607	1.0000	918,607	22,111,805	16,249,646	606,842,631
2126	3,666,220	2,694,252	75.7508	204,091,749	1,816,475	1,334,902	21.3928	28,557,281	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	233,567,637
2127	3,666,220	2,694,252	78.8187	212,357,445	1,816,475	1,334,902	22.0025	29,371,171	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	242,647,223
2128	7,521,050	5,527,111	82.0109	453,283,338	13,359,207	9,817,488	22.6296	222,165,823	1,250,000	918,607	1.0000	918,607	22,130,257	16,263,206	676,367,768
2129	3,666,220	2,694,252	85.3323	229,906,725	1,816,475	1,334,902	23.2745	31,069,166	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	261,894,498
2130	3,666,220	2,694,252	88.7883	239,218,060	1,816,475	1,334,902	23.9379	31,954,739	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	272,091,406
2131	3,666,220	2,694,252	92.3842	248,906,321	1,816,475	1,334,902	24.6201	32,865,409	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	282,690,337
2132	7,521,050	5,527,111	96.1257	531,297,403	13,359,207	9,817,488	25.3218	248,596,464	1,250,000	918,607	1.0000	918,607	22,130,257	16,263,206	780,812,473
2133	3,666,220	2,694,252	100.0188	269,475,858	1,816,475	1,334,902	26.0434	34,765,375	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	305,159,839
2134	3,666,220	2,694,252	104.0696	280,389,734	1,816,475	1,334,902	26.7857	35,756,272	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	317,064,613
2135	3,666,220	2,694,252	108.2844	291,745,468	1,816,475	1,334,902	27.5491	36,775,336	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	329,439,410
2136	3,676,270	2,701,638	112.6699	304,393,245	1,824,877	1,341,076	28.3342	37,998,302	1,250,000	918,607	1.0000	918,607	6,751,147	4,961,320	343,310,154
2137	3,666,220	2,694,252	117.2331	315,855,521	1,816,475	1,334,902	29.1417	38,901,300	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	355,675,428
2138	3,666,220	2,694,252	121.9810	328,647,561	1,816,475	1,334,902	29.9723	40,010,069	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	369,576,237
2139	26,780,760	19,680,793	126.9212	2,497,909,896	71,160,065	52,294,503	30.8265	1,612,056,498	1,250,000	918,607	1.0000	918,607	99,190,825	72,893,903	4,110,885,000
2140	3,676,270	2,701,638	132.0616	356,782,592	1,824,877	1,341,076	31.7050	42,518,800	1,250,000	918,607	1.0000	918,607	6,751,147	4,961,320	400,219,998
2141	3,666,220	2,694,252	137.4100	370,217,176	1,816,475	1,334,902	32.6086	43,529,270	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	414,665,053
2142	3,666,220	2,694,252	142.9752	385,211,227	1,816,475	1,334,902	33.5380	44,769,928	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	430,899,762
2143	3,666,220	2,694,252	148.7656	400,812,024	1,816,475	1,334,902	34.4938	46,045,826	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	447,776,458
2144	3,676,270	2,701,638	154.7907	418,188,385	1,824,877	1,341,076	35.4769	47,577,202	1,250,000	918,607	1.0000	918,607	6,751,147	4,961,320	466,684,194

Xcel Energy
Nuclear Decommissioning Accrual
200-Year Decommissioning Period
DECON Method

Docket No. E002/M-17-828
Schedule F.17

Proposed

AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
2145	5,973,090	4,389,537	161.0597	706,977,587	8,737,075	6,420,750	36.4880	234,280,340	1,250,000	918,607	1.0000	918,607	15,960,165	11,728,895	942,176,534
2146	5,204,130	3,824,440	167.5826	640,909,579	6,430,205	4,725,465	37.5279	177,336,778	1,250,000	918,607	1.0000	918,607	12,884,335	9,468,512	819,164,963
2147	5,204,130	3,824,440	174.3697	666,866,434	6,430,205	4,725,465	38.5974	182,390,662	1,250,000	918,607	1.0000	918,607	12,884,335	9,468,512	850,175,704
2148	3,676,270	2,701,638	181.4317	490,162,713	1,824,877	1,341,076	39.6975	53,237,346	1,250,000	918,607	1.0000	918,607	6,751,147	4,961,320	544,318,666
2149	3,666,220	2,694,252	188.7796	508,619,826	1,816,475	1,334,902	40.8288	54,502,428	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	564,040,861
2150	5,973,090	4,389,537	196.4252	862,215,774	8,737,075	6,420,750	41.9925	269,623,361	1,250,000	918,607	1.0000	918,607	15,960,165	11,728,895	1,132,757,742
2151	5,973,090	4,389,537	204.3804	897,135,423	8,737,075	6,420,750	43.1893	277,307,715	1,250,000	918,607	1.0000	918,607	15,960,165	11,728,895	1,175,361,744
2152	5,983,130	4,396,916	212.6578	935,038,423	8,745,477	6,426,924	44.4201	285,484,624	1,250,000	918,607	1.0000	918,607	15,978,607	11,742,447	1,221,441,653
2153	3,666,220	2,694,252	221.2705	596,158,501	1,816,475	1,334,902	45.6861	60,986,445	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	658,063,552
2154	3,666,220	2,694,252	230.2319	620,302,771	1,816,475	1,334,902	46.9882	62,724,620	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	683,945,998
2155	6,304,910	4,633,387	239.5563	1,109,957,090	9,732,545	7,152,307	48.3273	345,651,681	1,250,000	918,607	1.0000	918,607	17,287,455	12,704,301	1,456,527,378
2156	5,214,180	3,831,825	249.2584	955,114,688	6,438,607	4,731,639	49.7047	235,184,696	1,250,000	918,607	1.0000	918,607	12,902,787	9,482,071	1,191,217,991
2157	5,204,130	3,824,440	259.3533	991,881,103	6,430,205	4,725,465	51.1212	241,571,441	1,250,000	918,607	1.0000	918,607	12,884,335	9,468,512	1,234,371,151
2158	3,666,220	2,694,252	269.8571	727,063,048	1,816,475	1,334,902	52.5782	70,186,720	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	798,168,374
2159	5,204,130	3,824,440	280.7864	1,073,850,706	6,430,205	4,725,465	54.0767	255,537,553	1,250,000	918,607	1.0000	918,607	12,884,335	9,468,512	1,330,306,865
2160	5,214,180	3,831,825	292.1582	1,119,499,235	6,438,607	4,731,639	55.6179	263,163,824	1,250,000	918,607	1.0000	918,607	12,902,787	9,482,071	1,383,581,665
2161	5,204,130	3,824,440	303.9906	1,162,593,774	6,430,205	4,725,465	57.2030	270,310,774	1,250,000	918,607	1.0000	918,607	12,884,335	9,468,512	1,433,823,154
2162	3,666,220	2,694,252	316.3022	852,197,854	1,816,475	1,334,902	58.8333	78,536,662	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	931,653,123
2163	8,279,960	6,084,823	329.1125	2,002,591,266	15,657,675	11,506,599	60.5100	696,264,321	1,250,000	918,607	1.0000	918,607	25,187,635	18,510,029	2,699,774,193
2164	6,752,090	4,962,013	342.4415	1,699,199,277	11,052,337	8,122,202	62.2345	505,481,208	1,250,000	918,607	1.0000	918,607	19,054,427	14,002,823	2,205,599,092
2165	5,204,130	3,824,440	356.3104	1,362,687,703	6,430,205	4,725,465	64.0082	302,468,508	1,250,000	918,607	1.0000	918,607	12,884,335	9,468,512	1,666,074,818
2166	3,666,220	2,694,252	370.7410	998,869,703	1,816,475	1,334,902	65.8325	87,879,905	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	1,087,668,215
2167	3,666,220	2,694,252	385.7560	1,039,323,898	1,816,475	1,334,902	67.7087	90,384,447	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	1,130,626,952
2168	6,752,090	4,962,013	401.3791	1,991,648,432	11,052,337	8,122,202	69.6384	565,617,182	1,250,000	918,607	1.0000	918,607	19,054,427	14,002,823	2,558,184,221
2169	5,973,090	4,389,537	417.6350	1,833,224,479	8,737,075	6,420,750	71.6231	459,874,047	1,250,000	918,607	1.0000	918,607	15,960,165	11,728,895	2,294,017,133
2170	3,666,220	2,694,252	434.5492	1,170,785,077	1,816,475	1,334,902	73.6643	98,334,587	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	1,270,038,271
2171	3,666,220	2,694,252	452.1484	1,218,201,758	1,816,475	1,334,902	75.7638	101,137,213	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	1,320,257,578
2172	7,521,050	5,527,111	470.4604	2,600,286,797	13,359,207	9,817,488	77.9230	765,008,105	1,250,000	918,607	1.0000	918,607	22,130,257	16,263,206	3,366,213,509
2173	3,666,220	2,694,252	489.5141	1,318,874,373	1,816,475	1,334,902	80.1438	106,984,081	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	1,426,777,061
2174	3,666,220	2,694,252	509.3394	1,372,288,728	1,816,475	1,334,902	82.4279	110,033,130	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	1,483,240,465
2175	7,511,000	5,519,725	529.9676	2,925,275,561	13,350,805	9,811,314	84.7771	831,774,735	1,250,000	918,607	1.0000	918,607	22,111,805	16,249,646	3,757,968,903
2176	3,676,270	2,701,638	551.4313	1,489,767,567	1,824,877	1,341,076	87.1933	116,932,801	1,250,000	918,607	1.0000	918,607	6,751,147	4,961,320	1,607,618,975
2177	3,666,220	2,694,252	573.7643	1,545,865,647	1,816,475	1,334,902	89.6783	119,711,700	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	1,666,495,954
2178	7,511,000	5,519,725	597.0018	3,295,285,929	13,350,805	9,811,314	92.2341	904,937,703	1,250,000	918,607	1.0000	918,607	22,111,805	16,249,646	4,201,142,239
2179	3,666,220	2,694,252	621.1803	1,673,616,303	1,816,475	1,334,902	94.8628	126,632,497	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	1,801,167,407
2180	3,676,270	2,701,638	646.3381	1,746,171,352	1,824,877	1,341,076	97.5664	130,843,911	1,250,000	918,607	1.0000	918,607	6,751,147	4,961,320	1,877,933,870
2181	3,666,220	2,694,252	672.5148	1,811,924,386	1,816,475	1,334,902	100.3470	133,953,364	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	1,946,796,356
2182	7,511,000	5,519,725	699.7517	3,862,437,150	13,350,805	9,811,314	103.2069	1,012,595,287	1,250,000	918,607	1.0000	918,607	22,111,805	16,249,646	4,875,951,044
2183	3,666,220	2,694,252	728.0916	1,961,662,293	1,816,475	1,334,902	106.1483	141,697,528	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	2,104,278,428
2184	3,676,270	2,701,638	757.5793	2,046,704,767	1,824,877	1,341,076	109.1736	146,410,043	1,250,000	918,607	1.0000	918,607	6,751,147	4,961,320	2,194,033,417
2185	3,666,220	2,694,252	788.2613	2,123,774,632	1,816,475	1,334,902	112.2850	149,889,418	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	2,274,582,657
2186	3,666,220	2,694,252	820.1859	2,209,787,551	1,816,475	1,334,902	115.4851	154,161,237	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	2,364,867,395
2187	3,666,220	2,694,252	853.4034	2,299,283,869	1,816,475	1,334,902	118.7764	158,554,798	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	2,458,757,274
2188	3,676,270	2,701,638	887.9662	2,398,962,927	1,824,877	1,341,076	122.1616	163,827,932	1,250,000	918,607	1.0000	918,607	6,751,147	4,961,320	2,563,709,466
2189	26,780,760	19,680,793	923.9289	18,183,653,653	71,160,065	52,294,503	125.6432	6,570,448,704	1,250,000	918,607	1.0000	918,607	99,190,825	72,893,903	24,755,020,964
2190	3,666,220	2,694,252	961.3480	2,590,113,830	1,816,475	1,334,902	129.2240	172,501,315	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	2,763,533,752
2191	3,666,220	2,694,252	1,000.2826	2,695,013,456	1,816,475	1,334,902	132.9069	177,417,624	1,250,000	918,607	1.0000	918,607	6,732,695	4,947,761	2,873,349,687
2192	3,676,270	2,701,638	1,040.7940	2,811,848,267	1,824,877	1,341,076	136.6947	183,317,917	1,250,000	918,607	1.0000	918,607	6,751,147	4,961,320	2,996,084,790
2193	3,050,090	2,241,467	1,082.9462	2,427,388,206	1,970,568	1,448,142	140.5905	203,594,977	1,250,000	918,607	1.0000	918,607	6,270,658	4,608,216	2,631,901,790
2194	3,145,780	2,311,788	1,126.8055	2,604,935,693	2,257,628	1,659,098	144.5974	239,901,260	1,250,000	918,607	1.0000	918,607	6,653,408	4,889,493	2,845,755,560
2195	5,784,470	4,250,923	1,172.4411	4,983,957,252	10,173,688	7,476,496	148.7184	1,111,892,529	1,250,000	918,607	1.0000	918,607	17,208,158	12,646,026	6,096,768,388
2196	4,739,630	3,483,086	1,219.9250	4,249,103,136	7,022,925	5,161,046	152.9569	789,417,579	1,250,000	918,607	1.0000	918,607	13,012,555	9,562,738	5,039,439,321
2197	4,635,850	3,406,819	1,269.3320	4,324,384,534	6,727,828	4,944,183	157.3161	777,799,643	1,250,000	918,607	1.0000	918,607	12,613,678	9,269,609	5,103,102,785
2198	3,241,470	2,382,109	1,320.7399	3,146,146,967	2,544,688	1,870,054	161.7997	302,574,219	1,250,000	918,607	1.0000	918,607	7,036,158	5,170,771	3,449,639,793
2199	3,097,940	2,276,631	1,374.2299	3,128,614,812	2,114,098	1,553,620	166.4109	258,539,286	1,250,000	918,607	1.0000	918,607	6,462,038	4,748,858	3,388,072,705
2200	5,356,960	3,936,752	1,429.8862	5,629,107,982	8,891,168	6,533,991	171.1537	1,118,316,674	1,250,000	918,607	1.0000	918,607	15,498,128	11,389,350	6,748,343,262
2201	5,452,650	4,007,074	1,487.7966	5,961,710,528	9,178,228	6,744,947	176.0315	1,187,323,117	1,250,000	918,607	1.0000	918,607	15,880,878	11,670,627	7,149,952,252

Xcel Energy
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AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
2202	5,452,650	4,007,074	1,548.0523	6,203,159,555	9,178,228	6,744,947	181.0484	1,221,161,841	1,250,000	918,607	1.0000	918,607	15,880,878	11,670,627	7,425,240,003
2203	3,097,940	2,276,631	1,610.7485	3,667,080,462	2,114,098	1,553,620	186.2083	289,296,920	1,250,000	918,607	1.0000	918,607	6,462,038	4,748,858	3,957,295,989
2204	3,153,870	2,317,733	1,675.9838	3,884,483,723	2,265,665	1,665,004	191.5152	318,873,632	1,250,000	918,607	1.0000	918,607	6,669,535	4,901,345	4,204,275,961
2205	5,452,650	4,007,074	1,743.8611	6,987,779,835	9,178,228	6,744,947	196.9734	1,328,575,120	1,250,000	918,607	1.0000	918,607	15,880,878	11,670,627	8,317,273,562
2206	4,635,850	3,406,819	1,814.4875	6,181,630,718	6,727,828	4,944,183	202.5872	1,001,628,263	1,250,000	918,607	1.0000	918,607	12,613,678	9,269,609	7,184,177,587
2207	4,683,690	3,441,976	1,887.9742	6,498,361,979	6,871,358	5,049,661	208.3609	1,052,152,010	1,250,000	918,607	1.0000	918,607	12,805,048	9,410,244	7,551,432,596
2208	3,153,870	2,317,733	1,964.4372	4,553,041,818	2,265,665	1,665,004	214.2992	356,809,090	1,250,000	918,607	1.0000	918,607	6,669,535	4,901,345	4,910,769,515
2209	4,635,850	3,406,819	2,043.9969	6,963,527,731	6,727,828	4,944,183	220.4067	1,089,731,138	1,250,000	918,607	1.0000	918,607	12,613,678	9,269,609	8,054,177,476
2210	4,676,510	3,436,700	2,126.7788	7,309,099,791	6,849,828	5,033,839	226.6883	1,141,112,494	1,250,000	918,607	1.0000	918,607	12,776,338	9,389,146	8,451,130,892
2211	4,669,340	3,431,430	2,212.9133	7,593,458,063	6,828,298	5,018,017	233.1489	1,169,945,215	1,250,000	918,607	1.0000	918,607	12,747,638	9,368,055	8,764,321,886
2212	3,139,520	2,307,188	2,302.5363	5,312,383,769	2,222,605	1,633,360	239.7937	391,669,469	1,250,000	918,607	1.0000	918,607	6,612,125	4,859,155	5,704,971,845
2213	7,745,160	5,691,806	2,395.7890	13,636,366,398	16,055,768	11,799,152	246.6278	2,909,998,794	1,250,000	918,607	1.0000	918,607	25,050,928	18,409,565	16,547,283,798
2214	6,207,250	4,561,618	2,492.8185	11,371,286,392	11,442,028	8,408,581	253.6567	2,132,892,848	1,250,000	918,607	1.0000	918,607	18,899,278	13,888,806	13,505,097,847
2215	4,669,340	3,431,430	2,593.7776	8,900,367,417	6,828,298	5,018,017	260.8859	1,309,129,961	1,250,000	918,607	1.0000	918,607	12,747,638	9,368,055	10,210,415,985
2216	3,139,520	2,307,188	2,698.8256	6,226,697,626	13,878,683	10,199,243	268.3212	2,736,673,199	1,250,000	918,607	1.0000	918,607	18,268,203	13,425,038	8,964,289,432
2217	3,145,780	2,311,788	2,808.1281	6,491,797,491	2,257,628	1,659,098	275.9683	457,858,460	1,250,000	918,607	1.0000	918,607	6,653,408	4,889,493	6,950,574,559
2218	1,058,128	777,603	2,921.8572	2,272,044,845	2,283,531	1,678,134	283.8334	476,310,374	0	0	1.0000	0	3,341,659	2,455,737	2,748,355,219
	$1,259,022,756	$925,237,616		$257,498,187,414	$1,487,265,430	$1,092,969,857		$50,395,864,825	$231,250,000	$169,942,281		$169,942,281	$2,977,538,186	$2,188,149,754	$308,063,994,519

Xcel Energy
Nuclear Decommissioning Accrual
200-Year Decommissioning Period
DECON Method

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Proposed

AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
Prairie Island Unit 2															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2034	$7,760,265	$5,702,906	1.9639	$11,199,938	$4,479,535	$3,291,946	1.6124	$5,307,933	$1,250,000	$918,607	1.0000	$918,607	$13,489,800	$9,913,459	$17,426,478
2035	46,911,429	34,474,531	2.0434	70,445,256	35,601,336	26,162,907	1.6584	43,388,565	1,250,000	918,607	1.0000	918,607	83,762,765	61,556,044	114,752,428
2036	67,514,041	49,615,092	2.1262	105,491,609	86,298,834	63,419,765	1.7056	108,168,751	1,250,000	918,607	1.0000	918,607	155,062,874	113,953,464	214,578,967
2037	72,593,441	53,347,870	2.2123	118,021,492	75,650,363	55,594,358	1.7542	97,523,623	1,250,000	918,607	1.0000	918,607	149,493,804	109,860,835	216,463,722
2038	46,603,525	34,248,257	2.3019	78,836,063	42,782,150	31,439,983	1.8042	56,724,017	1,250,000	918,607	1.0000	918,607	90,635,675	66,606,847	136,478,687
2039	40,341,063	29,646,064	2.3951	71,005,287	76,484,927	56,207,667	1.8556	104,298,947	1,250,000	918,607	1.0000	918,607	118,075,990	86,772,338	176,222,841
2040	37,417,178	27,497,343	2.4921	68,526,129	14,193,500	10,430,598	1.9085	19,906,796	1,250,000	918,607	1.0000	918,607	52,860,678	38,846,548	89,351,532
2041	23,380,886	17,182,275	2.5930	44,553,639	13,070,130	9,605,049	1.9629	18,853,752	1,250,000	918,607	1.0000	918,607	37,701,016	27,705,931	64,325,998
2042	16,738,669	12,301,006	2.6981	33,189,343	17,178,640	12,624,334	2.0189	25,487,268	1,250,000	918,607	1.0000	918,607	35,167,309	25,843,947	59,595,219
2043	9,790,575	7,194,952	2.8073	20,198,388	9,014,069	6,624,309	2.0764	13,754,715	1,250,000	918,607	1.0000	918,607	20,054,644	14,737,868	34,871,710
2044	3,676,269	2,701,637	2.9210	7,891,481	1,825,866	1,341,803	2.1356	2,865,554	1,250,000	918,607	1.0000	918,607	6,752,135	4,962,047	11,675,642
2045	5,973,090	4,389,537	3.0393	13,341,121	8,738,060	6,421,474	2.1964	14,104,126	1,250,000	918,607	1.0000	918,607	15,961,150	11,729,619	28,363,854
2046	5,204,135	3,824,444	3.1624	12,094,420	6,431,194	4,726,192	2.2590	10,676,467	1,250,000	918,607	1.0000	918,607	12,885,329	9,469,242	23,689,494
2047	5,204,135	3,824,444	3.2905	12,584,332	6,431,194	4,726,192	2.3234	10,980,834	1,250,000	918,607	1.0000	918,607	12,885,329	9,469,242	24,483,772
2048	3,676,269	2,701,637	3.4238	9,249,865	1,825,866	1,341,803	2.3896	3,206,372	1,250,000	918,607	1.0000	918,607	6,752,135	4,962,047	13,374,843
2049	5,204,135	3,824,444	3.5624	13,624,198	6,431,194	4,726,192	2.4577	11,615,561	1,250,000	918,607	1.0000	918,607	12,885,329	9,469,242	26,158,366
2050	5,973,090	4,389,537	3.7067	16,270,699	8,738,060	6,421,474	2.5278	16,232,202	1,250,000	918,607	1.0000	918,607	15,961,150	11,729,619	33,421,508
2051	5,779,135	4,247,003	3.8568	16,379,840	8,156,192	5,993,868	2.5998	15,582,857	1,250,000	918,607	1.0000	918,607	15,185,327	11,159,477	32,881,304
2052	5,983,135	4,396,919	4.0130	17,644,838	8,746,464	6,427,650	2.6739	17,186,894	1,250,000	918,607	1.0000	918,607	15,979,599	11,743,176	35,750,338
2053	3,666,224	2,694,255	4.1756	11,250,131	1,817,462	1,335,627	2.7501	3,673,107	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	15,841,845
2054	3,666,224	2,694,255	4.3447	11,705,730	1,817,462	1,335,627	2.8285	3,777,820	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	16,402,157
2055	5,973,090	4,389,537	4.5206	19,843,343	8,738,060	6,421,474	2.9091	18,680,710	1,250,000	918,607	1.0000	918,607	15,961,150	11,729,619	39,442,660
2056	5,214,179	3,831,825	4.7037	18,023,754	6,439,598	4,732,368	2.9920	14,159,244	1,250,000	918,607	1.0000	918,607	12,903,777	9,482,799	33,101,605
2057	5,204,135	3,824,444	4.8942	18,717,592	6,431,194	4,726,192	3.0773	14,543,910	1,250,000	918,607	1.0000	918,607	12,885,329	9,469,242	34,180,108
2058	3,666,224	2,694,255	5.0924	13,720,224	1,817,462	1,335,627	3.1650	4,227,259	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	18,866,090
2059	5,010,180	3,681,909	5.2987	19,509,330	5,849,328	4,298,587	3.2552	13,992,760	1,250,000	918,607	1.0000	918,607	12,109,508	8,899,102	34,420,697
2060	5,214,179	3,831,825	5.5133	21,125,999	6,439,598	4,732,368	3.3480	15,843,967	1,250,000	918,607	1.0000	918,607	12,903,777	9,482,799	37,888,573
2061	5,204,135	3,824,444	5.7366	21,939,303	6,431,194	4,726,192	3.4434	16,274,168	1,250,000	918,607	1.0000	918,607	12,885,329	9,469,242	39,132,078
2062	3,666,224	2,694,255	5.9689	16,081,739	1,817,462	1,335,627	3.5415	4,730,122	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	21,730,468
2063	8,279,956	6,084,820	6.2106	37,790,383	15,658,658	11,507,322	3.6425	41,915,419	1,250,000	918,607	1.0000	918,607	25,188,614	18,510,748	80,624,408
2064	6,558,135	4,819,479	6.4622	31,144,434	10,471,464	7,695,328	3.7463	28,829,006	1,250,000	918,607	1.0000	918,607	18,279,599	13,433,413	60,892,047
2065	5,204,135	3,824,444	6.7239	25,715,176	6,431,194	4,726,192	3.8531	18,210,489	1,250,000	918,607	1.0000	918,607	12,885,329	9,469,242	44,844,272
2066	3,666,224	2,694,255	6.9962	18,849,547	1,817,462	1,335,627	3.9629	5,292,955	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	25,061,109
2067	3,666,224	2,694,255	7.2795	19,612,829	1,817,462	1,335,627	4.0758	5,443,747	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	25,975,184
2068	6,752,090	4,962,013	7.5744	37,584,274	11,053,330	8,122,933	4.1920	34,051,333	1,250,000	918,607	1.0000	918,607	19,055,420	14,003,553	72,554,214
2069	5,973,090	4,389,537	7.8811	34,594,384	8,738,060	6,421,474	4.3115	27,686,186	1,250,000	918,607	1.0000	918,607	15,961,150	11,729,619	63,199,176
2070	3,666,224	2,694,255	8.2003	22,093,699	1,817,462	1,335,627	4.4343	5,922,570	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	28,934,876
2071	3,666,224	2,694,255	8.5324	22,988,461	1,817,462	1,335,627	4.5607	6,091,393	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	29,998,461
2072	7,327,090	5,384,572	8.8780	47,804,235	12,778,330	9,390,610	4.6907	44,048,535	1,250,000	918,607	1.0000	918,607	21,355,420	15,693,790	92,771,376
2073	3,666,224	2,694,255	9.2375	24,888,181	1,817,462	1,335,627	4.8244	6,443,598	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	32,250,385
2074	3,666,224	2,694,255	9.6117	25,896,371	1,817,462	1,335,627	4.9619	6,627,246	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	33,442,224
2075	7,842,823	5,763,577	10.0009	57,640,959	14,347,260	10,543,594	5.1033	53,807,124	1,250,000	918,607	1.0000	918,607	23,440,083	17,225,778	112,366,690
2076	3,676,269	2,701,637	10.4060	28,113,234	1,825,866	1,341,803	5.2487	7,042,720	1,250,000	918,607	1.0000	918,607	6,752,135	4,962,047	36,074,561
2077	3,666,224	2,694,255	10.8274	29,171,777	1,817,462	1,335,627	5.3983	7,210,114	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	37,300,497
2078	7,511,001	5,519,726	11.2659	62,184,681	13,351,792	9,812,039	5.5522	54,478,403	1,250,000	918,607	1.0000	918,607	22,112,793	16,250,372	117,581,691
2079	3,666,224	2,694,255	11.7222	31,582,596	1,817,462	1,335,627	5.7104	7,626,963	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	40,128,166
2080	3,676,269	2,701,637	12.1970	32,951,866	1,825,866	1,341,803	5.8731	7,880,541	1,250,000	918,607	1.0000	918,607	6,752,135	4,962,047	41,751,014
2081	3,666,224	2,694,255	12.6909	34,192,521	1,817,462	1,335,627	6.0405	8,067,853	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	43,178,981
2082	7,123,090	5,234,656	13.2049	69,123,107	12,188,060	8,956,829	6.2127	55,646,093	1,250,000	918,607	1.0000	918,607	20,561,150	15,110,092	125,687,807
2083	3,666,224	2,694,255	13.7397	37,018,255	1,817,462	1,335,627	6.3897	8,534,254	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	46,471,116
2084	3,676,269	2,701,637	14.2962	38,623,142	1,825,866	1,341,803	6.5719	8,818,193	1,250,000	918,607	1.0000	918,607	6,752,135	4,962,047	48,359,942
2085	3,666,224	2,694,255	14.8752	40,077,582	1,817,462	1,335,627	6.7592	9,027,768	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	50,023,957
2086	3,666,224	2,694,255	15.4776	41,700,601	1,817,462	1,335,627	6.9518	9,285,010	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	51,904,218
2087	3,666,224	2,694,255	16.1045	43,389,630	1,817,462	1,335,627	7.1499	9,549,598	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	53,857,834
2088	3,676,269	2,701,637	16.7567	45,270,519	1,825,866	1,341,803	7.3537	9,867,215	1,250,000	918,607	1.0000	918,607	6,752,135	4,962,047	56,056,341

Xcel Energy
Nuclear Decommissioning Accrual
200-Year Decommissioning Period
DECON Method

Docket No. E002/M-17-828
Schedule F.17

Proposed

AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
2089	26,770,052	19,672,924	17.4353	343,003,333	73,063,378	53,693,220	7.5633	406,097,928	1,250,000	918,607	1.0000	918,607	101,083,430	74,284,751	750,019,869
2090	3,666,224	2,694,255	18.1415	48,877,827	1,817,462	1,335,627	7.7788	10,389,573	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	60,186,007
2091	3,666,224	2,694,255	18.8762	50,857,296	1,817,462	1,335,627	8.0005	10,685,682	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	62,461,585
2092	3,676,269	2,701,637	19.6407	53,062,040	1,825,866	1,341,803	8.2285	11,041,024	1,250,000	918,607	1.0000	918,607	6,752,135	4,962,047	65,021,671
2093	3,666,224	2,694,255	20.4361	55,060,065	1,817,462	1,335,627	8.4630	11,303,409	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	67,282,081
2094	3,666,224	2,694,255	21.2638	57,290,099	1,817,462	1,335,627	8.7042	11,625,562	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	69,834,269
2095	5,973,090	4,389,537	22.1250	97,118,516	8,738,060	6,421,474	8.9523	57,486,963	1,250,000	918,607	1.0000	918,607	15,961,150	11,729,619	155,524,086
2096	5,214,179	3,831,825	23.0210	88,212,437	6,439,598	4,732,368	9.2075	43,573,275	1,250,000	918,607	1.0000	918,607	12,903,777	9,482,799	132,704,319
2097	5,204,135	3,824,444	23.9534	91,608,426	6,431,194	4,726,192	9.4699	44,756,562	1,250,000	918,607	1.0000	918,607	12,885,329	9,469,242	137,283,595
2098	3,666,224	2,694,255	24.9235	67,150,264	1,817,462	1,335,627	9.7398	13,008,737	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	81,077,609
2099	3,666,224	2,694,255	25.9329	69,869,845	1,817,462	1,335,627	10.0173	13,379,374	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	84,167,826
2100	5,973,090	4,389,537	26.9832	118,443,767	8,738,060	6,421,474	10.3028	66,159,164	1,250,000	918,607	1.0000	918,607	15,961,150	11,729,619	185,521,538
2101	5,973,090	4,389,537	28.0760	123,240,654	8,738,060	6,421,474	10.5965	68,045,150	1,250,000	918,607	1.0000	918,607	15,961,150	11,729,619	192,204,411
2102	5,973,090	4,389,537	29.2131	128,231,997	8,738,060	6,421,474	10.8985	69,984,436	1,250,000	918,607	1.0000	918,607	15,961,150	11,729,619	199,135,039
2103	3,666,224	2,694,255	30.3962	81,895,114	1,817,462	1,335,627	11.2091	14,971,174	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	97,784,894
2104	3,676,269	2,701,637	31.6272	85,445,211	1,825,866	1,341,803	11.5285	15,468,973	1,250,000	918,607	1.0000	918,607	6,752,135	4,962,047	101,832,791
2105	5,973,090	4,389,537	32.9081	144,451,338	8,738,060	6,421,474	11.8571	76,140,061	1,250,000	918,607	1.0000	918,607	15,961,150	11,729,619	221,510,005
2106	5,204,135	3,824,444	34.2409	130,952,389	6,431,194	4,726,192	12.1950	57,635,907	1,250,000	918,607	1.0000	918,607	12,885,329	9,469,242	189,506,903
2107	5,204,135	3,824,444	35.6277	136,256,128	6,431,194	4,726,192	12.5426	59,278,731	1,250,000	918,607	1.0000	918,607	12,885,329	9,469,242	196,453,466
2108	3,676,269	2,701,637	37.0706	100,151,302	1,825,866	1,341,803	12.9000	17,309,255	1,250,000	918,607	1.0000	918,607	6,752,135	4,962,047	118,379,164
2109	5,204,135	3,824,444	38.5720	147,516,437	6,431,194	4,726,192	13.2677	62,705,693	1,250,000	918,607	1.0000	918,607	12,885,329	9,469,242	211,140,737
2110	5,204,135	3,824,444	40.1341	153,490,600	6,431,194	4,726,192	13.6458	64,492,666	1,250,000	918,607	1.0000	918,607	12,885,329	9,469,242	218,901,873
2111	5,204,135	3,824,444	41.7596	159,707,233	6,431,194	4,726,192	14.0347	66,330,682	1,250,000	918,607	1.0000	918,607	12,885,329	9,469,242	226,956,522
2112	3,676,269	2,701,637	43.4508	117,388,286	1,825,866	1,341,803	14.4347	19,368,520	1,250,000	918,607	1.0000	918,607	6,752,135	4,962,047	137,675,412
2113	8,279,956	6,084,820	45.2106	275,098,360	15,658,658	11,507,322	14.8461	170,838,846	1,250,000	918,607	1.0000	918,607	25,188,614	18,510,748	446,855,813
2114	6,742,046	4,954,632	47.0416	233,073,822	11,044,926	8,116,757	15.2692	123,936,380	1,250,000	918,607	1.0000	918,607	19,036,972	13,989,996	357,928,808
2115	5,535,957	4,068,295	48.9468	199,130,009	7,426,662	5,457,747	15.7044	85,710,637	1,250,000	918,607	1.0000	918,607	14,212,619	10,444,648	285,759,253
2116	3,676,269	2,701,637	50.9291	137,591,937	1,825,866	1,341,803	16.1520	21,672,797	1,250,000	918,607	1.0000	918,607	6,752,135	4,962,047	160,183,341
2117	3,666,224	2,694,255	52.9918	142,773,422	1,817,462	1,335,627	16.6123	22,187,832	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	165,879,861
2118	6,742,046	4,954,632	55.1379	273,188,010	11,044,926	8,116,757	17.0857	138,680,468	1,250,000	918,607	1.0000	918,607	19,036,972	13,989,996	412,787,085
2119	5,973,090	4,389,537	57.3710	251,832,154	8,738,060	6,421,474	17.5727	112,842,638	1,250,000	918,607	1.0000	918,607	15,961,150	11,729,619	365,593,399
2120	3,676,269	2,701,637	59.6946	161,273,136	1,825,866	1,341,803	18.0735	24,251,071	1,250,000	918,607	1.0000	918,607	6,752,135	4,962,047	186,442,814
2121	3,666,224	2,694,255	62.1122	167,346,105	1,817,462	1,335,627	18.5886	24,827,431	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	193,092,143
2122	7,511,001	5,519,726	64.6277	356,727,197	13,351,792	9,812,039	19.1184	187,590,487	1,250,000	918,607	1.0000	918,607	22,112,793	16,250,372	545,236,291
2123	3,666,224	2,694,255	67.2451	181,175,447	1,817,462	1,335,627	19.6633	26,262,829	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	208,356,883
2124	3,676,269	2,701,637	69.9686	189,029,753	1,825,866	1,341,803	20.2237	27,136,215	1,250,000	918,607	1.0000	918,607	6,752,135	4,962,047	217,084,576
2125	7,511,001	5,519,726	72.8023	401,848,749	13,351,792	9,812,039	20.8000	204,090,412	1,250,000	918,607	1.0000	918,607	22,112,793	16,250,372	606,857,768
2126	3,666,224	2,694,255	75.7508	204,091,972	1,817,462	1,335,627	21.3928	28,572,795	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	233,583,374
2127	3,666,224	2,694,255	78.8187	212,357,677	1,817,462	1,335,627	22.0025	29,387,127	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	242,663,411
2128	7,521,045	5,527,107	82.0109	453,283,037	13,360,196	9,818,215	22.6296	222,182,279	1,250,000	918,607	1.0000	918,607	22,131,241	16,263,929	676,383,922
2129	3,666,224	2,694,255	85.3323	229,906,976	1,817,462	1,335,627	23.2745	31,086,044	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	261,911,627
2130	3,666,224	2,694,255	88.7883	239,218,321	1,817,462	1,335,627	23.9379	31,972,099	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	272,109,027
2131	3,666,224	2,694,255	92.3842	248,906,593	1,817,462	1,335,627	24.6201	32,883,264	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	282,708,463
2132	7,521,045	5,527,107	96.1257	531,297,049	13,360,196	9,818,215	25.3218	248,614,877	1,250,000	918,607	1.0000	918,607	22,131,241	16,263,929	780,830,534
2133	3,666,224	2,694,255	100.0188	269,476,152	1,817,462	1,335,627	26.0434	34,784,261	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	305,179,020
2134	3,666,224	2,694,255	104.0696	280,390,040	1,817,462	1,335,627	26.7857	35,775,697	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	317,084,344
2135	3,666,224	2,694,255	108.2844	291,745,786	1,817,462	1,335,627	27.5491	36,795,314	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	329,459,707
2136	3,676,269	2,701,637	112.6699	304,393,162	1,825,866	1,341,803	28.3342	38,018,906	1,250,000	918,607	1.0000	918,607	6,752,135	4,962,047	343,330,675
2137	3,666,224	2,694,255	117.2331	315,855,866	1,817,462	1,335,627	29.1417	38,922,433	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	355,696,906
2138	3,666,224	2,694,255	121.9810	328,647,919	1,817,462	1,335,627	29.9723	40,031,805	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	369,598,331
2139	26,780,755	19,680,790	126.9212	2,497,909,429	71,161,056	52,295,231	30.8265	1,612,078,944	1,250,000	918,607	1.0000	918,607	99,191,811	72,894,628	4,110,906,980
2140	3,676,269	2,701,637	132.0616	356,782,495	1,825,866	1,341,803	31.7050	42,541,855	1,250,000	918,607	1.0000	918,607	6,752,135	4,962,047	400,242,957
2141	3,666,224	2,694,255	137.4100	370,217,580	1,817,462	1,335,627	32.6086	43,552,918	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	414,689,104
2142	3,666,224	2,694,255	142.9752	385,211,647	1,817,462	1,335,627	33.5380	44,794,249	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	430,924,504
2143	3,666,224	2,694,255	148.7656	400,812,462	1,817,462	1,335,627	34.4938	46,070,841	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	447,801,910
2144	3,676,269	2,701,637	154.7907	418,188,271	1,825,866	1,341,803	35.4769	47,603,001	1,250,000	918,607	1.0000	918,607	6,752,135	4,962,047	466,709,878
2145	5,973,090	4,389,537	161.0597	706,977,587	8,738,060	6,421,474	36.4880	234,306,748	1,250,000	918,607	1.0000	918,607	15,961,150	11,729,619	942,202,942

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	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
2146	5,204,135	3,824,444	167.5826	640,910,194	6,431,194	4,726,192	37.5279	177,364,048	1,250,000	918,607	1.0000	918,607	12,885,329	9,469,242	819,192,849
2147	5,204,135	3,824,444	174.3697	666,867,075	6,431,194	4,726,192	38.5974	182,418,710	1,250,000	918,607	1.0000	918,607	12,885,329	9,469,242	850,204,392
2148	3,676,269	2,701,637	181.4317	490,162,580	1,825,866	1,341,803	39.6975	53,266,213	1,250,000	918,607	1.0000	918,607	6,752,135	4,962,047	544,347,400
2149	3,666,224	2,694,255	188.7796	508,620,381	1,817,462	1,335,627	40.8288	54,532,036	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	564,071,025
2150	5,973,090	4,389,537	196.4252	862,215,774	8,738,060	6,421,474	41.9925	269,653,752	1,250,000	918,607	1.0000	918,607	15,961,150	11,729,619	1,132,788,133
2151	5,973,090	4,389,537	204.3804	897,135,423	8,738,060	6,421,474	43.1893	277,338,972	1,250,000	918,607	1.0000	918,607	15,961,150	11,729,619	1,175,393,002
2152	5,983,135	4,396,919	212.6578	935,039,204	8,746,464	6,427,650	44.4201	285,516,860	1,250,000	918,607	1.0000	918,607	15,979,599	11,743,176	1,221,474,671
2153	3,666,224	2,694,255	221.2705	596,159,151	1,817,462	1,335,627	45.6861	61,019,576	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	658,097,334
2154	3,666,224	2,694,255	230.2319	620,303,448	1,817,462	1,335,627	46.9882	62,758,696	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	683,980,750
2155	6,304,913	4,633,389	239.5563	1,109,957,618	9,733,528	7,153,029	48.3273	345,686,586	1,250,000	918,607	1.0000	918,607	17,288,441	12,705,025	1,456,562,811
2156	5,214,179	3,831,825	249.2584	955,114,505	6,439,598	4,732,368	49.7047	235,220,914	1,250,000	918,607	1.0000	918,607	12,903,777	9,482,799	1,191,254,025
2157	5,204,135	3,824,444	259.3533	991,882,056	6,431,194	4,726,192	51.1212	241,608,589	1,250,000	918,607	1.0000	918,607	12,885,329	9,469,242	1,234,409,252
2158	3,666,224	2,694,255	269.8571	727,063,841	1,817,462	1,335,627	52.5782	70,224,849	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	798,207,297
2159	5,204,135	3,824,444	280.7864	1,073,851,738	6,431,194	4,726,192	54.0767	255,576,848	1,250,000	918,607	1.0000	918,607	12,885,329	9,469,242	1,330,347,193
2160	5,214,179	3,831,825	292.1582	1,119,499,020	6,439,598	4,732,368	55.6179	263,204,350	1,250,000	918,607	1.0000	918,607	12,903,777	9,482,799	1,383,621,977
2161	5,204,135	3,824,444	303.9906	1,162,594,891	6,431,194	4,726,192	57.2030	270,352,341	1,250,000	918,607	1.0000	918,607	12,885,329	9,469,242	1,433,865,839
2162	3,666,224	2,694,255	316.3022	852,198,784	1,817,462	1,335,627	58.8333	78,579,328	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	931,696,719
2163	8,279,956	6,084,820	329.1125	2,002,590,298	15,658,658	11,507,322	60.5100	696,308,024	1,250,000	918,607	1.0000	918,607	25,188,614	18,510,748	2,699,816,930
2164	6,752,090	4,962,013	342.4415	1,699,199,277	11,053,330	8,122,933	62.2345	505,526,647	1,250,000	918,607	1.0000	918,607	19,055,420	14,003,553	2,205,644,530
2165	5,204,135	3,824,444	356.3104	1,362,689,012	6,431,194	4,726,192	64.0082	302,515,021	1,250,000	918,607	1.0000	918,607	12,885,329	9,469,242	1,666,122,640
2166	3,666,224	2,694,255	370.7410	998,870,793	1,817,462	1,335,627	65.8325	87,927,646	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	1,087,717,046
2167	3,666,224	2,694,255	385.7560	1,039,325,032	1,817,462	1,335,627	67.7087	90,433,549	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	1,130,677,188
2168	6,752,090	4,962,013	401.3791	1,991,648,432	11,053,330	8,122,933	69.6384	565,668,027	1,250,000	918,607	1.0000	918,607	19,055,420	14,003,553	2,558,235,066
2169	5,973,090	4,389,537	417.6350	1,833,224,479	8,738,060	6,421,474	71.6231	459,925,883	1,250,000	918,607	1.0000	918,607	15,961,150	11,729,619	2,294,068,968
2170	3,666,224	2,694,255	434.5492	1,170,786,355	1,817,462	1,335,627	73.6643	98,388,008	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	1,270,092,970
2171	3,666,224	2,694,255	452.1484	1,218,203,087	1,817,462	1,335,627	75.7638	101,192,156	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	1,320,313,851
2172	7,521,045	5,527,107	470.4604	2,600,285,068	13,360,196	9,818,215	77.9230	765,064,770	1,250,000	918,607	1.0000	918,607	22,131,241	16,263,929	3,366,268,444
2173	3,666,224	2,694,255	489.5141	1,318,875,811	1,817,462	1,335,627	80.1438	107,042,201	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	1,426,836,620
2174	3,666,224	2,694,255	509.3394	1,372,290,225	1,817,462	1,335,627	82.4279	110,092,906	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	1,483,301,738
2175	7,511,001	5,519,726	529.9676	2,925,275,950	13,351,792	9,812,039	84.7771	831,836,215	1,250,000	918,607	1.0000	918,607	22,112,793	16,250,372	3,758,030,772
2176	3,676,269	2,701,637	551.4313	1,489,767,162	1,825,866	1,341,803	87.1933	116,996,206	1,250,000	918,607	1.0000	918,607	6,752,135	4,962,047	1,607,681,975
2177	3,666,224	2,694,255	573.7643	1,545,867,334	1,817,462	1,335,627	89.6783	119,776,734	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	1,666,562,675
2178	7,511,001	5,519,726	597.0018	3,295,286,368	13,351,792	9,812,039	92.2341	905,004,590	1,250,000	918,607	1.0000	918,607	22,112,793	16,250,372	4,201,209,565
2179	3,666,224	2,694,255	621.1803	1,673,618,129	1,817,462	1,335,627	94.8628	126,701,291	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	1,801,238,027
2180	3,676,269	2,701,637	646.3381	1,746,170,877	1,825,866	1,341,803	97.5664	130,914,860	1,250,000	918,607	1.0000	918,607	6,752,135	4,962,047	1,878,004,344
2181	3,666,224	2,694,255	672.5148	1,811,926,362	1,817,462	1,335,627	100.3470	134,026,135	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	1,946,871,104
2182	7,511,001	5,519,726	699.7517	3,862,437,664	13,351,792	9,812,039	103.2069	1,012,670,132	1,250,000	918,607	1.0000	918,607	22,112,793	16,250,372	4,876,026,404
2183	3,666,224	2,694,255	728.0916	1,961,664,434	1,817,462	1,335,627	106.1483	141,774,506	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	2,104,357,547
2184	3,676,269	2,701,637	757.5793	2,046,704,211	1,825,866	1,341,803	109.1736	146,489,432	1,250,000	918,607	1.0000	918,607	6,752,135	4,962,047	2,194,112,250
2185	3,666,224	2,694,255	788.2613	2,123,776,949	1,817,462	1,335,627	112.2850	149,970,847	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	2,274,666,403
2186	3,666,224	2,694,255	820.1859	2,209,789,962	1,817,462	1,335,627	115.4851	154,244,986	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	2,364,953,555
2187	3,666,224	2,694,255	853.4034	2,299,286,377	1,817,462	1,335,627	118.7764	158,640,934	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	2,458,845,919
2188	3,676,269	2,701,637	887.9662	2,398,962,274	1,825,866	1,341,803	122.1616	163,916,766	1,250,000	918,607	1.0000	918,607	6,752,135	4,962,047	2,563,797,647
2189	26,780,755	19,680,790	923.9289	18,183,650,259	71,161,056	52,295,231	125.6432	6,570,540,189	1,250,000	918,607	1.0000	918,607	99,191,811	72,894,628	24,755,109,055
2190	3,666,224	2,694,255	961.3480	2,590,116,656	1,817,462	1,335,627	129.2240	172,595,028	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	2,763,630,291
2191	3,666,224	2,694,255	1,000.2826	2,695,016,396	1,817,462	1,335,627	132.9069	177,514,008	1,250,000	918,607	1.0000	918,607	6,733,686	4,948,489	2,873,449,011
2192	3,676,269	2,701,637	1,040.7940	2,811,847,502	1,825,866	1,341,803	136.6947	183,417,319	1,250,000	918,607	1.0000	918,607	6,752,135	4,962,047	2,996,183,428
2193	3,050,093	2,241,469	1,082.9462	2,427,390,594	1,970,568	1,448,142	140.5905	203,594,977	1,250,000	918,607	1.0000	918,607	6,270,661	4,608,218	2,631,904,177
2194	3,145,779	2,311,787	1,126.8055	2,604,934,865	2,257,627	1,659,097	144.5974	239,901,154	1,250,000	918,607	1.0000	918,607	6,653,406	4,889,492	2,845,754,626
2195	5,784,468	4,250,922	1,172.4411	4,983,955,529	10,173,693	7,476,500	148.7184	1,111,893,075	1,250,000	918,607	1.0000	918,607	17,208,161	12,646,029	6,096,767,211
2196	4,739,628	3,483,084	1,219.9250	4,249,101,343	7,022,926	5,161,047	152.9569	789,417,691	1,250,000	918,607	1.0000	918,607	13,012,554	9,562,738	5,039,437,641
2197	4,635,847	3,406,817	1,269.3320	4,324,381,736	6,727,830	4,944,185	157.3161	777,799,875	1,250,000	918,607	1.0000	918,607	12,613,677	9,269,609	5,103,100,217
2198	3,241,466	2,382,106	1,320.7399	3,146,143,085	2,544,687	1,870,054	161.7997	302,574,100	1,250,000	918,607	1.0000	918,607	7,036,153	5,170,767	3,449,635,792
2199	3,097,936	2,276,628	1,374.2299	3,128,610,773	2,114,098	1,553,620	166.4109	258,539,286	1,250,000	918,607	1.0000	918,607	6,462,034	4,748,855	3,388,068,666
2200	5,356,959	3,936,752	1,429.8862	5,629,106,931	8,891,166	6,533,989	171.1537	1,118,316,422	1,250,000	918,607	1.0000	918,607	15,498,125	11,389,348	6,748,341,960
2201	5,452,645	4,007,070	1,487.7966	5,961,705,061	9,178,225	6,744,945	176.0315	1,187,322,729	1,250,000	918,607	1.0000	918,607	15,880,870	11,670,622	7,149,946,397
2202	5,452,645	4,007,070	1,548.0523	6,203,153,867	9,178,225	6,744,945	181.0484	1,221,161,442	1,250,000	918,607	1.0000	918,607	15,880,870	11,670,622	7,425,233,915

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AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
2203	3,097,936	2,276,628	1,610.7485	3,667,075,727	2,114,098	1,553,620	186.2083	289,296,920	1,250,000	918,607	1.0000	918,607	6,462,034	4,748,855	3,957,291,254
2204	3,153,874	2,317,736	1,675.9838	3,884,488,649	2,265,664	1,665,004	191.5152	318,873,491	1,250,000	918,607	1.0000	918,607	6,669,538	4,901,347	4,204,280,747
2205	5,452,645	4,007,070	1,743.8611	6,987,773,427	9,178,225	6,744,945	196.9734	1,328,574,686	1,250,000	918,607	1.0000	918,607	15,880,870	11,670,622	8,317,266,720
2206	4,635,847	3,406,817	1,814.4875	6,181,626,718	6,727,830	4,944,185	202.5872	1,001,628,560	1,250,000	918,607	1.0000	918,607	12,613,677	9,269,609	7,184,173,885
2207	4,683,690	3,441,976	1,887.9742	6,498,361,979	6,871,359	5,049,662	208.3609	1,052,152,164	1,250,000	918,607	1.0000	918,607	12,805,049	9,410,245	7,551,432,749
2208	3,153,874	2,317,736	1,964.4372	4,553,047,592	2,265,664	1,665,004	214.2992	356,808,932	1,250,000	918,607	1.0000	918,607	6,669,538	4,901,347	4,910,775,132
2209	4,635,847	3,406,817	2,043.9969	6,963,523,225	6,727,830	4,944,185	220.4067	1,089,731,462	1,250,000	918,607	1.0000	918,607	12,613,677	9,269,609	8,054,173,294
2210	4,676,514	3,436,703	2,126.7788	7,309,106,042	6,849,830	5,033,841	226.6883	1,141,112,828	1,250,000	918,607	1.0000	918,607	12,776,344	9,389,150	8,451,137,477
2211	4,669,337	3,431,428	2,212.9133	7,593,453,185	6,828,301	5,018,020	233.1489	1,169,945,729	1,250,000	918,607	1.0000	918,607	12,747,638	9,368,055	8,764,317,521
2212	3,139,521	2,307,189	2,302.5363	5,312,385,461	2,222,606	1,633,361	239.7937	391,669,645	1,250,000	918,607	1.0000	918,607	6,612,127	4,859,156	5,704,973,713
2213	7,745,159	5,691,805	2,395.7890	13,636,364,637	16,055,764	11,799,149	246.6278	2,909,998,069	1,250,000	918,607	1.0000	918,607	25,050,923	18,409,561	16,547,281,313
2214	6,207,248	4,561,617	2,492.8185	11,371,282,728	11,442,033	8,408,584	253.6567	2,132,893,780	1,250,000	918,607	1.0000	918,607	18,899,281	13,888,808	13,505,095,115
2215	4,669,337	3,431,428	2,593.7776	8,900,361,698	6,828,301	5,018,020	260.8859	1,309,130,537	1,250,000	918,607	1.0000	918,607	12,747,638	9,368,055	10,210,410,842
2216	3,139,521	2,307,189	2,698.8256	6,226,699,609	13,878,684	10,199,244	268.3212	2,736,673,397	1,250,000	918,607	1.0000	918,607	18,268,205	13,425,040	8,964,291,613
2217	3,145,779	2,311,787	2,808.1281	6,491,795,428	2,257,627	1,659,097	275.9683	457,858,258	1,250,000	918,607	1.0000	918,607	6,653,406	4,889,492	6,950,572,292
2218	1,058,128	777,603	2,921.8572	2,272,044,845	2,283,531	1,678,134	283.8334	476,310,374	0	-	1.0000	-	3,341,659	2,455,737	2,748,355,219
	$1,254,481,263	$921,900,139		$257,514,109,402	$1,495,365,399	$1,098,922,407		$50,419,031,894	$230,000,000	$169,023,674		$169,023,674	$2,979,846,662	$2,189,846,220	$308,102,164,970
	$4,769,359,832	$3,504,933,570		$1,232,278,635,160	$4,988,218,698	$3,665,769,786		$174,047,975,724	$461,250,000	$338,965,955		$338,965,955	$10,218,828,530	$7,509,669,311	$1,406,665,576,839

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EXTERNAL FUND CALCULATION

Monticello

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	623,672,182	15,800,910	-	6,696,113	646,169,205
2018	646,169,205	32,904,412	-	13,392,226	692,465,843
2019	692,465,843	35,237,763	-	13,392,226	741,095,832
2020	741,095,832	37,688,714	-	13,392,226	792,176,772
2021	792,176,772	42,038,742	-	83,850,493	918,066,006
2022	918,066,006	48,383,559	-	83,850,493	1,050,300,058
2023	1,050,300,058	55,048,155	-	83,850,493	1,189,198,706
2024	1,189,198,706	62,048,647	-	83,850,493	1,335,097,846
2025	1,335,097,846	69,401,964	-	83,850,493	1,488,350,302
2026	1,488,350,302	77,125,888	-	83,850,493	1,649,326,682
2027	1,649,326,682	85,239,097	-	83,850,493	1,818,416,272
2028	1,818,416,272	93,761,213	-	83,850,493	1,996,027,977
2029	1,996,027,977	102,712,842	-	83,850,493	2,182,591,313
2030	2,182,591,313	110,037,552	(35,447,395)	62,887,869	2,320,069,339
2031	2,320,069,339	115,307,446	(139,568,856)	-	2,295,807,930
2032	2,295,807,930	114,101,654	(235,103,206)	-	2,174,806,377
2033	2,174,806,377	108,087,877	(224,495,044)	-	2,058,399,210
2034	2,058,399,210	102,302,441	(141,890,431)	-	2,018,811,220
2035	2,018,811,220	100,334,918	(268,360,592)	-	1,850,785,546
2036	1,850,785,546	91,984,042	(104,537,352)	-	1,838,232,235
2037	1,838,232,235	91,360,142	(74,807,126)	-	1,854,785,251
2038	1,854,785,251	92,182,827	(70,466,465)	-	1,876,501,613
2039	1,876,501,613	93,262,130	(15,456,182)	-	1,954,307,561
2040	1,954,307,561	97,129,086	(16,091,729)	-	2,035,344,917
2041	2,035,344,917	101,156,642	(16,662,702)	-	2,119,838,858
2042	2,119,838,858	105,355,991	(17,301,946)	-	2,207,892,903
2043	2,207,892,903	109,732,277	(17,965,078)	-	2,299,660,102
2044	2,299,660,102	114,293,107	(18,705,321)	-	2,395,247,888
2045	2,395,247,888	119,043,820	(19,370,615)	-	2,494,921,093
2046	2,494,921,093	123,997,578	(20,114,754)	-	2,598,803,918
2047	2,598,803,918	129,160,555	(20,887,978)	-	2,707,076,494
2048	2,707,076,494	134,541,702	(26,916,472)	-	2,814,701,724
2049	2,814,701,724	139,890,676	(22,525,524)	-	2,932,066,876
2050	2,932,066,876	145,723,724	(35,781,808)	-	3,042,008,791
2051	3,042,008,791	151,187,837	(37,084,255)	-	3,156,112,374
2052	3,156,112,374	156,858,785	(38,504,356)	-	3,274,466,803
2053	3,274,466,803	162,741,000	(39,837,891)	-	3,397,369,912
2054	3,397,369,912	168,849,285	(41,292,108)	-	3,524,927,088
2055	3,524,927,088	175,188,876	(42,800,207)	-	3,657,315,757
2056	3,657,315,757	181,768,593	(44,445,167)	-	3,794,639,184
2057	3,794,639,184	188,593,567	(45,988,884)	-	3,937,243,867
2058	3,937,243,867	195,681,020	(113,026,766)	-	4,019,898,121
2059	4,019,898,121	199,788,937	(49,420,970)	-	4,170,266,088
2060	4,170,266,088	207,262,225	(51,327,230)	-	4,326,201,083
2061	4,326,201,083	215,012,194	(53,115,265)	-	4,488,098,012
2062	4,488,098,012	223,058,471	(55,066,654)	-	4,656,089,830
2063	4,656,089,830	231,407,665	(57,091,844)	-	4,830,405,651

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EXTERNAL FUND CALCULATION

2064	4,830,405,651	240,071,161	(59,301,884)	-	5,011,174,928
2065	5,011,174,928	249,055,394	(61,373,962)	-	5,198,856,360
2066	5,198,856,360	258,383,161	(114,400,551)	-	5,342,838,971
2067	5,342,838,971	265,539,097	(65,983,601)	-	5,542,394,466
2068	5,542,394,466	275,457,005	(194,934,193)	-	5,622,917,278
2069	5,622,917,278	279,458,989	(70,948,647)	-	5,831,427,620
2070	5,831,427,620	289,821,953	(73,572,125)	-	6,047,677,448
2071	6,047,677,448	300,569,569	(76,295,052)	-	6,271,951,965
2072	6,271,951,965	311,716,013	(79,268,228)	-	6,504,399,749
2073	6,504,399,749	323,268,668	(82,053,729)	-	6,745,614,688
2074	6,745,614,688	335,257,050	(85,098,079)	-	6,995,773,659
2075	6,995,773,659	347,689,951	(88,256,686)	-	7,255,206,924
2076	7,255,206,924	360,583,784	(91,707,017)	-	7,524,083,691
2077	7,524,083,691	373,946,959	(94,938,806)	-	7,803,091,844
2078	7,803,091,844	387,813,665	(98,471,402)	-	8,092,434,106
2079	8,092,434,106	402,193,975	(102,138,001)	-	8,392,490,081
2080	8,392,490,081	417,106,757	(106,143,610)	-	8,703,453,228
2081	8,703,453,228	432,561,625	(109,894,241)	-	9,026,120,612
2082	9,026,120,612	448,598,194	(113,995,512)	-	9,360,723,295
2083	9,360,723,295	465,227,948	(118,252,284)	-	9,707,698,959
2084	9,707,698,959	482,472,638	(122,904,877)	-	10,067,266,720
2085	10,067,266,720	500,343,156	(127,259,911)	-	10,440,349,964
2086	10,440,349,964	518,885,393	(132,022,065)	-	10,827,213,292
2087	10,827,213,292	538,112,501	(136,966,641)	-	11,228,359,152
2088	11,228,359,152	558,049,450	(161,302,438)	-	11,625,106,164
2089	11,625,106,164	577,767,776	(147,428,700)	-	12,055,445,240
2090	12,055,445,240	599,155,628	(152,961,784)	-	12,501,639,084
2091	12,501,639,084	621,331,462	(158,706,116)	-	12,964,264,430
2092	12,964,264,430	644,323,942	(164,986,810)	-	13,443,601,562
2093	13,443,601,562	668,146,998	(170,862,753)	-	13,940,885,807
2094	13,940,885,807	692,862,025	(177,292,894)	-	14,456,454,938
2095	14,456,454,938	718,485,810	(1,011,713,130)	-	14,163,227,618
2096	14,163,227,618	703,912,413	(191,270,742)	-	14,675,869,289
2097	14,675,869,289	729,390,704	(198,100,321)	-	15,207,159,672
2098	15,207,159,672	755,795,836	(205,574,971)	-	15,757,380,537
2099	15,757,380,537	783,141,813	(213,336,340)	-	16,327,186,010
2100	16,327,186,010	811,461,145	(221,396,538)	-	16,917,250,616
2101	16,917,250,616	840,787,356	(229,766,711)	-	17,528,271,261
2102	17,528,271,261	871,155,082	(238,458,794)	-	18,160,967,549
2103	18,160,967,549	902,600,087	(247,485,050)	-	18,816,082,586
2104	18,816,082,586	935,159,305	(257,360,900)	-	19,493,880,991
2105	19,493,880,991	968,845,885	(266,593,898)	-	20,196,132,978
2106	20,196,132,978	1,003,747,809	(276,704,354)	-	20,923,176,433
2107	20,923,176,433	1,039,881,869	(287,205,190)	-	21,675,853,112
2108	21,675,853,112	1,077,289,900	(638,159,674)	-	22,114,983,337
2109	22,114,983,337	1,099,114,672	(309,437,221)	-	22,904,660,788
2110	22,904,660,788	1,138,361,641	(321,200,578)	-	23,721,821,851
2111	23,721,821,851	1,178,974,546	(333,419,432)	-	24,567,376,965
2112	24,567,376,965	1,220,998,635	(346,794,281)	-	25,441,581,319
2113	25,441,581,319	1,264,446,592	(359,291,772)	-	26,346,736,139
2114	26,346,736,139	1,309,432,786	(372,983,147)	-	27,283,185,778
2115	27,283,185,778	1,355,974,333	(387,205,007)	-	28,251,955,104
2116	28,251,955,104	1,404,122,169	(669,932,049)	-	28,986,145,224
2117	28,986,145,224	1,440,611,418	(417,322,320)	-	30,009,434,321

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External Levelized	2118	30,009,434,321	1,491,468,886	(1,100,591,847)	-	30,400,311,360
	2119	30,400,311,360	1,510,895,475	(449,819,313)	-	31,461,387,522
	2120	31,461,387,522	1,563,630,960	(467,952,861)	-	32,557,065,621
	2121	32,557,065,621	1,618,086,161	(484,887,338)	-	33,690,264,444
	2122	33,690,264,444	1,674,406,143	(503,448,710)	-	34,861,221,877
	2123	34,861,221,877	1,732,602,727	(522,731,285)	-	36,071,093,319
	2124	36,071,093,319	1,792,733,338	(543,853,439)	-	37,319,973,218
	2125	37,319,973,218	1,854,802,669	(563,574,012)	-	38,611,201,874
	2126	38,611,201,874	1,918,976,733	(585,194,345)	-	39,944,984,263
	2127	39,944,984,263	1,985,265,718	(607,655,908)	-	41,322,594,072
	2128	41,322,594,072	2,053,732,925	(705,371,327)	-	42,670,955,670
	2129	42,670,955,670	2,120,746,497	(655,236,600)	-	44,136,465,568
	2130	44,136,465,568	2,193,582,339	(680,426,570)	-	45,649,621,337
	2131	45,649,621,337	2,268,786,180	(706,597,370)	-	47,211,810,147
	2132	47,211,810,147	2,346,426,964	(735,275,655)	-	48,822,961,457
	2133	48,822,961,457	2,426,501,184	(762,040,497)	-	50,487,422,145
	2134	50,487,422,145	2,509,224,881	(791,395,600)	-	52,205,251,425
	2135	52,205,251,425	2,594,600,996	(821,895,968)	-	53,977,956,452
	2136	53,977,956,452	2,682,704,436	(855,324,546)	-	55,805,336,342
	2137	55,805,336,342	2,773,525,216	(886,516,984)	-	57,692,344,575
	2138	57,692,344,575	2,867,309,525	(920,733,462)	-	59,638,920,638
	2139	59,638,920,638	2,964,054,356	(956,287,326)	-	61,646,687,668
	2140	61,646,687,668	3,063,840,377	(995,262,492)	-	63,715,265,553
	2141	63,715,265,553	3,166,648,698	(1,031,621,624)	-	65,850,292,627
	2142	65,850,292,627	3,272,759,544	(1,071,514,914)	-	68,051,537,256
	2143	68,051,537,256	3,382,161,402	(1,112,968,427)	-	70,320,730,232
	2144	70,320,730,232	3,494,940,293	(1,158,419,743)	-	72,657,250,781
	2145	72,657,250,781	3,611,065,364	(5,442,760,511)	-	70,825,555,634
	2146	70,825,555,634	3,520,030,115	(1,247,332,243)	-	73,098,253,506
	2147	73,098,253,506	3,632,983,199	(1,295,675,896)	-	75,435,560,809
	2148	75,435,560,809	3,749,147,372	(1,348,689,696)	-	77,836,018,485
	2149	77,836,018,485	3,868,450,119	(1,398,126,197)	-	80,306,342,407
	2150	80,306,342,407	3,991,225,218	(1,452,386,597)	-	82,845,181,027
	2151	82,845,181,027	4,117,405,497	(1,508,776,544)	-	85,453,809,981
	2152	85,453,809,981	4,247,054,356	(1,570,622,673)	-	88,130,241,663
	2153	88,130,241,663	4,380,073,011	(1,628,287,746)	-	90,882,026,928
	2154	90,882,026,928	4,516,836,738	(1,691,587,741)	-	93,707,275,925
	2155	93,707,275,925	4,657,251,613	(1,757,375,858)	-	96,607,151,681
	2156	96,607,151,681	4,801,375,439	(1,829,542,347)	-	99,578,984,772
	2157	99,578,984,772	4,949,075,543	(1,896,815,797)	-	102,631,244,519
	2158	102,631,244,519	5,100,772,853	(3,886,348,451)	-	103,845,668,920
	2159	103,845,668,920	5,161,129,745	(2,047,445,183)	-	106,959,353,482
	2160	106,959,353,482	5,315,879,868	(2,131,667,054)	-	110,143,566,297
	2161	110,143,566,297	5,474,135,245	(2,210,167,344)	-	113,407,534,197
	2162	113,407,534,197	5,636,354,450	(2,296,366,634)	-	116,747,522,013
	2163	116,747,522,013	5,802,351,844	(2,385,962,792)	-	120,163,911,065
	2164	120,163,911,065	5,972,146,380	(2,484,272,480)	-	123,651,784,965
	2165	123,651,784,965	6,145,493,713	(2,575,889,374)	-	127,221,389,303
	2166	127,221,389,303	6,322,903,048	(4,203,981,063)	-	129,340,311,289
	2167	129,340,311,289	6,428,213,471	(2,781,093,090)	-	132,987,431,670
	2168	132,987,431,670	6,609,475,354	(7,021,398,585)	-	132,575,508,439
	2169	132,575,508,439	6,589,002,769	(3,002,811,427)	-	136,161,699,782
	2170	136,161,699,782	6,767,236,479	(3,120,277,441)	-	139,808,658,820
	2171	139,808,658,820	6,948,490,343	(3,242,383,078)	-	143,514,766,085

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2172	143,514,766,085	7,132,683,874	(3,376,401,038)	-	147,271,048,922
2173	147,271,048,922	7,319,371,131	(3,501,257,157)	-	151,089,162,896
2174	151,089,162,896	7,509,131,396	(3,638,417,086)	-	154,959,877,206
2175	154,959,877,206	7,701,505,897	(3,780,999,585)	-	158,880,383,519
2176	158,880,383,519	7,896,355,061	(3,937,513,425)	-	162,839,225,155
2177	162,839,225,155	8,093,109,490	(4,083,305,789)	-	166,849,028,856
2178	166,849,028,856	8,292,396,734	(4,243,486,841)	-	170,897,938,750
2179	170,897,938,750	8,493,627,556	(4,410,006,760)	-	174,981,559,546
2180	174,981,559,546	8,696,583,509	(4,592,819,228)	-	179,085,323,828
2181	179,085,323,828	8,900,540,594	(4,763,085,289)	-	183,222,779,133
2182	183,222,779,133	9,106,172,123	(4,950,179,855)	-	187,378,771,401
2183	187,378,771,401	9,312,724,939	(5,144,685,508)	-	191,546,810,832
2184	191,546,810,832	9,519,876,498	(5,358,247,477)	-	195,708,439,853
2185	195,708,439,853	9,726,709,461	(5,557,126,407)	-	199,878,022,907
2186	199,878,022,907	9,933,937,738	(5,775,687,978)	-	204,036,272,667
2187	204,036,272,667	10,140,602,752	(6,002,915,676)	-	208,173,959,742
2188	208,173,959,742	10,346,245,799	(6,252,433,947)	-	212,267,771,595
2189	212,267,771,595	10,549,708,248	(6,484,768,180)	-	216,332,711,663
2190	216,332,711,663	10,751,735,770	(6,740,125,432)	-	220,344,322,001
2191	220,344,322,001	10,951,112,803	(7,005,617,695)	-	224,289,817,109
2192	224,289,817,109	11,147,203,910	(8,216,807,977)	-	227,220,213,042
2193	227,220,213,042	11,292,844,588	(9,237,695,262)	-	229,275,362,369
2194	229,275,362,369	11,394,985,510	(8,114,316,172)	-	232,556,031,706
2195	232,556,031,706	11,558,034,776	(35,096,569,593)	-	209,017,496,888
2196	209,017,496,888	10,388,169,595	(10,646,190,792)	-	208,759,475,691
2197	208,759,475,691	10,375,345,942	(6,903,223,641)	-	212,231,597,992
2198	212,231,597,992	10,547,910,420	(7,179,978,104)	-	215,599,530,308
2199	215,599,530,308	10,715,296,656	(7,467,860,728)	-	218,846,966,236
2200	218,846,966,236	10,876,694,222	(7,767,319,798)	-	221,956,340,659
2201	221,956,340,659	11,031,230,131	(8,078,821,612)	-	224,908,749,178
2202	224,908,749,178	11,177,964,834	(8,402,851,376)	-	227,683,862,636
2203	227,683,862,636	11,315,887,973	(8,739,915,007)	-	230,259,835,602
2204	230,259,835,602	11,443,913,829	(9,115,450,044)	-	232,588,299,388
2205	232,588,299,388	11,559,638,480	(9,455,262,620)	-	234,692,675,247
2206	234,692,675,247	11,664,225,960	(9,834,662,594)	-	236,522,238,613
2207	236,522,238,613	11,755,155,259	(10,229,326,918)	-	238,048,066,953
2208	238,048,066,953	11,830,988,928	(23,621,875,444)	-	226,257,180,437
2209	226,257,180,437	11,244,981,868	(11,066,937,090)	-	226,435,225,215
2210	226,435,225,215	11,253,830,693	(11,511,188,856)	-	226,177,867,052
2211	226,177,867,052	11,241,039,992	(11,973,319,588)	-	225,445,587,456
2212	225,445,587,456	11,204,645,697	(12,488,182,665)	-	224,162,050,487
2213	224,162,050,487	11,140,853,909	(14,621,371,106)	-	220,681,533,291
2214	220,681,533,291	10,967,872,205	(13,474,344,519)	-	218,175,060,976
2215	218,175,060,976	10,843,300,531	(14,015,498,561)	-	215,002,862,946
2216	215,002,862,946	10,685,642,288	(24,036,881,734)	-	201,651,623,501
2217	201,651,623,501	10,022,085,688	(15,164,046,883)	-	196,509,662,306
2218	196,509,662,306	9,766,530,217	(38,123,338,117)	-	168,152,854,406
2219	168,152,854,406	8,357,196,864	(15,307,988,630)	-	161,202,062,639
2220	161,202,062,639	8,011,742,513	(15,671,223,343)	-	153,542,581,810
2221	153,542,581,810	7,631,066,316	(16,255,993,316)	-	144,917,654,810
2222	144,917,654,810	7,202,407,444	(16,904,673,455)	-	135,215,388,799
2223	135,215,388,799	6,720,204,823	(17,898,815,350)	-	124,036,778,272
2224	124,036,778,272	6,164,627,880	(18,326,615,231)	-	111,874,790,922
2225	111,874,790,922	5,560,177,109	(19,010,909,673)	-	98,424,058,358

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2226	98,424,058,358	4,891,675,700	(19,770,011,773)	-	83,545,722,285
2227	83,545,722,285	4,152,222,398	(20,930,335,445)	-	66,767,609,238
2228	66,767,609,238	3,318,350,179	(21,434,056,187)	-	48,651,903,230
2229	48,651,903,230	2,417,999,591	(22,234,870,241)	-	28,835,032,579
2230	28,835,032,579	1,433,101,119	(21,879,025,883)	-	8,389,107,815
2231	8,389,107,815	416,938,658	(8,806,046,474)	-	0

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Prairie Island Unit 1

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	374,367,055	9,434,360	-	24,632	383,826,047
2018	383,826,047	19,346,074	-	49,264	403,221,386
2019	403,221,386	20,323,599	-	49,264	423,594,249
2020	423,594,249	21,350,392	-	49,264	444,993,905
2021	444,993,905	23,749,787	-	52,464,065	521,207,757
2022	521,207,757	27,590,965	-	52,464,065	601,262,787
2023	601,262,787	31,625,739	-	52,464,065	685,352,591
2024	685,352,591	35,863,865	-	52,464,065	773,680,520
2025	773,680,520	40,315,593	-	52,464,065	866,460,178
2026	866,460,178	44,991,687	-	52,464,065	963,915,930
2027	963,915,930	49,903,457	-	52,464,065	1,066,283,452
2028	1,066,283,452	55,062,780	-	52,464,065	1,173,810,297
2029	1,173,810,297	60,482,133	-	52,464,065	1,286,756,495
2030	1,286,756,495	66,174,622	-	52,464,065	1,405,395,181
2031	1,405,395,181	72,154,012	-	52,464,065	1,530,013,257
2032	1,530,013,257	78,434,763	-	52,464,065	1,660,912,084
2033	1,660,912,084	82,917,285	(42,768,206)	35,150,923	1,736,212,087
2034	1,736,212,087	85,768,877	(131,752,423)	-	1,690,228,541
2035	1,690,228,541	83,497,290	(198,854,133)	-	1,574,871,698
2036	1,574,871,698	77,798,662	(173,386,484)	-	1,479,283,876
2037	1,479,283,876	73,076,623	(119,758,863)	-	1,432,601,637
2038	1,432,601,637	70,770,521	(48,446,231)	-	1,454,925,926
2039	1,454,925,926	71,873,341	(166,746,609)	-	1,360,052,659
2040	1,360,052,659	67,186,601	(78,122,012)	-	1,349,117,248
2041	1,349,117,248	66,646,392	(51,940,215)	-	1,363,823,426
2042	1,363,823,426	67,372,877	(47,702,660)	-	1,383,493,643
2043	1,383,493,643	68,344,586	(29,119,754)	-	1,422,718,475
2044	1,422,718,475	70,282,293	(11,674,091)	-	1,481,326,676
2045	1,481,326,676	73,177,538	(28,362,264)	-	1,526,141,949
2046	1,526,141,949	75,391,412	(23,687,841)	-	1,577,845,521
2047	1,577,845,521	77,945,569	(24,482,072)	-	1,631,309,018
2048	1,631,309,018	80,586,665	(13,373,108)	-	1,698,522,575
2049	1,698,522,575	83,907,015	(26,156,567)	-	1,756,273,023
2050	1,756,273,023	86,759,887	(33,419,678)	-	1,809,613,232
2051	1,809,613,232	89,394,894	(32,879,405)	-	1,866,128,721
2052	1,866,128,721	92,186,759	(35,748,383)	-	1,922,567,097
2053	1,922,567,097	94,974,815	(15,839,839)	-	2,001,702,073
2054	2,001,702,073	98,884,082	(16,400,093)	-	2,084,186,063
2055	2,084,186,063	102,958,792	(39,440,555)	-	2,147,704,300
2056	2,147,704,300	106,096,592	(33,099,428)	-	2,220,701,464
2057	2,220,701,464	109,702,652	(34,177,854)	-	2,296,226,262
2058	2,296,226,262	113,433,577	(18,863,779)	-	2,390,796,060
2059	2,390,796,060	118,105,325	(34,418,346)	-	2,474,483,039
2060	2,474,483,039	122,239,462	(37,886,138)	-	2,558,836,364
2061	2,558,836,364	126,406,516	(39,129,555)	-	2,646,113,325
2062	2,646,113,325	130,717,998	(21,727,882)	-	2,755,103,442
2063	2,755,103,442	136,102,110	(80,621,796)	-	2,810,583,756

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	2064	2,810,583,756	138,842,838	(60,889,305)	-	2,888,537,289
	2065	2,888,537,289	142,693,742	(44,841,447)	-	2,986,389,584
	2066	2,986,389,584	147,527,645	(25,058,214)	-	3,108,859,015
	2067	3,108,859,015	153,577,635	(25,972,206)	-	3,236,464,444
	2068	3,236,464,444	159,881,344	(72,551,153)	-	3,323,794,634
	2069	3,323,794,634	164,195,455	(63,196,056)	-	3,424,794,033
	2070	3,424,794,033	169,184,825	(28,931,636)	-	3,565,047,222
	2071	3,565,047,222	176,113,333	(29,995,129)	-	3,711,165,426
	2072	3,711,165,426	183,331,572	(92,767,952)	-	3,801,729,047
	2073	3,801,729,047	187,805,415	(32,246,859)	-	3,957,287,603
	2074	3,957,287,603	195,490,008	(33,438,597)	-	4,119,339,013
	2075	4,119,339,013	203,495,347	(112,362,974)	-	4,210,471,386
	2076	4,210,471,386	207,997,286	(36,070,752)	-	4,382,397,921
	2077	4,382,397,921	216,490,457	(37,296,551)	-	4,561,591,827
	2078	4,561,591,827	225,342,636	(117,577,657)	-	4,669,356,807
	2079	4,669,356,807	230,666,226	(40,123,990)	-	4,859,899,043
	2080	4,859,899,043	240,079,013	(41,746,752)	-	5,058,231,304
	2081	5,058,231,304	249,876,626	(43,174,563)	-	5,264,933,367
	2082	5,264,933,367	260,087,708	(125,683,310)	-	5,399,337,765
	2083	5,399,337,765	266,727,286	(46,466,442)	-	5,619,598,608
	2084	5,619,598,608	277,608,171	(48,355,173)	-	5,848,851,606
	2085	5,848,851,606	288,933,269	(50,019,012)	-	6,087,765,864
	2086	6,087,765,864	300,735,634	(51,899,131)	-	6,336,602,366
	2087	6,336,602,366	313,028,157	(53,852,602)	-	6,595,777,921
	2088	6,595,777,921	325,831,429	(56,051,006)	-	6,865,558,345
	2089	6,865,558,345	339,158,582	(750,835,061)	-	6,453,881,866
	2090	6,453,881,866	318,821,764	(60,180,313)	-	6,712,523,318
	2091	6,712,523,318	331,598,652	(62,455,727)	-	6,981,666,242
	2092	6,981,666,242	344,894,312	(65,015,702)	-	7,261,544,853
	2093	7,261,544,853	358,720,316	(67,275,883)	-	7,552,989,285
	2094	7,552,989,285	373,117,671	(69,827,894)	-	7,856,279,062
	2095	7,856,279,062	388,100,186	(155,517,607)	-	8,088,861,641
	2096	8,088,861,641	399,589,765	(132,697,627)	-	8,355,753,779
	2097	8,355,753,779	412,774,237	(137,276,626)	-	8,631,251,390
	2098	8,631,251,390	426,383,819	(81,070,472)	-	8,976,564,736
	2099	8,976,564,736	443,442,298	(84,160,485)	-	9,335,846,549
	2100	9,335,846,549	461,190,820	(185,514,081)	-	9,611,523,287
	2101	9,611,523,287	474,809,250	(192,196,742)	-	9,894,135,795
	2102	9,894,135,795	488,770,308	(199,127,152)	-	10,183,778,951
	2103	10,183,778,951	503,078,680	(97,776,676)	-	10,589,080,955
	2104	10,589,080,955	523,100,599	(101,824,431)	-	11,010,357,124
	2105	11,010,357,124	543,911,642	(221,501,424)	-	11,332,767,342
	2106	11,332,767,342	559,838,707	(189,497,916)	-	11,703,108,132
	2107	11,703,108,132	578,133,542	(196,444,221)	-	12,084,797,453
	2108	12,084,797,453	596,988,994	(118,369,810)	-	12,563,416,637
	2109	12,563,416,637	620,632,782	(211,130,954)	-	12,972,918,465
	2110	12,972,918,465	640,862,172	(218,891,810)	-	13,394,888,828
	2111	13,394,888,828	661,707,508	(226,946,170)	-	13,829,650,166
	2112	13,829,650,166	683,184,718	(137,664,947)	-	14,375,169,937
	2113	14,375,169,937	710,133,395	(446,845,223)	-	14,638,458,109
	2114	14,638,458,109	723,139,831	(357,917,829)	-	15,003,680,111
	2115	15,003,680,111	741,181,797	(285,747,972)	-	15,459,113,936
	2116	15,459,113,936	763,680,228	(160,171,633)	-	16,062,622,531
External Levelized	2117	16,062,622,531	793,493,553	(165,867,658)	-	16,690,248,426

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2118	16,690,248,426	824,498,272	(412,774,806)	-	17,101,971,893
2119	17,101,971,893	844,837,412	(365,580,681)	-	17,581,228,623
2120	17,581,228,623	868,512,694	(186,429,715)	-	18,263,311,602
2121	18,263,311,602	902,207,593	(193,078,480)	-	18,972,440,715
2122	18,972,440,715	937,238,571	(545,222,379)	-	19,364,456,907
2123	19,364,456,907	956,604,171	(208,342,425)	-	20,112,718,653
2124	20,112,718,653	993,568,301	(217,069,921)	-	20,889,217,033
2125	20,889,217,033	1,031,927,321	(606,842,631)	-	21,314,301,724
2126	21,314,301,724	1,052,926,505	(233,567,637)	-	22,133,660,592
2127	22,133,660,592	1,093,402,833	(242,647,223)	-	22,984,416,202
2128	22,984,416,202	1,135,430,160	(676,367,768)	-	23,443,478,595
2129	23,443,478,595	1,158,107,843	(261,894,498)	-	24,339,691,940
2130	24,339,691,940	1,202,380,782	(272,091,406)	-	25,269,981,315
2131	25,269,981,315	1,248,337,077	(282,690,337)	-	26,235,628,055
2132	26,235,628,055	1,296,040,026	(780,812,473)	-	26,750,855,608
2133	26,750,855,608	1,321,492,267	(305,159,839)	-	27,767,188,035
2134	27,767,188,035	1,371,699,089	(317,064,613)	-	28,821,822,511
2135	28,821,822,511	1,423,798,032	(329,439,410)	-	29,916,181,133
2136	29,916,181,133	1,477,859,348	(343,310,154)	-	31,050,730,327
2137	31,050,730,327	1,533,906,078	(355,675,428)	-	32,228,960,977
2138	32,228,960,977	1,592,110,672	(369,576,237)	-	33,451,495,412
2139	33,451,495,412	1,652,503,873	(4,110,885,000)	-	30,993,114,285
2140	30,993,114,285	1,531,059,846	(400,219,998)	-	32,123,954,133
2141	32,123,954,133	1,586,923,334	(414,665,053)	-	33,296,212,414
2142	33,296,212,414	1,644,832,893	(430,899,762)	-	34,510,145,546
2143	34,510,145,546	1,704,801,190	(447,776,458)	-	35,767,170,278
2144	35,767,170,278	1,766,898,212	(466,684,194)	-	37,067,384,296
2145	37,067,384,296	1,831,128,784	(942,176,534)	-	37,956,336,546
2146	37,956,336,546	1,875,043,025	(819,164,963)	-	39,012,214,609
2147	39,012,214,609	1,927,203,402	(850,175,704)	-	40,089,242,307
2148	40,089,242,307	1,980,408,570	(544,318,666)	-	41,525,332,210
2149	41,525,332,210	2,051,351,411	(564,040,861)	-	43,012,642,761
2150	43,012,642,761	2,124,824,552	(1,132,757,742)	-	44,004,709,571
2151	44,004,709,571	2,173,832,653	(1,175,361,744)	-	45,003,180,480
2152	45,003,180,480	2,223,157,116	(1,221,441,653)	-	46,004,895,942
2153	46,004,895,942	2,272,641,860	(658,063,552)	-	47,619,474,249
2154	47,619,474,249	2,352,402,028	(683,945,998)	-	49,287,930,279
2155	49,287,930,279	2,434,823,756	(1,456,527,378)	-	50,266,226,657
2156	50,266,226,657	2,483,151,597	(1,191,217,991)	-	51,558,160,263
2157	51,558,160,263	2,546,973,117	(1,234,371,151)	-	52,870,762,229
2158	52,870,762,229	2,611,815,654	(798,168,374)	-	54,684,409,508
2159	54,684,409,508	2,701,409,830	(1,330,306,865)	-	56,055,512,473
2160	56,055,512,473	2,769,142,316	(1,383,581,665)	-	57,441,073,124
2161	57,441,073,124	2,837,589,012	(1,433,823,154)	-	58,844,838,982
2162	58,844,838,982	2,906,935,046	(931,653,123)	-	60,820,120,904
2163	60,820,120,904	3,004,513,973	(2,699,774,193)	-	61,124,860,684
2164	61,124,860,684	3,019,568,118	(2,205,599,092)	-	61,938,829,710
2165	61,938,829,710	3,059,778,188	(1,666,074,818)	-	63,332,533,079
2166	63,332,533,079	3,128,627,134	(1,087,668,215)	-	65,373,491,998
2167	65,373,491,998	3,229,450,505	(1,130,626,952)	-	67,472,315,551
2168	67,472,315,551	3,333,132,388	(2,558,184,221)	-	68,247,263,718
2169	68,247,263,718	3,371,414,828	(2,294,017,133)	-	69,324,661,413
2170	69,324,661,413	3,424,638,274	(1,270,038,271)	-	71,479,261,415
2171	71,479,261,415	3,531,075,514	(1,320,257,578)	-	73,690,079,352

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2172	73,690,079,352	3,640,289,920	(3,366,213,509)	-	73,964,155,763
2173	73,964,155,763	3,653,829,295	(1,426,777,061)	-	76,191,207,997
2174	76,191,207,997	3,763,845,675	(1,483,240,465)	-	78,471,813,207
2175	78,471,813,207	3,876,507,572	(3,757,968,903)	-	78,590,351,877
2176	78,590,351,877	3,882,363,383	(1,607,618,975)	-	80,865,096,285
2177	80,865,096,285	3,994,735,756	(1,666,495,954)	-	83,193,336,087
2178	83,193,336,087	4,109,750,803	(4,201,142,239)	-	83,101,944,651
2179	83,101,944,651	4,105,236,066	(1,801,167,407)	-	85,406,013,310
2180	85,406,013,310	4,219,057,058	(1,877,933,870)	-	87,747,136,497
2181	87,747,136,497	4,334,708,543	(1,946,796,356)	-	90,135,048,684
2182	90,135,048,684	4,452,671,405	(4,875,951,044)	-	89,711,769,045
2183	89,711,769,045	4,431,761,391	(2,104,278,428)	-	92,039,252,007
2184	92,039,252,007	4,546,739,049	(2,194,033,417)	-	94,391,957,639
2185	94,391,957,639	4,662,962,707	(2,274,582,657)	-	96,780,337,689
2186	96,780,337,689	4,780,948,682	(2,364,867,395)	-	99,196,418,976
2187	99,196,418,976	4,900,303,097	(2,458,757,274)	-	101,637,964,800
2188	101,637,964,800	5,020,915,461	(2,563,709,466)	-	104,095,170,795
2189	104,095,170,795	5,142,301,437	(24,755,020,964)	-	84,482,451,268
2190	84,482,451,268	4,173,433,093	(2,763,533,752)	-	85,892,350,609
2191	85,892,350,609	4,243,082,120	(2,873,349,687)	-	87,262,083,042
2192	87,262,083,042	4,310,746,902	(2,996,084,790)	-	88,576,745,154
2193	88,576,745,154	4,375,691,211	(2,631,901,790)	-	90,320,534,575
2194	90,320,534,575	4,461,834,408	(2,845,755,560)	-	91,936,613,423
2195	91,936,613,423	4,541,668,703	(6,096,768,388)	-	90,381,513,738
2196	90,381,513,738	4,464,846,779	(5,039,439,321)	-	89,806,921,195
2197	89,806,921,195	4,436,461,907	(5,103,102,785)	-	89,140,280,318
2198	89,140,280,318	4,403,529,848	(3,449,639,793)	-	90,094,170,372
2199	90,094,170,372	4,450,652,016	(3,388,072,705)	-	91,156,749,684
2200	91,156,749,684	4,503,143,434	(6,748,343,262)	-	88,911,549,856
2201	88,911,549,856	4,392,230,563	(7,149,952,252)	-	86,153,828,167
2202	86,153,828,167	4,255,999,111	(7,425,240,003)	-	82,984,587,275
2203	82,984,587,275	4,099,438,611	(3,957,295,989)	-	83,126,729,898
2204	83,126,729,898	4,106,460,457	(4,204,275,961)	-	83,028,914,393
2205	83,028,914,393	4,101,628,371	(8,317,273,562)	-	78,813,269,203
2206	78,813,269,203	3,893,375,499	(7,184,177,587)	-	75,522,467,114
2207	75,522,467,114	3,730,809,875	(7,551,432,596)	-	71,701,844,393
2208	71,701,844,393	3,542,071,113	(4,910,769,515)	-	70,333,145,992
2209	70,333,145,992	3,474,457,412	(8,054,177,476)	-	65,753,425,928
2210	65,753,425,928	3,248,219,241	(8,451,130,892)	-	60,550,514,276
2211	60,550,514,276	2,991,195,405	(8,764,321,886)	-	54,777,387,796
2212	54,777,387,796	2,706,002,957	(5,704,971,845)	-	51,778,418,908
2213	51,778,418,908	2,557,853,894	(16,547,283,798)	-	37,788,989,004
2214	37,788,989,004	1,866,776,057	(13,505,097,847)	-	26,150,667,214
2215	26,150,667,214	1,291,842,960	(10,210,415,985)	-	17,232,094,189
2216	17,232,094,189	851,265,453	(8,964,289,432)	-	9,119,070,210
2217	9,119,070,210	450,482,068	(6,950,574,559)	-	2,618,977,720
2218	2,618,977,720	129,377,499	(2,748,355,219)	-	0

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Prairie Island Unit 2

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	420,208,967	10,677,050	-	294,670	431,180,688
2018	431,180,688	21,918,948	-	589,341	453,688,977
2019	453,688,977	23,062,369	-	589,341	477,340,687
2020	477,340,687	24,263,876	-	589,341	502,193,904
2021	502,193,904	26,603,986	-	43,013,201	571,811,091
2022	571,811,091	30,140,539	-	43,013,201	644,964,831
2023	644,964,831	33,856,749	-	43,013,201	721,834,781
2024	721,834,781	37,761,742	-	43,013,201	802,609,725
2025	802,609,725	41,865,109	-	43,013,201	887,488,036
2026	887,488,036	46,176,928	-	43,013,201	976,678,165
2027	976,678,165	50,707,786	-	43,013,201	1,070,399,152
2028	1,070,399,152	55,468,812	-	43,013,201	1,168,881,166
2029	1,168,881,166	60,471,699	-	43,013,201	1,272,366,066
2030	1,272,366,066	65,728,731	-	43,013,201	1,381,107,999
2031	1,381,107,999	71,252,822	-	43,013,201	1,495,374,022
2032	1,495,374,022	77,057,536	-	43,013,201	1,615,444,759
2033	1,615,444,759	83,157,129	-	43,013,201	1,741,615,090
2034	1,741,615,090	86,741,653	(17,426,478)	35,700,957	1,846,631,222
2035	1,846,631,222	91,038,919	(114,752,428)	-	1,822,917,714
2036	1,822,917,714	89,869,843	(214,578,967)	-	1,698,208,590
2037	1,698,208,590	83,721,683	(216,463,722)	-	1,565,466,552
2038	1,565,466,552	77,177,501	(136,478,687)	-	1,506,165,366
2039	1,506,165,366	74,253,953	(176,222,841)	-	1,404,196,477
2040	1,404,196,477	69,226,886	(89,351,532)	-	1,384,071,832
2041	1,384,071,832	68,234,741	(64,325,998)	-	1,387,980,575
2042	1,387,980,575	68,427,442	(59,595,219)	-	1,396,812,799
2043	1,396,812,799	68,862,871	(34,871,710)	-	1,430,803,960
2044	1,430,803,960	70,538,635	(11,675,642)	-	1,489,666,953
2045	1,489,666,953	73,440,581	(28,363,854)	-	1,534,743,680
2046	1,534,743,680	75,662,863	(23,689,494)	-	1,586,717,049
2047	1,586,717,049	78,225,151	(24,483,772)	-	1,640,458,427
2048	1,640,458,427	80,874,600	(13,374,843)	-	1,707,958,185
2049	1,707,958,185	84,202,339	(26,158,366)	-	1,766,002,157
2050	1,766,002,157	87,063,906	(33,421,508)	-	1,819,644,556
2051	1,819,644,556	89,708,477	(32,881,304)	-	1,876,471,728
2052	1,876,471,728	92,510,056	(35,750,338)	-	1,933,231,446
2053	1,933,231,446	95,308,310	(15,841,845)	-	2,012,697,911
2054	2,012,697,911	99,226,007	(16,402,157)	-	2,095,521,762
2055	2,095,521,762	103,309,223	(39,442,660)	-	2,159,388,324
2056	2,159,388,324	106,457,844	(33,101,605)	-	2,232,744,564
2057	2,232,744,564	110,074,307	(34,180,108)	-	2,308,638,762
2058	2,308,638,762	113,815,891	(18,866,090)	-	2,403,588,564
2059	2,403,588,564	118,496,916	(34,420,697)	-	2,487,664,783
2060	2,487,664,783	122,641,874	(37,888,573)	-	2,572,418,084
2061	2,572,418,084	126,820,212	(39,132,078)	-	2,660,106,217
2062	2,660,106,217	131,143,237	(21,730,468)	-	2,769,518,986
2063	2,769,518,986	136,537,286	(80,624,408)	-	2,825,431,864

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	2064	2,825,431,864	139,293,791	(60,892,047)	-	2,903,833,608
	2065	2,903,833,608	143,158,997	(44,844,272)	-	3,002,148,332
	2066	3,002,148,332	148,005,913	(25,061,109)	-	3,125,093,136
	2067	3,125,093,136	154,067,092	(25,975,184)	-	3,253,185,044
	2068	3,253,185,044	160,382,023	(72,554,214)	-	3,341,012,853
	2069	3,341,012,853	164,711,934	(63,199,176)	-	3,442,525,611
	2070	3,442,525,611	169,716,513	(28,934,876)	-	3,583,307,247
	2071	3,583,307,247	176,657,047	(29,998,461)	-	3,729,965,834
	2072	3,729,965,834	183,887,316	(92,771,376)	-	3,821,081,773
	2073	3,821,081,773	188,379,331	(32,250,385)	-	3,977,210,719
	2074	3,977,210,719	196,076,488	(33,442,224)	-	4,139,844,984
	2075	4,139,844,984	204,094,358	(112,366,690)	-	4,231,572,651
	2076	4,231,572,651	208,616,532	(36,074,561)	-	4,404,114,623
	2077	4,404,114,623	217,122,851	(37,300,497)	-	4,583,936,976
	2078	4,583,936,976	225,988,093	(117,581,691)	-	4,692,343,378
	2079	4,692,343,378	231,332,529	(40,128,166)	-	4,883,547,740
	2080	4,883,547,740	240,758,904	(41,751,014)	-	5,082,555,630
	2081	5,082,555,630	250,569,993	(43,178,981)	-	5,289,946,642
	2082	5,289,946,642	260,794,369	(125,687,807)	-	5,425,053,204
	2083	5,425,053,204	267,455,123	(46,471,116)	-	5,646,037,211
	2084	5,646,037,211	278,349,635	(48,359,942)	-	5,876,026,904
	2085	5,876,026,904	289,688,126	(50,023,957)	-	6,115,691,073
	2086	6,115,691,073	301,503,570	(51,904,218)	-	6,365,290,425
	2087	6,365,290,425	313,808,818	(53,857,834)	-	6,625,241,409
	2088	6,625,241,409	326,624,401	(56,056,341)	-	6,895,809,469
	2089	6,895,809,469	339,963,407	(750,019,869)	-	6,485,753,007
	2090	6,485,753,007	319,747,623	(60,186,007)	-	6,745,314,623
	2091	6,745,314,623	332,544,011	(62,461,585)	-	7,015,397,049
	2092	7,015,397,049	345,859,075	(65,021,671)	-	7,296,234,453
	2093	7,296,234,453	359,704,359	(67,282,081)	-	7,588,656,731
	2094	7,588,656,731	374,120,777	(69,834,269)	-	7,892,943,239
	2095	7,892,943,239	389,122,102	(155,524,086)	-	8,126,541,255
	2096	8,126,541,255	400,638,484	(132,704,319)	-	8,394,475,420
	2097	8,394,475,420	413,847,638	(137,283,595)	-	8,671,039,462
	2098	8,671,039,462	427,482,245	(81,077,609)	-	9,017,444,099
	2099	9,017,444,099	444,559,994	(84,167,826)	-	9,377,836,267
	2100	9,377,836,267	462,327,328	(185,521,538)	-	9,654,642,057
	2101	9,654,642,057	475,973,853	(192,204,411)	-	9,938,411,500
	2102	9,938,411,500	489,963,687	(199,135,039)	-	10,229,240,147
	2103	10,229,240,147	504,301,539	(97,784,894)	-	10,635,756,792
	2104	10,635,756,792	524,342,810	(101,832,791)	-	11,058,266,811
	2105	11,058,266,811	545,172,554	(221,510,005)	-	11,381,929,359
	2106	11,381,929,359	561,129,117	(189,506,903)	-	11,753,551,573
	2107	11,753,551,573	579,450,093	(196,453,466)	-	12,136,548,200
External Levelized	2108	12,136,548,200	598,331,826	(118,379,164)	-	12,616,500,863
	2109	12,616,500,863	621,993,493	(211,140,737)	-	13,027,353,618
	2110	13,027,353,618	642,248,533	(218,901,873)	-	13,450,700,279
	2111	13,450,700,279	663,119,524	(226,956,522)	-	13,886,863,281
	2112	13,886,863,281	684,622,360	(137,675,412)	-	14,433,810,228
	2113	14,433,810,228	711,586,844	(446,855,813)	-	14,698,541,260
	2114	14,698,541,260	724,638,084	(357,928,808)	-	15,065,250,536
	2115	15,065,250,536	742,716,851	(285,759,253)	-	15,522,208,134
	2116	15,522,208,134	765,244,861	(160,183,341)	-	16,127,269,653
	2117	16,127,269,653	795,074,394	(165,879,861)	-	16,756,464,186

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2118	16,756,464,186	826,093,684	(412,787,085)	-	17,169,770,786
2119	17,169,770,786	846,469,700	(365,593,399)	-	17,650,647,087
2120	17,650,647,087	870,176,901	(186,442,814)	-	18,334,381,175
2121	18,334,381,175	903,884,992	(193,092,143)	-	19,045,174,023
2122	19,045,174,023	938,927,079	(545,236,291)	-	19,438,864,811
2123	19,438,864,811	958,336,035	(208,356,883)	-	20,188,843,964
2124	20,188,843,964	995,310,007	(217,084,576)	-	20,967,069,395
2125	20,967,069,395	1,033,676,521	(606,857,768)	-	21,393,888,148
2126	21,393,888,148	1,054,718,686	(233,583,374)	-	22,215,023,460
2127	22,215,023,460	1,095,200,657	(242,663,411)	-	23,067,560,706
2128	23,067,560,706	1,137,230,743	(676,383,922)	-	23,528,407,526
2129	23,528,407,526	1,159,950,491	(261,911,627)	-	24,426,446,390
2130	24,426,446,390	1,204,223,807	(272,109,027)	-	25,358,561,170
2131	25,358,561,170	1,250,177,066	(282,708,463)	-	26,326,029,773
2132	26,326,029,773	1,297,873,268	(780,830,534)	-	26,843,072,507
2133	26,843,072,507	1,323,363,475	(305,179,020)	-	27,861,256,962
2134	27,861,256,962	1,373,559,968	(317,084,344)	-	28,917,732,586
2135	28,917,732,586	1,425,644,216	(329,459,707)	-	30,013,917,095
2136	30,013,917,095	1,479,686,113	(343,330,675)	-	31,150,272,533
2137	31,150,272,533	1,535,708,436	(355,696,906)	-	32,330,284,062
2138	32,330,284,062	1,593,883,004	(369,598,331)	-	33,554,568,735
2139	33,554,568,735	1,654,240,239	(4,110,906,980)	-	31,097,901,994
2140	31,097,901,994	1,533,126,568	(400,242,957)	-	32,230,785,606
2141	32,230,785,606	1,588,977,730	(414,689,104)	-	33,405,074,232
2142	33,405,074,232	1,646,870,160	(430,924,504)	-	34,621,019,888
2143	34,621,019,888	1,706,816,280	(447,801,910)	-	35,880,034,259
2144	35,880,034,259	1,768,885,689	(466,709,878)	-	37,182,210,070
2145	37,182,210,070	1,833,082,956	(942,202,942)	-	38,073,090,085
2146	38,073,090,085	1,877,003,341	(819,192,849)	-	39,130,900,577
2147	39,130,900,577	1,929,153,398	(850,204,392)	-	40,209,849,583
2148	40,209,849,583	1,982,345,584	(544,347,400)	-	41,647,847,768
2149	41,647,847,768	2,053,238,895	(564,071,025)	-	43,137,015,638
2150	43,137,015,638	2,126,654,871	(1,132,788,133)	-	44,130,882,376
2151	44,130,882,376	2,175,652,501	(1,175,393,002)	-	45,131,141,876
2152	45,131,141,876	2,224,965,294	(1,221,474,671)	-	46,134,632,499
2153	46,134,632,499	2,274,437,382	(658,097,334)	-	47,750,972,547
2154	47,750,972,547	2,354,122,947	(683,980,750)	-	49,421,114,743
2155	49,421,114,743	2,436,460,957	(1,456,562,811)	-	50,401,012,889
2156	50,401,012,889	2,484,769,935	(1,191,254,025)	-	51,694,528,799
2157	51,694,528,799	2,548,540,270	(1,234,409,252)	-	53,008,659,817
2158	53,008,659,817	2,613,326,929	(798,207,297)	-	54,823,779,449
2159	54,823,779,449	2,702,812,327	(1,330,347,193)	-	56,196,244,583
2160	56,196,244,583	2,770,474,858	(1,383,621,977)	-	57,583,097,464
2161	57,583,097,464	2,838,846,705	(1,433,865,839)	-	58,988,078,330
2162	58,988,078,330	2,908,112,262	(931,696,719)	-	60,964,493,873
2163	60,964,493,873	3,005,549,548	(2,699,816,930)	-	61,270,226,492
2164	61,270,226,492	3,020,622,166	(2,205,644,530)	-	62,085,204,127
2165	62,085,204,127	3,060,800,563	(1,666,122,640)	-	63,479,882,051
2166	63,479,882,051	3,129,558,185	(1,087,717,046)	-	65,521,723,190
2167	65,521,723,190	3,230,220,953	(1,130,677,188)	-	67,621,266,955
2168	67,621,266,955	3,333,728,461	(2,558,235,066)	-	68,396,760,350
2169	68,396,760,350	3,371,960,285	(2,294,068,968)	-	69,474,651,667
2170	69,474,651,667	3,425,100,327	(1,270,092,970)	-	71,629,659,024
2171	71,629,659,024	3,531,342,190	(1,320,313,851)	-	73,840,687,364

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2172	73,840,687,364	3,640,345,887	(3,366,268,444)	-	74,114,764,806
2173	74,114,764,806	3,653,857,905	(1,426,836,620)	-	76,341,786,092
2174	76,341,786,092	3,763,650,054	(1,483,301,738)	-	78,622,134,408
2175	78,622,134,408	3,876,071,226	(3,758,030,772)	-	78,740,174,862
2176	78,740,174,862	3,881,890,621	(1,607,681,975)	-	81,014,383,508
2177	81,014,383,508	3,994,009,107	(1,666,562,675)	-	83,341,829,939
2178	83,341,829,939	4,108,752,216	(4,201,209,565)	-	83,249,372,590
2179	83,249,372,590	4,104,194,069	(1,801,238,027)	-	85,552,328,632
2180	85,552,328,632	4,217,729,802	(1,878,004,344)	-	87,892,054,089
2181	87,892,054,089	4,333,078,267	(1,946,871,104)	-	90,278,261,251
2182	90,278,261,251	4,450,718,280	(4,876,026,404)	-	89,852,953,127
2183	89,852,953,127	4,429,750,589	(2,104,357,547)	-	92,178,346,169
2184	92,178,346,169	4,544,392,466	(2,194,112,250)	-	94,528,626,386
2185	94,528,626,386	4,660,261,281	(2,274,666,403)	-	96,914,221,264
2186	96,914,221,264	4,777,871,108	(2,364,953,555)	-	99,327,138,817
2187	99,327,138,817	4,896,827,944	(2,458,845,919)	-	101,765,120,842
2188	101,765,120,842	5,017,020,458	(2,563,797,647)	-	104,218,343,653
2189	104,218,343,653	5,137,964,342	(24,755,109,055)	-	84,601,198,940
2190	84,601,198,940	4,170,839,108	(2,763,630,291)	-	86,008,407,757
2191	86,008,407,757	4,240,214,502	(2,873,449,011)	-	87,375,173,249
2192	87,375,173,249	4,307,596,041	(2,996,183,428)	-	88,686,585,862
2193	88,686,585,862	4,372,248,683	(2,631,904,177)	-	90,426,930,368
2194	90,426,930,368	4,458,047,667	(2,845,754,626)	-	92,039,223,409
2195	92,039,223,409	4,537,533,714	(6,096,767,211)	-	90,479,989,912
2196	90,479,989,912	4,460,663,503	(5,039,437,641)	-	89,901,215,775
2197	89,901,215,775	4,432,129,938	(5,103,100,217)	-	89,230,245,495
2198	89,230,245,495	4,399,051,103	(3,449,635,792)	-	90,179,660,806
2199	90,179,660,806	4,445,857,278	(3,388,068,666)	-	91,237,449,418
2200	91,237,449,418	4,498,006,256	(6,748,341,960)	-	88,987,113,714
2201	88,987,113,714	4,387,064,706	(7,149,946,397)	-	86,224,232,024
2202	86,224,232,024	4,250,854,639	(7,425,233,915)	-	83,049,852,747
2203	83,049,852,747	4,094,357,740	(3,957,291,254)	-	83,186,919,233
2204	83,186,919,233	4,101,115,118	(4,204,280,747)	-	83,083,753,604
2205	83,083,753,604	4,096,029,053	(8,317,266,720)	-	78,862,515,937
2206	78,862,515,937	3,887,922,036	(7,184,173,885)	-	75,566,264,088
2207	75,566,264,088	3,725,416,820	(7,551,432,749)	-	71,740,248,158
2208	71,740,248,158	3,536,794,234	(4,910,775,132)	-	70,366,267,261
2209	70,366,267,261	3,469,056,976	(8,054,173,294)	-	65,781,150,943
2210	65,781,150,943	3,243,010,741	(8,451,137,477)	-	60,573,024,208
2211	60,573,024,208	2,986,250,093	(8,764,317,521)	-	54,794,956,780
2212	54,794,956,780	2,701,391,369	(5,704,973,713)	-	51,791,374,436
2213	51,791,374,436	2,553,314,760	(16,547,281,313)	-	37,797,407,883
2214	37,797,407,883	1,863,412,209	(13,505,095,115)	-	26,155,724,977
2215	26,155,724,977	1,289,477,241	(10,210,410,842)	-	17,234,791,376
2216	17,234,791,376	849,675,215	(8,964,291,613)	-	9,120,174,978
2217	9,120,174,978	449,624,626	(6,950,572,292)	-	2,619,227,312
2218	2,619,227,312	129,127,906	(2,748,355,219)	-	(0)

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2021 ACCRUAL COMPARISON

	Present	Proposed	Difference
Monticello	$13,392,226	$9,627,369	($3,764,857)
Prairie Island Unit 1	49,264	13,677,983	13,628,719
Prairie Island Unit 2	589,341	3,832,669	3,243,328
TOTAL	$14,030,831	$27,138,020	$13,107,189

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2021 MN RETAIL SUMMARY

	Remaining Life (yrs)	Operational Earnings Rate	Post-Shutdown Earnings Rate	Market Value Balance 6/30/2017	Book Value 6/30/2017	Unrealized Gain/Loss 6/30/2017	Tax-Effect Adjustment	Tax-Adjusted Fund Balance 6/30/2017	2021 Decommissioning Accrual
Monticello	13.75	5.10%	4.83%	$660,140,345	$529,148,381	$130,991,964	$36,468,163	$623,672,182	**9,627,369**
Prairie Island Unit 1	16.67	5.12%	4.82%	399,941,696	308,078,761	91,862,935	25,574,641	374,367,055	**13,677,983**
Prairie Island Unit 2	17.83	5.14%	4.83%	448,597,551	346,627,064	101,970,487	28,388,583	420,208,967	**3,832,669**
TOTAL DECOMMISSIONING ACCRUAL				**$1,508,679,592**	**$1,183,854,206**	**$324,825,386**	**$90,431,387**	**$1,418,248,204**	**$27,138,020**

INPUT DATA

Escalation Rate (Labor)	4.05%
Escalation Rate (Non-Labor)	2.85%
Escalation Rate (PIIC)	0.00%
Jurisdictional Factor	73.4886%
Tax Rate for tax-effect adjustment	27.84%

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AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
Monticello															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2030	$17,759,328	$13,051,073	1.6755	$21,867,073	$8,763,593	$6,440,238	1.4410	$9,280,383	$0	$0	1.0000	$0	$26,522,921	$19,491,311	$31,147,456
2031	63,231,064	46,467,594	1.7434	81,011,604	46,823,276	34,409,748	1.4820	50,995,247	0	0	1.0000	0	110,054,340	80,877,343	132,006,851
2032	30,098,747	22,119,134	1.8140	40,124,109	21,963,833	16,140,903	1.5243	24,603,579	0	0	1.0000	0	52,062,580	38,260,037	64,727,688
2033	30,011,960	22,055,355	1.8874	41,627,277	35,867,567	26,358,556	1.5677	41,322,308	0	0	1.0000	0	65,879,526	48,413,911	82,949,586
2034	24,261,956	17,829,760	1.9639	35,015,866	18,617,567	13,681,781	1.6124	22,060,503	0	0	1.0000	0	42,879,522	31,511,541	57,076,369
2035	43,935,865	32,287,832	2.0434	65,976,955	88,132,650	64,767,410	1.6584	107,410,272	0	0	1.0000	0	132,068,514	97,055,241	173,387,228
2036	8,481,485	6,232,921	2.1262	13,252,436	4,523,995	3,324,618	1.7056	5,670,469	0	0	1.0000	0	13,005,479	9,557,539	18,922,905
2037	8,458,357	6,215,924	2.2123	13,751,489	4,511,770	3,315,635	1.7542	5,816,286	0	0	1.0000	0	12,970,127	9,531,559	19,567,775
2038	8,458,357	6,215,924	2.3019	14,308,436	4,511,770	3,315,635	1.8042	5,982,068	0	0	1.0000	0	12,970,127	9,531,559	20,290,504
2039	8,458,357	6,215,924	2.3951	14,887,760	4,511,770	3,315,635	1.8556	6,152,491	0	0	1.0000	0	12,970,127	9,531,559	21,040,251
2040	8,481,485	6,232,921	2.4921	15,533,061	4,523,995	3,324,618	1.9085	6,345,034	0	0	1.0000	0	13,005,479	9,557,539	21,878,095
2041	8,458,357	6,215,924	2.5930	16,117,891	4,511,770	3,315,635	1.9629	6,508,259	0	0	1.0000	0	12,970,127	9,531,559	22,626,150
2042	8,458,357	6,215,924	2.6981	16,771,185	4,511,770	3,315,635	2.0189	6,693,935	0	0	1.0000	0	12,970,127	9,531,559	23,465,119
2043	8,458,357	6,215,924	2.8073	17,449,964	4,511,770	3,315,635	2.0764	6,884,584	0	0	1.0000	0	12,970,127	9,531,559	24,334,547
2044	8,481,485	6,232,921	2.9210	18,206,361	4,523,995	3,324,618	2.1356	7,100,055	0	0	1.0000	0	13,005,479	9,557,539	25,306,416
2045	8,458,357	6,215,924	3.0393	18,892,058	4,511,770	3,315,635	2.1964	7,282,460	0	0	1.0000	0	12,970,127	9,531,559	26,174,518
2046	8,458,357	6,215,924	3.1624	19,657,238	4,511,770	3,315,635	2.2590	7,490,018	0	0	1.0000	0	12,970,127	9,531,559	27,147,257
2047	8,458,357	6,215,924	3.2905	20,453,498	4,511,770	3,315,635	2.3234	7,703,545	0	0	1.0000	0	12,970,127	9,531,559	28,157,044
2048	9,145,130	6,720,624	3.4238	23,010,071	6,514,932	4,787,729	2.3896	11,440,757	0	0	1.0000	0	15,660,061	11,508,353	34,450,829
2049	8,458,357	6,215,924	3.5624	22,143,608	4,511,767	3,315,632	2.4577	8,148,830	0	0	1.0000	0	12,970,124	9,531,556	30,292,438
2050	9,951,558	7,313,256	3.7067	27,108,046	8,991,374	6,607,631	2.5278	16,702,769	0	0	1.0000	0	18,942,932	13,920,887	43,810,815
2051	9,951,558	7,313,256	3.8568	28,205,765	8,991,374	6,607,631	2.5998	17,178,518	0	0	1.0000	0	18,942,932	13,920,887	45,384,284
2052	10,837,186	7,964,091	4.0130	31,959,898	11,591,099	8,518,131	2.6739	22,776,630	0	0	1.0000	0	22,428,284	16,482,222	54,736,528
2053	11,460,933	8,422,474	4.1756	35,168,881	13,519,499	9,935,284	2.7501	27,323,025	0	0	1.0000	0	24,980,432	18,357,758	62,491,907
2054	10,167,183	7,471,716	4.3447	32,462,363	9,638,249	7,083,010	2.8285	20,034,293	0	0	1.0000	0	19,805,432	14,554,725	52,496,656
2055	11,245,308	8,264,014	4.5206	37,358,302	12,872,624	9,459,905	2.9091	27,519,810	0	0	1.0000	0	24,117,932	17,723,919	64,878,112
2056	11,699,686	8,597,930	4.7037	40,442,083	14,178,599	10,419,647	2.9920	31,175,584	0	0	1.0000	0	25,878,284	19,017,577	71,617,667
2057	8,441,765	6,203,731	4.8942	30,362,300	4,461,997	3,279,057	3.0773	10,090,642	0	0	1.0000	0	12,903,762	9,482,788	40,452,942
2058	8,441,765	6,203,731	5.0924	31,591,879	4,461,997	3,279,057	3.1650	10,378,216	0	0	1.0000	0	12,903,762	9,482,788	41,970,095
2059	8,441,765	6,203,731	5.2987	32,871,709	4,461,997	3,279,057	3.2552	10,673,987	0	0	1.0000	0	12,903,762	9,482,788	43,545,695
2060	8,464,894	6,220,728	5.5133	34,296,740	4,474,222	3,288,041	3.3480	11,008,361	0	0	1.0000	0	12,939,115	9,508,769	45,305,101
2061	8,441,765	6,203,731	5.7366	35,588,322	4,461,997	3,279,057	3.4434	11,291,105	0	0	1.0000	0	12,903,762	9,482,788	46,879,428
2062	8,441,765	6,203,731	5.9689	37,029,449	4,461,997	3,279,057	3.5415	11,612,781	0	0	1.0000	0	12,903,762	9,482,788	48,642,230
2063	8,441,765	6,203,731	6.2106	38,528,891	4,461,997	3,279,057	3.6425	11,943,965	0	0	1.0000	0	12,903,762	9,482,788	50,472,856
2064	8,464,894	6,220,728	6.4622	40,199,589	4,474,222	3,288,041	3.7463	12,317,987	0	0	1.0000	0	12,939,115	9,508,769	52,517,576
2065	8,441,765	6,203,731	6.7239	41,713,266	4,461,997	3,279,057	3.8531	12,634,535	0	0	1.0000	0	12,903,762	9,482,788	54,347,801
2066	8,441,765	6,203,731	6.9962	43,402,542	4,461,997	3,279,057	3.9629	12,994,575	0	0	1.0000	0	12,903,762	9,482,788	56,397,117
2067	8,441,765	6,203,731	7.2795	45,160,059	4,461,997	3,279,057	4.0758	13,364,781	0	0	1.0000	0	12,903,762	9,482,788	58,524,840
2068	8,464,894	6,220,728	7.5744	47,118,282	4,474,222	3,288,041	4.1920	13,783,467	0	0	1.0000	0	12,939,115	9,508,769	60,901,750
2069	8,441,765	6,203,731	7.8811	48,892,223	4,461,997	3,279,057	4.3115	14,137,655	0	0	1.0000	0	12,903,762	9,482,788	63,029,878
2070	8,441,765	6,203,731	8.2003	50,872,454	4,461,997	3,279,057	4.4343	14,540,323	0	0	1.0000	0	12,903,762	9,482,788	65,412,777
2071	8,441,765	6,203,731	8.5324	52,932,713	4,461,997	3,279,057	4.5607	14,954,796	0	0	1.0000	0	12,903,762	9,482,788	67,887,509
2072	8,464,894	6,220,728	8.8780	55,227,624	4,474,222	3,288,041	4.6907	15,423,213	0	0	1.0000	0	12,939,115	9,508,769	70,650,837
2073	8,441,765	6,203,731	9.2375	57,306,964	4,461,997	3,279,057	4.8244	15,819,483	0	0	1.0000	0	12,903,762	9,482,788	73,126,447
2074	8,441,765	6,203,731	9.6117	59,628,400	4,461,997	3,279,057	4.9619	16,270,353	0	0	1.0000	0	12,903,762	9,482,788	75,898,753
2075	8,441,765	6,203,731	10.0009	62,042,892	4,461,997	3,279,057	5.1033	16,734,012	0	0	1.0000	0	12,903,762	9,482,788	78,776,904
2076	8,464,894	6,220,728	10.4060	64,732,896	4,474,222	3,288,041	5.2487	17,257,940	0	0	1.0000	0	12,939,115	9,508,769	81,990,836
2077	8,441,765	6,203,731	10.8274	67,170,276	4,461,997	3,279,057	5.3983	17,701,334	0	0	1.0000	0	12,903,762	9,482,788	84,871,609
2078	8,920,197	6,555,324	11.2659	73,851,620	5,897,293	4,333,835	5.5522	24,062,321	0	0	1.0000	0	14,817,490	10,889,159	97,913,941
2079	9,015,884	6,625,643	11.7222	77,667,108	6,184,352	4,544,791	5.7104	25,952,574	0	0	1.0000	0	15,200,236	11,170,433	103,619,682
2080	8,943,325	6,572,320	12.1970	80,162,588	5,909,518	4,342,819	5.8731	25,505,811	0	0	1.0000	0	14,852,842	10,915,139	105,668,399
2081	8,920,197	6,555,324	12.6909	83,192,957	5,897,293	4,333,835	6.0405	26,178,533	0	0	1.0000	0	14,817,490	10,889,159	109,371,489
2082	8,920,197	6,555,324	13.2049	86,562,393	5,897,293	4,333,835	6.2127	26,924,819	0	0	1.0000	0	14,817,490	10,889,159	113,487,212
2083	9,015,884	6,625,643	13.7397	91,034,342	6,184,352	4,544,791	6.3897	29,039,850	0	0	1.0000	0	15,200,236	11,170,433	120,074,192
2084	8,943,325	6,572,320	14.2962	93,959,202	5,909,518	4,342,819	6.5719	28,540,573	0	0	1.0000	0	14,852,842	10,915,139	122,499,775

Xcel Energy
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60-Year Decommissioning Period
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AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
2085	46,126,149	33,897,440	14.8752	504,231,201	12,314,062	9,049,426	6.7592	61,166,882	0	0	1.0000	0	58,440,212	42,946,866	565,398,083
2086	53,631,139	39,412,748	15.4776	610,014,753	46,945,385	34,499,485	6.9518	239,833,517	0	0	1.0000	0	100,576,524	73,912,233	849,848,270
2087	57,419,114	42,196,476	16.1045	679,553,153	80,273,242	58,991,645	7.1499	421,784,362	0	0	1.0000	0	137,692,356	101,188,121	1,101,337,516
2088	52,652,752	38,693,746	16.7567	648,379,491	33,214,319	24,408,722	7.3537	179,494,423	0	0	1.0000	0	85,867,070	63,102,468	827,873,914
2089	50,913,638	37,415,697	17.4353	652,353,896	30,841,715	22,665,130	7.5633	171,423,181	0	0	1.0000	0	81,755,354	60,080,827	823,777,077
2090	32,667,889	24,007,160	18.1415	435,525,885	23,001,023	16,903,119	7.7788	131,485,985	0	0	1.0000	0	55,668,913	40,910,279	567,011,870
2091	21,071,356	15,485,035	18.8762	292,298,617	16,131,940	11,855,130	8.0005	94,846,965	0	0	1.0000	0	37,203,297	27,340,165	387,145,582
2092	8,832,651	6,490,987	19.6407	127,487,533	6,762,156	4,969,411	8.2285	40,890,795	0	0	1.0000	0	15,594,807	11,460,398	168,378,328
	$967,171,883	$710,760,631		$6,275,707,486	$750,282,438	$551,371,714		$2,329,665,815	$0	$0		$0	$1,717,454,322	$1,262,132,345	$8,605,373,301

Xcel Energy
Nuclear Decommissioning Accrual
60-Year Decommissioning Period
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Proposed

AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
Prairie Island Unit 1															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2033	$18,446,908	$13,556,366	1.8874	$25,586,285	$4,190,856	$3,079,799	1.5677	$4,828,201	$1,250,000	$918,607	1.0000	$918,607	$23,887,764	$17,554,772	$31,333,093
2034	46,142,627	33,909,549	1.9639	66,594,964	29,162,161	21,430,850	1.6124	34,555,103	1,250,000	918,607	1.0000	918,607	76,554,787	56,259,006	102,068,673
2035	16,398,923	12,051,331	2.0434	24,625,691	15,491,742	11,384,657	1.6584	18,880,315	1,250,000	918,607	1.0000	918,607	33,140,665	24,354,595	44,424,613
2036	12,659,656	9,303,398	2.1262	19,780,886	13,774,811	10,122,909	1.7056	17,265,634	1,250,000	918,607	1.0000	918,607	27,684,467	20,344,915	37,965,127
2037	12,625,333	9,278,174	2.2123	20,526,105	13,734,545	10,093,318	1.7542	17,705,699	1,250,000	918,607	1.0000	918,607	27,609,877	20,290,100	39,150,411
2038	15,404,499	11,320,543	2.3019	26,058,758	22,072,045	16,220,427	1.8042	29,264,894	1,250,000	918,607	1.0000	918,607	38,726,543	28,459,577	56,242,259
2039	32,688,492	24,022,300	2.3951	57,535,811	76,524,027	56,236,401	1.8556	104,352,265	1,250,000	918,607	1.0000	918,607	110,462,519	81,177,308	162,806,683
2040	4,604,176	3,383,542	2.4921	8,432,126	4,477,123	3,290,173	1.9085	6,279,295	1,250,000	918,607	1.0000	918,607	10,331,299	7,592,322	15,630,028
2041	4,591,596	3,374,297	2.5930	8,749,553	4,461,475	3,278,674	1.9629	6,435,709	1,250,000	918,607	1.0000	918,607	10,303,071	7,571,578	16,103,868
2042	4,591,596	3,374,297	2.6981	9,104,191	4,461,475	3,278,674	2.0189	6,619,314	1,250,000	918,607	1.0000	918,607	10,303,071	7,571,578	16,642,112
2043	4,591,596	3,374,297	2.8073	9,472,665	4,461,475	3,278,674	2.0764	6,807,838	1,250,000	918,607	1.0000	918,607	10,303,071	7,571,578	17,199,109
2044	4,604,176	3,383,542	2.9210	9,883,328	4,477,123	3,290,173	2.1356	7,026,494	1,250,000	918,607	1.0000	918,607	10,331,299	7,592,322	17,828,428
2045	4,591,596	3,374,297	3.0393	10,255,502	4,461,475	3,278,674	2.1964	7,201,279	1,250,000	918,607	1.0000	918,607	10,303,071	7,571,578	18,375,387
2046	4,591,596	3,374,297	3.1624	10,670,878	4,461,475	3,278,674	2.2590	7,406,524	1,250,000	918,607	1.0000	918,607	10,303,071	7,571,578	18,996,008
2047	4,591,596	3,374,297	3.2905	11,103,125	4,461,475	3,278,674	2.3234	7,617,670	1,250,000	918,607	1.0000	918,607	10,303,071	7,571,578	19,639,402
2048	4,604,176	3,383,542	3.4238	11,584,573	4,477,123	3,290,173	2.3896	7,862,198	1,250,000	918,607	1.0000	918,607	10,331,299	7,592,322	20,365,377
2049	4,591,596	3,374,297	3.5624	12,020,596	4,461,475	3,278,674	2.4577	8,057,996	1,250,000	918,607	1.0000	918,607	10,303,071	7,571,578	20,997,200
2050	4,591,596	3,374,297	3.7067	12,507,507	4,461,475	3,278,674	2.5278	8,287,831	1,250,000	918,607	1.0000	918,607	10,303,071	7,571,578	21,713,946
2051	4,591,596	3,374,297	3.8568	13,013,990	4,461,475	3,278,674	2.5998	8,523,896	1,250,000	918,607	1.0000	918,607	10,303,071	7,571,578	22,456,492
2052	4,604,176	3,383,542	4.0130	13,578,156	4,477,123	3,290,173	2.6739	8,797,594	1,250,000	918,607	1.0000	918,607	10,331,299	7,592,322	23,294,357
2053	4,687,283	3,444,616	4.1756	14,383,339	4,748,534	3,489,629	2.7501	9,596,829	1,250,000	918,607	1.0000	918,607	10,685,817	7,852,852	24,898,776
2054	4,782,969	3,514,934	4.3447	15,271,336	5,035,593	3,700,585	2.8285	10,467,104	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	26,657,046
2055	4,782,969	3,514,934	4.5206	15,889,613	5,035,593	3,700,585	2.9091	10,765,371	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	27,573,591
2056	4,843,392	3,559,339	4.7037	16,742,062	5,194,771	3,817,562	2.9920	11,422,146	1,250,000	918,607	1.0000	918,607	11,288,163	8,295,508	29,082,815
2057	4,735,126	3,479,775	4.8942	17,030,716	4,892,064	3,595,107	3.0773	11,063,224	1,250,000	918,607	1.0000	918,607	10,877,190	7,993,490	29,012,547
2058	4,878,656	3,585,253	5.0924	18,257,545	5,322,652	3,911,540	3.1650	12,380,025	1,250,000	918,607	1.0000	918,607	11,451,308	8,415,401	31,556,176
2059	4,735,126	3,479,775	5.2987	18,438,286	4,892,064	3,595,107	3.2552	11,702,793	1,250,000	918,607	1.0000	918,607	10,877,190	7,993,490	31,059,686
2060	4,699,862	3,453,861	5.5133	19,042,170	4,764,182	3,501,129	3.3480	11,721,778	1,250,000	918,607	1.0000	918,607	10,714,044	7,873,596	31,682,556
2061	4,782,969	3,514,934	5.7366	20,163,773	5,035,593	3,700,585	3.4434	12,742,593	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	33,824,973
2062	4,782,969	3,514,934	5.9689	20,980,292	5,035,593	3,700,585	3.5415	13,105,621	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	35,004,520
2063	4,735,126	3,479,775	6.2106	21,611,493	4,892,064	3,595,107	3.6425	13,095,178	1,250,000	918,607	1.0000	918,607	10,877,190	7,993,490	35,625,278
2064	4,795,548	3,524,179	6.4622	22,773,949	5,051,241	3,712,084	3.7463	13,906,581	1,250,000	918,607	1.0000	918,607	11,096,789	8,154,870	37,599,137
2065	4,782,969	3,514,934	6.7239	23,634,068	5,035,593	3,700,585	3.8531	14,258,723	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	38,811,398
2066	4,735,126	3,479,775	6.9962	24,345,204	4,892,064	3,595,107	3.9629	14,247,051	1,250,000	918,607	1.0000	918,607	10,877,190	7,993,490	39,510,862
2067	4,782,969	3,514,934	7.2795	25,586,965	5,035,593	3,700,585	4.0758	15,082,843	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	41,588,415
2068	4,795,548	3,524,179	7.5744	26,693,541	5,051,241	3,712,084	4.1920	15,561,056	1,250,000	918,607	1.0000	918,607	11,096,789	8,154,870	43,173,205
2069	4,735,126	3,479,775	7.8811	27,424,457	4,892,064	3,595,107	4.3115	15,500,305	1,250,000	918,607	1.0000	918,607	10,877,190	7,993,490	43,843,369
2070	4,782,969	3,514,934	8.2003	28,823,517	5,035,593	3,700,585	4.4343	16,409,503	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	46,151,627
2071	4,782,969	3,514,934	8.5324	29,990,827	5,035,593	3,700,585	4.5607	16,877,257	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	47,786,690
2072	4,795,548	3,524,179	8.8780	31,287,661	5,051,241	3,712,084	4.6907	17,412,273	1,250,000	918,607	1.0000	918,607	11,096,789	8,154,870	49,618,541
2073	4,782,969	3,514,934	9.2375	32,469,207	5,035,593	3,700,585	4.8244	17,853,101	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	51,240,915
2074	4,782,969	3,514,934	9.6117	33,784,496	5,035,593	3,700,585	4.9619	18,361,931	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	53,065,034
2075	5,114,792	3,758,786	10.0009	37,591,247	6,031,061	4,432,140	5.1033	22,618,539	1,250,000	918,607	1.0000	918,607	12,395,853	9,109,533	61,128,392
2076	4,795,548	3,524,179	10.4060	36,672,606	5,051,241	3,712,084	5.2487	19,483,616	1,250,000	918,607	1.0000	918,607	11,096,789	8,154,870	57,074,829
2077	4,782,969	3,514,934	10.8274	38,057,601	5,035,593	3,700,585	5.3983	19,976,866	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	58,953,075
2078	3,942,348	2,897,174	11.2659	32,639,275	3,256,582	2,393,215	5.5522	13,287,607	0	0	1.0000	0	7,198,929	5,290,389	45,926,882
2079	3,942,348	2,897,174	11.7222	33,961,256	3,256,582	2,393,215	5.7104	13,666,214	0	0	1.0000	0	7,198,929	5,290,389	47,627,470
2080	3,953,149	2,905,112	12.1970	35,433,647	3,265,504	2,399,772	5.8731	14,094,099	0	0	1.0000	0	7,218,652	5,304,883	49,527,746
2081	3,942,348	2,897,174	12.6909	36,767,748	3,256,582	2,393,215	6.0405	14,456,214	0	0	1.0000	0	7,198,929	5,290,389	51,223,963
2082	3,942,348	2,897,174	13.2049	38,256,896	3,256,582	2,393,215	6.2127	14,868,326	0	0	1.0000	0	7,198,929	5,290,389	53,125,222
2083	3,942,348	2,897,174	13.7397	39,806,305	3,256,582	2,393,215	6.3897	15,291,925	0	0	1.0000	0	7,198,929	5,290,389	55,098,229
2084	3,953,149	2,905,112	14.2962	41,532,058	3,265,504	2,399,772	6.5719	15,771,059	0	0	1.0000	0	7,218,652	5,304,883	57,303,117
2085	3,942,348	2,897,174	14.8752	43,096,046	3,256,582	2,393,215	6.7592	16,176,218	0	0	1.0000	0	7,198,929	5,290,389	59,272,264
2086	3,942,348	2,897,174	15.4776	44,841,304	3,256,582	2,393,215	6.9518	16,637,151	0	0	1.0000	0	7,198,929	5,290,389	61,478,455
2087	11,802,691	8,673,627	16.1045	139,684,421	4,951,569	3,638,837	7.1499	26,017,319	0	0	1.0000	0	16,754,260	12,312,463	165,701,740

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AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
2088	45,111,220	33,151,584	16.7567	555,511,141	11,805,071	8,675,376	7.3537	63,796,110	0	0	1.0000	0	56,916,291	41,826,959	619,307,251
2089	51,818,304	38,080,522	17.4353	663,945,327	62,277,980	45,767,187	7.5633	346,150,962	0	0	1.0000	0	114,096,283	83,847,709	1,010,096,289
2090	44,187,860	32,473,019	18.1415	589,109,275	56,754,748	41,708,244	7.7788	324,440,085	0	0	1.0000	0	100,942,608	74,181,263	913,549,360
2091	35,668,367	26,212,167	18.8762	494,786,111	31,834,151	23,394,458	8.0005	187,167,358	0	0	1.0000	0	67,502,519	49,606,625	681,953,469
2092	13,715,750	10,079,506	19.6407	197,968,561	10,259,487	7,539,548	8.2285	62,039,173	0	0	1.0000	0	23,975,237	17,619,055	260,007,735
2093	18,089,191	13,293,485	20.4361	271,666,992	6,228,187	4,577,005	8.4630	38,735,191	0	0	1.0000	0	24,317,379	17,870,490	310,402,183
2094	12,584,719	9,248,328	21.2638	196,654,598	9,264,588	6,808,412	8.7042	59,261,777	0	0	1.0000	0	21,849,307	16,056,740	255,916,375
2095	9,102,372	6,689,202	22.1250	147,998,586	6,700,962	4,924,440	8.9523	44,085,066	0	0	1.0000	0	15,803,334	11,613,642	192,083,653
	$611,385,166	$449,298,117		$4,601,690,206	$588,533,792	$432,504,973		$1,975,329,908	$56,250,000	$41,337,312		$41,337,312	$1,256,168,958	$923,140,402	$6,618,357,426

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AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
Prairie Island Unit 2															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2034	$7,248,794	$5,327,034	1.9639	$10,461,762	$2,826,485	$2,077,143	1.6124	$3,349,185	$1,250,000	$918,607	1.0000	$918,607	$11,325,279	$8,322,784	$14,729,554
2035	44,817,806	32,935,958	2.0434	67,301,336	32,275,248	23,718,613	1.6584	39,334,948	1,250,000	918,607	1.0000	918,607	78,343,054	57,573,177	107,554,890
2036	23,021,476	16,918,150	2.1262	35,971,370	19,944,127	14,656,651	1.7056	24,998,384	1,250,000	918,607	1.0000	918,607	44,215,603	32,493,407	61,888,360
2037	10,761,111	7,908,185	2.2123	17,495,278	12,388,936	9,104,450	1.7542	15,971,026	1,250,000	918,607	1.0000	918,607	24,400,047	17,931,242	34,384,910
2038	13,540,277	9,950,554	2.3019	22,905,180	20,726,436	15,231,558	1.8042	27,480,777	1,250,000	918,607	1.0000	918,607	35,516,713	26,100,719	51,304,564
2039	31,160,880	22,899,680	2.3951	54,847,024	75,415,818	55,421,994	1.8556	102,841,052	1,250,000	918,607	1.0000	918,607	107,826,698	79,240,281	158,606,683
2040	4,659,832	3,424,443	2.4921	8,534,055	4,485,457	3,296,297	1.9085	6,290,984	1,250,000	918,607	1.0000	918,607	10,395,289	7,639,347	15,743,645
2041	4,647,099	3,415,086	2.5930	8,855,319	4,469,786	3,284,781	1.9629	6,447,697	1,250,000	918,607	1.0000	918,607	10,366,886	7,618,474	16,221,623
2042	4,647,099	3,415,086	2.6981	9,214,244	4,469,786	3,284,781	2.0189	6,631,645	1,250,000	918,607	1.0000	918,607	10,366,886	7,618,474	16,764,496
2043	4,647,099	3,415,086	2.8073	9,587,172	4,469,786	3,284,781	2.0764	6,820,520	1,250,000	918,607	1.0000	918,607	10,366,886	7,618,474	17,326,298
2044	4,659,832	3,424,443	2.9210	10,002,799	4,485,457	3,296,297	2.1356	7,039,573	1,250,000	918,607	1.0000	918,607	10,395,289	7,639,347	17,960,978
2045	4,647,099	3,415,086	3.0393	10,379,472	4,469,786	3,284,781	2.1964	7,214,693	1,250,000	918,607	1.0000	918,607	10,366,886	7,618,474	18,512,772
2046	4,647,099	3,415,086	3.1624	10,799,869	4,469,786	3,284,781	2.2590	7,420,321	1,250,000	918,607	1.0000	918,607	10,366,886	7,618,474	19,138,796
2047	4,647,099	3,415,086	3.2905	11,237,341	4,469,786	3,284,781	2.3234	7,631,861	1,250,000	918,607	1.0000	918,607	10,366,886	7,618,474	19,787,809
2048	4,659,832	3,424,443	3.4238	11,724,609	4,485,457	3,296,297	2.3896	7,876,832	1,250,000	918,607	1.0000	918,607	10,395,289	7,639,347	20,520,048
2049	4,647,099	3,415,086	3.5624	12,165,903	4,469,786	3,284,781	2.4577	8,073,007	1,250,000	918,607	1.0000	918,607	10,366,886	7,618,474	21,157,517
2050	4,647,099	3,415,086	3.7067	12,658,700	4,469,786	3,284,781	2.5278	8,303,270	1,250,000	918,607	1.0000	918,607	10,366,886	7,618,474	21,880,577
2051	4,647,099	3,415,086	3.8568	13,171,304	4,469,786	3,284,781	2.5998	8,539,774	1,250,000	918,607	1.0000	918,607	10,366,886	7,618,474	22,629,686
2052	4,659,832	3,424,443	4.0130	13,742,291	4,485,457	3,296,297	2.6739	8,813,970	1,250,000	918,607	1.0000	918,607	10,395,289	7,639,347	23,474,867
2053	4,742,786	3,485,405	4.1756	14,553,658	4,756,846	3,495,737	2.7501	9,613,628	1,250,000	918,607	1.0000	918,607	10,749,633	7,899,750	25,085,893
2054	4,838,472	3,555,723	4.3447	15,448,552	5,043,904	3,706,692	2.8285	10,484,379	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	26,851,538
2055	4,838,472	3,555,723	4.5206	16,074,003	5,043,904	3,706,692	2.9091	10,783,138	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	27,775,749
2056	4,899,048	3,600,240	4.7037	16,934,447	5,203,105	3,823,687	2.9920	11,440,470	1,250,000	918,607	1.0000	918,607	11,352,153	8,342,533	29,293,524
2057	4,790,629	3,520,564	4.8942	17,230,346	4,900,375	3,601,215	3.0773	11,082,018	1,250,000	918,607	1.0000	918,607	10,941,005	8,040,386	29,230,971
2058	4,934,159	3,626,042	5.0924	18,465,259	5,330,963	3,917,648	3.1650	12,399,355	1,250,000	918,607	1.0000	918,607	11,515,123	8,462,297	31,783,221
2059	4,790,629	3,520,564	5.2987	18,654,414	4,900,375	3,601,215	3.2552	11,722,675	1,250,000	918,607	1.0000	918,607	10,941,005	8,040,386	31,295,696
2060	4,755,518	3,494,761	5.5133	19,267,668	4,772,516	3,507,253	3.3480	11,742,283	1,250,000	918,607	1.0000	918,607	10,778,034	7,920,621	31,928,558
2061	4,838,472	3,555,723	5.7366	20,397,763	5,043,904	3,706,692	3.4434	12,763,624	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	34,079,994
2062	4,838,472	3,555,723	5.9689	21,223,758	5,043,904	3,706,692	3.5415	13,127,251	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	35,269,615
2063	4,790,629	3,520,564	6.2106	21,864,817	4,900,375	3,601,215	3.6425	13,117,425	1,250,000	918,607	1.0000	918,607	10,941,005	8,040,386	35,900,849
2064	4,851,204	3,565,080	6.4622	23,038,258	5,059,575	3,718,208	3.7463	13,929,524	1,250,000	918,607	1.0000	918,607	11,160,779	8,201,895	37,886,389
2065	4,838,472	3,555,723	6.7239	23,908,329	5,043,904	3,706,692	3.8531	14,282,256	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	39,109,192
2066	4,790,629	3,520,564	6.9962	24,630,572	4,900,375	3,601,215	3.9629	14,271,254	1,250,000	918,607	1.0000	918,607	10,941,005	8,040,386	39,820,433
2067	4,838,472	3,555,723	7.2795	25,883,889	5,043,904	3,706,692	4.0758	15,107,736	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	41,910,232
2068	4,851,204	3,565,080	7.5744	27,003,340	5,059,575	3,718,208	4.1920	15,586,730	1,250,000	918,607	1.0000	918,607	11,160,779	8,201,895	43,508,676
2069	4,790,629	3,520,564	7.8811	27,745,920	4,900,375	3,601,215	4.3115	15,526,638	1,250,000	918,607	1.0000	918,607	10,941,005	8,040,386	44,191,164
2070	4,838,472	3,555,723	8.2003	29,157,999	5,043,904	3,706,692	4.4343	16,436,585	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	46,513,191
2071	4,838,472	3,555,723	8.5324	30,338,855	5,043,904	3,706,692	4.5607	16,905,111	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	48,162,573
2072	4,851,204	3,565,080	8.8780	31,650,778	5,059,575	3,718,208	4.6907	17,441,000	1,250,000	918,607	1.0000	918,607	11,160,779	8,201,895	50,010,385
2073	4,838,472	3,555,723	9.2375	32,845,995	5,043,904	3,706,692	4.8244	17,882,566	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	51,647,168
2074	4,838,472	3,555,723	9.6117	34,176,547	5,043,904	3,706,692	4.9619	18,392,236	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	53,487,390
2075	5,170,295	3,799,575	10.0009	37,999,173	6,039,372	4,438,247	5.1033	22,649,707	1,250,000	918,607	1.0000	918,607	12,459,668	9,156,430	61,567,488
2076	4,851,204	3,565,080	10.4060	37,098,220	5,059,575	3,718,208	5.2487	19,515,760	1,250,000	918,607	1.0000	918,607	11,160,779	8,201,895	57,532,587
2077	4,838,472	3,555,723	10.8274	38,499,240	5,043,904	3,706,692	5.3983	20,009,837	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	59,427,684
2078	823,359	605,074	11.2659	6,816,708	3,272,479	2,404,897	5.5522	13,352,471	0	-	1.0000	-	4,095,838	3,009,972	20,169,179
2079	823,359	605,074	11.7222	7,092,804	3,272,479	2,404,897	5.7104	13,732,926	0	-	1.0000	-	4,095,838	3,009,972	20,825,729
2080	825,615	606,732	12.1970	7,400,312	3,281,444	2,411,486	5.8731	14,162,899	0	-	1.0000	-	4,107,059	3,018,218	21,563,211
2081	823,359	605,074	12.6909	7,678,939	3,272,479	2,404,897	6.0405	14,526,782	0	-	1.0000	-	4,095,838	3,009,972	22,205,721
2082	823,359	605,074	13.2049	7,989,947	3,272,479	2,404,897	6.2127	14,940,906	0	-	1.0000	-	4,095,838	3,009,972	22,930,853
2083	823,359	605,074	13.7397	8,313,541	3,272,479	2,404,897	6.3897	15,366,573	0	-	1.0000	-	4,095,838	3,009,972	23,680,114
2084	825,615	606,732	14.2962	8,673,964	3,281,444	2,411,486	6.5719	15,848,045	0	-	1.0000	-	4,107,059	3,018,218	24,522,010
2085	823,359	605,074	14.8752	9,000,603	3,272,479	2,404,897	6.7592	16,255,182	0	-	1.0000	-	4,095,838	3,009,972	25,255,785
2086	823,359	605,074	15.4776	9,365,100	3,272,479	2,404,897	6.9518	16,718,365	0	-	1.0000	-	4,095,838	3,009,972	26,083,465
2087	823,359	605,074	16.1045	9,744,421	3,272,479	2,404,897	7.1499	17,194,775	0	-	1.0000	-	4,095,838	3,009,972	26,939,197
2088	11,274,587	8,285,531	16.7567	138,838,152	5,987,760	4,400,318	7.3537	32,358,621	0	-	1.0000	-	17,262,347	12,685,849	171,196,773

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AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
2089	29,172,411	21,438,383	17.4353	373,784,641	10,590,974	7,783,154	7.5633	58,866,327	0	-	1.0000	-	39,763,385	29,221,537	432,650,967
2090	57,665,154	42,377,288	18.1415	768,787,572	90,528,180	66,527,851	7.7788	517,506,845	0	-	1.0000	-	148,193,335	108,905,139	1,286,294,416
2091	55,538,057	40,814,115	18.8762	770,415,403	42,217,329	31,024,904	8.0005	248,214,748	0	-	1.0000	-	97,755,386	71,839,020	1,018,630,150
2092	51,408,076	37,779,052	19.6407	742,007,025	32,588,487	23,948,808	8.2285	197,062,766	0	-	1.0000	-	83,996,563	61,727,860	939,069,791
2093	23,223,558	17,066,657	20.4361	348,775,903	8,238,061	6,054,032	8.4630	51,235,271	0	-	1.0000	-	31,461,619	23,120,689	400,011,174
2094	14,460,844	10,627,065	21.2638	225,971,787	14,186,680	10,425,586	8.7042	90,746,385	0	-	1.0000	-	28,647,524	21,052,651	316,718,172
2095	10,459,350	7,686,425	22.1250	170,062,157	10,261,051	7,540,698	8.9523	67,506,588	0	-	1.0000	-	20,720,401	15,227,123	237,568,746
	$573,536,674	$421,483,808		$4,595,865,805	$595,414,118	$437,561,225		$2,092,889,180	$55,000,000	$40,418,705		$40,418,705	$1,223,950,791	$899,463,737	$6,729,173,689
	$2,152,093,723	$1,581,542,556		$15,473,263,497	$1,934,230,348	$1,421,437,911		$6,397,884,902	$111,250,000	$81,756,016		$81,756,016	$4,197,574,071	$3,084,736,483	$21,952,904,416

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EXTERNAL FUND CALCULATION

Monticello

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	623,672,182	15,989,016	-	6,696,113	646,357,311
2018	646,357,311	33,305,725	-	13,392,226	693,055,262
2019	693,055,262	35,687,320	-	13,392,226	742,134,808
2020	742,134,808	38,190,377	-	13,392,226	793,717,411
2021	793,717,411	40,725,086	-	9,627,369	844,069,865
2022	844,069,865	43,293,061	-	9,627,369	896,990,295
2023	896,990,295	45,992,003	-	9,627,369	952,609,667
2024	952,609,667	48,828,591	-	9,627,369	1,011,065,626
2025	1,011,065,626	51,809,845	-	9,627,369	1,072,502,840
2026	1,072,502,840	54,943,143	-	9,627,369	1,137,073,351
2027	1,137,073,351	58,236,239	-	9,627,369	1,204,936,959
2028	1,204,936,959	61,697,283	-	9,627,369	1,276,261,610
2029	1,276,261,610	65,334,840	-	9,627,369	1,351,223,819
2030	1,351,223,819	65,438,486	(31,147,456)	7,220,526	1,392,735,375
2031	1,392,735,375	67,269,119	(132,006,851)	-	1,327,997,643
2032	1,327,997,643	64,142,286	(64,727,688)	-	1,327,412,241
2033	1,327,412,241	64,114,011	(82,949,586)	-	1,308,576,666
2034	1,308,576,666	63,204,253	(57,076,369)	-	1,314,704,550
2035	1,314,704,550	63,500,230	(173,387,228)	-	1,204,817,552
2036	1,204,817,552	58,192,688	(18,922,905)	-	1,244,087,335
2037	1,244,087,335	60,089,418	(19,567,775)	-	1,284,608,979
2038	1,284,608,979	62,046,614	(20,290,504)	-	1,326,365,089
2039	1,326,365,089	64,063,434	(21,040,251)	-	1,369,388,271
2040	1,369,388,271	66,141,454	(21,878,095)	-	1,413,651,630
2041	1,413,651,630	68,279,374	(22,626,150)	-	1,459,304,853
2042	1,459,304,853	70,484,424	(23,465,119)	-	1,506,324,158
2043	1,506,324,158	72,755,457	(24,334,547)	-	1,554,745,068
2044	1,554,745,068	75,094,187	(25,306,416)	-	1,604,532,839
2045	1,604,532,839	77,498,936	(26,174,518)	-	1,655,857,257
2046	1,655,857,257	79,977,906	(27,147,257)	-	1,708,687,906
2047	1,708,687,906	82,529,626	(28,157,044)	-	1,763,060,488
2048	1,763,060,488	85,155,822	(34,450,829)	-	1,813,765,481
2049	1,813,765,481	87,604,873	(30,292,438)	-	1,871,077,916
2050	1,871,077,916	90,373,063	(43,810,815)	-	1,917,640,165
2051	1,917,640,165	92,622,020	(45,384,284)	-	1,964,877,901
2052	1,964,877,901	94,903,603	(54,736,528)	-	2,005,044,976
2053	2,005,044,976	96,843,672	(62,491,907)	-	2,039,396,741
2054	2,039,396,741	98,502,863	(52,496,656)	-	2,085,402,948
2055	2,085,402,948	100,724,962	(64,878,112)	-	2,121,249,798
2056	2,121,249,798	102,456,365	(71,617,667)	-	2,152,088,496

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2057	2,152,088,496	103,945,874	(40,452,942)	-	2,215,581,428
2058	2,215,581,428	107,012,583	(41,970,095)	-	2,280,623,917
2059	2,280,623,917	110,154,135	(43,545,695)	-	2,347,232,356
2060	2,347,232,356	113,371,323	(45,305,101)	-	2,415,298,579
2061	2,415,298,579	116,658,921	(46,879,428)	-	2,485,078,072
2062	2,485,078,072	120,029,271	(48,642,230)	-	2,556,465,113
2063	2,556,465,113	123,477,265	(50,472,856)	-	2,629,469,522
2064	2,629,469,522	127,003,378	(52,517,576)	-	2,703,955,324
2065	2,703,955,324	130,601,042	(54,347,801)	-	2,780,208,565
2066	2,780,208,565	134,284,074	(56,397,117)	-	2,858,095,521
2067	2,858,095,521	138,046,014	(58,524,840)	-	2,937,616,695
2068	2,937,616,695	141,886,886	(60,901,750)	-	3,018,601,832
2069	3,018,601,832	145,798,468	(63,029,878)	-	3,101,370,423
2070	3,101,370,423	149,796,191	(65,412,777)	-	3,185,753,837
2071	3,185,753,837	153,871,910	(67,887,509)	-	3,271,738,238
2072	3,271,738,238	158,024,957	(70,650,837)	-	3,359,112,359
2073	3,359,112,359	162,245,127	(73,126,447)	-	3,448,231,039
2074	3,448,231,039	166,549,559	(75,898,753)	-	3,538,881,845
2075	3,538,881,845	170,927,993	(78,776,904)	-	3,631,032,934
2076	3,631,032,934	175,378,891	(81,990,836)	-	3,724,420,988
2077	3,724,420,988	179,889,534	(84,871,609)	-	3,819,438,913
2078	3,819,438,913	184,478,899	(97,913,941)	-	3,906,003,871
2079	3,906,003,871	188,659,987	(103,619,682)	-	3,991,044,176
2080	3,991,044,176	192,767,434	(105,668,399)	-	4,078,143,211
2081	4,078,143,211	196,974,317	(109,371,489)	-	4,165,746,039
2082	4,165,746,039	201,205,534	(113,487,212)	-	4,253,464,361
2083	4,253,464,361	205,442,329	(120,074,192)	-	4,338,832,498
2084	4,338,832,498	209,565,610	(122,499,775)	-	4,425,898,332
2085	4,425,898,332	213,770,889	(565,398,083)	-	4,074,271,139
2086	4,074,271,139	196,787,296	(849,848,270)	-	3,421,210,166
2087	3,421,210,166	165,244,451	(1,101,337,516)	-	2,485,117,101
2088	2,485,117,101	120,031,156	(827,873,914)	-	1,777,274,343
2089	1,777,274,343	85,842,351	(823,777,077)	-	1,039,339,617
2090	1,039,339,617	50,200,104	(567,011,870)	-	522,527,851
2091	522,527,851	25,238,095	(387,145,582)	-	160,620,364
2092	160,620,364	7,757,964	(168,378,328)	-	0

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Prairie Island Unit 1

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	374,367,055	9,584,112	-	24,632	383,975,799
2018	383,975,799	19,660,822	-	49,264	403,685,885
2019	403,685,885	20,669,978	-	49,264	424,405,128
2020	424,405,128	21,730,804	-	49,264	446,185,196
2021	446,185,196	23,194,838	-	13,677,983	483,058,017
2022	483,058,017	25,082,727	-	13,677,983	521,818,727
2023	521,818,727	27,067,275	-	13,677,983	562,563,985
2024	562,563,985	29,153,432	-	13,677,983	605,395,401
2025	605,395,401	31,346,401	-	13,677,983	650,419,784
2026	650,419,784	33,651,649	-	13,677,983	697,749,417
2027	697,749,417	36,074,926	-	13,677,983	747,502,326
2028	747,502,326	38,622,275	-	13,677,983	799,802,584
2029	799,802,584	41,300,049	-	13,677,983	854,780,616
2030	854,780,616	44,114,924	-	13,677,983	912,573,523
2031	912,573,523	47,073,921	-	13,677,983	973,325,427
2032	973,325,427	50,184,418	-	13,677,983	1,037,187,828
2033	1,037,187,828	50,256,165	(31,333,093)	10,942,386	1,067,053,286
2034	1,067,053,286	51,431,968	(102,068,673)	-	1,016,416,581
2035	1,016,416,581	48,991,279	(44,424,613)	-	1,020,983,247
2036	1,020,983,247	49,211,393	(37,965,127)	-	1,032,229,513
2037	1,032,229,513	49,753,463	(39,150,411)	-	1,042,832,565
2038	1,042,832,565	50,264,530	(56,242,259)	-	1,036,854,835
2039	1,036,854,835	49,976,403	(162,806,683)	-	924,024,555
2040	924,024,555	44,537,984	(15,630,028)	-	952,932,510
2041	952,932,510	45,931,347	(16,103,868)	-	982,759,989
2042	982,759,989	47,369,031	(16,642,112)	-	1,013,486,908
2043	1,013,486,908	48,850,069	(17,199,109)	-	1,045,137,867
2044	1,045,137,867	50,375,645	(17,828,428)	-	1,077,685,085
2045	1,077,685,085	51,944,421	(18,375,387)	-	1,111,254,118
2046	1,111,254,118	53,562,449	(18,996,008)	-	1,145,820,559
2047	1,145,820,559	55,228,551	(19,639,402)	-	1,181,409,707
2048	1,181,409,707	56,943,948	(20,365,377)	-	1,217,988,278
2049	1,217,988,278	58,707,035	(20,997,200)	-	1,255,698,114
2050	1,255,698,114	60,524,649	(21,713,946)	-	1,294,508,817
2051	1,294,508,817	62,395,325	(22,456,492)	-	1,334,447,650
2052	1,334,447,650	64,320,377	(23,294,357)	-	1,375,473,670
2053	1,375,473,670	66,297,831	(24,898,776)	-	1,416,872,725
2054	1,416,872,725	68,293,265	(26,657,046)	-	1,458,508,944
2055	1,458,508,944	70,300,131	(27,573,591)	-	1,501,235,485
2056	1,501,235,485	72,359,550	(29,082,815)	-	1,544,512,220

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EXTERNAL FUND CALCULATION

2057	1,544,512,220	74,445,489	(29,012,547)	-	1,589,945,162
2058	1,589,945,162	76,635,357	(31,556,176)	-	1,635,024,342
2059	1,635,024,342	78,808,173	(31,059,686)	-	1,682,772,830
2060	1,682,772,830	81,109,650	(31,682,556)	-	1,732,199,925
2061	1,732,199,925	83,492,036	(33,824,973)	-	1,781,866,988
2062	1,781,866,988	85,885,989	(35,004,520)	-	1,832,748,457
2063	1,832,748,457	88,338,476	(35,625,278)	-	1,885,461,654
2064	1,885,461,654	90,879,252	(37,599,137)	-	1,938,741,769
2065	1,938,741,769	93,447,353	(38,811,398)	-	1,993,377,725
2066	1,993,377,725	96,080,806	(39,510,862)	-	2,049,947,670
2067	2,049,947,670	98,807,478	(41,588,415)	-	2,107,166,732
2068	2,107,166,732	101,565,436	(43,173,205)	-	2,165,558,964
2069	2,165,558,964	104,379,942	(43,843,369)	-	2,226,095,536
2070	2,226,095,536	107,297,805	(46,151,627)	-	2,287,241,715
2071	2,287,241,715	110,245,051	(47,786,690)	-	2,349,700,075
2072	2,349,700,075	113,255,544	(49,618,541)	-	2,413,337,078
2073	2,413,337,078	116,322,847	(51,240,915)	-	2,478,419,010
2074	2,478,419,010	119,459,796	(53,065,034)	-	2,544,813,773
2075	2,544,813,773	122,660,024	(61,128,392)	-	2,606,345,405
2076	2,606,345,405	125,625,849	(57,074,829)	-	2,674,896,424
2077	2,674,896,424	128,930,008	(58,953,075)	-	2,744,873,357
2078	2,744,873,357	132,302,896	(45,926,882)	-	2,831,249,371
2079	2,831,249,371	136,466,220	(47,627,470)	-	2,920,088,121
2080	2,920,088,121	140,748,247	(49,527,746)	-	3,011,308,622
2081	3,011,308,622	145,145,076	(51,223,963)	-	3,105,229,735
2082	3,105,229,735	149,672,073	(53,125,222)	-	3,201,776,587
2083	3,201,776,587	154,325,631	(55,098,229)	-	3,301,003,989
2084	3,301,003,989	159,108,392	(57,303,117)	-	3,402,809,265
2085	3,402,809,265	164,015,407	(59,272,264)	-	3,507,552,407
2086	3,507,552,407	169,064,026	(61,478,455)	-	3,615,137,979
2087	3,615,137,979	174,249,651	(165,701,740)	-	3,623,685,889
2088	3,623,685,889	174,661,660	(619,307,251)	-	3,179,040,298
2089	3,179,040,298	153,229,742	(1,010,096,289)	-	2,322,173,751
2090	2,322,173,751	111,928,775	(913,549,360)	-	1,520,553,166
2091	1,520,553,166	73,290,663	(681,953,469)	-	911,890,360
2092	911,890,360	43,953,115	(260,007,735)	-	695,835,741
2093	695,835,741	33,539,283	(310,402,183)	-	418,972,840
2094	418,972,840	20,194,491	(255,916,375)	-	183,250,957
2095	183,250,957	8,832,696	(192,083,653)	-	(0)

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EXTERNAL FUND CALCULATION

Prairie Island Unit 2

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	420,208,967	10,803,157	-	294,670	431,306,795
2018	431,306,795	22,184,315	-	589,341	454,080,451
2019	454,080,451	23,354,881	-	589,341	478,024,673
2020	478,024,673	24,585,614	-	589,341	503,199,628
2021	503,199,628	25,962,960	-	3,832,669	532,995,257
2022	532,995,257	27,494,456	-	3,832,669	564,322,382
2023	564,322,382	29,104,670	-	3,832,669	597,259,721
2024	597,259,721	30,797,649	-	3,832,669	631,890,039
2025	631,890,039	32,577,648	-	3,832,669	668,300,356
2026	668,300,356	34,449,138	-	3,832,669	706,582,162
2027	706,582,162	36,416,823	-	3,832,669	746,831,654
2028	746,831,654	38,485,647	-	3,832,669	789,149,970
2029	789,149,970	40,660,808	-	3,832,669	833,643,446
2030	833,643,446	42,947,773	-	3,832,669	880,423,888
2031	880,423,888	45,352,287	-	3,832,669	929,608,844
2032	929,608,844	47,880,394	-	3,832,669	981,321,907
2033	981,321,907	50,538,446	-	3,832,669	1,035,693,022
2034	1,035,693,022	50,098,020	(14,729,554)	3,066,135	1,074,127,623
2035	1,074,127,623	51,880,364	(107,554,890)	-	1,018,453,097
2036	1,018,453,097	49,191,285	(61,888,360)	-	1,005,756,021
2037	1,005,756,021	48,578,016	(34,384,910)	-	1,019,949,126
2038	1,019,949,126	49,263,543	(51,304,564)	-	1,017,908,105
2039	1,017,908,105	49,164,961	(158,606,683)	-	908,466,384
2040	908,466,384	43,878,926	(15,743,645)	-	936,601,665
2041	936,601,665	45,237,860	(16,221,623)	-	965,617,903
2042	965,617,903	46,639,345	(16,764,496)	-	995,492,752
2043	995,492,752	48,082,300	(17,326,298)	-	1,026,248,754
2044	1,026,248,754	49,567,815	(17,960,978)	-	1,057,855,590
2045	1,057,855,590	51,094,425	(18,512,772)	-	1,090,437,244
2046	1,090,437,244	52,668,119	(19,138,796)	-	1,123,966,566
2047	1,123,966,566	54,287,585	(19,787,809)	-	1,158,466,342
2048	1,158,466,342	55,953,924	(20,520,048)	-	1,193,900,219
2049	1,193,900,219	57,665,381	(21,157,517)	-	1,230,408,083
2050	1,230,408,083	59,428,710	(21,880,577)	-	1,267,956,216
2051	1,267,956,216	61,242,285	(22,629,686)	-	1,306,568,816
2052	1,306,568,816	63,107,274	(23,474,867)	-	1,346,201,222
2053	1,346,201,222	65,021,519	(25,085,893)	-	1,386,136,849
2054	1,386,136,849	66,950,410	(26,851,538)	-	1,426,235,721
2055	1,426,235,721	68,887,185	(27,775,749)	-	1,467,347,158
2056	1,467,347,158	70,872,868	(29,293,524)	-	1,508,926,501

External Levelized

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EXTERNAL FUND CALCULATION

2057	1,508,926,501	72,881,150	(29,230,971)	-	1,552,576,680
2058	1,552,576,680	74,989,454	(31,783,221)	-	1,595,782,913
2059	1,595,782,913	77,076,315	(31,295,696)	-	1,641,563,532
2060	1,641,563,532	79,287,519	(31,928,558)	-	1,688,922,493
2061	1,688,922,493	81,574,956	(34,079,994)	-	1,736,417,455
2062	1,736,417,455	83,868,963	(35,269,615)	-	1,785,016,803
2063	1,785,016,803	86,216,312	(35,900,849)	-	1,835,332,265
2064	1,835,332,265	88,646,548	(37,886,389)	-	1,886,092,425
2065	1,886,092,425	91,098,264	(39,109,192)	-	1,938,081,497
2066	1,938,081,497	93,609,336	(39,820,433)	-	1,991,870,400
2067	1,991,870,400	96,207,340	(41,910,232)	-	2,046,167,508
2068	2,046,167,508	98,829,891	(43,508,676)	-	2,101,488,722
2069	2,101,488,722	101,501,905	(44,191,164)	-	2,158,799,463
2070	2,158,799,463	104,270,014	(46,513,191)	-	2,216,556,286
2071	2,216,556,286	107,059,669	(48,162,573)	-	2,275,453,381
2072	2,275,453,381	109,904,398	(50,010,385)	-	2,335,347,395
2073	2,335,347,395	112,797,279	(51,647,168)	-	2,396,497,506
2074	2,396,497,506	115,750,830	(53,487,390)	-	2,458,760,945
2075	2,458,760,945	118,758,154	(61,567,488)	-	2,515,951,611
2076	2,515,951,611	121,520,463	(57,532,587)	-	2,579,939,487
2077	2,579,939,487	124,611,077	(59,427,684)	-	2,645,122,880
2078	2,645,122,880	127,759,435	(20,169,179)	-	2,752,713,136
2079	2,752,713,136	132,956,044	(20,825,729)	-	2,864,843,451
2080	2,864,843,451	138,371,939	(21,563,211)	-	2,981,652,179
2081	2,981,652,179	144,013,800	(22,205,721)	-	3,103,460,257
2082	3,103,460,257	149,897,130	(22,930,853)	-	3,230,426,535
2083	3,230,426,535	156,029,602	(23,680,114)	-	3,362,776,023
2084	3,362,776,023	162,422,082	(24,522,010)	-	3,500,676,095
2085	3,500,676,095	169,082,655	(25,255,785)	-	3,644,502,965
2086	3,644,502,965	176,029,493	(26,083,465)	-	3,794,448,993
2087	3,794,448,993	183,271,886	(26,939,197)	-	3,950,781,682
2088	3,950,781,682	190,822,755	(171,196,773)	-	3,970,407,664
2089	3,970,407,664	191,770,690	(432,650,967)	-	3,729,527,387
2090	3,729,527,387	180,136,173	(1,286,294,416)	-	2,623,369,144
2091	2,623,369,144	126,708,730	(1,018,630,150)	-	1,731,447,723
2092	1,731,447,723	83,628,925	(939,069,791)	-	876,006,857
2093	876,006,857	42,311,131	(400,011,174)	-	518,306,814
2094	518,306,814	25,034,219	(316,718,172)	-	226,622,861
2095	226,622,861	10,945,884	(237,568,746)	-	0

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2021 ACCRUAL COMPARISON

	Present	Proposed	Difference
Monticello	$13,392,226	$32,521,178	$19,128,952
Prairie Island Unit 1	49,264	27,503,535	27,454,270
Prairie Island Unit 2	589,341	11,536,963	10,947,622
TOTAL	$14,030,831	$71,561,676	$57,530,845

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2021 MN RETAIL SUMMARY

	Remaining Life (yrs)	Operational Earnings Rate	Post-Shutdown Earnings Rate	Market Value Balance 6/30/2017	Book Value 6/30/2017	Unrealized Gain/Loss 6/30/2017	Tax-Effect Adjustment	Tax-Adjusted Fund Balance 6/30/2017	2021 Decommissioning Accrual
Monticello	8.75	5.10%	4.83%	$660,140,345	$529,148,381	$130,991,964	$36,468,163	$623,672,182	**32,521,178**
Prairie Island Unit 1	11.67	5.12%	4.82%	399,941,696	308,078,761	91,862,935	25,574,641	374,367,055	**27,503,535**
Prairie Island Unit 2	12.83	5.14%	4.83%	448,597,551	346,627,064	101,970,487	28,388,583	420,208,967	**11,536,963**
TOTAL DECOMMISSIONING ACCRUAL				**$1,508,679,592**	**$1,183,854,206**	**$324,825,386**	**$90,431,387**	**$1,418,248,204**	**$71,561,676**

INPUT DATA

Escalation Rate (Labor)	4.05%
Escalation Rate (Non-Labor)	2.85%
Escalation Rate (PIIC)	0.00%
Jurisdictional Factor	73.4886%
Tax Rate for tax-effect adjustment	27.84%

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	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
Monticello															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2025	$17,759,328	$13,051,073	1.3738	$17,929,565	$8,763,593	$6,440,238	1.2521	$8,063,822	$0	$0	1.0000	$0	$26,522,921	$19,491,311	$25,993,386
2026	63,231,064	46,467,594	1.4295	66,425,426	46,823,276	34,409,748	1.2878	44,312,874	0	0	1.0000	0	110,054,340	80,877,343	110,738,300
2027	30,098,747	22,119,134	1.4874	32,900,000	21,963,833	16,140,903	1.3245	21,378,627	0	0	1.0000	0	52,062,580	38,260,037	54,278,627
2028	30,011,960	22,055,355	1.5476	34,132,868	35,867,567	26,358,556	1.3622	35,905,625	0	0	1.0000	0	65,879,526	48,413,911	70,038,493
2029	24,261,956	17,829,760	1.6103	28,711,263	18,617,567	13,681,781	1.4010	19,168,175	0	0	1.0000	0	42,879,522	31,511,541	47,879,438
2030	43,935,865	32,287,832	1.6755	54,098,262	88,132,650	64,767,410	1.4410	93,329,837	0	0	1.0000	0	132,068,514	97,055,241	147,428,099
2031	8,481,485	6,232,921	1.7434	10,866,474	4,523,995	3,324,618	1.4820	4,927,084	0	0	1.0000	0	13,005,479	9,557,539	15,793,558
2032	8,458,357	6,215,924	1.8140	11,275,686	4,511,770	3,315,635	1.5243	5,054,022	0	0	1.0000	0	12,970,127	9,531,559	16,329,708
2033	8,458,357	6,215,924	1.8874	11,731,935	4,511,770	3,315,635	1.5677	5,197,920	0	0	1.0000	0	12,970,127	9,531,559	16,929,855
2034	8,458,357	6,215,924	1.9639	12,207,453	4,511,770	3,315,635	1.6124	5,346,129	0	0	1.0000	0	12,970,127	9,531,559	17,553,582
2035	8,481,485	6,232,921	2.0434	12,736,350	4,523,995	3,324,618	1.6584	5,513,547	0	0	1.0000	0	13,005,479	9,557,539	18,249,897
2036	8,458,357	6,215,924	2.1262	13,216,298	4,511,770	3,315,635	1.7056	5,655,146	0	0	1.0000	0	12,970,127	9,531,559	18,871,444
2037	8,458,357	6,215,924	2.2123	13,751,489	4,511,770	3,315,635	1.7542	5,816,286	0	0	1.0000	0	12,970,127	9,531,559	19,567,775
2038	8,458,357	6,215,924	2.3019	14,308,436	4,511,770	3,315,635	1.8042	5,982,068	0	0	1.0000	0	12,970,127	9,531,559	20,290,504
2039	8,481,485	6,232,921	2.3951	14,928,468	4,523,995	3,324,618	1.8556	6,169,162	0	0	1.0000	0	13,005,479	9,557,539	21,097,630
2040	8,458,357	6,215,924	2.4921	15,490,704	4,511,770	3,315,635	1.9085	6,327,889	0	0	1.0000	0	12,970,127	9,531,559	21,818,593
2041	8,458,357	6,215,924	2.5930	16,117,891	4,511,770	3,315,635	1.9629	6,508,259	0	0	1.0000	0	12,970,127	9,531,559	22,626,150
2042	8,458,357	6,215,924	2.6981	16,771,185	4,511,770	3,315,635	2.0189	6,693,935	0	0	1.0000	0	12,970,127	9,531,559	23,465,119
2043	9,145,130	6,720,624	2.8073	18,866,807	6,514,932	4,787,729	2.0764	9,941,241	0	0	1.0000	0	15,660,061	11,508,353	28,808,047
2044	8,458,357	6,215,924	2.9210	18,156,714	4,511,767	3,315,632	2.1356	7,080,864	0	0	1.0000	0	12,970,124	9,531,556	25,237,579
2045	9,951,558	7,313,256	3.0393	22,227,179	8,991,374	6,607,631	2.1964	14,513,000	0	0	1.0000	0	18,942,932	13,920,887	36,740,179
2046	9,951,558	7,313,256	3.1624	23,127,440	8,991,374	6,607,631	2.2590	14,926,638	0	0	1.0000	0	18,942,932	13,920,887	38,054,078
2047	10,837,186	7,964,091	3.2905	26,205,842	11,591,099	8,518,131	2.3234	19,791,025	0	0	1.0000	0	22,428,284	16,482,222	45,996,867
2048	11,460,933	8,422,474	3.4238	28,836,866	13,519,499	9,935,284	2.3896	23,741,355	0	0	1.0000	0	24,980,432	18,357,758	52,578,221
2049	10,167,183	7,471,716	3.5624	26,617,240	9,638,249	7,083,010	2.4577	17,407,913	0	0	1.0000	0	19,805,432	14,554,725	44,025,153
2050	11,245,308	8,264,014	3.7067	30,632,221	12,872,624	9,459,905	2.5278	23,912,748	0	0	1.0000	0	24,117,932	17,723,919	54,544,969
2051	11,699,686	8,597,930	3.8568	33,160,496	14,178,599	10,419,647	2.5998	27,088,999	0	0	1.0000	0	25,878,284	19,017,577	60,249,495
2052	8,441,765	6,203,731	4.0130	24,895,572	4,461,997	3,279,057	2.6739	8,767,871	0	0	1.0000	0	12,903,762	9,482,788	33,663,443
2053	8,441,765	6,203,731	4.1756	25,904,299	4,461,997	3,279,057	2.7501	9,017,735	0	0	1.0000	0	12,903,762	9,482,788	34,922,034
2054	8,441,765	6,203,731	4.3447	26,953,349	4,461,997	3,279,057	2.8285	9,274,813	0	0	1.0000	0	12,903,762	9,482,788	36,228,162
2055	8,464,894	6,220,728	4.5206	28,121,423	4,474,222	3,288,041	2.9091	9,565,240	0	0	1.0000	0	12,939,115	9,508,769	37,686,663
2056	8,441,765	6,203,731	4.7037	29,180,489	4,461,997	3,279,057	2.9920	9,810,939	0	0	1.0000	0	12,903,762	9,482,788	38,991,428
2057	8,441,765	6,203,731	4.8942	30,362,300	4,461,997	3,279,057	3.0773	10,090,642	0	0	1.0000	0	12,903,762	9,482,788	40,452,942
2058	8,441,765	6,203,731	5.0924	31,591,879	4,461,997	3,279,057	3.1650	10,378,216	0	0	1.0000	0	12,903,762	9,482,788	41,970,095
2059	8,464,894	6,220,728	5.2987	32,961,772	4,474,222	3,288,041	3.2552	10,703,230	0	0	1.0000	0	12,939,115	9,508,769	43,665,002
2060	8,441,765	6,203,731	5.5133	34,203,029	4,461,997	3,279,057	3.3480	10,978,283	0	0	1.0000	0	12,903,762	9,482,788	45,181,313
2061	8,441,765	6,203,731	5.7366	35,588,322	4,461,997	3,279,057	3.4434	11,291,105	0	0	1.0000	0	12,903,762	9,482,788	46,879,428
2062	8,441,765	6,203,731	5.9689	37,029,449	4,461,997	3,279,057	3.5415	11,612,781	0	0	1.0000	0	12,903,762	9,482,788	48,642,230
2063	8,464,894	6,220,728	6.2106	38,634,454	4,474,222	3,288,041	3.6425	11,976,689	0	0	1.0000	0	12,939,115	9,508,769	50,611,142
2064	8,441,765	6,203,731	6.4622	40,089,750	4,461,997	3,279,057	3.7463	12,284,332	0	0	1.0000	0	12,903,762	9,482,788	52,374,081
2065	8,441,765	6,203,731	6.7239	41,713,266	4,461,997	3,279,057	3.8531	12,634,535	0	0	1.0000	0	12,903,762	9,482,788	54,347,801
2066	8,441,765	6,203,731	6.9962	43,402,542	4,461,997	3,279,057	3.9629	12,994,575	0	0	1.0000	0	12,903,762	9,482,788	56,397,117
2067	8,464,894	6,220,728	7.2795	45,283,790	4,474,222	3,288,041	4.0758	13,401,397	0	0	1.0000	0	12,939,115	9,508,769	58,685,187
2068	8,441,765	6,203,731	7.5744	46,989,539	4,461,997	3,279,057	4.1920	13,745,807	0	0	1.0000	0	12,903,762	9,482,788	60,735,346
2069	8,441,765	6,203,731	7.8811	48,892,223	4,461,997	3,279,057	4.3115	14,137,655	0	0	1.0000	0	12,903,762	9,482,788	63,029,878
2070	8,441,765	6,203,731	8.2003	50,872,454	4,461,997	3,279,057	4.4343	14,540,323	0	0	1.0000	0	12,903,762	9,482,788	65,412,777
2071	8,464,894	6,220,728	8.5324	53,077,740	4,474,222	3,288,041	4.5607	14,995,768	0	0	1.0000	0	12,939,115	9,508,769	68,073,508
2072	8,441,765	6,203,731	8.8780	55,076,723	4,461,997	3,279,057	4.6907	15,381,073	0	0	1.0000	0	12,903,762	9,482,788	70,457,796
2073	8,920,197	6,555,324	9.2375	60,554,802	5,897,293	4,333,835	4.8244	20,908,155	0	0	1.0000	0	14,817,490	10,889,159	81,462,957
2074	9,015,884	6,625,643	9.6117	63,683,689	6,184,352	4,544,791	4.9619	22,550,798	0	0	1.0000	0	15,200,236	11,170,433	86,234,487
2075	8,943,325	6,572,320	10.0009	65,729,116	5,909,518	4,342,819	5.1033	22,162,709	0	0	1.0000	0	14,852,842	10,915,139	87,891,824
2076	8,920,197	6,555,324	10.4060	68,214,698	5,897,293	4,333,835	5.2487	22,747,002	0	0	1.0000	0	14,817,490	10,889,159	90,961,699
2077	8,920,197	6,555,324	10.8274	70,977,111	5,897,293	4,333,835	5.3983	23,395,343	0	0	1.0000	0	14,817,490	10,889,159	94,372,454
2078	9,015,884	6,625,643	11.2659	74,643,827	6,184,352	4,544,791	5.5522	25,233,588	0	0	1.0000	0	15,200,236	11,170,433	99,877,415
2079	8,943,325	6,572,320	11.7222	77,042,050	5,909,518	4,342,819	5.7104	24,799,234	0	0	1.0000	0	14,852,842	10,915,139	101,841,284

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	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
2080	46,126,149	33,897,440	12.1970	413,447,077	12,314,062	9,049,426	5.8731	53,148,185	0	0	1.0000	0	58,440,212	42,946,866	466,595,262
2081	53,631,139	39,412,748	12.6909	500,183,247	46,945,385	34,499,485	6.0405	208,394,136	0	0	1.0000	0	100,576,524	73,912,233	708,577,384
2082	57,419,114	42,196,476	13.2049	557,200,251	80,273,242	58,991,645	6.2127	366,497,393	0	0	1.0000	0	137,692,356	101,188,121	923,697,643
2083	52,652,752	38,693,746	13.7397	531,640,460	33,214,319	24,408,722	6.3897	155,964,414	0	0	1.0000	0	85,867,070	63,102,468	687,604,874
2084	50,913,638	37,415,697	14.2962	534,902,283	30,841,715	22,665,130	6.5719	148,952,970	0	0	1.0000	0	81,755,354	60,080,827	683,855,253
2085	32,667,889	24,007,160	14.8752	357,111,300	23,001,023	16,903,119	6.7592	114,251,564	0	0	1.0000	0	55,668,913	40,910,279	471,362,864
2086	21,071,356	15,485,035	15.4776	239,671,177	16,131,940	11,855,130	6.9518	82,414,491	0	0	1.0000	0	37,203,297	27,340,165	322,085,668
2087	8,832,651	6,490,987	16.1045	104,534,104	6,762,156	4,969,411	7.1499	35,530,788	0	0	1.0000	0	15,594,807	11,460,398	140,064,893
	$967,171,883	$710,760,631		$5,145,790,110	$750,282,438	$551,371,714		$2,024,287,970	$0	$0		$0	$1,717,454,322	$1,262,132,345	$7,170,078,080

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AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
Prairie Island Unit 1															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2028	$18,446,908	$13,556,366	1.5476	$20,979,832	$4,190,856	$3,079,799	1.3622	$4,195,302	$1,250,000	$918,607	1.0000	$918,607	$23,887,764	$17,554,772	$26,093,741
2029	46,142,627	33,909,549	1.6103	54,604,547	29,162,161	21,430,850	1.4010	30,024,621	1,250,000	918,607	1.0000	918,607	76,554,787	56,259,006	85,547,775
2030	16,398,923	12,051,331	1.6755	20,192,006	15,491,742	11,384,657	1.4410	16,405,291	1,250,000	918,607	1.0000	918,607	33,140,665	24,354,595	37,515,903
2031	12,659,656	9,303,398	1.7434	16,219,545	13,774,811	10,122,909	1.4820	15,002,152	1,250,000	918,607	1.0000	918,607	27,684,467	20,344,915	32,140,303
2032	12,625,333	9,278,174	1.8140	16,830,608	13,734,545	10,093,318	1.5243	15,385,245	1,250,000	918,607	1.0000	918,607	27,609,877	20,290,100	33,134,460
2033	15,404,499	11,320,543	1.8874	21,366,393	22,072,045	16,220,427	1.5677	25,428,763	1,250,000	918,607	1.0000	918,607	38,726,543	28,459,577	47,713,763
2034	32,688,492	24,022,300	1.9639	47,177,395	76,524,027	56,236,401	1.6124	90,675,573	1,250,000	918,607	1.0000	918,607	110,462,519	81,177,308	138,771,575
2035	4,604,176	3,383,542	2.0434	6,913,931	4,477,123	3,290,173	1.6584	5,456,423	1,250,000	918,607	1.0000	918,607	10,331,299	7,592,322	13,288,961
2036	4,591,596	3,374,297	2.1262	7,174,431	4,461,475	3,278,674	1.7056	5,592,106	1,250,000	918,607	1.0000	918,607	10,303,071	7,571,578	13,685,143
2037	4,591,596	3,374,297	2.2123	7,464,958	4,461,475	3,278,674	1.7542	5,751,449	1,250,000	918,607	1.0000	918,607	10,303,071	7,571,578	14,135,014
2038	4,591,596	3,374,297	2.3019	7,767,295	4,461,475	3,278,674	1.8042	5,915,383	1,250,000	918,607	1.0000	918,607	10,303,071	7,571,578	14,601,285
2039	4,604,176	3,383,542	2.3951	8,103,923	4,477,123	3,290,173	1.8556	6,105,245	1,250,000	918,607	1.0000	918,607	10,331,299	7,592,322	15,127,775
2040	4,591,596	3,374,297	2.4921	8,409,086	4,461,475	3,278,674	1.9085	6,257,349	1,250,000	918,607	1.0000	918,607	10,303,071	7,571,578	15,585,042
2041	4,591,596	3,374,297	2.5930	8,749,553	4,461,475	3,278,674	1.9629	6,435,709	1,250,000	918,607	1.0000	918,607	10,303,071	7,571,578	16,103,868
2042	4,591,596	3,374,297	2.6981	9,104,191	4,461,475	3,278,674	2.0189	6,619,314	1,250,000	918,607	1.0000	918,607	10,303,071	7,571,578	16,642,112
2043	4,604,176	3,383,542	2.8073	9,498,619	4,477,123	3,290,173	2.0764	6,831,715	1,250,000	918,607	1.0000	918,607	10,331,299	7,592,322	17,248,941
2044	4,591,596	3,374,297	2.9210	9,856,322	4,461,475	3,278,674	2.1356	7,001,935	1,250,000	918,607	1.0000	918,607	10,303,071	7,571,578	17,776,865
2045	4,591,596	3,374,297	3.0393	10,255,502	4,461,475	3,278,674	2.1964	7,201,279	1,250,000	918,607	1.0000	918,607	10,303,071	7,571,578	18,375,387
2046	4,591,596	3,374,297	3.1624	10,670,878	4,461,475	3,278,674	2.2590	7,406,524	1,250,000	918,607	1.0000	918,607	10,303,071	7,571,578	18,996,008
2047	4,604,176	3,383,542	3.2905	11,133,546	4,477,123	3,290,173	2.3234	7,644,388	1,250,000	918,607	1.0000	918,607	10,331,299	7,592,322	19,696,541
2048	4,687,283	3,444,616	3.4238	11,793,677	4,748,534	3,489,629	2.3896	8,338,818	1,250,000	918,607	1.0000	918,607	10,685,817	7,852,852	21,051,102
2049	4,782,969	3,514,934	3.5624	12,521,603	5,035,593	3,700,585	2.4577	9,094,927	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	22,535,136
2050	4,782,969	3,514,934	3.7067	13,028,808	5,035,593	3,700,585	2.5278	9,354,338	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	23,301,752
2051	4,843,392	3,559,339	3.8568	13,727,658	5,194,771	3,817,562	2.5998	9,924,898	1,250,000	918,607	1.0000	918,607	11,288,163	8,295,508	24,571,163
2052	4,735,126	3,479,775	4.0130	13,964,338	4,892,064	3,595,107	2.6739	9,612,957	1,250,000	918,607	1.0000	918,607	10,877,190	7,993,490	24,495,903
2053	4,878,656	3,585,253	4.1756	14,970,584	5,322,652	3,911,540	2.7501	10,757,127	1,250,000	918,607	1.0000	918,607	11,451,308	8,415,401	26,646,318
2054	4,735,126	3,479,775	4.3447	15,118,580	4,892,064	3,595,107	2.8285	10,168,761	1,250,000	918,607	1.0000	918,607	10,877,190	7,993,490	26,205,948
2055	4,699,862	3,453,861	4.5206	15,613,523	4,764,182	3,501,129	2.9091	10,185,133	1,250,000	918,607	1.0000	918,607	10,714,044	7,873,596	26,717,263
2056	4,782,969	3,514,934	4.7037	16,533,197	5,035,593	3,700,585	2.9920	11,072,149	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	28,523,954
2057	4,782,969	3,514,934	4.8942	17,202,792	5,035,593	3,700,585	3.0773	11,387,809	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	29,509,208
2058	4,735,126	3,479,775	5.0924	17,720,408	4,892,064	3,595,107	3.1650	11,378,515	1,250,000	918,607	1.0000	918,607	10,877,190	7,993,490	30,017,529
2059	4,795,548	3,524,179	5.2987	18,673,567	5,051,241	3,712,084	3.2552	12,083,576	1,250,000	918,607	1.0000	918,607	11,096,789	8,154,870	31,675,750
2060	4,782,969	3,514,934	5.5133	19,378,888	5,035,593	3,700,585	3.3480	12,389,557	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	32,687,053
2061	4,735,126	3,479,775	5.7366	19,962,079	4,892,064	3,595,107	3.4434	12,379,392	1,250,000	918,607	1.0000	918,607	10,877,190	7,993,490	33,260,079
2062	4,782,969	3,514,934	5.9689	20,980,292	5,035,593	3,700,585	3.5415	13,105,621	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	35,004,520
2063	4,795,548	3,524,179	6.2106	21,887,266	5,051,241	3,712,084	3.6425	13,521,266	1,250,000	918,607	1.0000	918,607	11,096,789	8,154,870	36,327,139
2064	4,735,126	3,479,775	6.4622	22,487,004	4,892,064	3,595,107	3.7463	13,468,350	1,250,000	918,607	1.0000	918,607	10,877,190	7,993,490	36,873,962
2065	4,782,969	3,514,934	6.7239	23,634,068	5,035,593	3,700,585	3.8531	14,258,723	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	38,811,398
2066	4,782,969	3,514,934	6.9962	24,591,185	5,035,593	3,700,585	3.9629	14,665,047	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	40,174,838
2067	4,795,548	3,524,179	7.2795	25,654,261	5,051,241	3,712,084	4.0758	15,129,712	1,250,000	918,607	1.0000	918,607	11,096,789	8,154,870	41,702,580
2068	4,782,969	3,514,934	7.5744	26,623,520	5,035,593	3,700,585	4.1920	15,512,851	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	43,054,977
2069	4,782,969	3,514,934	7.8811	27,701,550	5,035,593	3,700,585	4.3115	15,955,071	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	44,575,228
2070	5,114,792	3,758,786	8.2003	30,823,176	6,031,061	4,432,140	4.4343	19,653,437	1,250,000	918,607	1.0000	918,607	12,395,853	9,109,533	51,395,220
2071	4,795,548	3,524,179	8.5324	30,069,705	5,051,241	3,712,084	4.5607	16,929,702	1,250,000	918,607	1.0000	918,607	11,096,789	8,154,870	47,918,013
2072	4,782,969	3,514,934	8.8780	31,205,588	5,035,593	3,700,585	4.6907	17,358,333	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	49,482,528
2073	3,942,348	2,897,174	9.2375	26,762,647	3,256,582	2,393,215	4.8244	11,545,826	0	0	1.0000	0	7,198,929	5,290,389	38,308,473
2074	3,942,348	2,897,174	9.6117	27,846,769	3,256,582	2,393,215	4.9619	11,874,893	0	0	1.0000	0	7,198,929	5,290,389	39,721,662
2075	3,953,149	2,905,112	10.0009	29,053,731	3,265,504	2,399,772	5.1033	12,246,754	0	0	1.0000	0	7,218,652	5,304,883	41,300,486
2076	3,942,348	2,897,174	10.4060	30,147,995	3,256,582	2,393,215	5.2487	12,561,267	0	0	1.0000	0	7,198,929	5,290,389	42,709,262
2077	3,942,348	2,897,174	10.8274	31,368,864	3,256,582	2,393,215	5.3983	12,919,292	0	0	1.0000	0	7,198,929	5,290,389	44,288,156
2078	3,942,348	2,897,174	11.2659	32,639,275	3,256,582	2,393,215	5.5522	13,287,607	0	0	1.0000	0	7,198,929	5,290,389	45,926,882
2079	3,953,149	2,905,112	11.7222	34,054,300	3,265,504	2,399,772	5.7104	13,703,656	0	0	1.0000	0	7,218,652	5,304,883	47,757,956
2080	3,942,348	2,897,174	12.1970	35,336,834	3,256,582	2,393,215	5.8731	14,055,590	0	0	1.0000	0	7,198,929	5,290,389	49,392,424
2081	3,942,348	2,897,174	12.6909	36,767,748	3,256,582	2,393,215	6.0405	14,456,214	0	0	1.0000	0	7,198,929	5,290,389	51,223,963
2082	11,802,691	8,673,627	13.2049	114,534,373	4,951,569	3,638,837	6.2127	22,607,001	0	0	1.0000	0	16,754,260	12,312,463	137,141,374

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	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
2083	45,111,220	33,151,584	13.7397	455,492,813	11,805,071	8,675,376	6.3897	55,433,048	0	0	1.0000	0	56,916,291	41,826,959	510,925,861
2084	51,818,304	38,080,522	14.2962	544,406,760	62,277,980	45,767,187	6.5719	300,777,373	0	0	1.0000	0	114,096,283	83,847,709	845,184,134
2085	44,187,860	32,473,019	14.8752	483,042,653	56,754,748	41,708,244	6.7592	281,914,360	0	0	1.0000	0	100,942,608	74,181,263	764,957,013
2086	35,668,367	26,212,167	15.4776	405,701,439	31,834,151	23,394,458	6.9518	162,633,590	0	0	1.0000	0	67,502,519	49,606,625	568,335,029
2087	13,715,750	10,079,506	16.1045	162,325,411	10,259,487	7,539,548	7.1499	53,907,017	0	0	1.0000	0	23,975,237	17,619,055	216,232,427
2088	18,089,191	13,293,485	16.7567	222,754,942	6,228,187	4,577,005	7.3537	33,657,920	0	0	1.0000	0	24,317,379	17,870,490	256,412,862
2089	12,584,719	9,248,328	17.4353	161,247,374	9,264,588	6,808,412	7.5633	51,494,060	0	0	1.0000	0	21,849,307	16,056,740	212,741,434
2090	9,102,372	6,689,202	18.1415	121,352,152	6,700,962	4,924,440	7.7788	38,306,236	0	0	1.0000	0	15,803,334	11,613,642	159,658,387
	$611,385,166	$449,298,117		$3,773,175,957	$588,533,792	$432,504,973		$1,716,403,540	$56,250,000	$41,337,312		$41,337,312	$1,256,168,958	$923,140,402	$5,530,916,809

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AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
Prairie Island Unit 2															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2029	$7,248,794	$5,327,034	1.6103	$8,578,123	$2,826,485	$2,077,143	1.4010	$2,910,077	$1,250,000	$918,607	1.0000	$918,607	$11,325,279	$8,322,784	$12,406,807
2030	44,817,806	32,935,958	1.6755	55,184,197	32,275,248	23,718,613	1.4410	34,178,521	1,250,000	918,607	1.0000	918,607	78,343,054	57,573,177	90,281,325
2031	23,021,476	16,918,150	1.7434	29,495,102	19,944,127	14,656,651	1.4820	21,721,156	1,250,000	918,607	1.0000	918,607	44,215,603	32,493,407	52,134,866
2032	10,761,111	7,908,185	1.8140	14,345,447	12,388,936	9,104,450	1.5243	13,877,913	1,250,000	918,607	1.0000	918,607	24,400,047	17,931,242	29,141,967
2033	13,540,277	9,950,554	1.8874	18,780,675	20,726,436	15,231,558	1.5677	23,878,514	1,250,000	918,607	1.0000	918,607	35,516,713	26,100,719	43,577,796
2034	31,160,880	22,899,680	1.9639	44,972,682	75,415,818	55,421,994	1.6124	89,362,423	1,250,000	918,607	1.0000	918,607	107,826,698	79,240,281	135,253,712
2035	4,659,832	3,424,443	2.0434	6,997,507	4,485,457	3,296,297	1.6584	5,466,580	1,250,000	918,607	1.0000	918,607	10,395,289	7,639,347	13,382,694
2036	4,647,099	3,415,086	2.1262	7,261,156	4,469,786	3,284,781	1.7056	5,602,523	1,250,000	918,607	1.0000	918,607	10,366,886	7,618,474	13,782,286
2037	4,647,099	3,415,086	2.2123	7,555,195	4,469,786	3,284,781	1.7542	5,762,163	1,250,000	918,607	1.0000	918,607	10,366,886	7,618,474	14,235,965
2038	4,647,099	3,415,086	2.3019	7,861,187	4,469,786	3,284,781	1.8042	5,926,402	1,250,000	918,607	1.0000	918,607	10,366,886	7,618,474	14,706,196
2039	4,659,832	3,424,443	2.3951	8,201,884	4,485,457	3,296,297	1.8556	6,116,609	1,250,000	918,607	1.0000	918,607	10,395,289	7,639,347	15,237,100
2040	4,647,099	3,415,086	2.4921	8,510,736	4,469,786	3,284,781	1.9085	6,269,005	1,250,000	918,607	1.0000	918,607	10,366,886	7,618,474	15,698,348
2041	4,647,099	3,415,086	2.5930	8,855,319	4,469,786	3,284,781	1.9629	6,447,697	1,250,000	918,607	1.0000	918,607	10,366,886	7,618,474	16,221,623
2042	4,647,099	3,415,086	2.6981	9,214,244	4,469,786	3,284,781	2.0189	6,631,645	1,250,000	918,607	1.0000	918,607	10,366,886	7,618,474	16,764,496
2043	4,659,832	3,424,443	2.8073	9,613,439	4,485,457	3,296,297	2.0764	6,844,432	1,250,000	918,607	1.0000	918,607	10,395,289	7,639,347	17,376,478
2044	4,647,099	3,415,086	2.9210	9,975,467	4,469,786	3,284,781	2.1356	7,014,979	1,250,000	918,607	1.0000	918,607	10,366,886	7,618,474	17,909,053
2045	4,647,099	3,415,086	3.0393	10,379,472	4,469,786	3,284,781	2.1964	7,214,693	1,250,000	918,607	1.0000	918,607	10,366,886	7,618,474	18,512,772
2046	4,647,099	3,415,086	3.1624	10,799,869	4,469,786	3,284,781	2.2590	7,420,321	1,250,000	918,607	1.0000	918,607	10,366,886	7,618,474	19,138,796
2047	4,659,832	3,424,443	3.2905	11,268,130	4,485,457	3,296,297	2.3234	7,658,617	1,250,000	918,607	1.0000	918,607	10,395,289	7,639,347	19,845,355
2048	4,742,786	3,485,405	3.4238	11,933,330	4,756,846	3,495,737	2.3896	8,353,414	1,250,000	918,607	1.0000	918,607	10,749,633	7,899,750	21,205,352
2049	4,838,472	3,555,723	3.5624	12,666,909	5,043,904	3,706,692	2.4577	9,109,938	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	22,695,454
2050	4,838,472	3,555,723	3.7067	13,180,000	5,043,904	3,706,692	2.5278	9,369,777	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	23,468,384
2051	4,899,048	3,600,240	3.8568	13,885,404	5,203,105	3,823,687	2.5998	9,940,820	1,250,000	918,607	1.0000	918,607	11,352,153	8,342,533	24,744,831
2052	4,790,629	3,520,564	4.0130	14,128,025	4,900,375	3,601,215	2.6739	9,629,288	1,250,000	918,607	1.0000	918,607	10,941,005	8,040,386	24,675,920
2053	4,934,159	3,626,042	4.1756	15,140,903	5,330,963	3,917,648	2.7501	10,773,923	1,250,000	918,607	1.0000	918,607	11,515,123	8,462,297	26,833,433
2054	4,790,629	3,520,564	4.3447	15,295,796	4,900,375	3,601,215	2.8285	10,186,036	1,250,000	918,607	1.0000	918,607	10,941,005	8,040,386	26,400,439
2055	4,755,518	3,494,761	4.5206	15,798,419	4,772,516	3,507,253	2.9091	10,202,949	1,250,000	918,607	1.0000	918,607	10,778,034	7,920,621	26,919,975
2056	4,838,472	3,555,723	4.7037	16,725,056	5,043,904	3,706,692	2.9920	11,090,423	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	28,734,087
2057	4,838,472	3,555,723	4.8942	17,402,422	5,043,904	3,706,692	3.0773	11,406,604	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	29,727,633
2058	4,790,629	3,520,564	5.0924	17,928,122	4,900,375	3,601,215	3.1650	11,397,845	1,250,000	918,607	1.0000	918,607	10,941,005	8,040,386	30,244,574
2059	4,851,204	3,565,080	5.2987	18,890,288	5,059,575	3,718,208	3.2552	12,103,512	1,250,000	918,607	1.0000	918,607	11,160,779	8,201,895	31,912,407
2060	4,838,472	3,555,723	5.5133	19,603,770	5,043,904	3,706,692	3.3480	12,410,006	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	32,932,383
2061	4,790,629	3,520,564	5.7366	20,196,069	4,900,375	3,601,215	3.4434	12,400,423	1,250,000	918,607	1.0000	918,607	10,941,005	8,040,386	33,515,100
2062	4,838,472	3,555,723	5.9689	21,223,758	5,043,904	3,706,692	3.5415	13,127,251	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	35,269,615
2063	4,851,204	3,565,080	6.2106	22,141,284	5,059,575	3,718,208	3.6425	13,543,574	1,250,000	918,607	1.0000	918,607	11,160,779	8,201,895	36,603,465
2064	4,790,629	3,520,564	6.4622	22,750,591	4,900,375	3,601,215	3.7463	13,491,231	1,250,000	918,607	1.0000	918,607	10,941,005	8,040,386	37,160,429
2065	4,838,472	3,555,723	6.7239	23,908,329	5,043,904	3,706,692	3.8531	14,282,256	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	39,109,192
2066	4,838,472	3,555,723	6.9962	24,876,552	5,043,904	3,706,692	3.9629	14,689,251	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	40,484,410
2067	4,851,204	3,565,080	7.2795	25,951,998	5,059,575	3,718,208	4.0758	15,154,674	1,250,000	918,607	1.0000	918,607	11,160,779	8,201,895	42,025,278
2068	4,838,472	3,555,723	7.5744	26,932,472	5,043,904	3,706,692	4.1920	15,538,454	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	43,389,533
2069	4,838,472	3,555,723	7.8811	28,023,012	5,043,904	3,706,692	4.3115	15,981,404	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	44,923,023
2070	5,170,295	3,799,575	8.2003	31,157,658	6,039,372	4,438,247	4.4343	19,680,520	1,250,000	918,607	1.0000	918,607	12,459,668	9,156,430	51,756,785
2071	4,851,204	3,565,080	8.5324	30,418,686	5,059,575	3,718,208	4.5607	16,957,633	1,250,000	918,607	1.0000	918,607	11,160,779	8,201,895	48,294,926
2072	4,838,472	3,555,723	8.8780	31,567,713	5,043,904	3,706,692	4.6907	17,386,981	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	49,873,301
2073	823,359	605,074	9.2375	5,589,375	3,272,479	2,404,897	4.8244	11,602,187	0	-	1.0000	-	4,095,838	3,009,972	17,191,562
2074	823,359	605,074	9.6117	5,815,794	3,272,479	2,404,897	4.9619	11,932,860	0	-	1.0000	-	4,095,838	3,009,972	17,748,654
2075	825,615	606,732	10.0009	6,067,868	3,281,444	2,411,486	5.1033	12,306,537	0	-	1.0000	-	4,107,059	3,018,218	18,374,405
2076	823,359	605,074	10.4060	6,296,405	3,272,479	2,404,897	5.2487	12,622,585	0	-	1.0000	-	4,095,838	3,009,972	18,918,989
2077	823,359	605,074	10.8274	6,551,383	3,272,479	2,404,897	5.3983	12,982,357	0	-	1.0000	-	4,095,838	3,009,972	19,533,740
2078	823,359	605,074	11.2659	6,816,708	3,272,479	2,404,897	5.5522	13,352,471	0	-	1.0000	-	4,095,838	3,009,972	20,169,179
2079	825,615	606,732	11.7222	7,112,236	3,281,444	2,411,486	5.7104	13,770,550	0	-	1.0000	-	4,107,059	3,018,218	20,882,786
2080	823,359	605,074	12.1970	7,380,093	3,272,479	2,404,897	5.8731	14,124,203	0	-	1.0000	-	4,095,838	3,009,972	21,504,295
2081	823,359	605,074	12.6909	7,678,939	3,272,479	2,404,897	6.0405	14,526,782	0	-	1.0000	-	4,095,838	3,009,972	22,205,721
2082	823,359	605,074	13.2049	7,989,947	3,272,479	2,404,897	6.2127	14,940,906	0	-	1.0000	-	4,095,838	3,009,972	22,930,853
2083	11,274,587	8,285,531	13.7397	113,840,706	5,987,760	4,400,318	6.3897	28,116,714	0	-	1.0000	-	17,262,347	12,685,849	141,957,420

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5-Year Early Shutdown

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Proposed

AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
2084	29,172,411	21,438,383	14.2962	306,487,412	10,590,974	7,783,154	6.5719	51,150,108	0	-	1.0000	-	39,763,385	29,221,537	357,637,520
2085	57,665,154	42,377,288	14.8752	630,370,636	90,528,180	66,527,851	6.7592	449,675,048	0	-	1.0000	-	148,193,335	108,905,139	1,080,045,684
2086	55,538,057	40,814,115	15.4776	631,704,550	42,217,329	31,024,904	6.9518	215,678,931	0	-	1.0000	-	97,755,386	71,839,020	847,383,481
2087	51,408,076	37,779,052	16.1045	608,412,741	32,588,487	23,948,808	7.1499	171,231,582	0	-	1.0000	-	83,996,563	61,727,860	779,644,323
2088	23,223,558	17,066,657	16.7567	285,980,846	8,238,061	6,054,032	7.3537	44,519,534	0	-	1.0000	-	31,461,619	23,120,689	330,500,380
2089	14,460,844	10,627,065	17.4353	185,286,068	14,186,680	10,425,586	7.5633	78,851,834	0	-	1.0000	-	28,647,524	21,052,651	264,137,902
2090	10,459,350	7,686,425	18.1415	139,443,282	10,261,051	7,540,698	7.7788	58,657,580	0	-	1.0000	-	20,720,401	15,227,123	198,100,862
	$573,536,674	$421,483,808		$3,768,401,389	$595,414,118	$437,561,225		$1,818,555,225	$55,000,000	$40,418,705		$40,418,705	$1,223,950,791	$899,463,737	$5,627,375,318
	$2,152,093,723	$1,581,542,556		$12,687,367,456	$1,934,230,348	$1,421,437,911		$5,559,246,735	$111,250,000	$81,756,016		$81,756,016	$4,197,574,071	$3,084,736,483	$18,328,370,207

Xcel Energy
Nuclear Decommissioning Accrual
60-Year Decommissioning Period
SAFSTOR Method
5-Year Early Shutdown

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Proposed

EXTERNAL FUND CALCULATION

Monticello

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	623,672,182	15,989,016	-	6,696,113	646,357,311
2018	646,357,311	33,305,725	-	13,392,226	693,055,262
2019	693,055,262	35,687,320	-	13,392,226	742,134,808
2020	742,134,808	38,190,377	-	13,392,226	793,717,411
2021	793,717,411	41,308,878	-	32,521,178	867,547,467
2022	867,547,467	45,074,211	-	32,521,178	945,142,856
2023	945,142,856	49,031,576	-	32,521,178	1,026,695,610
2024	1,026,695,610	53,190,766	-	32,521,178	1,112,407,555
2025	1,112,407,555	54,318,325	(25,993,386)	24,390,884	1,165,123,377
2026	1,165,123,377	56,275,459	(110,738,300)	-	1,110,660,536
2027	1,110,660,536	53,644,904	(54,278,627)	-	1,110,026,813
2028	1,110,026,813	53,614,295	(70,038,493)	-	1,093,602,616
2029	1,093,602,616	52,821,006	(47,879,438)	-	1,098,544,184
2030	1,098,544,184	53,059,684	(147,428,099)	-	1,004,175,769
2031	1,004,175,769	48,501,690	(15,793,558)	-	1,036,883,900
2032	1,036,883,900	50,081,492	(16,329,708)	-	1,070,635,685
2033	1,070,635,685	51,711,704	(16,929,855)	-	1,105,417,533
2034	1,105,417,533	53,391,667	(17,553,582)	-	1,141,255,617
2035	1,141,255,617	55,122,646	(18,249,897)	-	1,178,128,367
2036	1,178,128,367	56,903,600	(18,871,444)	-	1,216,160,523
2037	1,216,160,523	58,740,553	(19,567,775)	-	1,255,333,301
2038	1,255,333,301	60,632,598	(20,290,504)	-	1,295,675,396
2039	1,295,675,396	62,581,122	(21,097,630)	-	1,337,158,888
2040	1,337,158,888	64,584,774	(21,818,593)	-	1,379,925,069
2041	1,379,925,069	66,650,381	(22,626,150)	-	1,423,949,300
2042	1,423,949,300	68,776,751	(23,465,119)	-	1,469,260,932
2043	1,469,260,932	70,965,303	(28,808,047)	-	1,511,418,187
2044	1,511,418,187	73,001,498	(25,237,579)	-	1,559,182,107
2045	1,559,182,107	75,308,496	(36,740,179)	-	1,597,750,424
2046	1,597,750,424	77,171,345	(38,054,078)	-	1,636,867,691
2047	1,636,867,691	79,060,709	(45,996,867)	-	1,669,931,534
2048	1,669,931,534	80,657,693	(52,578,221)	-	1,698,011,006
2049	1,698,011,006	82,013,932	(44,025,153)	-	1,735,999,784
2050	1,735,999,784	83,848,790	(54,544,969)	-	1,765,303,604
2051	1,765,303,604	85,264,164	(60,249,495)	-	1,790,318,274
2052	1,790,318,274	86,472,373	(33,663,443)	-	1,843,127,204
2053	1,843,127,204	89,023,044	(34,922,034)	-	1,897,228,214
2054	1,897,228,214	91,636,123	(36,228,162)	-	1,952,636,174
2055	1,952,636,174	94,312,327	(37,686,663)	-	2,009,261,839
2056	2,009,261,839	97,047,347	(38,991,428)	-	2,067,317,758

External Levelized

Xcel Energy **Docket No. E002/M-17-828**
Nuclear Decommissioning Accrual **Schedule F.19**
60-Year Decommissioning Period **Page 10 of 14**
SAFSTOR Method
5-Year Early Shutdown **Proposed**

EXTERNAL FUND CALCULATION

2057	2,067,317,758	99,851,448	(40,452,942)	-	2,126,716,264
2058	2,126,716,264	102,720,396	(41,970,095)	-	2,187,466,565
2059	2,187,466,565	105,654,635	(43,665,002)	-	2,249,456,198
2060	2,249,456,198	108,648,734	(45,181,313)	-	2,312,923,619
2061	2,312,923,619	111,714,211	(46,879,428)	-	2,377,758,402
2062	2,377,758,402	114,845,731	(48,642,230)	-	2,443,961,903
2063	2,443,961,903	118,043,360	(50,611,142)	-	2,511,394,121
2064	2,511,394,121	121,300,336	(52,374,081)	-	2,580,320,376
2065	2,580,320,376	124,629,474	(54,347,801)	-	2,650,602,049
2066	2,650,602,049	128,024,079	(56,397,117)	-	2,722,229,011
2067	2,722,229,011	131,483,661	(58,685,187)	-	2,795,027,486
2068	2,795,027,486	134,999,828	(60,735,346)	-	2,869,291,967
2069	2,869,291,967	138,586,802	(63,029,878)	-	2,944,848,891
2070	2,944,848,891	142,236,201	(65,412,777)	-	3,021,672,315
2071	3,021,672,315	145,946,773	(68,073,508)	-	3,099,545,580
2072	3,099,545,580	149,708,052	(70,457,796)	-	3,178,795,836
2073	3,178,795,836	153,535,839	(81,462,957)	-	3,250,868,718
2074	3,250,868,718	157,016,959	(86,234,487)	-	3,321,651,190
2075	3,321,651,190	160,435,752	(87,891,824)	-	3,394,195,118
2076	3,394,195,118	163,939,624	(90,961,699)	-	3,467,173,043
2077	3,467,173,043	167,464,458	(94,372,454)	-	3,540,265,046
2078	3,540,265,046	170,994,802	(99,877,415)	-	3,611,382,433
2079	3,611,382,433	174,429,772	(101,841,284)	-	3,683,970,920
2080	3,683,970,920	177,935,795	(466,595,262)	-	3,395,311,454
2081	3,395,311,454	163,993,543	(708,577,384)	-	2,850,727,613
2082	2,850,727,613	137,690,144	(923,697,643)	-	2,064,720,113
2083	2,064,720,113	99,725,981	(687,604,874)	-	1,476,841,221
2084	1,476,841,221	71,331,431	(683,855,253)	-	864,317,399
2085	864,317,399	41,746,530	(471,362,864)	-	434,701,065
2086	434,701,065	20,996,061	(322,085,668)	-	133,611,459
2087	133,611,459	6,453,433	(140,064,893)	-	(0)

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60-Year Decommissioning Period **Page 11 of 14**
SAFSTOR Method
5-Year Early Shutdown **Proposed**

EXTERNAL FUND CALCULATION

Prairie Island Unit 1

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	374,367,055	9,584,112	-	24,632	383,975,799
2018	383,975,799	19,660,822	-	49,264	403,685,885
2019	403,685,885	20,669,978	-	49,264	424,405,128
2020	424,405,128	21,730,804	-	49,264	446,185,196
2021	446,185,196	23,548,773	-	27,503,535	497,237,503
2022	497,237,503	26,162,651	-	27,503,535	550,903,689
2023	550,903,689	28,910,359	-	27,503,535	607,317,583
2024	607,317,583	31,798,751	-	27,503,535	666,619,868
2025	666,619,868	34,835,028	-	27,503,535	728,958,430
2026	728,958,430	38,026,762	-	27,503,535	794,488,727
2027	794,488,727	41,381,913	-	27,503,535	863,374,175
2028	863,374,175	42,058,735	(26,093,741)	18,427,368	897,766,537
2029	897,766,537	43,272,347	(85,547,775)	-	855,491,109
2030	855,491,109	41,234,671	(37,515,903)	-	859,209,877
2031	859,209,877	41,413,916	(32,140,303)	-	868,483,490
2032	868,483,490	41,860,904	(33,134,460)	-	877,209,934
2033	877,209,934	42,281,519	(47,713,763)	-	871,777,690
2034	871,777,690	42,019,685	(138,771,575)	-	775,025,800
2035	775,025,800	37,356,244	(13,288,961)	-	799,093,082
2036	799,093,082	38,516,287	(13,685,143)	-	823,924,226
2037	823,924,226	39,713,148	(14,135,014)	-	849,502,359
2038	849,502,359	40,946,014	(14,601,285)	-	875,847,088
2039	875,847,088	42,215,830	(15,127,775)	-	902,935,143
2040	902,935,143	43,521,474	(15,585,042)	-	930,871,576
2041	930,871,576	44,868,010	(16,103,868)	-	959,635,717
2042	959,635,717	46,254,442	(16,642,112)	-	989,248,047
2043	989,248,047	47,681,756	(17,248,941)	-	1,019,680,861
2044	1,019,680,861	49,148,618	(17,776,865)	-	1,051,052,614
2045	1,051,052,614	50,660,736	(18,375,387)	-	1,083,337,963
2046	1,083,337,963	52,216,890	(18,996,008)	-	1,116,558,845
2047	1,116,558,845	53,818,136	(19,696,541)	-	1,150,680,440
2048	1,150,680,440	55,462,797	(21,051,102)	-	1,185,092,135
2049	1,185,092,135	57,121,441	(22,535,136)	-	1,219,678,439
2050	1,219,678,439	58,788,501	(23,301,752)	-	1,255,165,188
2051	1,255,165,188	60,498,962	(24,571,163)	-	1,291,092,987
2052	1,291,092,987	62,230,682	(24,495,903)	-	1,328,827,766
2053	1,328,827,766	64,049,498	(26,646,318)	-	1,366,230,946
2054	1,366,230,946	65,852,332	(26,205,948)	-	1,405,877,330
2055	1,405,877,330	67,763,287	(26,717,263)	-	1,446,923,355
2056	1,446,923,355	69,741,706	(28,523,954)	-	1,488,141,107

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5-Year Early Shutdown **Proposed**

EXTERNAL FUND CALCULATION

2057	1,488,141,107	71,728,401	(29,509,208)	-	1,530,360,300
2058	1,530,360,300	73,763,366	(30,017,529)	-	1,574,106,137
2059	1,574,106,137	75,871,916	(31,675,750)	-	1,618,302,302
2060	1,618,302,302	78,002,171	(32,687,053)	-	1,663,617,421
2061	1,663,617,421	80,186,360	(33,260,079)	-	1,710,543,702
2062	1,710,543,702	82,448,206	(35,004,520)	-	1,757,987,389
2063	1,757,987,389	84,734,992	(36,327,139)	-	1,806,395,242
2064	1,806,395,242	87,068,251	(36,873,962)	-	1,856,589,531
2065	1,856,589,531	89,487,615	(38,811,398)	-	1,907,265,748
2066	1,907,265,748	91,930,209	(40,174,838)	-	1,959,021,119
2067	1,959,021,119	94,424,818	(41,702,580)	-	2,011,743,357
2068	2,011,743,357	96,966,030	(43,054,977)	-	2,065,654,409
2069	2,065,654,409	99,564,543	(44,575,228)	-	2,120,643,724
2070	2,120,643,724	102,215,028	(51,395,220)	-	2,171,463,532
2071	2,171,463,532	104,664,542	(47,918,013)	-	2,228,210,060
2072	2,228,210,060	107,399,725	(49,482,528)	-	2,286,127,258
2073	2,286,127,258	110,191,334	(38,308,473)	-	2,358,010,119
2074	2,358,010,119	113,656,088	(39,721,662)	-	2,431,944,544
2075	2,431,944,544	117,219,727	(41,300,486)	-	2,507,863,786
2076	2,507,863,786	120,879,034	(42,709,262)	-	2,586,033,559
2077	2,586,033,559	124,646,818	(44,288,156)	-	2,666,392,220
2078	2,666,392,220	128,520,105	(45,926,882)	-	2,748,985,443
2079	2,748,985,443	132,501,098	(47,757,956)	-	2,833,728,585
2080	2,833,728,585	136,585,718	(49,392,424)	-	2,920,921,879
2081	2,920,921,879	140,788,435	(51,223,963)	-	3,010,486,351
2082	3,010,486,351	145,105,442	(137,141,374)	-	3,018,450,419
2083	3,018,450,419	145,489,310	(510,925,861)	-	2,653,013,868
2084	2,653,013,868	127,875,268	(845,184,134)	-	1,935,705,003
2085	1,935,705,003	93,300,981	(764,957,013)	-	1,264,048,971
2086	1,264,048,971	60,927,160	(568,335,029)	-	756,641,102
2087	756,641,102	36,470,101	(216,232,427)	-	576,878,776
2088	576,878,776	27,805,557	(256,412,862)	-	348,271,470
2089	348,271,470	16,786,685	(212,741,434)	-	152,316,721
2090	152,316,721	7,341,666	(159,658,387)	-	(0)

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EXTERNAL FUND CALCULATION

Prairie Island Unit 2

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	420,208,967	10,803,157	-	294,670	431,306,795
2018	431,306,795	22,184,315	-	589,341	454,080,451
2019	454,080,451	23,354,881	-	589,341	478,024,673
2020	478,024,673	24,585,614	-	589,341	503,199,628
2021	503,199,628	26,160,961	-	11,536,963	540,897,552
2022	540,897,552	28,098,634	-	11,536,963	580,533,149
2023	580,533,149	30,135,904	-	11,536,963	622,206,016
2024	622,206,016	32,277,889	-	11,536,963	666,020,869
2025	666,020,869	34,529,973	-	11,536,963	712,087,805
2026	712,087,805	36,897,813	-	11,536,963	760,522,581
2027	760,522,581	39,387,361	-	11,536,963	811,446,905
2028	811,446,905	42,004,871	-	11,536,963	864,988,739
2029	864,988,739	42,010,209	(12,406,807)	9,575,679	904,167,820
2030	904,167,820	43,671,306	(90,281,325)	-	857,557,801
2031	857,557,801	41,420,042	(52,134,866)	-	846,842,977
2032	846,842,977	40,902,516	(29,141,967)	-	858,603,525
2033	858,603,525	41,470,550	(43,577,796)	-	856,496,280
2034	856,496,280	41,368,770	(135,253,712)	-	762,611,338
2035	762,611,338	36,834,128	(13,382,694)	-	786,062,772
2036	786,062,772	37,966,832	(13,782,286)	-	810,247,318
2037	810,247,318	39,134,945	(14,235,965)	-	835,146,298
2038	835,146,298	40,337,566	(14,706,196)	-	860,777,668
2039	860,777,668	41,575,561	(15,237,100)	-	887,116,129
2040	887,116,129	42,847,709	(15,698,348)	-	914,265,490
2041	914,265,490	44,159,023	(16,221,623)	-	942,202,891
2042	942,202,891	45,508,400	(16,764,496)	-	970,946,794
2043	970,946,794	46,896,730	(17,376,478)	-	1,000,467,046
2044	1,000,467,046	48,322,558	(17,909,053)	-	1,030,880,552
2045	1,030,880,552	49,791,531	(18,512,772)	-	1,062,159,311
2046	1,062,159,311	51,302,295	(19,138,796)	-	1,094,322,809
2047	1,094,322,809	52,855,792	(19,845,355)	-	1,127,333,246
2048	1,127,333,246	54,450,196	(21,205,352)	-	1,160,578,091
2049	1,160,578,091	56,055,922	(22,695,454)	-	1,193,938,559
2050	1,193,938,559	57,667,232	(23,468,384)	-	1,228,137,407
2051	1,228,137,407	59,319,037	(24,744,831)	-	1,262,711,613
2052	1,262,711,613	60,988,971	(24,675,920)	-	1,299,024,664
2053	1,299,024,664	62,742,891	(26,833,433)	-	1,334,934,122
2054	1,334,934,122	64,477,318	(26,400,439)	-	1,373,011,002
2055	1,373,011,002	66,316,431	(26,919,975)	-	1,412,407,458
2056	1,412,407,458	68,219,280	(28,734,087)	-	1,451,892,652

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5-Year Early Shutdown **Proposed**

EXTERNAL FUND CALCULATION

2057	1,451,892,652	70,126,415	(29,727,633)	-	1,492,291,434
2058	1,492,291,434	72,077,676	(30,244,574)	-	1,534,124,536
2059	1,534,124,536	74,098,215	(31,912,407)	-	1,576,310,345
2060	1,576,310,345	76,135,790	(32,932,383)	-	1,619,513,752
2061	1,619,513,752	78,222,514	(33,515,100)	-	1,664,221,166
2062	1,664,221,166	80,381,882	(35,269,615)	-	1,709,333,434
2063	1,709,333,434	82,560,805	(36,603,465)	-	1,755,290,773
2064	1,755,290,773	84,780,544	(37,160,429)	-	1,802,910,889
2065	1,802,910,889	87,080,596	(39,109,192)	-	1,850,882,293
2066	1,850,882,293	89,397,615	(40,484,410)	-	1,899,795,497
2067	1,899,795,497	91,760,123	(42,025,278)	-	1,949,530,341
2068	1,949,530,341	94,162,315	(43,389,533)	-	2,000,303,124
2069	2,000,303,124	96,614,641	(44,923,023)	-	2,051,994,743
2070	2,051,994,743	99,111,346	(51,756,785)	-	2,099,349,304
2071	2,099,349,304	101,398,571	(48,294,926)	-	2,152,452,949
2072	2,152,452,949	103,963,477	(49,873,301)	-	2,206,543,125
2073	2,206,543,125	106,576,033	(17,191,562)	-	2,295,927,596
2074	2,295,927,596	110,893,303	(17,748,654)	-	2,389,072,245
2075	2,389,072,245	115,392,189	(18,374,405)	-	2,486,090,030
2076	2,486,090,030	120,078,148	(18,918,989)	-	2,587,249,189
2077	2,587,249,189	124,964,136	(19,533,740)	-	2,692,679,585
2078	2,692,679,585	130,056,424	(20,169,179)	-	2,802,566,830
2079	2,802,566,830	135,363,978	(20,882,786)	-	2,917,048,022
2080	2,917,048,022	140,893,419	(21,504,295)	-	3,036,437,146
2081	3,036,437,146	146,659,914	(22,205,721)	-	3,160,891,338
2082	3,160,891,338	152,671,052	(22,930,853)	-	3,290,631,537
2083	3,290,631,537	158,937,503	(141,957,420)	-	3,307,611,620
2084	3,307,611,620	159,757,641	(357,637,520)	-	3,109,731,741
2085	3,109,731,741	150,200,043	(1,080,045,684)	-	2,179,886,100
2086	2,179,886,100	105,288,499	(847,383,481)	-	1,437,791,118
2087	1,437,791,118	69,445,311	(779,644,323)	-	727,592,106
2088	727,592,106	35,142,699	(330,500,380)	-	432,234,424
2089	432,234,424	20,876,923	(264,137,902)	-	188,973,445
2090	188,973,445	9,127,417	(198,100,862)	-	0

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Proposed

2021 ACCRUAL COMPARISON

	Present	Proposed	Difference
Monticello	$13,392,226	($8,586,256)	($21,978,482)
Prairie Island Unit 1	49,264	(1,085,269)	(1,134,533)
Prairie Island Unit 2	589,341	(6,304,910)	(6,894,251)
TOTAL	$14,030,831	($15,976,435)	($30,007,266)

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2021 MN RETAIL SUMMARY

	Remaining Life (yrs)	Operational Earnings Rate	Post-Shutdown Earnings Rate	Market Value Balance 6/30/2017	Book Value 6/30/2017	Unrealized Gain/Loss 6/30/2017	Tax-Effect Adjustment	Tax-Adjusted Fund Balance 6/30/2017	2021 Decommissioning Accrual
Monticello	33.75	5.10%	4.83%	$660,140,345	$529,148,381	$130,991,964	$36,468,163	$623,672,182	**(8,586,256)**
Prairie Island Unit 1	36.67	5.12%	4.82%	399,941,696	308,078,761	91,862,935	25,574,641	374,367,055	**(1,085,269)**
Prairie Island Unit 2	37.83	5.14%	4.83%	448,597,551	346,627,064	101,970,487	28,388,583	420,208,967	**(6,304,910)**
TOTAL DECOMMISSIONING ACCRUAL				**$1,508,679,592**	**$1,183,854,206**	**$324,825,386**	**$90,431,387**	**$1,418,248,204**	**($15,976,435)**

INPUT DATA

Escalation Rate (Labor)	4.05%
Escalation Rate (Non-Labor)	2.85%
Escalation Rate (PIIC)	0.00%
Jurisdictional Factor	73.4886%
Tax Rate for tax-effect adjustment	27.84%

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AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
Monticello															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2050	$17,759,328	$13,051,073	3.7067	$48,376,414	$8,763,593	$6,440,238	2.5278	$16,279,633	$0	$0	1.0000	$0	$26,522,921	$19,491,311	$64,656,047
2051	63,231,064	46,467,594	3.8568	179,216,218	46,823,276	34,409,748	2.5998	89,458,463	0	0	1.0000	0	110,054,340	80,877,343	268,674,682
2052	30,098,747	22,119,134	4.0130	88,764,085	21,963,833	16,140,903	2.6739	43,159,162	0	0	1.0000	0	52,062,580	38,260,037	131,923,246
2053	30,011,960	22,055,355	4.1756	92,094,341	35,867,567	26,358,556	2.7501	72,488,665	0	0	1.0000	0	65,879,526	48,413,911	164,583,006
2054	24,261,956	17,829,760	4.3447	77,464,960	18,617,567	13,681,781	2.8285	38,698,916	0	0	1.0000	0	42,879,522	31,511,541	116,163,876
2055	43,935,865	32,287,832	4.5206	145,960,372	88,132,650	64,767,410	2.9091	188,414,872	0	0	1.0000	0	132,068,514	97,055,241	334,375,244
2056	8,481,485	6,232,921	4.7037	29,317,788	4,523,995	3,324,618	2.9920	9,947,258	0	0	1.0000	0	13,005,479	9,557,539	39,265,046
2057	8,458,357	6,215,924	4.8942	30,421,976	4,511,770	3,315,635	3.0773	10,203,202	0	0	1.0000	0	12,970,127	9,531,559	40,625,178
2058	8,458,357	6,215,924	5.0924	31,653,972	4,511,770	3,315,635	3.1650	10,493,983	0	0	1.0000	0	12,970,127	9,531,559	42,147,955
2059	8,458,357	6,215,924	5.2987	32,936,317	4,511,770	3,315,635	3.2552	10,793,054	0	0	1.0000	0	12,970,127	9,531,559	43,729,371
2060	8,481,485	6,232,921	5.5133	34,363,961	4,523,995	3,324,618	3.3480	11,130,822	0	0	1.0000	0	13,005,479	9,557,539	45,494,783
2061	8,458,357	6,215,924	5.7366	35,658,270	4,511,770	3,315,635	3.4434	11,417,056	0	0	1.0000	0	12,970,127	9,531,559	47,075,326
2062	8,458,357	6,215,924	5.9689	37,102,229	4,511,770	3,315,635	3.5415	11,742,320	0	0	1.0000	0	12,970,127	9,531,559	48,844,549
2063	8,458,357	6,215,924	6.2106	38,604,618	4,511,770	3,315,635	3.6425	12,077,199	0	0	1.0000	0	12,970,127	9,531,559	50,681,817
2064	8,481,485	6,232,921	6.4622	40,278,379	4,523,995	3,324,618	3.7463	12,455,017	0	0	1.0000	0	13,005,479	9,557,539	52,733,396
2065	8,458,357	6,215,924	6.7239	41,795,252	4,511,770	3,315,635	3.8531	12,775,472	0	0	1.0000	0	12,970,127	9,531,559	54,570,723
2066	8,458,357	6,215,924	6.9962	43,487,848	4,511,770	3,315,635	3.9629	13,139,528	0	0	1.0000	0	12,970,127	9,531,559	56,627,376
2067	8,458,357	6,215,924	7.2795	45,248,819	4,511,770	3,315,635	4.0758	13,513,863	0	0	1.0000	0	12,970,127	9,531,559	58,762,683
2068	9,145,130	6,720,624	7.5744	50,904,692	6,514,932	4,787,729	4.1920	20,070,160	0	0	1.0000	0	15,660,061	11,508,353	70,974,852
2069	8,458,357	6,215,924	7.8811	48,988,319	4,511,767	3,315,632	4.3115	14,295,349	0	0	1.0000	0	12,970,124	9,531,556	63,283,668
2070	9,951,558	7,313,256	8.2003	59,970,892	8,991,374	6,607,631	4.4343	29,300,217	0	0	1.0000	0	18,942,932	13,920,887	89,271,109
2071	9,951,558	7,313,256	8.5324	62,399,625	8,991,374	6,607,631	4.5607	30,135,422	0	0	1.0000	0	18,942,932	13,920,887	92,535,046
2072	10,837,186	7,964,091	8.8780	70,705,201	11,591,099	8,518,131	4.6907	39,955,996	0	0	1.0000	0	22,428,284	16,482,222	110,661,197
2073	11,460,933	8,422,474	9.2375	77,802,601	13,519,499	9,935,284	4.8244	47,931,786	0	0	1.0000	0	24,980,432	18,357,758	125,734,387
2074	10,167,183	7,471,716	9.6117	71,815,889	9,638,249	7,083,010	4.9619	35,145,187	0	0	1.0000	0	19,805,432	14,554,725	106,961,075
2075	11,245,308	8,264,014	10.0009	82,647,578	12,872,624	9,459,905	5.1033	48,276,734	0	0	1.0000	0	24,117,932	17,723,919	130,924,313
2076	11,699,686	8,597,930	10.4060	89,470,059	14,178,599	10,419,647	5.2487	54,689,602	0	0	1.0000	0	25,878,284	19,017,577	144,159,660
2077	8,441,765	6,203,731	10.8274	67,170,276	4,461,997	3,279,057	5.3983	17,701,334	0	0	1.0000	0	12,903,762	9,482,788	84,871,609
2078	8,441,765	6,203,731	11.2659	69,890,612	4,461,997	3,279,057	5.5522	18,205,981	0	0	1.0000	0	12,903,762	9,482,788	88,096,592
2079	8,441,765	6,203,731	11.7222	72,721,374	4,461,997	3,279,057	5.7104	18,724,728	0	0	1.0000	0	12,903,762	9,482,788	91,446,102
2080	8,464,894	6,220,728	12.1970	75,874,220	4,474,222	3,288,041	5.8731	19,310,993	0	0	1.0000	0	12,939,115	9,508,769	95,185,212
2081	8,441,765	6,203,731	12.6909	78,730,928	4,461,997	3,279,057	6.0405	19,807,144	0	0	1.0000	0	12,903,762	9,482,788	98,538,072
2082	8,441,765	6,203,731	13.2049	81,919,646	4,461,997	3,279,057	6.2127	20,371,798	0	0	1.0000	0	12,903,762	9,482,788	102,291,444
2083	8,441,765	6,203,731	13.7397	85,237,401	4,461,997	3,279,057	6.3897	20,952,191	0	0	1.0000	0	12,903,762	9,482,788	106,189,592
2084	8,464,894	6,220,728	14.2962	88,932,772	4,474,222	3,288,041	6.5719	21,608,675	0	0	1.0000	0	12,939,115	9,508,769	110,541,448
2085	8,441,765	6,203,731	14.8752	92,281,737	4,461,997	3,279,057	6.7592	22,163,803	0	0	1.0000	0	12,903,762	9,482,788	114,445,540
2086	8,441,765	6,203,731	15.4776	96,018,865	4,461,997	3,279,057	6.9518	22,795,349	0	0	1.0000	0	12,903,762	9,482,788	118,814,214
2087	8,441,765	6,203,731	16.1045	99,907,984	4,461,997	3,279,057	7.1499	23,444,930	0	0	1.0000	0	12,903,762	9,482,788	123,352,914
2088	8,464,894	6,220,728	16.7567	104,238,874	4,474,222	3,288,041	7.3537	24,179,266	0	0	1.0000	0	12,939,115	9,508,769	128,418,139
2089	8,441,765	6,203,731	17.4353	108,163,909	4,461,997	3,279,057	7.5633	24,800,493	0	0	1.0000	0	12,903,762	9,482,788	132,964,401
2090	8,441,765	6,203,731	18.1415	112,544,983	4,461,997	3,279,057	7.7788	25,507,129	0	0	1.0000	0	12,903,762	9,482,788	138,052,113
2091	8,441,765	6,203,731	18.8762	117,102,865	4,461,997	3,279,057	8.0005	26,234,096	0	0	1.0000	0	12,903,762	9,482,788	143,336,961
2092	8,464,894	6,220,728	19.6407	122,179,453	4,474,222	3,288,041	8.2285	27,055,644	0	0	1.0000	0	12,939,115	9,508,769	149,235,097
2093	8,441,765	6,203,731	20.4361	126,780,064	4,461,997	3,279,057	8.4630	27,750,660	0	0	1.0000	0	12,903,762	9,482,788	154,530,725
2094	8,441,765	6,203,731	21.2638	131,914,892	4,461,997	3,279,057	8.7042	28,541,569	0	0	1.0000	0	12,903,762	9,482,788	160,456,461
2095	8,441,765	6,203,731	22.1250	137,257,545	4,461,997	3,279,057	8.9523	29,355,103	0	0	1.0000	0	12,903,762	9,482,788	166,612,648
2096	8,464,894	6,220,728	23.0210	143,207,380	4,474,222	3,288,041	9.2075	30,274,636	0	0	1.0000	0	12,939,115	9,508,769	173,482,016
2097	8,441,765	6,203,731	23.9534	148,600,447	4,461,997	3,279,057	9.4699	31,052,343	0	0	1.0000	0	12,903,762	9,482,788	179,652,790
2098	8,920,197	6,555,324	24.9235	163,381,608	5,897,293	4,333,835	9.7398	42,210,690	0	0	1.0000	0	14,817,490	10,889,159	205,592,298
2099	9,015,884	6,625,643	25.9329	171,822,127	6,184,352	4,544,791	10.0173	45,526,534	0	0	1.0000	0	15,200,236	11,170,433	217,348,661
2100	8,943,325	6,572,320	26.9832	177,342,227	5,909,518	4,342,819	10.3028	44,743,197	0	0	1.0000	0	14,852,842	10,915,139	222,085,423
2101	8,920,197	6,555,324	28.0760	184,047,266	5,897,293	4,333,835	10.5965	45,923,487	0	0	1.0000	0	14,817,490	10,889,159	229,970,753
2102	8,920,197	6,555,324	29.2131	191,501,325	5,897,293	4,333,835	10.8985	47,232,305	0	0	1.0000	0	14,817,490	10,889,159	238,733,629
2103	9,015,884	6,625,643	30.3962	201,394,358	6,184,352	4,544,791	11.2091	50,943,015	0	0	1.0000	0	15,200,236	11,170,433	252,337,374
2104	8,943,325	6,572,320	31.6272	207,864,081	5,909,518	4,342,819	11.5285	50,066,190	0	0	1.0000	0	14,852,842	10,915,139	257,930,271

Xcel Energy
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AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
2105	46,126,149	33,897,440	32.9081	1,115,500,348	12,314,062	9,049,426	11.8571	107,299,952	0	0	1.0000	0	58,440,212	42,946,866	1,222,800,300
2106	53,631,139	39,412,748	34.2409	1,349,527,973	46,945,385	34,499,485	12.1950	420,721,214	0	0	1.0000	0	100,576,524	73,912,233	1,770,249,187
2107	57,419,114	42,196,476	35.6277	1,503,363,401	80,273,242	58,991,645	12.5426	739,908,606	0	0	1.0000	0	137,692,356	101,188,121	2,243,272,007
2108	52,652,752	38,693,746	37.0706	1,434,400,375	33,214,319	24,408,722	12.9000	314,872,520	0	0	1.0000	0	85,867,070	63,102,468	1,749,272,895
2109	50,913,638	37,415,697	38.5720	1,443,198,252	30,841,715	22,665,130	13.2677	300,714,150	0	0	1.0000	0	81,755,354	60,080,827	1,743,912,402
2110	32,667,889	24,007,160	40.1341	963,505,742	23,001,023	16,903,119	13.6458	230,656,586	0	0	1.0000	0	55,668,913	40,910,279	1,194,162,328
2111	21,071,356	15,485,035	41.7596	646,648,865	16,131,940	11,855,130	14.0347	166,383,189	0	0	1.0000	0	37,203,297	27,340,165	813,032,054
2112	8,832,651	6,490,987	43.4508	282,038,589	6,762,156	4,969,411	14.4347	71,731,950	0	0	1.0000	0	15,594,807	11,460,398	353,770,539
	$967,171,883	$710,760,631		$13,883,663,437	$750,282,438	$551,371,714		$4,086,760,388	$0	$0		$0	$1,717,454,322	$1,262,132,345	$17,970,423,825

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Proposed

AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
Prairie Island Unit 1															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2053	$18,446,908	$13,556,366	4.1756	$56,605,961	$4,190,856	$3,079,799	2.7501	$8,469,756	$1,250,000	$918,607	1.0000	$918,607	$23,887,764	$17,554,772	$65,994,324
2054	46,142,627	33,909,549	4.3447	147,326,818	29,162,161	21,430,850	2.8285	60,617,159	1,250,000	918,607	1.0000	918,607	76,554,787	56,259,006	208,862,585
2055	16,398,923	12,051,331	4.5206	54,479,249	15,491,742	11,384,657	2.9091	33,119,105	1,250,000	918,607	1.0000	918,607	33,140,665	24,354,595	88,516,961
2056	12,659,656	9,303,398	4.7037	43,760,395	13,774,811	10,122,909	2.9920	30,287,745	1,250,000	918,607	1.0000	918,607	27,684,467	20,344,915	74,966,746
2057	12,625,333	9,278,174	4.8942	45,409,241	13,734,545	10,093,318	3.0773	31,060,169	1,250,000	918,607	1.0000	918,607	27,609,877	20,290,100	77,388,016
2058	15,404,499	11,320,543	5.0924	57,648,734	22,072,045	16,220,427	3.1650	51,337,650	1,250,000	918,607	1.0000	918,607	38,726,543	28,459,577	109,904,991
2059	32,688,492	24,022,300	5.2987	127,286,962	76,524,027	56,236,401	3.2552	183,060,732	1,250,000	918,607	1.0000	918,607	110,462,519	81,177,308	311,266,301
2060	4,604,176	3,383,542	5.5133	18,654,485	4,477,123	3,290,173	3.3480	11,015,499	1,250,000	918,607	1.0000	918,607	10,331,299	7,592,322	30,588,591
2061	4,591,596	3,374,297	5.7366	19,356,993	4,461,475	3,278,674	3.4434	11,289,785	1,250,000	918,607	1.0000	918,607	10,303,071	7,571,578	31,565,385
2062	4,591,596	3,374,297	5.9689	20,140,843	4,461,475	3,278,674	3.5415	11,611,423	1,250,000	918,607	1.0000	918,607	10,303,071	7,571,578	32,670,872
2063	4,591,596	3,374,297	6.2106	20,956,410	4,461,475	3,278,674	3.6425	11,942,569	1,250,000	918,607	1.0000	918,607	10,303,071	7,571,578	33,817,586
2064	4,604,176	3,383,542	6.4622	21,865,128	4,477,123	3,290,173	3.7463	12,325,975	1,250,000	918,607	1.0000	918,607	10,331,299	7,592,322	35,109,710
2065	4,591,596	3,374,297	6.7239	22,688,437	4,461,475	3,278,674	3.8531	12,633,057	1,250,000	918,607	1.0000	918,607	10,303,071	7,571,578	36,240,101
2066	4,591,596	3,374,297	6.9962	23,607,258	4,461,475	3,278,674	3.9629	12,993,056	1,250,000	918,607	1.0000	918,607	10,303,071	7,571,578	37,518,921
2067	4,591,596	3,374,297	7.2795	24,563,197	4,461,475	3,278,674	4.0758	13,363,218	1,250,000	918,607	1.0000	918,607	10,303,071	7,571,578	38,845,022
2068	4,604,176	3,383,542	7.5744	25,628,304	4,477,123	3,290,173	4.1920	13,792,405	1,250,000	918,607	1.0000	918,607	10,331,299	7,592,322	40,339,316
2069	4,591,596	3,374,297	7.8811	26,593,174	4,461,475	3,278,674	4.3115	14,136,001	1,250,000	918,607	1.0000	918,607	10,303,071	7,571,578	41,647,782
2070	4,591,596	3,374,297	8.2003	27,670,249	4,461,475	3,278,674	4.4343	14,538,623	1,250,000	918,607	1.0000	918,607	10,303,071	7,571,578	43,127,479
2071	4,591,596	3,374,297	8.5324	28,790,854	4,461,475	3,278,674	4.5607	14,953,047	1,250,000	918,607	1.0000	918,607	10,303,071	7,571,578	44,662,507
2072	4,604,176	3,383,542	8.8780	30,039,090	4,477,123	3,290,173	4.6907	15,433,215	1,250,000	918,607	1.0000	918,607	10,331,299	7,592,322	46,390,912
2073	4,687,283	3,444,616	9.2375	31,819,642	4,748,534	3,489,629	4.8244	16,835,367	1,250,000	918,607	1.0000	918,607	10,685,817	7,852,852	49,573,616
2074	4,782,969	3,514,934	9.6117	33,784,496	5,035,593	3,700,585	4.9619	18,361,931	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	53,065,034
2075	4,782,969	3,514,934	10.0009	35,152,508	5,035,593	3,700,585	5.1033	18,885,194	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	54,956,309
2076	4,843,392	3,559,339	10.4060	37,038,480	5,194,771	3,817,562	5.2487	20,037,239	1,250,000	918,607	1.0000	918,607	11,288,163	8,295,508	57,994,326
2077	4,735,126	3,479,775	10.8274	37,676,920	4,892,064	3,595,107	5.3983	19,407,468	1,250,000	918,607	1.0000	918,607	10,877,190	7,993,490	58,002,994
2078	4,878,656	3,585,253	11.2659	40,391,107	5,322,652	3,911,540	5.5522	21,717,653	1,250,000	918,607	1.0000	918,607	11,451,308	8,415,401	63,027,367
2079	4,735,126	3,479,775	11.7222	40,790,622	4,892,064	3,595,107	5.7104	20,529,501	1,250,000	918,607	1.0000	918,607	10,877,190	7,993,490	62,238,730
2080	4,699,862	3,453,861	12.1970	42,126,739	4,764,182	3,501,129	5.8731	20,562,478	1,250,000	918,607	1.0000	918,607	10,714,044	7,873,596	63,607,824
2081	4,782,969	3,514,934	12.6909	44,607,682	5,035,593	3,700,585	6.0405	22,353,382	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	67,879,670
2082	4,782,969	3,514,934	13.2049	46,414,358	5,035,593	3,700,585	6.2127	22,990,622	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	70,323,587
2083	4,735,126	3,479,775	13.7397	47,811,069	4,892,064	3,595,107	6.3897	22,971,657	1,250,000	918,607	1.0000	918,607	10,877,190	7,993,490	71,701,333
2084	4,795,548	3,524,179	14.2962	50,382,367	5,051,241	3,712,084	6.5719	24,395,445	1,250,000	918,607	1.0000	918,607	11,096,789	8,154,870	75,696,420
2085	4,782,969	3,514,934	14.8752	52,285,353	5,035,593	3,700,585	6.7592	25,012,992	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	78,216,952
2086	4,735,126	3,479,775	15.4776	53,858,571	4,892,064	3,595,107	6.9518	24,992,467	1,250,000	918,607	1.0000	918,607	10,877,190	7,993,490	79,769,645
2087	4,782,969	3,514,934	16.1045	56,606,262	5,035,593	3,700,585	7.1499	26,458,810	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	83,983,679
2088	4,795,548	3,524,179	16.7567	59,053,610	5,051,241	3,712,084	7.3537	27,297,553	1,250,000	918,607	1.0000	918,607	11,096,789	8,154,870	87,269,769
2089	4,735,126	3,479,775	17.4353	60,670,927	4,892,064	3,595,107	7.5633	27,190,875	1,250,000	918,607	1.0000	918,607	10,877,190	7,993,490	88,780,409
2090	4,782,969	3,514,934	18.1415	63,766,184	5,035,593	3,700,585	7.7788	28,786,108	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	93,470,899
2091	4,782,969	3,514,934	18.8762	66,348,606	5,035,593	3,700,585	8.0005	29,606,528	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	96,873,741
2092	4,795,548	3,524,179	19.6407	69,217,342	5,051,241	3,712,084	8.2285	30,544,884	1,250,000	918,607	1.0000	918,607	11,096,789	8,154,870	100,680,833
2093	4,782,969	3,514,934	20.4361	71,831,552	5,035,593	3,700,585	8.4630	31,318,048	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	104,068,207
2094	4,782,969	3,514,934	21.2638	74,740,864	5,035,593	3,700,585	8.7042	32,210,629	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	107,870,100
2095	5,114,792	3,758,786	22.1250	83,163,149	6,031,061	4,432,140	8.9523	39,677,844	1,250,000	918,607	1.0000	918,607	12,395,853	9,109,533	123,759,600
2096	4,795,548	3,524,179	23.0210	81,130,124	5,051,241	3,712,084	9.2075	34,179,014	1,250,000	918,607	1.0000	918,607	11,096,789	8,154,870	116,227,745
2097	4,782,969	3,514,934	23.9534	84,194,631	5,035,593	3,700,585	9.4699	35,044,167	1,250,000	918,607	1.0000	918,607	11,068,562	8,134,126	120,157,405
2098	3,942,348	2,897,174	24.9235	72,207,722	3,256,582	2,393,215	9.7398	23,309,434	0	0	1.0000	0	7,198,929	5,290,389	95,517,156
2099	3,942,348	2,897,174	25.9329	75,132,129	3,256,582	2,393,215	10.0173	23,973,551	0	0	1.0000	0	7,198,929	5,290,389	99,105,680
2100	3,953,149	2,905,112	26.9832	78,389,210	3,265,504	2,399,772	10.3028	24,724,367	0	0	1.0000	0	7,218,652	5,304,883	103,113,576
2101	3,942,348	2,897,174	28.0760	81,341,063	3,256,582	2,393,215	10.5965	25,359,701	0	0	1.0000	0	7,198,929	5,290,389	106,700,764
2102	3,942,348	2,897,174	29.2131	84,635,440	3,256,582	2,393,215	10.8985	26,082,452	0	0	1.0000	0	7,198,929	5,290,389	110,717,892
2103	3,942,348	2,897,174	30.3962	88,063,087	3,256,582	2,393,215	11.2091	26,825,784	0	0	1.0000	0	7,198,929	5,290,389	114,888,871
2104	3,953,149	2,905,112	31.6272	91,880,548	3,265,504	2,399,772	11.5285	27,665,767	0	0	1.0000	0	7,218,652	5,304,883	119,546,315
2105	3,942,348	2,897,174	32.9081	95,340,499	3,256,582	2,393,215	11.8571	28,376,588	0	0	1.0000	0	7,198,929	5,290,389	123,717,087
2106	3,942,348	2,897,174	34.2409	99,201,853	3,256,582	2,393,215	12.1950	29,185,255	0	0	1.0000	0	7,198,929	5,290,389	128,387,108
2107	11,802,691	8,673,627	35.6277	309,021,370	4,951,569	3,638,837	12.5426	45,640,474	0	0	1.0000	0	16,754,260	12,312,463	354,661,844

Xcel Energy
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60-Year Decommissioning Period
SAFSTOR Method
20-Year Life Extension

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AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
2108	45,111,220	33,151,584	37.0706	1,228,949,094	11,805,071	8,675,376	12.9000	111,912,347	0	0	1.0000	0	56,916,291	41,826,959	1,340,861,441
2109	51,818,304	38,080,522	38.5720	1,468,841,899	62,277,980	45,767,187	13.2677	607,225,301	0	0	1.0000	0	114,096,283	83,847,709	2,076,067,200
2110	44,187,860	32,473,019	40.1341	1,303,275,394	56,754,748	41,708,244	13.6458	569,142,350	0	0	1.0000	0	100,942,608	74,181,263	1,872,417,744
2111	35,668,367	26,212,167	41.7596	1,094,609,618	31,834,151	23,394,458	14.0347	328,334,194	0	0	1.0000	0	67,502,519	49,606,625	1,422,943,812
2112	13,715,750	10,079,506	43.4508	437,962,617	10,259,487	7,539,548	14.4347	108,831,118	0	0	1.0000	0	23,975,237	17,619,055	546,793,735
2113	18,089,191	13,293,485	45.2106	601,006,439	6,228,187	4,577,005	14.8461	67,950,670	0	0	1.0000	0	24,317,379	17,870,490	668,957,109
2114	12,584,719	9,248,328	47.0416	435,056,148	9,264,588	6,808,412	15.2692	103,959,000	0	0	1.0000	0	21,849,307	16,056,740	539,015,148
2115	9,102,372	6,689,202	48.9468	327,415,015	6,700,962	4,924,440	15.7044	77,335,379	0	0	1.0000	0	15,803,334	11,613,642	404,750,394
	$611,385,166	$449,298,117		$10,180,264,092	$588,533,792	$432,504,973		$3,465,181,777	$56,250,000	$41,337,312		$41,337,312	$1,256,168,958	$923,140,402	$13,686,783,181

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AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
Prairie Island Unit 2															
Factors	*2017*	*73.4886%*	*4.05%*				*2.85%*				*0.00%*				
2054	$7,248,794	$5,327,034	4.3447	$23,144,365	$2,826,485	$2,077,143	2.8285	$5,875,198	$1,250,000	$918,607	1.0000	$918,607	$11,325,279	$8,322,784	$29,938,170
2055	44,817,806	32,935,958	4.5206	148,890,290	32,275,248	23,718,613	2.9091	68,999,817	1,250,000	918,607	1.0000	918,607	78,343,054	57,573,177	218,808,713
2056	23,021,476	16,918,150	4.7037	79,577,901	19,944,127	14,656,651	2.9920	43,852,699	1,250,000	918,607	1.0000	918,607	44,215,603	32,493,407	124,349,207
2057	10,761,111	7,908,185	4.8942	38,704,239	12,388,936	9,104,450	3.0773	28,017,124	1,250,000	918,607	1.0000	918,607	24,400,047	17,931,242	67,639,969
2058	13,540,277	9,950,554	5.0924	50,672,200	20,726,436	15,231,558	3.1650	48,207,881	1,250,000	918,607	1.0000	918,607	35,516,713	26,100,719	99,798,689
2059	31,160,880	22,899,680	5.2987	121,338,535	75,415,818	55,421,994	3.2552	180,409,674	1,250,000	918,607	1.0000	918,607	107,826,698	79,240,281	302,666,816
2060	4,659,832	3,424,443	5.5133	18,879,983	4,485,457	3,296,297	3.3480	11,036,004	1,250,000	918,607	1.0000	918,607	10,395,289	7,639,347	30,834,593
2061	4,647,099	3,415,086	5.7366	19,590,984	4,469,786	3,284,781	3.4434	11,310,816	1,250,000	918,607	1.0000	918,607	10,366,886	7,618,474	31,820,406
2062	4,647,099	3,415,086	5.9689	20,384,308	4,469,786	3,284,781	3.5415	11,633,053	1,250,000	918,607	1.0000	918,607	10,366,886	7,618,474	32,935,968
2063	4,647,099	3,415,086	6.2106	21,209,734	4,469,786	3,284,781	3.6425	11,964,816	1,250,000	918,607	1.0000	918,607	10,366,886	7,618,474	34,093,157
2064	4,659,832	3,424,443	6.4622	22,129,437	4,485,457	3,296,297	3.7463	12,348,919	1,250,000	918,607	1.0000	918,607	10,395,289	7,639,347	35,396,963
2065	4,647,099	3,415,086	6.7239	22,962,698	4,469,786	3,284,781	3.8531	12,656,591	1,250,000	918,607	1.0000	918,607	10,366,886	7,618,474	36,537,896
2066	4,647,099	3,415,086	6.9962	23,892,626	4,469,786	3,284,781	3.9629	13,017,260	1,250,000	918,607	1.0000	918,607	10,366,886	7,618,474	37,828,493
2067	4,647,099	3,415,086	7.2795	24,860,120	4,469,786	3,284,781	4.0758	13,388,111	1,250,000	918,607	1.0000	918,607	10,366,886	7,618,474	39,166,838
2068	4,659,832	3,424,443	7.5744	25,938,103	4,485,457	3,296,297	4.1920	13,818,079	1,250,000	918,607	1.0000	918,607	10,395,289	7,639,347	40,674,788
2069	4,647,099	3,415,086	7.8811	26,914,636	4,469,786	3,284,781	4.3115	14,162,334	1,250,000	918,607	1.0000	918,607	10,366,886	7,618,474	41,995,577
2070	4,647,099	3,415,086	8.2003	28,004,731	4,469,786	3,284,781	4.4343	14,565,705	1,250,000	918,607	1.0000	918,607	10,366,886	7,618,474	43,489,044
2071	4,647,099	3,415,086	8.5324	29,138,882	4,469,786	3,284,781	4.5607	14,980,902	1,250,000	918,607	1.0000	918,607	10,366,886	7,618,474	45,038,390
2072	4,659,832	3,424,443	8.8780	30,402,207	4,485,457	3,296,297	4.6907	15,461,942	1,250,000	918,607	1.0000	918,607	10,395,289	7,639,347	46,782,756
2073	4,742,786	3,485,405	9.2375	32,196,431	4,756,846	3,495,737	4.8244	16,864,836	1,250,000	918,607	1.0000	918,607	10,749,633	7,899,750	49,979,873
2074	4,838,472	3,555,723	9.6117	34,176,547	5,043,904	3,706,692	4.9619	18,392,236	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	53,487,390
2075	4,838,472	3,555,723	10.0009	35,560,435	5,043,904	3,706,692	5.1033	18,916,363	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	55,395,404
2076	4,899,048	3,600,240	10.4060	37,464,093	5,203,105	3,823,687	5.2487	20,069,383	1,250,000	918,607	1.0000	918,607	11,352,153	8,342,533	58,452,083
2077	4,790,629	3,520,564	10.8274	38,118,558	4,900,375	3,601,215	5.3983	19,440,438	1,250,000	918,607	1.0000	918,607	10,941,005	8,040,386	58,477,603
2078	4,934,159	3,626,042	11.2659	40,850,632	5,330,963	3,917,648	5.5522	21,751,564	1,250,000	918,607	1.0000	918,607	11,515,123	8,462,297	63,520,802
2079	4,790,629	3,520,564	11.7222	41,268,759	4,900,375	3,601,215	5.7104	20,564,377	1,250,000	918,607	1.0000	918,607	10,941,005	8,040,386	62,751,743
2080	4,755,518	3,494,761	12.1970	42,625,606	4,772,516	3,507,253	5.8731	20,598,447	1,250,000	918,607	1.0000	918,607	10,778,034	7,920,621	64,142,659
2081	4,838,472	3,555,723	12.6909	45,125,331	5,043,904	3,706,692	6.0405	22,390,275	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	68,434,212
2082	4,838,472	3,555,723	13.2049	46,952,973	5,043,904	3,706,692	6.2127	23,028,567	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	70,900,147
2083	4,790,629	3,520,564	13.7397	48,371,498	4,900,375	3,601,215	6.3897	23,010,683	1,250,000	918,607	1.0000	918,607	10,941,005	8,040,386	72,300,787
2084	4,851,204	3,565,080	14.2962	50,967,093	5,059,575	3,718,208	6.5719	24,435,694	1,250,000	918,607	1.0000	918,607	11,160,779	8,201,895	76,321,393
2085	4,838,472	3,555,723	14.8752	52,892,098	5,043,904	3,706,692	6.7592	25,054,274	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	78,864,979
2086	4,790,629	3,520,564	15.4776	54,489,887	4,900,375	3,601,215	6.9518	25,034,925	1,250,000	918,607	1.0000	918,607	10,941,005	8,040,386	80,443,419
2087	4,838,472	3,555,723	16.1045	57,263,148	5,043,904	3,706,692	7.1499	26,502,479	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	84,684,234
2088	4,851,204	3,565,080	16.7567	59,738,971	5,059,575	3,718,208	7.3537	27,342,589	1,250,000	918,607	1.0000	918,607	11,160,779	8,201,895	88,000,167
2089	4,790,629	3,520,564	17.4353	61,382,095	4,900,375	3,601,215	7.5633	27,237,068	1,250,000	918,607	1.0000	918,607	10,941,005	8,040,386	89,537,771
2090	4,838,472	3,555,723	18.1415	64,506,157	5,043,904	3,706,692	7.7788	28,833,618	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	94,258,382
2091	4,838,472	3,555,723	18.8762	67,118,547	5,043,904	3,706,692	8.0005	29,655,391	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	97,692,545
2092	4,851,204	3,565,080	19.6407	70,020,661	5,059,575	3,718,208	8.2285	30,595,278	1,250,000	918,607	1.0000	918,607	11,160,779	8,201,895	101,534,546
2093	4,838,472	3,555,723	20.4361	72,665,120	5,043,904	3,706,692	8.4630	31,369,736	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	104,953,464
2094	4,838,472	3,555,723	21.2638	75,608,193	5,043,904	3,706,692	8.7042	32,263,791	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	108,790,590
2095	5,170,295	3,799,575	22.1250	84,065,605	6,039,372	4,438,247	8.9523	39,732,521	1,250,000	918,607	1.0000	918,607	12,459,668	9,156,430	124,716,733
2096	4,851,204	3,565,080	23.0210	82,071,700	5,059,575	3,718,208	9.2075	34,235,404	1,250,000	918,607	1.0000	918,607	11,160,779	8,201,895	117,225,711
2097	4,838,472	3,555,723	23.9534	85,171,666	5,043,904	3,706,692	9.4699	35,102,005	1,250,000	918,607	1.0000	918,607	11,132,377	8,181,023	121,192,278
2098	823,359	605,074	24.9235	15,080,573	3,272,479	2,404,897	9.7398	23,423,219	0	-	1.0000	-	4,095,838	3,009,972	38,503,792
2099	823,359	605,074	25.9329	15,691,335	3,272,479	2,404,897	10.0173	24,090,578	0	-	1.0000	-	4,095,838	3,009,972	39,781,913
2100	825,615	606,732	26.9832	16,371,576	3,281,444	2,411,486	10.3028	24,845,059	0	-	1.0000	-	4,107,059	3,018,218	41,216,634
2101	823,359	605,074	28.0760	16,988,070	3,272,479	2,404,897	10.5965	25,483,495	0	-	1.0000	-	4,095,838	3,009,972	42,471,564
2102	823,359	605,074	29.2131	17,676,100	3,272,479	2,404,897	10.8985	26,209,774	0	-	1.0000	-	4,095,838	3,009,972	43,885,874
2103	823,359	605,074	30.3962	18,391,963	3,272,479	2,404,897	11.2091	26,956,735	0	-	1.0000	-	4,095,838	3,009,972	45,348,698
2104	825,615	606,732	31.6272	19,189,240	3,281,444	2,411,486	11.5285	27,800,817	0	-	1.0000	-	4,107,059	3,018,218	46,990,057
2105	823,359	605,074	32.9081	19,911,850	3,272,479	2,404,897	11.8571	28,515,108	0	-	1.0000	-	4,095,838	3,009,972	48,426,958
2106	823,359	605,074	34.2409	20,718,293	3,272,479	2,404,897	12.1950	29,327,723	0	-	1.0000	-	4,095,838	3,009,972	50,046,016
2107	823,359	605,074	35.6277	21,557,410	3,272,479	2,404,897	12.5426	30,163,665	0	-	1.0000	-	4,095,838	3,009,972	51,721,076
2108	11,274,587	8,285,531	37.0706	307,149,594	5,987,760	4,400,318	12.9000	56,764,107	0	-	1.0000	-	17,262,347	12,685,849	363,913,701

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AMOUNT TO RECOVER

	LABOR				NON-LABOR				PIIC Payment						
	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Cost Estimate Nominal $s	Jurisdictional Cost in Nominal $s	Escalation Factor	Jurisdictional Cost in Future $'s	Total Cost Estimate Nominal $s	Total Jurisdictional Cost in Nominal $s	Total Jurisdictional Cost in Future $'s
2109	29,172,411	21,438,383	38.5720	826,921,313	10,590,974	7,783,154	13.2677	103,264,549	0	-	1.0000	-	39,763,385	29,221,537	930,185,861
2110	57,665,154	42,377,288	40.1341	1,700,774,317	90,528,180	66,527,851	13.6458	907,825,744	0	-	1.0000	-	148,193,335	108,905,139	2,608,600,062
2111	55,538,057	40,814,115	41.7596	1,704,381,128	42,217,329	31,024,904	14.0347	435,425,226	0	-	1.0000	-	97,755,386	71,839,020	2,139,806,354
2112	51,408,076	37,779,052	43.4508	1,641,530,028	32,588,487	23,948,808	14.4347	345,693,858	0	-	1.0000	-	83,996,563	61,727,860	1,987,223,886
2113	23,223,558	17,066,657	45.2106	771,593,789	8,238,061	6,054,032	14.8461	89,878,762	0	-	1.0000	-	31,461,619	23,120,689	861,472,551
2114	14,460,844	10,627,065	47.0416	499,914,146	14,186,680	10,425,586	15.2692	159,190,356	0	-	1.0000	-	28,647,524	21,052,651	659,104,503
2115	10,459,350	7,686,425	48.9468	376,225,916	10,261,051	7,540,698	15.7044	118,422,134	0	-	1.0000	-	20,720,401	15,227,123	494,648,050
	$573,536,674	$421,483,808		$10,167,374,423	$595,414,118	$437,561,225		$3,671,409,774	$55,000,000	$40,418,705		$40,418,705	$1,223,950,791	$899,463,737	$13,879,202,902
	$2,152,093,723	$1,581,542,556		$34,231,301,951	$1,934,230,348	$1,421,437,911		$11,223,351,940	$111,250,000	$81,756,016		$81,756,016	$4,197,574,071	$3,084,736,483	$45,536,409,907

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60-Year Decommissioning Period **Page 9 of 17**
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20-Year Life Extension **Proposed**

EXTERNAL FUND CALCULATION

Monticello

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	623,672,182	15,989,016	-	6,696,113	646,357,311
2018	646,357,311	33,305,725	-	13,392,226	693,055,262
2019	693,055,262	35,687,320	-	13,392,226	742,134,808
2020	742,134,808	38,190,377	-	13,392,226	793,717,411
2021	793,717,411	40,260,638	-	(8,586,256)	825,391,793
2022	825,391,793	41,876,032	-	(8,586,256)	858,681,569
2023	858,681,569	43,573,811	-	(8,586,256)	893,669,124
2024	893,669,124	45,358,176	-	(8,586,256)	930,441,043
2025	930,441,043	47,233,544	-	(8,586,256)	969,088,331
2026	969,088,331	49,204,555	-	(8,586,256)	1,009,706,630
2027	1,009,706,630	51,276,089	-	(8,586,256)	1,052,396,463
2028	1,052,396,463	53,453,270	-	(8,586,256)	1,097,263,477
2029	1,097,263,477	55,741,488	-	(8,586,256)	1,144,418,709
2030	1,144,418,709	58,146,405	-	(8,586,256)	1,193,978,857
2031	1,193,978,857	60,673,972	-	(8,586,256)	1,246,066,574
2032	1,246,066,574	63,330,446	-	(8,586,256)	1,300,810,763
2033	1,300,810,763	66,122,399	-	(8,586,256)	1,358,346,907
2034	1,358,346,907	69,056,743	-	(8,586,256)	1,418,817,393
2035	1,418,817,393	72,140,738	-	(8,586,256)	1,482,371,875
2036	1,482,371,875	75,382,016	-	(8,586,256)	1,549,167,635
2037	1,549,167,635	78,788,600	-	(8,586,256)	1,619,369,979
2038	1,619,369,979	82,368,919	-	(8,586,256)	1,693,152,642
2039	1,693,152,642	86,131,835	-	(8,586,256)	1,770,698,221
2040	1,770,698,221	90,086,660	-	(8,586,256)	1,852,198,625
2041	1,852,198,625	94,243,180	-	(8,586,256)	1,937,855,549
2042	1,937,855,549	98,611,683	-	(8,586,256)	2,027,880,977
2043	2,027,880,977	103,202,980	-	(8,586,256)	2,122,497,701
2044	2,122,497,701	108,028,433	-	(8,586,256)	2,221,939,878
2045	2,221,939,878	113,099,984	-	(8,586,256)	2,326,453,606
2046	2,326,453,606	118,430,184	-	(8,586,256)	2,436,297,535
2047	2,436,297,535	124,032,225	-	(8,586,256)	2,551,743,503
2048	2,551,743,503	129,919,969	-	(8,586,256)	2,673,077,217
2049	2,673,077,217	136,107,989	-	(8,586,256)	2,800,598,949
2050	2,800,598,949	135,113,411	(64,656,047)	(6,439,692)	2,864,616,621
2051	2,864,616,621	138,360,983	(268,674,682)	-	2,734,302,922
2052	2,734,302,922	132,066,831	(131,923,246)	-	2,734,446,507
2053	2,734,446,507	132,073,766	(164,583,006)	-	2,701,937,267
2054	2,701,937,267	130,503,570	(116,163,876)	-	2,716,276,961
2055	2,716,276,961	131,196,177	(334,375,244)	-	2,513,097,894
2056	2,513,097,894	121,382,628	(39,265,046)	-	2,595,215,476

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External Levelized	2057	2,595,215,476	125,348,908	(40,625,178)	-	2,679,939,206
	2058	2,679,939,206	129,441,064	(42,147,955)	-	2,767,232,314
	2059	2,767,232,314	133,657,321	(43,729,371)	-	2,857,160,265
	2060	2,857,160,265	138,000,841	(45,494,783)	-	2,949,666,323
	2061	2,949,666,323	142,468,883	(47,075,326)	-	3,045,059,880
	2062	3,045,059,880	147,076,392	(48,844,549)	-	3,143,291,723
	2063	3,143,291,723	151,820,990	(50,681,817)	-	3,244,430,896
	2064	3,244,430,896	156,706,012	(52,733,396)	-	3,348,403,512
	2065	3,348,403,512	161,727,890	(54,570,723)	-	3,455,560,678
	2066	3,455,560,678	166,903,581	(56,627,376)	-	3,565,836,883
	2067	3,565,836,883	172,229,921	(58,762,683)	-	3,679,304,122
	2068	3,679,304,122	177,710,389	(70,974,852)	-	3,786,039,659
	2069	3,786,039,659	182,865,716	(63,283,668)	-	3,905,621,706
	2070	3,905,621,706	188,641,528	(89,271,109)	-	4,004,992,125
	2071	4,004,992,125	193,441,120	(92,535,046)	-	4,105,898,198
	2072	4,105,898,198	198,314,883	(110,661,197)	-	4,193,551,884
	2073	4,193,551,884	202,548,556	(125,734,387)	-	4,270,366,053
	2074	4,270,366,053	206,258,680	(106,961,075)	-	4,369,663,658
	2075	4,369,663,658	211,054,755	(130,924,313)	-	4,449,794,100
	2076	4,449,794,100	214,925,055	(144,159,660)	-	4,520,559,494
	2077	4,520,559,494	218,343,024	(84,871,609)	-	4,654,030,909
	2078	4,654,030,909	224,789,693	(88,096,592)	-	4,790,724,009
	2079	4,790,724,009	231,391,970	(91,446,102)	-	4,930,669,877
	2080	4,930,669,877	238,151,355	(95,185,212)	-	5,073,636,020
	2081	5,073,636,020	245,056,620	(98,538,072)	-	5,220,154,567
	2082	5,220,154,567	252,133,466	(102,291,444)	-	5,369,996,589
	2083	5,369,996,589	259,370,835	(106,189,592)	-	5,523,177,832
	2084	5,523,177,832	266,769,489	(110,541,448)	-	5,679,405,874
	2085	5,679,405,874	274,315,304	(114,445,540)	-	5,839,275,637
	2086	5,839,275,637	282,037,013	(118,814,214)	-	6,002,498,437
	2087	6,002,498,437	289,920,674	(123,352,914)	-	6,169,066,197
	2088	6,169,066,197	297,965,897	(128,418,139)	-	6,338,613,955
	2089	6,338,613,955	306,155,054	(132,964,401)	-	6,511,804,608
	2090	6,511,804,608	314,520,163	(138,052,113)	-	6,688,272,658
	2091	6,688,272,658	323,043,569	(143,336,961)	-	6,867,979,266
	2092	6,867,979,266	331,723,399	(149,235,097)	-	7,050,467,568
	2093	7,050,467,568	340,537,584	(154,530,725)	-	7,236,474,427
	2094	7,236,474,427	349,521,715	(160,456,461)	-	7,425,539,680
	2095	7,425,539,680	358,653,567	(166,612,648)	-	7,617,580,599
	2096	7,617,580,599	367,929,143	(173,482,016)	-	7,812,027,726
	2097	7,812,027,726	377,320,939	(179,652,790)	-	8,009,695,875
	2098	8,009,695,875	386,868,311	(205,592,298)	-	8,190,971,888
	2099	8,190,971,888	395,623,942	(217,348,661)	-	8,369,247,169
	2100	8,369,247,169	404,234,638	(222,085,423)	-	8,551,396,384
	2101	8,551,396,384	413,032,445	(229,970,753)	-	8,734,458,077
	2102	8,734,458,077	421,874,325	(238,733,629)	-	8,917,598,772

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2103	8,917,598,772	430,720,021	(252,337,374)	-	9,095,981,420
2104	9,095,981,420	439,335,903	(257,930,271)	-	9,277,387,051
2105	9,277,387,051	448,097,795	(1,222,800,300)	-	8,502,684,546
2106	8,502,684,546	410,679,664	(1,770,249,187)	-	7,143,115,022
2107	7,143,115,022	345,012,456	(2,243,272,007)	-	5,244,855,471
2108	5,244,855,471	253,326,519	(1,749,272,895)	-	3,748,909,095
2109	3,748,909,095	181,072,309	(1,743,912,402)	-	2,186,069,003
2110	2,186,069,003	105,587,133	(1,194,162,328)	-	1,097,493,808
2111	1,097,493,808	53,008,951	(813,032,054)	-	337,470,704
2112	337,470,704	16,299,835	(353,770,539)	-	(0)

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EXTERNAL FUND CALCULATION

Prairie Island Unit 1

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	374,367,055	9,584,112	-	24,632	383,975,799
2018	383,975,799	19,660,822	-	49,264	403,685,885
2019	403,685,885	20,669,978	-	49,264	424,405,128
2020	424,405,128	21,730,804	-	49,264	446,185,196
2021	446,185,196	22,816,899	-	(1,085,269)	467,916,827
2022	467,916,827	23,929,559	-	(1,085,269)	490,761,117
2023	490,761,117	25,099,186	-	(1,085,269)	514,775,035
2024	514,775,035	26,328,699	-	(1,085,269)	540,018,465
2025	540,018,465	27,621,163	-	(1,085,269)	566,554,359
2026	566,554,359	28,979,800	-	(1,085,269)	594,448,891
2027	594,448,891	30,408,000	-	(1,085,269)	623,771,623
2028	623,771,623	31,909,324	-	(1,085,269)	654,595,678
2029	654,595,678	33,487,516	-	(1,085,269)	686,997,926
2030	686,997,926	35,146,511	-	(1,085,269)	721,059,168
2031	721,059,168	36,890,447	-	(1,085,269)	756,864,346
2032	756,864,346	38,723,672	-	(1,085,269)	794,502,749
2033	794,502,749	40,650,758	-	(1,085,269)	834,068,238
2034	834,068,238	42,676,511	-	(1,085,269)	875,659,481
2035	875,659,481	44,805,983	-	(1,085,269)	919,380,195
2036	919,380,195	47,044,483	-	(1,085,269)	965,339,409
2037	965,339,409	49,397,595	-	(1,085,269)	1,013,651,736
2038	1,013,651,736	51,871,186	-	(1,085,269)	1,064,437,653
2039	1,064,437,653	54,471,425	-	(1,085,269)	1,117,823,809
2040	1,117,823,809	57,204,796	-	(1,085,269)	1,173,943,337
2041	1,173,943,337	60,078,116	-	(1,085,269)	1,232,936,185
2042	1,232,936,185	63,098,550	-	(1,085,269)	1,294,949,466
2043	1,294,949,466	66,273,630	-	(1,085,269)	1,360,137,827
2044	1,360,137,827	69,611,274	-	(1,085,269)	1,428,663,832
2045	1,428,663,832	73,119,805	-	(1,085,269)	1,500,698,369
2046	1,500,698,369	76,807,974	-	(1,085,269)	1,576,421,074
2047	1,576,421,074	80,684,976	-	(1,085,269)	1,656,020,782
2048	1,656,020,782	84,760,481	-	(1,085,269)	1,739,695,994
2049	1,739,695,994	89,044,652	-	(1,085,269)	1,827,655,378
2050	1,827,655,378	93,548,172	-	(1,085,269)	1,920,118,282
2051	1,920,118,282	98,282,273	-	(1,085,269)	2,017,315,286
2052	2,017,315,286	103,258,760	-	(1,085,269)	2,119,488,778
2053	2,119,488,778	102,141,835	(65,994,324)	(727,130)	2,154,909,159
2054	2,154,909,159	103,866,621	(208,862,585)	-	2,049,913,196
2055	2,049,913,196	98,805,816	(88,516,961)	-	2,060,202,050
2056	2,060,202,050	99,301,739	(74,966,746)	-	2,084,537,043

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EXTERNAL FUND CALCULATION

External Levelized	2057	2,084,537,043	100,474,685	(77,388,016)	-	2,107,623,712
	2058	2,107,623,712	101,587,463	(109,904,991)	-	2,099,306,183
	2059	2,099,306,183	101,186,558	(311,266,301)	-	1,889,226,441
	2060	1,889,226,441	91,060,714	(30,588,591)	-	1,949,698,564
	2061	1,949,698,564	93,975,471	(31,565,385)	-	2,012,108,650
	2062	2,012,108,650	96,983,637	(32,670,872)	-	2,076,421,414
	2063	2,076,421,414	100,083,512	(33,817,586)	-	2,142,687,341
	2064	2,142,687,341	103,277,530	(35,109,710)	-	2,210,855,160
	2065	2,210,855,160	106,563,219	(36,240,101)	-	2,281,178,277
	2066	2,281,178,277	109,952,793	(37,518,921)	-	2,353,612,149
	2067	2,353,612,149	113,444,106	(38,845,022)	-	2,428,211,233
	2068	2,428,211,233	117,039,781	(40,339,316)	-	2,504,911,698
	2069	2,504,911,698	120,736,744	(41,647,782)	-	2,584,000,660
	2070	2,584,000,660	124,548,832	(43,127,479)	-	2,665,422,013
	2071	2,665,422,013	128,473,341	(44,662,507)	-	2,749,232,847
	2072	2,749,232,847	132,513,023	(46,390,912)	-	2,835,354,958
	2073	2,835,354,958	136,664,109	(49,573,616)	-	2,922,445,451
	2074	2,922,445,451	140,861,871	(53,065,034)	-	3,010,242,288
	2075	3,010,242,288	145,093,678	(54,956,309)	-	3,100,379,658
	2076	3,100,379,658	149,438,299	(57,994,326)	-	3,191,823,632
	2077	3,191,823,632	153,845,899	(58,002,994)	-	3,287,666,537
	2078	3,287,666,537	158,465,527	(63,027,367)	-	3,383,104,696
	2079	3,383,104,696	163,065,646	(62,238,730)	-	3,483,931,613
	2080	3,483,931,613	167,925,504	(63,607,824)	-	3,588,249,292
	2081	3,588,249,292	172,953,616	(67,879,670)	-	3,693,323,238
	2082	3,693,323,238	178,018,180	(70,323,587)	-	3,801,017,830
	2083	3,801,017,830	183,209,059	(71,701,333)	-	3,912,525,556
	2084	3,912,525,556	188,583,732	(75,696,420)	-	4,025,412,868
	2085	4,025,412,868	194,024,900	(78,216,952)	-	4,141,220,817
	2086	4,141,220,817	199,606,843	(79,769,645)	-	4,261,058,016
	2087	4,261,058,016	205,382,996	(83,983,679)	-	4,382,457,332
	2088	4,382,457,332	211,234,443	(87,269,769)	-	4,506,422,007
	2089	4,506,422,007	217,209,541	(88,780,409)	-	4,634,851,138
	2090	4,634,851,138	223,399,825	(93,470,899)	-	4,764,780,065
	2091	4,764,780,065	229,662,399	(96,873,741)	-	4,897,568,723
	2092	4,897,568,723	236,062,812	(100,680,833)	-	5,032,950,703
	2093	5,032,950,703	242,588,224	(104,068,207)	-	5,171,470,720
	2094	5,171,470,720	249,264,889	(107,870,100)	-	5,312,865,509
	2095	5,312,865,509	256,080,118	(123,759,600)	-	5,445,186,026
	2096	5,445,186,026	262,457,966	(116,227,745)	-	5,591,416,247
	2097	5,591,416,247	269,506,263	(120,157,405)	-	5,740,765,105
	2098	5,740,765,105	276,704,878	(95,517,156)	-	5,921,952,828
	2099	5,921,952,828	285,438,126	(99,105,680)	-	6,108,285,274
	2100	6,108,285,274	294,419,350	(103,113,576)	-	6,299,591,048
	2101	6,299,591,048	303,640,289	(106,700,764)	-	6,496,530,572
	2102	6,496,530,572	313,132,774	(110,717,892)	-	6,698,945,453

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EXTERNAL FUND CALCULATION

2103	6,698,945,453	322,889,171	(114,888,871)	-	6,906,945,753
2104	6,906,945,753	332,914,785	(119,546,315)	-	7,120,314,223
2105	7,120,314,223	343,199,146	(123,717,087)	-	7,339,796,282
2106	7,339,796,282	353,778,181	(128,387,108)	-	7,565,187,355
2107	7,565,187,355	364,642,031	(354,661,844)	-	7,575,167,542
2108	7,575,167,542	365,123,076	(1,340,861,441)	-	6,599,429,176
2109	6,599,429,176	318,092,486	(2,076,067,200)	-	4,841,454,463
2110	4,841,454,463	233,358,105	(1,872,417,744)	-	3,202,394,824
2111	3,202,394,824	154,355,431	(1,422,943,812)	-	1,933,806,442
2112	1,933,806,442	93,209,471	(546,793,735)	-	1,480,222,178
2113	1,480,222,178	71,346,709	(668,957,109)	-	882,611,778
2114	882,611,778	42,541,888	(539,015,148)	-	386,138,518
2115	386,138,518	18,611,877	(404,750,394)	-	0

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EXTERNAL FUND CALCULATION

Prairie Island Unit 2

	Beginning Balance	Assumed Interest	Decommissioning Payment	Annuity	Ending Balance
2017	420,208,967	10,803,157	-	294,670	431,306,795
2018	431,306,795	22,184,315	-	589,341	454,080,451
2019	454,080,451	23,354,881	-	589,341	478,024,673
2020	478,024,673	24,585,614	-	589,341	503,199,628
2021	503,199,628	25,702,425	-	(6,304,910)	522,597,142
2022	522,597,142	26,699,457	-	(6,304,910)	542,991,689
2023	542,991,689	27,747,737	-	(6,304,910)	564,434,515
2024	564,434,515	28,849,898	-	(6,304,910)	586,979,503
2025	586,979,503	30,008,710	-	(6,304,910)	610,683,303
2026	610,683,303	31,227,086	-	(6,304,910)	635,605,478
2027	635,605,478	32,508,085	-	(6,304,910)	661,808,653
2028	661,808,653	33,854,929	-	(6,304,910)	689,358,671
2029	689,358,671	35,271,000	-	(6,304,910)	718,324,760
2030	718,324,760	36,759,856	-	(6,304,910)	748,779,707
2031	748,779,707	38,325,241	-	(6,304,910)	780,800,037
2032	780,800,037	39,971,086	-	(6,304,910)	814,466,212
2033	814,466,212	41,701,527	-	(6,304,910)	849,862,829
2034	849,862,829	43,520,913	-	(6,304,910)	887,078,832
2035	887,078,832	45,433,816	-	(6,304,910)	926,207,738
2036	926,207,738	47,445,042	-	(6,304,910)	967,347,869
2037	967,347,869	49,559,644	-	(6,304,910)	1,010,602,603
2038	1,010,602,603	51,782,938	-	(6,304,910)	1,056,080,630
2039	1,056,080,630	54,120,508	-	(6,304,910)	1,103,896,228
2040	1,103,896,228	56,578,230	-	(6,304,910)	1,154,169,547
2041	1,154,169,547	59,162,279	-	(6,304,910)	1,207,026,916
2042	1,207,026,916	61,879,147	-	(6,304,910)	1,262,601,152
2043	1,262,601,152	64,735,663	-	(6,304,910)	1,321,031,905
2044	1,321,031,905	67,739,004	-	(6,304,910)	1,382,465,999
2045	1,382,465,999	70,896,716	-	(6,304,910)	1,447,057,804
2046	1,447,057,804	74,216,735	-	(6,304,910)	1,514,969,629
2047	1,514,969,629	77,707,403	-	(6,304,910)	1,586,372,121
2048	1,586,372,121	81,377,491	-	(6,304,910)	1,661,444,702
2049	1,661,444,702	85,236,221	-	(6,304,910)	1,740,376,013
2050	1,740,376,013	89,293,291	-	(6,304,910)	1,823,364,394
2051	1,823,364,394	93,558,894	-	(6,304,910)	1,910,618,377
2052	1,910,618,377	98,043,748	-	(6,304,910)	2,002,357,215
2053	2,002,357,215	102,759,125	-	(6,304,910)	2,098,811,429
2054	2,098,811,429	101,246,213	(29,938,170)	(5,233,076)	2,164,886,397
2055	2,164,886,397	104,564,013	(218,808,713)	-	2,050,641,696
2056	2,050,641,696	99,045,994	(124,349,207)	-	2,025,338,483

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SAFSTOR Method
20-Year Life Extension **Proposed**

EXTERNAL FUND CALCULATION

External Levelized	2057	2,025,338,483	97,823,849	(67,639,969)	-	2,055,522,362
	2058	2,055,522,362	99,281,730	(99,798,689)	-	2,055,005,404
	2059	2,055,005,404	99,256,761	(302,666,816)	-	1,851,595,349
	2060	1,851,595,349	89,432,055	(30,834,593)	-	1,910,192,811
	2061	1,910,192,811	92,262,313	(31,820,406)	-	1,970,634,717
	2062	1,970,634,717	95,181,657	(32,935,968)	-	2,032,880,406
	2063	2,032,880,406	98,188,124	(34,093,157)	-	2,096,975,373
	2064	2,096,975,373	101,283,911	(35,396,963)	-	2,162,862,321
	2065	2,162,862,321	104,466,250	(36,537,896)	-	2,230,790,675
	2066	2,230,790,675	107,747,190	(37,828,493)	-	2,300,709,372
	2067	2,300,709,372	111,124,263	(39,166,838)	-	2,372,666,797
	2068	2,372,666,797	114,599,806	(40,674,788)	-	2,446,591,815
	2069	2,446,591,815	118,170,385	(41,995,577)	-	2,522,766,623
	2070	2,522,766,623	121,849,628	(43,489,044)	-	2,601,127,207
	2071	2,601,127,207	125,634,444	(45,038,390)	-	2,681,723,260
	2072	2,681,723,260	129,527,233	(46,782,756)	-	2,764,467,738
	2073	2,764,467,738	133,523,792	(49,979,873)	-	2,848,011,657
	2074	2,848,011,657	137,558,963	(53,487,390)	-	2,932,083,229
	2075	2,932,083,229	141,619,620	(55,395,404)	-	3,018,307,445
	2076	3,018,307,445	145,784,250	(58,452,083)	-	3,105,639,611
	2077	3,105,639,611	150,002,393	(58,477,603)	-	3,197,164,401
	2078	3,197,164,401	154,423,041	(63,520,802)	-	3,288,066,639
	2079	3,288,066,639	158,813,619	(62,751,743)	-	3,384,128,514
	2080	3,384,128,514	163,453,407	(64,142,659)	-	3,483,439,262
	2081	3,483,439,262	168,250,116	(68,434,212)	-	3,583,255,166
	2082	3,583,255,166	173,071,225	(70,900,147)	-	3,685,426,244
	2083	3,685,426,244	178,006,088	(72,300,787)	-	3,791,131,545
	2084	3,791,131,545	183,111,654	(76,321,393)	-	3,897,921,805
	2085	3,897,921,805	188,269,623	(78,864,979)	-	4,007,326,449
	2086	4,007,326,449	193,553,867	(80,443,419)	-	4,120,436,898
	2087	4,120,436,898	199,017,102	(84,684,234)	-	4,234,769,766
	2088	4,234,769,766	204,539,380	(88,000,167)	-	4,351,308,978
	2089	4,351,308,978	210,168,224	(89,537,771)	-	4,471,939,431
	2090	4,471,939,431	215,994,675	(94,258,382)	-	4,593,675,724
	2091	4,593,675,724	221,874,537	(97,692,545)	-	4,717,857,716
	2092	4,717,857,716	227,872,528	(101,534,546)	-	4,844,195,698
	2093	4,844,195,698	233,974,652	(104,953,464)	-	4,973,216,886
	2094	4,973,216,886	240,206,376	(108,790,590)	-	5,104,632,672
	2095	5,104,632,672	246,553,758	(124,716,733)	-	5,226,469,697
	2096	5,226,469,697	252,438,486	(117,225,711)	-	5,361,682,472
	2097	5,361,682,472	258,969,263	(121,192,278)	-	5,499,459,457
	2098	5,499,459,457	265,623,892	(38,503,792)	-	5,726,579,557
	2099	5,726,579,557	276,593,793	(39,781,913)	-	5,963,391,437
	2100	5,963,391,437	288,031,806	(41,216,634)	-	6,210,206,609
	2101	6,210,206,609	299,952,979	(42,471,564)	-	6,467,688,024
	2102	6,467,688,024	312,389,332	(43,885,874)	-	6,736,191,482

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EXTERNAL FUND CALCULATION

2103	6,736,191,482	325,358,049	(45,348,698)	-	7,016,200,832
2104	7,016,200,832	338,882,500	(46,990,057)	-	7,308,093,275
2105	7,308,093,275	352,980,905	(48,426,958)	-	7,612,647,222
2106	7,612,647,222	367,690,861	(50,046,016)	-	7,930,292,067
2107	7,930,292,067	383,033,107	(51,721,076)	-	8,261,604,098
2108	8,261,604,098	399,035,478	(363,913,701)	-	8,296,725,875
2109	8,296,725,875	400,731,860	(930,185,861)	-	7,767,271,873
2110	7,767,271,873	375,159,231	(2,608,600,062)	-	5,533,831,043
2111	5,533,831,043	267,284,039	(2,139,806,354)	-	3,661,308,729
2112	3,661,308,729	176,841,212	(1,987,223,886)	-	1,850,926,054
2113	1,850,926,054	89,399,728	(861,472,551)	-	1,078,853,232
2114	1,078,853,232	52,108,611	(659,104,503)	-	471,857,340
2115	471,857,340	22,790,710	(494,648,050)	-	(0)

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Historical Decommissioning Accruals and Recovery **Schedule F.21**
Minnesota Retail Jursidiction **Page 1 of 1**

Decommissioning Filings

Year of Filing	Docket No.	Date of Filing	Start Date of Accrual	End Date of Accrual	Accrual Amount
2005	E002/M-05-1648	10/11/2005	1/1/2006	12/31/2008	$32,016,646
2008	E002/M-08-1201	10/13/2008	1/1/2009	12/31/2011	-
2011	E002/M-11-939	12/30/2011	1/1/2012	12/31/2012	-
			1/1/2013	12/31/2014	14,189,132
2014	E002/M-14-761	12/1/2014	1/1/2015	12/31/2015	14,189,132
			1/1/2016	12/31/2018	14,030,831
2017	E002/M-17-828 (pending)	12/1/2017	1/1/2019	12/31/2021	14,030,831

Rate Cases

Year of Filing	Docket No.	Test Year	Accrual Amount	Recovery Amount
2005	E002/GR-05-1428	2006	$32,017,000	$32,017,000
2008	E002/GR-08-1065	2009	-	-
2010	E002/GR-10-971	2011	-	-
2012	E002/GR-12-961 *	2013	14,189,132	-
2013	E002/GR-13-868 *	2014/2015	14,189,132	-
2015	E002/GR-15-826	2016-2018	14,030,831	14,030,831

* Accrual was offset by DOE Refund

Xcel Energy
Nuclear Decommissioning Customer Rate Impact

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Schedule G

2019 Accrual Amounts

Current Accrual	14,030,831
32-Year Scenario (DECON)	28,483,732
60-Year Scenario (DECON) - No Recasking	45,593,406
60-Year Scenario (DECON) - No Recasking -5 years	87,157,100
60-Year Scenario (DECON) - No Recasking +20 years	(1,849,439)
60-Year Scenario (DECON) - With Recasking	56,932,276
60-Year Scenario (SAFSTOR) - No Recasking	24,896,813
60-Year Scenario (SAFSTOR) - No Recasking -5 years	55,836,840
60-Year Scenario (SAFSTOR) - No Recasking +20 years	(12,515,906)
100-Year Scenario (DECON)	107,438,894
200-Year Scenario (DECON)	147,056,491

Analysis by Customer Class		**Residential**	**C&I Non-Demand**	**C&I Demand**	**Lighting**	**Total**
Stratification[1]						
Capacity Component (D10S)	19.3%	35.53%	3.41%	61.06%	0.00%	100.00%
Energy Component (E8760)	80.7%	28.69%	3.16%	67.68%	0.47%	100.00%
Combined		**30.01%**	**3.21%**	**66.40%**	**0.38%**	**100.00%**
Combined Allocation to Class						
Current Accrual		4,210,669	450,144	9,316,800	53,218	14,030,831
32-Year Scenario (DECON)		8,548,002	913,829	18,913,865	108,036	28,483,732
60-Year Scenario (DECON) - No Recasking		13,682,636	1,462,750	30,275,088	172,931	45,593,406
60-Year Scenario (DECON) - No Recasking -5 years		26,155,950	2,796,218	57,874,354	330,578	87,157,100
60-Year Scenario (DECON) - No Recasking +20 years		(555,019)	(59,335)	(1,228,070)	(7,015)	(1,849,439)
60-Year Scenario (DECON) - With Recasking		17,085,444	1,826,530	37,804,363	215,938	56,932,276
60-Year Scenario (SAFSTOR) - No Recasking		7,471,564	798,752	16,532,067	94,431	24,896,813
60-Year Scenario (SAFSTOR) - No Recasking -5 years		16,756,703	1,791,385	37,076,968	211,784	55,836,840
60-Year Scenario (SAFSTOR) - No Recasking +20 years		(3,756,038)	(401,542)	(8,310,855)	(47,472)	(12,515,906)
100-Year Scenario (DECON)		32,242,541	3,446,908	71,341,940	407,505	107,438,894
200-Year Scenario (DECON)		44,131,830	4,717,940	97,648,951	557,771	147,056,491
Class MWh Sales[2]		**8,558,594**	**923,181**	**20,950,649**	**177,621**	**30,610,045**
Average Class Amount per kWh						
Current Accrual		0.000492	0.000488	0.000445	0.000300	
32-Year Scenario (DECON)		0.000999	0.000990	0.000903	0.000608	
60-Year Scenario (DECON) - No Recasking		0.001599	0.001584	0.001445	0.000974	
60-Year Scenario (DECON) - No Recasking -5 years		0.003056	0.003029	0.002762	0.001861	
60-Year Scenario (DECON) - No Recasking +20 years		(0.000065)	(0.000064)	(0.000059)	(0.000039)	
60-Year Scenario (DECON) - With Recasking		0.001996	0.001979	0.001804	0.001216	
60-Year Scenario (SAFSTOR) - No Recasking		0.000873	0.000865	0.000789	0.000532	
60-Year Scenario (SAFSTOR) - No Recasking -5 years		0.001958	0.001940	0.001770	0.001192	
60-Year Scenario (SAFSTOR) - No Recasking +20 years		(0.000439)	(0.000435)	(0.000397)	(0.000267)	
100-Year Scenario (DECON)		0.003767	0.003734	0.003405	0.002294	
200-Year Scenario (DECON)		0.005156	0.005111	0.004661	0.003140	
Average Customer Monthly kWh[2]		**629**	**891**	**37,098**	**3,370**	
Average Customer Monthly Amount						
Current Accrual		0.31	0.43	16.51	1.01	
32-Year Scenario (DECON)		0.63	0.88	33.50	2.05	
60-Year Scenario (DECON) - No Recasking		1.01	1.41	53.61	3.28	
60-Year Scenario (DECON) - No Recasking -5 years		1.92	2.70	102.46	6.27	
60-Year Scenario (DECON) - No Recasking +20 years		(0.04)	(0.06)	(2.19)	(0.13)	
60-Year Scenario (DECON) - With Recasking		1.26	1.76	66.92	4.10	
60-Year Scenario (SAFSTOR) - No Recasking		0.55	0.77	29.27	1.79	
60-Year Scenario (SAFSTOR) - No Recasking -5 years		1.23	1.73	65.66	4.02	
60-Year Scenario (SAFSTOR) - No Recasking +20 years		(0.28)	(0.39)	(14.73)	(0.90)	
100-Year Scenario (DECON)		2.37	3.33	126.32	7.73	
200-Year Scenario (DECON)		3.24	4.55	172.91	10.58	

(1) Docket No. E002/GR-15-826, Nuclear Stratification Percentages (Peppin Direct Testimony, Table 6) (Peppin Testimony, Schedule 4, Pages 13-14)
(2) Year Ending December 31, 2017. Sales and Revenue by Rate Schedule (Huso Direct Testimony, Schedule 4, Page 1)

Xcel Energy
Nuclear Decommissioning Customer Rate Impact

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2021 Accrual Amounts

Current Accrual	14,030,831
32-Year Scenario (DECON)	31,460,634
60-Year Scenario (DECON) - No Recasking	53,019,302
60-Year Scenario (DECON) - No Recasking -5 years	115,873,173
60-Year Scenario (DECON) - No Recasking +20 years	(3,814,517)
60-Year Scenario (DECON) - With Recasking	67,116,594
60-Year Scenario (SAFSTOR) - No Recasking	27,138,020
60-Year Scenario (SAFSTOR) - No Recasking -5 years	71,561,676
60-Year Scenario (SAFSTOR) - No Recasking +20 years	(15,976,435)
100-Year Scenario (DECON)	129,741,425
200-Year Scenario (DECON)	179,327,759

Analysis by Customer Class		**Residential**	**C&I Non-Demand**	**C&I Demand**	**Lighting**	**Total**
Stratification[1]						
Capacity Component (D10S)	19.3%	35.53%	3.41%	61.06%	0.00%	100.00%
Energy Component (E8760)	80.7%	28.69%	3.16%	67.68%	0.47%	100.00%
Combined		**30.01%**	**3.21%**	**66.40%**	**0.38%**	**100.00%**
Combined Allocation to Class						
Current Accrual		4,210,669	450,144	9,316,800	53,218	14,030,831
32-Year Scenario (DECON)		9,441,374	1,009,336	20,890,597	119,327	31,460,634
60-Year Scenario (DECON) - No Recasking		15,911,156	1,700,992	35,206,057	201,097	53,019,302
60-Year Scenario (DECON) - No Recasking -5 years		34,773,678	3,717,501	76,942,498	439,495	115,873,173
60-Year Scenario (DECON) - No Recasking +20 years		(1,144,741)	(122,379)	(2,532,929)	(14,468)	(3,814,517)
60-Year Scenario (DECON) - With Recasking		20,141,770	2,153,268	44,566,989	254,567	67,116,594
60-Year Scenario (SAFSTOR) - No Recasking		8,144,153	870,656	18,020,281	102,932	27,138,020
60-Year Scenario (SAFSTOR) - No Recasking -5 years		21,475,745	2,295,877	47,518,627	271,426	71,561,676
60-Year Scenario (SAFSTOR) - No Recasking +20 years		(4,794,547)	(512,564)	(10,608,727)	(60,597)	(15,976,435)
100-Year Scenario (DECON)		38,935,557	4,162,429	86,151,342	492,096	129,741,425
200-Year Scenario (DECON)		53,816,476	5,753,283	119,077,828	680,172	179,327,759
Class MWh Sales[2]		**8,558,594**	**923,181**	**20,950,649**	**177,621**	**30,610,045**
Average Class Amount per kWh						
Current Accrual		0.000492	0.000488	0.000445	0.000300	
32-Year Scenario (DECON)		0.001103	0.001093	0.000997	0.000672	
60-Year Scenario (DECON) - No Recasking		0.001859	0.001843	0.001680	0.001132	
60-Year Scenario (DECON) - No Recasking -5 years		0.004063	0.004027	0.003673	0.002474	
60-Year Scenario (DECON) - No Recasking +20 years		(0.000134)	(0.000133)	(0.000121)	(0.000081)	
60-Year Scenario (DECON) - With Recasking		0.002353	0.002332	0.002127	0.001433	
60-Year Scenario (SAFSTOR) - No Recasking		0.000952	0.000943	0.000860	0.000580	
60-Year Scenario (SAFSTOR) - No Recasking -5 years		0.002509	0.002487	0.002268	0.001528	
60-Year Scenario (SAFSTOR) - No Recasking +20 years		(0.000560)	(0.000555)	(0.000506)	(0.000341)	
100-Year Scenario (DECON)		0.004549	0.004509	0.004112	0.002770	
200-Year Scenario (DECON)		0.006288	0.006232	0.005684	0.003829	
Average Customer Monthly kWh[2]		**629**	**891**	**37,098**	**3,370**	
Average Customer Monthly Amount						
Current Accrual		$0.31	$0.43	$16.51	$1.01	
32-Year Scenario (DECON)		$0.69	$0.97	$36.99	$2.26	
60-Year Scenario (DECON) - No Recasking		$1.17	$1.64	$62.32	$3.82	
60-Year Scenario (DECON) - No Recasking -5 years		$2.56	$3.59	$136.26	$8.34	
60-Year Scenario (DECON) - No Recasking +20 years		($0.08)	($0.12)	($4.49)	($0.27)	
60-Year Scenario (DECON) - With Recasking		$1.48	$2.08	$78.91	$4.83	
60-Year Scenario (SAFSTOR) - No Recasking		$0.60	$0.84	$31.90	$1.95	
60-Year Scenario (SAFSTOR) - No Recasking -5 years		$1.58	$2.21	$84.14	$5.15	
60-Year Scenario (SAFSTOR) - No Recasking +20 years		($0.35)	($0.49)	($18.77)	($1.15)	
100-Year Scenario (DECON)		$2.86	$4.02	$152.55	$9.34	
200-Year Scenario (DECON)		$3.96	$5.55	$210.86	$12.90	

(1) Docket No. E002/GR-15-826, Nuclear Stratification Percentages (Peppin Direct Testimony, Table 6) (Peppin Testimony, Schedule 4, Pages 13-14)
(2) Year Ending December 31, 2017. Sales and Revenue by Rate Schedule (Huso Direct Testimony, Schedule 4, Page 1)

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EOL Nuclear Fuel Schedule H
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End-of-life nuclear fuel refers to the book recovery of unused nuclear fuel at the time of reactor shutdown. The unit of production method assures full recovery. However, the Company does not want a dramatic increase in recovery in the final period. To mitigate this possibility, the increase over usual amortization levels was isolated and a sinking fund method was established to spread this amount over the remaining life of the nuclear units. The Company received approval from the Minnesota Public Utilities Commission to recover for end-of-life nuclear fuel in 1992[1].

At the end of the final period or the last cycle, each reactor unit will contain fuel that is partially burned and fuel that is fully burned. Normally, the partially burned fuel would have been recovered in future periods, but without those future periods, the unit of production method takes the remaining depreciation in the last several cycles prior to permanent shutdown causing a spike in amortization expense. To eliminate this spike, the remaining recovery associated with the partially burned fuel becomes the amount to recover over the remaining life of the plant, using the sinking fund method.

Before quantifying this spike through the use of in-house plant specific core design models, fuel management strategies were developed to minimize the amount of unburned fuel in each reactor at end of licensed life (EOLL). As the reactors at Prairie Island and Monticello approach their EOLL, a spike in fuel expense is indicated since all useful energy in the fuel will not be recovered. By minimizing the amount of useful energy remaining in the fuel at EOLL, the spikes in fuel expense in the last several cycles of operation are lowered, thereby reducing the overall dollar amount to be recovered prior to permanent shutdown.

The strategy for Prairie Island Unit 1 and Unit 2 uses the ability to interchange fuel between the two reactors and the re-insertion of fuel burned from previous cycles. In this EOLL study, the last cycle of Unit 1 (Cycle 38 with an August 9, 2033 shutdown) utilizes 20 fresh assemblies. The last cycle for Unit 2 (Cycle 38 with an October 29, 2034 shutdown) utilizes 53 burned assemblies discharged from Unit 1 that contained the most useful remaining energy. Re-using these burned assemblies from Unit 1 permits more energy to be extracted from these assemblies resulting in reduced EOLL expense. Moreover, it eliminates the need to purchase a large number of fresh fuel assemblies for the final cycle of Unit 2. As such, 12 fresh assemblies are loaded

[1] The Commission's Order received on February 25, 1992, MPUC Docket No. E002/D-90-184, Triennial Review of Nuclear Decommissioning.

in the last cycle of Unit 2 based on operational considerations. This significantly reduces the EOLL cost for the combined Prairie Island units.

Since the previous EOLL study, both Prairie Island Units have transitioned to an almost two year cycle. This reduced the total cycles through the end of life from 39 cycles to 38 cycles for both units. The last cycle for both units used more fresh assemblies (4 more for each unit) compared to the previous EOLL study but resulted in one less refueling outage which reduces the fuel expense required for the life of both plants.

Monticello is on a two-year operating cycle and was uprated from its previous thermal capacity of 1,775 megawatt thermal ("MWth") to 2,004 MWth in 2014. The current operating conditions have resulted in typical cycle lengths ranging from approximately 15,200 to 15,800 megawatt days per metric ton of uranium ("MWd/MTU") and requires between 148-164 fresh fuel assemblies to be loaded into the core each new cycle. Due to operational factors associated with the two-year cycle lengths, the current EOLL study for Monticello does not utilize the reinsertion method employed by Prairie Island to reduce the number of fresh assemblies in the final cycle.

The multi-cycle Monticello fuel management strategy in this EOLL study loads 120 fresh assemblies into Monticello's final cycle (Cycle 35 with September 7, 2030 shutdown) compared with 100 in the 2014 Filing. Thus, 20 additional assemblies are loaded in the last cycle compared to the previous EOLL study due to the average enrichment being drastically lowered from 4.027 to 2.619 weight percent. The cost of a reload is mainly driven by the cost of the quantity of uranium, conversion and enrichment needed to build the fuel assemblies. By lowering the average enrichment in a reload you reduce the amount of uranium, conversion and enrichment needed to support the reload. Cycle 35 has a shortened cycle length requirement of about 10,470 MWd/MTU. The combination of shorter cycle length and fresh fuel loading in the last cycle results in about 100 days of gradual power coast down at the end of license life in order to minimize the fresh fuel reload costs.

Note that some of the decrease is also due to the drop in the unit price forecast for uranium and conversion, with a slight increase in the forecast price for enrichment. For each cycle through the end of life the uranium cost has dropped between $25 and $35 per pound which results in the lower overall cost to be recovered at the point of shutdown.

Since the strategy is to manage the fuel for the entire station at Prairie Island as indicated by the plan to re-insert partially burned fuel from Unit 1 into Unit 2, only

one net figure is shown for the Prairie Island Station. The amounts below represent the total cost to be recovered, and do not take into account the amounts already collected to date. The result of this analysis produced the following future amounts to be recovered:

Amount to Be Recovered	
Monticello	$52,856,869
Prairie Island	70,018,922
	$122,875,791

This projected recovery of $122,875,791 compares to $127,047,569 in the 2014 Filing. For the most part, this $4,171,778 decrease in the amount to recover is brought about by the following factors:

- Improved fuel utilization in the updated multi-cycle core designs close to EOLL
- Lower projected nuclear fuel commodity prices throughout the forecast period

The remaining life is the same as was used for decommissioning. The internal rate of return is the the weighted cost of capital from the MYRP. The after tax internal rate of return is 6.16 percent based on an approved rate of return of 7.08 percent using a 40.85 percent tax rate for the debt component.

The proposed 2019 accrual for total Company is $2,777,148. Applying the Minnesota jurisdictional factor of 73.4886 percent to this total Company amount, the result is a Minnesota jurisdictional amount of $2,040,887. This is a decrease of $372,402 over the present 2019 Minnesota jurisdictional accrual of $2,413,289. Therefore, the Company requests a 2019 accrual for EOL nuclear fuel of $2,040,887 for the MN Jurisdiction.

Schedule H contains the accrual worksheets supporting the end-of-life nuclear fuel numbers in the main document, the various sections of which are listed in the table below.

Xcel Energy
EOL Nuclear Fuel

Docket No. E002/M-17-828
Schedule H
Page 4 of 4

EOL Nuclear Fuel Supporting Schedules

H.1 Present to Proposed Accrual Comparison

H.2 2021 EOL Nuclear Fuel Accrual (Proposed)

H.3 2021 EOL Nuclear Fuel Accrual (Present)

Xcel Energy
End-of-Life Nuclear Fuel Accrual
Minnesota Retail Jurisdiction
January - December 2019

Docket No. E002/M-17-828
Schedule H.1
Page 1 of 1

Current Assumptions

ANNUAL ACCRUAL

Generating Plant	Sinking Fund Rate	Remaining Life 1/1/19	Amount to Recover	Amount Recovered	Annual Accrual
	(1)	(2)	(3)	(4)	(5)
Monticello	6.51%	11.75	$73,999,696	$35,490,547	$2,283,300
Prairie Island	6.51%	15.30	53,047,873	28,082,941	1,000,596
			$127,047,569	$63,573,488	$3,283,896

INPUT DATA

Tax Rate 41.37% (a)

Rate of Return - Internal

	Percent	Cost	Weight	
Short-Term	2.14	0.68	0.01	
Long-Term	45.30	5.02	2.27	
Total Debt	47.44		2.28	(c)
Preferred	0.00	0.00	0.00	
Common	52.56	9.83	5.17	
Total	100.00		7.45	(d)

After-Tax Rate 6.51% (e)

NOTES

Input Data

(e) = (d) - [(c) x (a)]
(2) = Remaining life based on E,G002/D-15-46
(3) = Final Core Analysis from 2014 filing

Annual Accrual

(5) = {[(3) - (4)] x (1)} / {[(1 + (1)) ^ (2)] -1}

Xcel Energy Docket No. E002/M-17-828
Premature Risk Investigation Schedule I
Page 1 of 7

This section discusses the issues surrounding premature decommissioning of nuclear generating facilities, which can be either accident or non-accident related. Presently, insurance is unavailable for non-accident related premature decommissioning such as those caused by regulatory directives. Therefore, the insurance analysis deals with accident related premature decommissioning.

The Company has insurance for accident-related premature decommissioning, covering property, liability, and replacement energy costs. In 1981, an internal sinking fund for the accrual of nuclear decommissioning costs was established. In 1990, an external fund was also created. In 2005, all internal funds were transferred to external funds. Further, in 2006 the Company established an external escrow fund. In 2016 the external escrow fund was transferred to the Qualified Trust, in accordance with the order in the 2014 Filing. Amounts have been accumulating in the Qualified Trust and would apply to all premature decommissioning expenses. The total fund accumulation as of June 30, 2017, for the Minnesota Jurisdiction is approximately $1,151 million.

Availability of Insurance

In the event of an accident-related premature decommissioning, the Company's property insurance coverage would apply to any resulting property damage and the cost of site decontamination and clean up. Insurance coverage for public liability and business interruption also would apply, if necessary. Marsh USA, a commercial nuclear insurance broker, is also the Company's insurance consultant and assists in providing the proper insurance coverage.

Property Insurance

The Company maintains property insurance in the amount of $2.25 billion per site. The insurance is currently provided by Nuclear Electric Insurance Limited (NEIL) in the form of two insurance policies per site. These insurance policies cover property damage to the Company's nuclear facilities plus site decontamination clean up caused by an accident.

The primary policy provides coverage limits of $1.5 billion per site; the excess policy provides an additional $750 million of insurance limits on a combined basis. There is a $5 million deductible per loss that would have to be satisfied. NEIL, a mutual insurance company owned by the insured utilities, including the Company, initiated a program in November 1981 to offer additional nuclear property insurance for each site. After receiving the approval of the Commission

in Docket No. E002/M-81-560, the Company purchased $118 million of NEIL nuclear property insurance.

Public Liability Insurance

The Price-Anderson liability provisions of the Atomic Energy Act of 1954 (Act) previously set a limit of $640 million for public liability claims that could arise from a nuclear incident. In August 1988, an extension of the Act was signed continuing the provision for another 15 years and increasing the liability limits. In August 2005, an additional 20 year extension of the Act was signed into law. The Company purchases the maximum available private insurance of $450 million to satisfy requirements under the Act. Claims above $450 million up to $13.436 billion would be satisfied by a NRC assessment against all owners of licensed nuclear generating units.

In the event of such an assessment by the NRC in response to an accident, the Company could be charged up to $127.314 million per accident for each of its three licensed nuclear reactors but limited to a maximum cash payment of $19.0 million per reactor per accident for any one year. The following is a breakdown of the coverage provided by the Act.

Price Anderson Act

Liability Coverage (Millions)		
Private Insurance	$450	
NRC Assessment	12,986	
	$13,436	Per accident
NRC Assessment (Millions)		
Per Unit Assessment	$127.314	
No. Of Nuclear Units	X 102	
Total Assessment	$12,986	

Accidental Outage Insurance

The Company purchases insurance to offset the potential additional outage-related expenses that would follow an accident at its nuclear generating plants.

The cost of replacement energy is included in this coverage. NEIL has provided this coverage since September 15, 1980.

NEIL accidental outage insurance provides coverage for a period of two years and forty-six and three-tenths (46.3) weeks following a 12-week waiting period deductible. Accidental outage insurance coverage amounts for the first 52 weeks are $3.75 million, per week, for each unit at Prairie Island and Monticello, respectively. Thereafter, payments would be reduced by 20 percent for another 98.3 weeks, at which time the coverage would be exhausted.

In the event of an accident at Prairie Island that causes outages at both units, accidental outage insurance payments for each unit would be 80 percent of the amount payable had the outage affected only one unit.

Accidental Outage Insurance

	Monticello	Prairie Island Unit 1	Prairie Island Unit 2
Deductible (weeks)	12	12	12
Coverage Dollar Amount (millions)*			
First Year	$3.75	$3.75	$3.75
Second Year	$3.0	$3.0	$3.0
Last 46.3 Weeks	$3.0	$3.0	$3.0
Total Limits (millions)	$490	$490	$490

*Coverage dollar amounts are in millions per week.

Federal Agency Programs and Studies

There are no known new federal agency programs or studies to report since the 2005 Triennial Nuclear Decommissioning Accrual filing.

Steps Taken To Minimize Possible Loss

The Company monitors NRC rulemaking to define methods for reducing risks associated with premature decommissioning. The Company purchases nuclear property and liability insurance from the commercial and captive markets in

amounts adequate to cover a maximum foreseeable loss. In addition, replacement power insurance is purchased to cover the cost of replacing megawatt hours lost while a unit is shut down.

Additionally, with Commission approval, the Company has accrued funds in an internal sinking fund for future decommissioning expenses since 1981. The internal fund amounts for the Minnesota Jurisdiction were transferred to the external fund under an accelerated schedule, with completion in 2005. The potential expense of a premature, non-accident related nuclear decommissioning would be partially offset by the external fund accumulations.

The Company's decommissioning fund plan and insurance levels are consistent with the NRC guidelines in NUREG-0584, Assuring the Availability of Funds for Decommissioning Nuclear Facilities, Page 49:

> Although premature decommissioning insurance would be preferable, as long as adequate levels of on-site accident decontamination insurance are maintained by licensees, the author believes that such insurance, together with an internal reserve, would provide a reasonable level of assurance.

Financial Ability to Withstand Premature Nuclear Decommissioning

The Commission attempts to coordinate several goals:

1. to ensure that funds are available at the time decommissioning takes place;
2. to avoid intergenerational subsidies which occur when ratepayers in one generation subsidize ratepayers in another generation; and
3. to avoid the rate shock that would result from placing an excessive burden on a specific group of ratepayers.

There are economic and financial consequences for any premature decommissioning in general and specific expenses associated with an accident-related decommissioning. The ability to manage these uncertainties will provide customers and shareholders with financial security.

Premature Decommissioning – General

There are five major financial consequences associated with any premature decommissioning. These consequences consist of the expense of

decommissioning, the replacement energy costs, the replacement capacity costs, the recovery of un-recovered plant investment and premature decommissioning specific.

Expense of Decommissioning

As a part of this filing, seven decommissioning cost estimates have been filed, showing various possible decommissioning scenarios.

The decommissioning cost estimates in 2017 dollars for DECON using dry storage is $3.0 billion for the estimate using a 32-year decommissioning period. The decommissioning cost estimate is $3.5 billion in 2017 dollars for the estimate using a 60-year decommissioning period that assumes no recasking occurs. The decommissioning cost estimate is $3.8 billion in 2017 dollars for the estimate using a 60-year decommissioning period that assumes a 50 year recasking requirement. The decommissioning cost estimate is $5.8 billion in 2017 dollars for the estimate using a 100-year decommissioning period. The decommissioning cost estimate is $10.2 billion in 2017 dollars for the estimate using a 200-year decommissioning period.

The decommissioning cost estimates in 2017 dollars for SAFSTOR is $3.8 billion for the estimate using a 32-year decommissioning period. The decommissioning cost estimate is $4.2billion in 2017 dollars for the estimate using a 60-year decommissioning period that assumes no recasking occurs.

Presently the Qualified Trust would be used to offset the potential costs resulting from premature decommissioning. The maximum annual, after-tax cash requirement for a worst-case premature decommissioning scenario involving all three Company's nuclear units is considerably reduced because of 100 percent external funding.

Replacement Energy Costs

A significant cost resulting from a premature shutdown is the cost of replacement energy. Replacement energy costs for a transitional period (until a more permanent asset could be constructed) would consist of increased fuel costs due to the use of more expensive coal, natural gas, and oil, costs associated with the increased operation of our existing generation fleet or the purchase of power from others, and the loss of revenues associated with a reduction in sales to other utilities. On a more permanent nature, replacement

energy costs would likely consist of a combination of increased fuel cost due to more expensive use of more natural gas, wind, solar and possibly coal. The unplanned nature of the power requirement, as well as the substantial increase in demand this replacement would represent in the open market also would be expected to command a substantial premium.

The variable operating costs associated with electric generation from nuclear facilities is less than for all other current forms of generation. Due to the low cost of nuclear production, relative to fossil production, the cost of replacement energy for a nuclear facility is larger than potential replacement energy costs for a fossil-generating unit. This cost could be compounded if the replacement energy is needed during a peak period. Nuclear plants provide base load capacity and produce more energy annually than most fossil units. Therefore, more expensive energy would have to replace nuclear energy if a nuclear unit were shut down prematurely.

Replacement Capacity Costs

Current nuclear plant net capability is 1,771 MW; 671 MW for Monticello and 1,100 MW for Prairie Island Units 1 and 2. If the Company's nuclear generating capability were lost, the Company's reserve margins would be below the 15.3 percent minimum reserve level currently specified by the Midcontinent Independent System Operator, Inc., as necessary to maintain adequate electric system reliability. Therefore, nearly all of the 1,771 of MW of lost nuclear capability would have to be replaced.

A premature shutdown of this magnitude may cause a severe capacity shortage, which would become more severe as demand increases. To overcome this, the capacity shortage would have to be handled in a two-step process. This process would be to 1) purchase temporary replacement capacity and 2) to construct replacement facilities that would likely be a combination of natural gas combustion turbines and combined cycle generating units. Current cost estimates for the construction of new natural gas combustion turbines and combined cycle units can be found in the Company's most current resource plan.

Due to the length of time to complete construction of new base load plants, premature retirement of a nuclear unit or a major coal unit would necessitate the purchase of temporary replacement capacity. The purchase of this quantity

of temporary replacement capacity would become a significant challenge in meeting customer demand.

Recovery of Un-recovered Investment

If there were a premature, non-accident related decommissioning, an un-recovered investment (original cost less accumulated depreciation) would continue as a revenue requirement. The un-recovered nuclear plant investment on January 1, 2017 was $2,070 million, $982 million at Monticello and $1,088 million at Prairie Island. These figures do not include land, nuclear fuel, and general plant equipment, such as office furniture. It also does not include the un-recovered decommissioning costs. However, it does include the licensing costs at both facilities and the held for future use assets at Monticello. These amounts are aligned with the 2017 Remaining Life Filing, Docket No. E,G002/D-17-147, when adjusted to include the $5.8 million of held for future use assets at Monticello.

Premature Decommissioning - Specific

An accident-related decommissioning would add additional expenses to those mentioned in the foregoing discussion. Potential contamination clean-up costs are the most significant expenses of an accident-related decommissioning. As an example, General Public Utilities has indicated that the total estimated cost for clean-up for the Three Mile Island nuclear site was approximately $1 billion, occurring over an estimated 11 to 12 year time period beginning in 1979. The damaged unit, at this time, is in SAFSTOR until Three Mile Island Unit 1 is ready to be decommissioned.

The Company's property insurance coverage of $2.25 billion would largely offset the potential impact of an accident-related decommissioning. Although accident-related decommissioning expenses are significant, the length of time involved in a clean-up process, insurance payments, tax deductibility of expenses, and related rate relief would affect the yearly expense. Although accident related premature decommissioning would impact both the Company and its customers, it is anticipated that, under reasonable regulation, the financial integrity of the Company would be maintained.

Xcel Energy **Docket No. E002/M-17-828**
Nuclear Asset Retirement Obligation Balances **Schedule J**
Page 1 of 1

ARO Balance Sheet Accounts	FERC Acct. Num.	2016	2017	
ASSETS				
Nuclear Plant In-Service - ARC		$ 482,670,802	$ 482,670,802	[1]
Beginning Accumulated Depreciation - Nuclear ARC	108	(115,085,517)	(154,326,898)	
Depreciation Expense		(39,241,381)	(11,100,334)	
Ending Accumulated Depreciation - Nuclear ARC		$ (154,326,898)	$ (165,427,232)	[1]
Regulatory Asset Nuclear - Beginning	182.3	$ 1,773,439,075	$ 1,920,978,498	
Asset Balance Adjustment		0	0	
Reserve Balance Adjustment		0	0	
ARO Liability Adjustment		0	0	
Accretion Expense		108,298,041	56,189,556	
Depreciation Expense		39,241,381	11,100,334	
Regulatory Asset Nuclear - Ending		$ 1,920,978,498	$ 1,988,268,388	[1]
Total Assets		$ 2,249,322,401	$ 2,305,511,958	
LIABILITIES				
Asset Retirement Obligation - Beginning	230	$ (2,141,024,360)	$ (2,249,322,401)	
Accretion Expense - Nuclear		(108,298,041)	(56,189,556)	
Liabilities Incurred		0	0	
Asset Retirement Obligation - Ending		$ (2,249,322,401)	$ (2,305,511,958)	[1]
Total Liabilities		$ (2,249,322,401)	$ (2,305,511,958)	

[1] As of June 30, 2017

Xcel Energy
Order Point Compliance Matrix

Docket No. E002/M-17-828
Schedule K
Page 1 of 1

This schedule presents the Commission Order Points from the 2014 Filing that require the Company to provide information in this filing. It also shows specifically where in the filing the Order Point is addressed.

	Order Point	Petition Reference
6.	Xcel shall provide more detailed analysis when proposing future assumption changes related to the transition to bonds.	Petition starting at page 26, Schedule D
12.	In its next triennial decommissioning filing, Xcel shall:	
	a. provide balance sheet accounts for SFAS 143 related to nuclear decommissioning, with a brief narrative explaining the numbers provided on the ARO (Asset Retirement Obligation) balance sheet.	Schedule J
	b. continue using a consultant (rather than Xcel) to prepare the Schedule C escalation analysis section and provide a statement indicating that the consultant is doing this calculation in an independent manner.	Schedule C
	c. develop a 60, 100 and 200-year plan for the City of Red Wing to enable Xcel to build, improve, communicate, and share an understanding of the long-term safety-related costs of spent fuel storage on host communities.	Schedule B
	d. discuss possible end of life nuclear cost mitigation alternatives.	Schedule H
	e. re-examine its 50-year recasking cost assumption and analysis, by providing two scenarios – one based on the same recasking assumptions used in this filing, and one assuming the need to replace all casks prior to being turned over to the custody of the federal government.	Petition starting at page 19
	f. provide an updated assessment of the risk of premature decommissioning.	Schedule I
	g. provide a detailed discussion of the status of the Nuclear Regulatory Commission relicensing of casks, on the anticipated life of casks used by Xcel, manufacturer and contractor warranties and liability obligations for the casks, the technical and regulatory barriers associated with transporting the casks used and the status of any federal storage initiatives whether permanent or temporary.	Petition starting at page 18
	h. include a detailed explanation of the anticipated financial responsibility of utilities for the delivery of the casks into federal custody that includes descriptions of when ratepayers' and Xcel's present storage duties terminate and the cost and liabilities would shift to the federal government.	Petition starting at page 21
13.	In next and future triennial decommissioning filings, Xcel shall provide a more detailed break out of "spent fuel management" costs.	Schedules A.1to A.14, A.17, L, and M

Document X01-1725-002, Rev. 0

DECOMMISSIONING COST ANALYSIS

for the

MONTICELLO NUCLEAR GENERATING PLANT

prepared for

Xcel Energy

prepared by

TLG Services, Inc.
Bridgewater, Connecticut

October 2017

APPROVALS

Project Manager	**Francis W. Seymore**	**Date** 10/17/17
Project Engineer	**Jeffrey M. Martin**	**Date** 10/17/17
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REVISION LOG

No.	Date	Item Revised	Reason for Revision
0	10-17-2017		Original Issue

EXECUTIVE SUMMARY

This report presents estimates of the cost to decommission the Monticello Nuclear Generating Plant (Monticello) for the identified decommissioning scenarios following a cessation of plant operations in 2030. The estimates are designed to provide Xcel Energy with the information to assess its current decommissioning liability, as it relates to Monticello.

The analysis relies upon site-specific, technical information from an evaluation prepared in 2014, [1] updated to reflect current assumptions pertaining to the disposition of the nuclear plant and relevant industry experience in undertaking such projects. The costs are based on several key assumptions in areas of regulation, component characterization, high-level radioactive waste management, low-level radioactive waste disposal, performance uncertainties (contingency) and site restoration requirements.

The analysis is not a detailed engineering evaluation, but an estimate prepared in advance of the detailed engineering required to carry out the decommissioning of the nuclear unit. It may also not reflect the actual plan to decommission Monticello; the plan may differ from the assumptions made in this analysis based on facts that exist at the time of decommissioning.

The primary goal of the decommissioning is the removal and disposal of the contaminated systems and structures so that the plant's operating license can be terminated. The analysis recognizes that spent fuel will be stored at the site in the reactor building's storage pool and/or in an Independent Spent Fuel Storage Installation (ISFSI) until such time that it can be transferred to a Department of Energy (DOE) facility. Consequently, the estimates also include those costs to manage and subsequently decommission these storage facilities.

The costs to decommission Monticello, for the scenarios evaluated, are tabulated at the end of this section. Costs are reported in 2017 dollars and include monies anticipated to be spent for radiological remediation and operating license termination, spent fuel management, and site restoration activities.

A complete discussion of the assumptions relied upon in this analysis is provided in Section 3, along with schedules of annual expenditures for each scenario. A sequence of significant project activities is provided in Section 4 with a timeline for

1 "Decommissioning Cost Analysis for the Monticello Nuclear Generating Plant," Document No. X01-1617-006, Rev. 0, TLG Services, Inc., October 2014

each scenario. Detailed cost reports used to generate the summary tables contained within this document are provided in Appendices C through J.

The current cost estimates assume that Monticello ceases operations in 2030. The cost estimates assume that the shutdown date of the nuclear unit is scheduled and pre-planned (i.e., there is no delay in transitioning the plant and workforce from operations or in obtaining regulatory relief from operating requirements, etc.). This estimate includes additional resources to support the engineering, planning, and licensing efforts for the station; this is done to support a decommissioning schedule similar to the prior estimate. The estimates include the continued operation of the reactor building as an interim wet fuel storage facility for approximately five years after operations cease. The spent fuel will remain in the ISFSI until the DOE is able to complete the transfer of the fuel to a federal facility (e.g., a monitored retrievable storage facility). [2] The estimates also include the dismantling of non-essential structures and limited restoration of the site.

Alternatives and Regulations

The ultimate objective of the decommissioning process is to reduce the inventory of contaminated and activated material so that the license can be terminated. The Nuclear Regulatory Commission (NRC or Commission) provided initial decommissioning requirements in its rule adopted on June 27, 1988.[3] In this rule, the NRC set forth technical and financial criteria for decommissioning licensed nuclear power facilities. The regulations addressed planning needs, timing, funding methods, and environmental review requirements for decommissioning. The rule also defined three decommissioning alternatives as being acceptable to the NRC: DECON, SAFSTOR, and ENTOMB.

> DECON is defined as "the alternative in which the equipment, structures, and portions of a facility and site containing radioactive contaminants are removed or decontaminated to a level that permits the property to be released for unrestricted use shortly after cessation of operations."[4]

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2 Projected expenditures for spent fuel management identified in the cost analysis do not consider any compensation for damages with regard to the delays incurred by Xcel Energy in the timely removal of spent fuel by the DOE.

3 U.S. Code of Federal Regulations, Title 10, Parts 30, 40, 50, 51, 70 and 72, "General Requirements for Decommissioning Nuclear Facilities," Nuclear Regulatory Commission, 53 Fed. Reg. 24018, June 27, 1988

4 Ibid. Page FR24022, Column 3

SAFSTOR is defined as "the alternative in which the nuclear facility is placed and maintained in a condition that allows the nuclear facility to be safely stored and subsequently decontaminated (deferred decontamination) to levels that permit release for unrestricted use."[5] Decommissioning is to be completed within 60 years, although longer time periods will be considered when necessary to protect public health and safety.

ENTOMB is defined as "the alternative in which radioactive contaminants are encased in a structurally long-lived material, such as concrete; the entombed structure is appropriately maintained and continued surveillance is carried out until the radioactivity decays to a level permitting unrestricted release of the property."[6] As with the SAFSTOR alternative, decommissioning is currently required to be completed within 60 years, although longer time periods will also be considered when necessary to protect public health and safety.

The 60-year restriction has limited the practicality for the ENTOMB alternative at commercial reactors that generate significant amounts of long-lived radioactive material. In 1997, the Commission directed its staff to re-evaluate this alternative and identify the technical requirements and regulatory actions that would be necessary for entombment to become a viable option. The resulting evaluation provided several recommendations, however, rulemaking has been deferred based upon several factors (e.g., no licensee has committed to pursuing the entombment option, the unresolved issues associated with the disposition of greater-than-Class C material (GTCC), and the NRC's current priorities) at least until after the additional research studies are complete. The Commission concurred with the staff's recommendation. In a draft regulatory basis document published in March 2017 in support of rulemaking that would amend NRC regulations concerning nuclear plant decommissioning, the NRC staff proposes removing any discussion of the ENTOMB option from existing guidance documents since the method is not deemed practically feasible.

In 1996, the NRC published revisions to its general requirements for decommissioning nuclear power plants to clarify ambiguities and codify procedures and terminology as a means of enhancing efficiency and uniformity in the decommissioning process.[7] The amendments allow for greater public participation and better define the transition

5 Ibid.

6 Ibid. Page FR24023, Column 2

7 U.S. Code of Federal Regulations, Title 10, Parts 2, 50 and 51, "Decommissioning of Nuclear Power Reactors," Nuclear Regulatory Commission, 61 Fed. Reg. 39278, July 29, 1996

process from operations to decommissioning. Regulatory Guide 1.184 Revision 1, issued in October 2013, further described the methods and procedures that are acceptable to the NRC staff for implementing the requirements of the 1996 revised rule that relate to the initial activities and the major phases of the decommissioning process. The costs and schedules presented in this analysis follow the general guidance and sequence in the amended regulations. The format and content of the estimates is also consistent with the recommendations of Regulatory Guide 1.202, issued February 2005. [8]

In 2011, the NRC published amended regulations to improve decommissioning planning and thereby reduce the likelihood that any current operating facility will become a legacy site.[9] The amended regulations require licensees to conduct their operations to minimize the introduction of residual radioactivity into the site, which includes the site's subsurface soil and groundwater. Licensees also may be required to perform site surveys to determine whether residual radioactivity is present in subsurface areas and to keep records of these surveys with records important for decommissioning. The amended regulations require licensees to report additional details in their decommissioning cost estimate as well as requiring additional financial reporting and assurances. These additional details are included in this analysis, including the ISFSI decommissioning estimate (Appendix J).

Decommissioning Scenarios

The following scenarios were evaluated and are intended to bound the liability associated with the removal of spent fuel from the site. The current operating license expires in 2030. The scenarios consist of five DECON scenarios, with differing spent fuel management assumptions, but essentially no changes to the decommissioning costs and timing of the power block. There are also two SAFSTOR scenarios (Scenarios 6 and 7) each corresponding to the first two DECON scenario spent fuel management assumptions. The spent fuel in the plant's spent fuel storage pool is transferred to the ISFSI within the first five years. The equipment, structures, and portions of the plant containing radioactive contaminants are removed or decontaminated to a level that permits the facility to be released for unrestricted use. Non-essential structures are then demolished. Spent fuel storage operations continue at the ISFSI until the transfer of the fuel to the DOE is completed (2062 in Scenarios 1 & 6, 2090 in Scenarios 2, 5 & 7, 2130 in Scenario 3, and 2230 in Scenario 4).

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8 "Standard Format and Content of Decommissioning Cost Estimates for Nuclear Power Reactors," Regulatory Guide 1.202, Nuclear Regulatory Commission, February 2005

9 U.S. Code of Federal Regulations, Title 10, Parts 20, 30, 40, 50, 70, and 72, "Decommissioning Planning," Nuclear Regulatory Commission, Federal Register Volume 76, (p 35512 et seq.), June 17, 2011

Scenario	1st Spent Fuel Canister Replacement	1st Spent Fuel Assembly Removed from Monticello*	Last Spent Fuel Assembly Removed from Monticello	Scenario Identification
1	n/a	2042	2062	DECON with 32 Year DFS+
2	n/a	2078	2090	DECON with 60 Year DFS
3	2058	2118	2130	DECON with 100 Year DFS
4	2058	2218	2230	DECON with 200 Year DFS
5	2058	2078	2090	DECON with 60 Year DFS and recasking
6	n/a	2042	2062	SAFSTOR with 32 Year DFS
7	n/a	2078	2090	SAFSTOR with 60 Year DFS

* Spent fuel stored at Morris is removed prior to fuel stored at the Monticello site.
+ Dry Fuel Storage

For Scenarios 2 and 7, although they provide a total fuel storage period of 60 years following plant shutdown, Xcel Energy directed TLG Services to not include the cost of transferring the spent fuel in dry storage to new canisters at 50 years after plant shutdown. The assumption to not transfer spent fuel at 50 years following plant shutdown in Scenarios 2 and 7 was premised on the likelihood that the life of the canisters could be successfully managed for an additional 10 years.

In Scenarios 3, 4 and 5, the DSCs are assumed to be replaced after fifty years of use. Since the reactor building spent fuel storage pool and fuel handling facilities are removed by the year 2038, a dry fuel transfer facility is assumed to be constructed on site to perform the transfers from the old to the new DSCs. For Scenarios 3 and 5, only one such transfer is needed over the time frame assumed (some fuel canisters in Scenario 5 will not require recasking). For Scenario 4, the spent fuel will be transferred three times following initial placement in the ISFSI.

Methodology

The methodology used to develop the estimates follows the basic approach originally presented in the cost estimating guidelines [10] developed by the Atomic Industrial

10 T.S. LaGuardia et al., "Guidelines for Producing Commercial Nuclear Power Plant Decommissioning Cost Estimates," AIF/NESP-036, May 1986

Forum (now Nuclear Energy Institute). This reference describes a unit cost factor method for estimating decommissioning activity costs. The unit cost factors used in this analysis incorporate site-specific costs and the latest available information about worker productivity in decommissioning.

An activity duration critical path is used to determine the total decommissioning program schedule. This is required for calculating the carrying costs, which include program management, administration, field engineering, equipment rental, quality assurance, and security. This systematic approach for assembling decommissioning estimates ensures a high degree of confidence in the reliability of the resulting costs.

The estimates also reflect lessons learned from previously completed decommissioning projects, including TLG's involvement in the Shippingport Station decommissioning, completed in 1989, and the decommissioning of the Cintichem reactor, hot cells and associated facilities, completed in 1997. In addition, the planning and engineering for the Pathfinder, Shoreham, Rancho Seco, Trojan, Yankee Rowe, Big Rock Point, Maine Yankee, Humboldt Bay-3, Oyster Creek, Connecticut Yankee, Crystal River, Vermont Yankee and Fort Calhoun nuclear units have provided additional insight into the process, the regulatory aspects, and the technical challenges of decommissioning commercial nuclear units.

Contingency

Consistent with cost estimating practice, contingencies are applied to the decontamination and dismantling costs developed as "specific provision for unforeseeable elements of cost within the defined project scope, particularly important where previous experience relating estimates and actual costs has shown that unforeseeable events which will increase costs are likely to occur."[11] The cost elements in the estimates are based on ideal conditions; therefore, the types of unforeseeable events that are almost certain to occur in decommissioning, based on industry experience, are addressed through a percentage contingency applied on a line-item basis. This contingency factor is a nearly universal element in all large-scale construction and demolition projects. It should be noted that contingency, as used in this analysis, does not account for price escalation and inflation in the cost of decommissioning over the remaining operating life of the station, or duration of the decommissioning program and dry fuel storage period.

11 Project and Cost Engineers' Handbook, Second Edition, American Association of Cost Engineers, Marcel Dekker, Inc., New York, New York, p. 239

Contingency funds are expected to be fully expended throughout the program. As such, inclusion of contingency is necessary to provide assurance that sufficient funding will be available to accomplish the intended tasks.

Low-Level Radioactive Waste Disposal

The contaminated and neutron-activated material generated in the decontamination and dismantling of a commercial nuclear reactor is classified as low-level (radioactive) waste, although not all of the material is suitable for "shallow-land" disposal. With the passage of the "Low-Level Radioactive Waste Policy Act" in 1980, [12] and its Amendments of 1985, [13] the states became ultimately responsible for the disposition of low-level radioactive waste generated within their own borders. It was expected that groups of states would combine together to jointly deal with their radioactive wastes; these organizations are referred to as waste disposal compacts.

With the exception of Texas, no new compact facilities have been successfully sited, licensed, and constructed. The Texas Compact disposal facility is now operational and waste is being accepted from generators within the Compact by the operator, Waste Control Specialists (WCS). The facility is also able to accept limited quantities of non-Compact waste.

Disposition of the various waste streams produced by the decommissioning process considered all options and services currently available to Xcel Energy. The majority of the low-level radioactive waste designated for direct disposal (Class A [14]) can be sent to Energy*Solutions*' facility in Clive, Utah. Therefore, disposal costs for Class A waste were based upon representative rates. This facility is not licensed to receive the higher activity portion (Classes B and C) of the decommissioning waste stream.

The Texas facility is licensed to receive the higher activity waste forms (Classes B and C). As such, for this analysis, disposal costs for the Class B and C waste were based upon the preliminary and indicative information on the cost for such from WCS.

The dismantling of the components residing closest to the reactor core generates radioactive waste considered unsuitable for shallow-land disposal (i.e., low-level radioactive waste with concentrations of radionuclides that exceed the limits established by the NRC for Class C radioactive waste (GTCC)). The Low-Level Radioactive Waste Policy Amendments Act of 1985 assigned the federal government

12 "Low-Level Radioactive Waste Policy Act," Public Law 96-573, 1980

13 "Low-Level Radioactive Waste Policy Amendments Act of 1985," Public Law 99-240, 1986

14 Waste is classified in accordance with U.S. Code of Federal Regulations, Title 10, Part 61.55

the responsibility for the disposal of this material. The Act also stated that the beneficiaries of the activities resulting in the generation of such radioactive waste bear all reasonable costs of disposing of such waste. However, to date, the federal government has not identified a cost for disposing of GTCC or a schedule for acceptance.

For purposes of this analysis, the GTCC radioactive waste is assumed to be packaged and disposed of in a similar manner as high-level waste and at a cost equivalent to that envisioned for the spent fuel. The GTCC is packaged in the same canisters used for spent fuel and either stored on site or shipped directly to a DOE facility as it is generated (depending upon the timing of the decommissioning and whether the spent fuel has been removed from the site prior to the start of decommissioning).

A significant portion of the waste material generated during decommissioning may only be potentially contaminated by radioactive materials. This waste can be analyzed on site or shipped off site to licensed facilities for further analysis, for processing and/or for conditioning/recovery. Reduction in the volume of low-level radioactive waste requiring disposal in a licensed low-level radioactive waste disposal facility can be accomplished through a variety of methods, including analyses and surveys or decontamination to isolate the portion of waste that does not require disposal as radioactive waste, compaction, incineration or metal melt. The estimates reflect the savings from waste recovery/volume reduction.

<u>High-Level Radioactive Waste Management</u>

Congress passed the "Nuclear Waste Policy Act" [15] (NWPA) in 1982, assigning the federal government's long-standing responsibility for disposal of the spent nuclear fuel created by the commercial nuclear generating plants to the DOE. The NWPA provided that DOE would enter into contracts with utilities in which DOE would promise to take the utilities' spent fuel and high-level radioactive waste and utilities would pay the cost of the disposition services for that material. NWPA, along with the individual contracts with the utilities, specified that the DOE was to begin accepting spent fuel by January 31, 1998.

Since the original legislation, the DOE has announced several delays in the program schedule. By January 1998, the DOE had failed to accept any spent fuel or high-level waste, as required by the NWPA and utility contracts. Delays continue and, as a result, generators have initiated legal action against the DOE in an attempt to obtain compensation for DOE's partial breach of contract. To date no spent fuel has been accepted from commercial generating sites for disposal.

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15 "Nuclear Waste Policy Act of 1982 and Amendments," DOE's Office of Civilian Radioactive Management, 1982

In 2010 the Obama Administration appointed a Blue Ribbon Commission on America's Nuclear Future (Blue Ribbon Commission) to make recommendations for a new plan for nuclear waste disposal. The Blue Ribbon Commission's charter includes a requirement that it consider "[o]ptions for safe storage of used nuclear fuel while final disposition pathways are selected and deployed."[16]

On January 26, 2012, the Blue Ribbon Commission issued its "Report to the Secretary of Energy" containing a number of recommendations on nuclear waste disposal. Two of the recommendations that may impact decommissioning planning are:

- "[T]he United States [should] establish a program that leads to the timely development of one or more consolidated storage facilities"[17]
- "[T]he United States should undertake an integrated nuclear waste management program that leads to the timely development of one or more permanent deep geological facilities for the safe disposal of spent fuel and high-level nuclear waste."[18]

In January 2013, the DOE issued the "Strategy for the Management and Disposal of Used Nuclear Fuel and High-Level Radioactive Waste," in response to the recommendations made by the Blue Ribbon Commission and as "a framework for moving toward a sustainable program to deploy an integrated system capable of transporting, storing, and disposing of used nuclear fuel..."[19] This document states:

"With the appropriate authorizations from Congress, the Obama Administration planned to implement a program over the next 10 years that would have:

- Sites, designs and licenses, constructs and begins operations of a pilot interim storage facility by 2021 with an initial focus on accepting used nuclear fuel from shut-down reactor sites;
- Advances toward the siting and licensing of a larger interim storage facility to be available by 2025 that will have sufficient capacity to provide

16 Charter of the Blue Ribbon Commission on America's Nuclear Future, "Objectives and Scope of Activities," 2010

17 "Blue Ribbon Commission on America's Nuclear Future, Report to the Secretary of Energy,", p. 32, January 2012

18 Ibid., p.27

19 "Strategy for the Management and Disposal of Used Nuclear Fuel and High-Level Radioactive Waste," U.S. DOE, January 11, 2013

flexibility in the waste management system and allows for acceptance of enough used nuclear fuel to reduce expected government liabilities; and

- Makes demonstrable progress on the siting and characterization of repository sites to facilitate the availability of a geologic repository by 2048."[20]

The NRC's review of DOE's license application to construct a geologic repository at Yucca Mountain was suspended in 2011 when the Obama Administration slashed the budget for completing that work. However, the US Court of Appeals for the District of Columbia Circuit issued a writ of mandamus (in August 2013) [21] ordering NRC to comply with federal law and restart its review of DOE's Yucca Mountain repository license application to the extent of previously appropriated funding for the review. That review is now complete with the publication of the five-volume safety evaluation report. A supplement to DOE's environmental impact statement and an adjudicatory hearing on the contentions filed by interested parties must be completed before a licensing decision can be made.

The state of Minnesota directed the Public Utilities Commission, "when considering approval of a plan for the accrual of funds for the decommissioning of nuclear facilities" …to "include an evaluation of the costs, if any, arising from storage of used nuclear fuel that may be incurred by the state of Minnesota, and any tribal community, county, city, or township where used nuclear fuel is located following the cessation of operations at a nuclear plant."[22]

The state of Minnesota statute also prescribed the parameters to be used in evaluating spent fuel management costs. "To assist the commission in making the determination … the filing shall provide cost estimates, including ratepayer impacts, assuming used nuclear fuel will be stored in the state for 60 years, 100 years, and 200 years following the cessation of operation of the nuclear plant." [23]

Xcel Energy's current spent fuel management plan for the Monticello spent fuel is based in general upon:

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20 Ibid., p.2

21 United States Court of Appeals for the District Of Columbia Circuit, In Re: Aiken County, et al, August 2013

22 Minnesota Statute 216B.1614, "Nuclear Power Plant Decommissioning and Storage of Used Nuclear Fuel"

23 Ibid.

1) Fuel transferred from the pool to the ISFSI within 5 years of shutdown;

2) Exchange of Monticello and Prairie Island spent fuel acceptance rights to best manage the overall cost of spent fuel storage for both plants;

3) Fuel will be shipped in the existing NUHOMS DSCs (Scenarios 1, 2, 6, and 7); the canisters and NUHOMS are periodically replaced in Scenarios 3, 4 and 5. Canisters that are unloaded in the spent fuel transfer operation will be surveyed for neutron activation.

4) As an allowance, some of these canisters and NUHOMS modules from the first off-load operation are assumed to be mildly neutron activated and therefore must be disposed of as radioactive waste.

The NRC requires that licensees establish a program to manage and provide funding for the caretaking of all irradiated fuel at the reactor site until title of the fuel is transferred to the Secretary of Energy, pursuant to 10 CFR Part 50.54(bb). [24] This requirement is prepared for through inclusion of certain cost elements in the decommissioning estimates, for example, associated with the isolation and continued operation of the spent fuel pool and the ISFSI.

The spent fuel pool is expected to contain freshly discharged assemblies (from the most recent refueling cycles) as well as the final reactor core at shutdown. The assemblies are packaged into dry shielded canisters (DSCs) over the first five years after shutdown for transfer to the ISFSI for interim storage. It is assumed that this period provides the necessary cooling for the final core to meet the transport and/or storage requirements for decay heat.

An ISFSI, operated under a Part 50 General License (in accordance with 10 CFR 72, Subpart K [25]), has been constructed to support continued plant operations. The facility is assumed to be expanded to support decommissioning. This will allow decommissioning activities to proceed within the reactor building.

DOE has breached its obligations to remove fuel from reactor sites, and has also failed to provide the plant owners with information about how it will ultimately perform. DOE officials have stated that DOE does not have an obligation to accept already-canistered fuel without an amendment to DOE's contracts with plant licensees to remove the fuel (the "Standard Contract"), but DOE has not explained what any such

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24 U.S. Code of Federal Regulations, Title 10, Part 50, "Domestic Licensing of Production and Utilization Facilities," Subpart 54 (bb), "Conditions of Licenses"

25 U.S. Code of Federal Regulations, Title 10, Part 72, Subpart K, "General License for Storage of Spent Fuel at Power Reactor Sites"

amendment would involve. Consequently, Xcel Energy has no information or expectations on how DOE will remove fuel from the site in the future. In the absence of information about how DOE will perform, and for purposes of this analysis only, it is assumed that DOE will accept already-canistered fuel. If this assumption is incorrect, it is assumed that DOE will have liability for costs incurred to transfer the fuel to DOE-supplied containers.

Xcel Energy's position is that the DOE has a contractual obligation to accept Monticello's fuel earlier than the projections set out above consistent with its contract commitments. No assumption made in this study should be interpreted to be inconsistent with this claim. However, including the cost of storing spent fuel in this study is appropriate to ensure the availability of sufficient decommissioning funds at the end of the station's life if the DOE has not met its obligation. The cost for the interim storage of spent fuel has been calculated and is separately presented as "Spent Fuel Management" expenditures in this report.

Site Restoration

The efficient removal of the contaminated materials at the site may result in damage to many of the site structures. Blasting, coring, drilling, and the other decontamination activities can substantially damage power block structures, potentially weakening the footings and structural supports. It is unreasonable to anticipate that these structures would be repaired and preserved after the radiological contamination is removed. The cost to dismantle site structures with a work force already mobilized is more efficient and less costly than if the process were deferred. Experience at shutdown generating stations has shown that plant facilities quickly degrade without maintenance, adding additional expense and creating potential hazards to the public and the demolition work force.

This estimate assumes that some site features will remain following the decommissioning project. These include the existing electrical switchyard, which is assumed to remain functional in support of the regional electrical distribution system. The existing shoreline will also be left intact.

Consequently, non-essential site structures addressed by this analysis are completely removed (including foundations) as required by Minnesota statute [26]. The site is then graded and stabilized. The cost for the site restoration of non-essential and/or non-contaminated structures has been calculated and is separately presented as "Site Restoration" expenditures in this report.

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26 Minnesota Administrative Rule part 7035.0400 "General Requirements"

Summary

The costs to decommission the Monticello station were evaluated for several decommissioning scenarios, based upon the DECON and SAFSTOR decommissioning alternatives. Regardless of the timing of the decommissioning activities, the estimates to decommission Monticello assume the removal of all contaminated and activated plant components and structural materials such that Xcel Energy may then have unrestricted use of the site with no further requirements for an operating license. In most of the scenarios, spent fuel remains on site following the decommissioning and site restoration of the power block structures. The spent fuel remains in storage at the site until such time that the transfer to a DOE facility can be completed. Once the transfer is complete, the storage facilities are also decommissioned.

The alternatives evaluated in this analysis are described in Section 2. The assumptions are presented in Section 3, along with schedules of annual expenditures. The major cost contributors are identified in Section 6, with detailed activity costs, waste volumes, and associated manpower requirements delineated in Appendices C through J. The major cost components are also identified in the cost summary provided at the end of this section.

The estimates presented in this document reflects the total cost to decontaminate the nuclear unit, manage the spent fuel until the DOE is able to complete the transfer to a federal facility, dismantle the plant and restore the site for alternative use.

The cost elements in the estimates for the five DECON and two SAFSTOR alternatives are assigned to one of three subcategories: NRC License Termination (radiological remediation), Spent Fuel Management, and Site Restoration. The subcategory "NRC License Termination" is used to accumulate costs that are consistent with "decommissioning" as defined by the NRC in its financial assurance regulations (i.e., 10 CFR §50.75). The cost reported for this subcategory is generally sufficient to terminate the unit's operating license, recognizing that there may be some additional cost impact from spent fuel management. The License Termination cost subcategory also includes costs to decommission the ISFSI (as required by 10 CFR §72.30). Section 3.4.1 provides the basis for the ISFSI decommissioning cost.

The "Spent Fuel Management" subcategory contains costs associated with the containerization and transfer of spent fuel from the wet storage pool to a DOE transport cask or to the ISFSI for interim storage, as well as the transfer of the spent fuel in storage at the ISFSI to the DOE. Costs are included for the operation of the storage pool and the management of the ISFSI until such time that the transfer is complete. It does not include any spent fuel management expenses

incurred prior to the cessation of plant operations, nor does it include any costs related to the final disposal of the spent fuel.

"Site Restoration" is used to capture costs associated with the dismantling and demolition of buildings and facilities demonstrated to be free from contamination. This includes structures never exposed to radioactive materials, as well as those facilities that have been decontaminated to appropriate levels. Structures are completely removed (including foundations) and backfilled to conform to local surface elevation.

It should be noted that the costs assigned to these subcategories are allocations. Delegation of cost elements is for the purposes of comparison (e.g., with NRC financial guidelines) or to permit specific financial treatment (e.g., Asset Retirement Obligation determinations). In reality, there can be considerable interaction between the activities in the three subcategories. For example, Xcel Energy may decide to remove non-contaminated structures early in the project to improve access to highly contaminated facilities or plant components. In these instances, the non-contaminated removal costs could be reassigned from Site Restoration to an NRC License Termination support activity. However, in general, the allocations represent a reasonable accounting of those costs that can be expected to be incurred for the specific subcomponents of the total estimated program cost, if executed as described.

As noted within this document, the estimates were developed and costs are presented in 2017 dollars. As such, the estimates do not reflect the escalation of costs (due to inflationary and market forces) over the remaining operating life of the plant or during the decommissioning period.

SCENARIO 1: DECON WITH 32 YEARS DFS
DECOMMISSIONING COST ELEMENTS
(thousands of 2017 dollars)

Cost Element	Total
Decontamination	23,268
Removal	119,462
Packaging	26,800
Transportation	12,389
Waste Disposal	95,919
Off-site Waste Processing	29,702
Program Management [1]	303,532
Security	233,970
Spent Fuel Pool Isolation	13,445
Spent Fuel Storage (Direct Costs) [2]	197,448
Insurance and Regulatory Fees	33,282
Energy	11,068
Characterization and Licensing Surveys	28,626
Property Taxes	36,452
Miscellaneous Equipment	7,265
Railroad Track Maintenance	5,048
Retention and Severance	43,877
Security Modifications	10,000
Total [3]	1,231,552

Cost Element	Total
NRC License Termination	759,294
Spent Fuel Management	400,983
Site Restoration	71,275
Total [3]	1,231,552

[1] Includes engineering costs

[2] Includes costs for the dry storage system components, spent fuel loading and transfer, spent fuel pool O&M and EP fees, but excludes program management costs (staffing), security and other related costs

[3] Columns may not add due to rounding

SCENARIO 2: DECON WITH 60 YEAR DFS
DECOMMISSIONING COST ELEMENTS
(thousands of 2017 dollars)

Cost Element	Total
Decontamination	23,268
Removal	119,501
Packaging	26,800
Transportation	12,389
Waste Disposal	95,919
Off-site Waste Processing	29,702
Program Management [1]	343,355
Security	359,469
Spent Fuel Pool Isolation	13,445
Spent Fuel Storage (Direct Costs) [2]	274,588
Insurance and Regulatory Fees	55,483
Energy	11,068
Characterization and Licensing Surveys	28,626
Property Taxes	52,336
Miscellaneous Equipment	7,265
Railroad Track Maintenance	8,759
Retention and Severance	43,877
Security Modifications	10,000
Total [3]	1,515,850

Cost Element	Total
NRC License Termination	759,047
Spent Fuel Management	685,479
Site Restoration	71,324
Total [3]	1,515,850

[1] Includes engineering costs

[2] Includes costs for the dry storage system components, spent fuel loading and transfer, spent fuel pool O&M and EP fees, but excludes program management costs (staffing), security and other related costs

[3] Columns may not add due to rounding

SCENARIO 3: DECON WITH 100 YEAR DFS
DECOMMISSIONING COST ELEMENTS
(thousands of 2017 dollars)

Cost Element	Total
Decontamination	23,306
Removal	119,474
Packaging	26,803
Transportation	11,749
Waste Disposal	95,178
Off-site Waste Processing	29,702
Program Management [1]	498,687
Security	538,987
Spent Fuel Pool Isolation	13,445
Spent Fuel Storage (Direct Costs) [2]	784,638
Insurance and Regulatory Fees	87,239
Energy	11,068
Characterization and Licensing Surveys	28,626
Property Taxes	75,024
Miscellaneous Equipment	7,265
Railroad Track Maintenance	14,068
Retention and Severance	43,877
Security Modifications	10,000
Total [3]	2,419,135

Cost Element	Total
NRC License Termination	748,156
Spent Fuel Management	1,599,295
Site Restoration	71,685
Total [3]	2,419,136

[1] Includes engineering costs

[2] Includes costs for the dry storage system components, spent fuel loading and transfer, spent fuel pool O&M and EP fees, but excludes program management costs (staffing), security and other related costs

[3] Columns may not add due to rounding

SCENARIO 4: DECON WITH 200 YEAR DFS
DECOMMISSIONING COST ELEMENTS
(thousands of 2017 dollars)

Cost Element	Total
Decontamination	23,306
Removal	119,474
Packaging	26,803
Transportation	11,749
Waste Disposal	95,178
Off-site Waste Processing	29,702
Program Management [1]	765,140
Security	987,801
Spent Fuel Pool Isolation	13,445
Spent Fuel Storage (Direct Costs) [2]	1,762,292
Insurance and Regulatory Fees	166,633
Energy	11,068
Characterization and Licensing Surveys	28,626
Property Taxes	131,743
Miscellaneous Equipment	7,265
Railroad Track Maintenance	27,341
Retention and Severance	43,877
Security Modifications	10,000
Total [3]	4,261,442

Cost Element	Total
NRC License Termination	748,155
Spent Fuel Management	3,441,602
Site Restoration	71,685
Total [3]	4,261,443

[1] Includes engineering costs

[2] Includes costs for the dry storage system components, spent fuel loading and transfer, spent fuel pool O&M and EP fees, but excludes program management costs (staffing), security and other related costs

[3] Columns may not add due to rounding

SCENARIO 5: DECON WITH 60 YEAR DFS WITH RECASKING
DECOMMISSIONING COST ELEMENTS
(thousands of 2017 dollars)

Cost Element	Total
Decontamination	23,306
Removal	119,505
Packaging	26,805
Transportation	12,393
Waste Disposal	95,943
Off-site Waste Processing	29,702
Program Management [1]	343,355
Security	359,469
Spent Fuel Pool Isolation	13,445
Spent Fuel Storage (Direct Costs) [2]	361,324
Insurance and Regulatory Fees	55,483
Energy	11,068
Characterization and Licensing Surveys	28,626
Property Taxes	52,336
Miscellaneous Equipment	7,265
Railroad Track Maintenance	8,759
Retention and Severance	43,877
Security Modifications	10,000
Total [3]	1,602,660

Cost Element	Total
NRC License Termination	759,122
Spent Fuel Management	772,214
Site Restoration	71,324
Total [3]	1,602,660

[1] Includes engineering costs

[2] Includes costs for the dry storage system components, spent fuel loading and transfer, spent fuel pool O&M and EP fees, but excludes program management costs (staffing), security and other related costs

[3] Columns may not add due to rounding

SCENARIO 6: SAFSTOR WITH 32 YEAR DFS
DECOMMISSIONING COST ELEMENTS
(thousands of 2017 dollars)

Cost Element	Total
Decontamination	25,220
Removal	122,447
Packaging	17,915
Transportation	8,026
Waste Disposal	66,222
Off-site Waste Processing	34,993
Program Management [1]	403,048
Security	236,063
Spent Fuel Pool Isolation	13,445
Spent Fuel Storage (Direct Costs) [2]	195,063
Insurance and Regulatory Fees	68,491
Energy	23,440
Characterization and Licensing Surveys	28,277
Property Taxes	148,737
Miscellaneous Equipment	20,825
Railroad Track Maintenance	8,536
Retention and Severance	43,877
Security Modifications	10,000
Total [3]	1,474,626

Cost Element	Total
NRC License Termination	1,045,043
Spent Fuel Management	364,666
Site Restoration	64,917
Total [3]	1,474,626

[1] Includes engineering costs

[2] Includes costs for the dry storage system components, spent fuel loading and transfer, spent fuel pool O&M and EP fees, but excludes program management costs (staffing), security and other related costs

[3] Columns may not add due to rounding

SCENARIO 7: SAFSTOR WITH 60 YEAR DFS
DECOMMISSIONING COST ELEMENTS
(thousands of 2017 dollars)

Cost Element	Total
Decontamination	25,220
Removal	122,659
Packaging	17,920
Transportation	8,028
Waste Disposal	66,243
Off-site Waste Processing	34,993
Program Management [1]	430,133
Security	386,682
Spent Fuel Pool Isolation	13,445
Spent Fuel Storage (Direct Costs) [2]	259,117
Insurance and Regulatory Fees	69,323
Energy	23,440
Characterization and Licensing Surveys	28,277
Property Taxes	148,737
Miscellaneous Equipment	20,825
Railroad Track Maintenance	8,536
Retention and Severance	43,877
Security Modifications	10,000
Total [3]	1,717,454

Cost Element	Total
NRC License Termination	1,099,775
Spent Fuel Management	552,724
Site Restoration	64,956
Total [3]	1,717,454

[1] Includes engineering costs

[2] Includes costs for the dry storage system components, spent fuel loading and transfer, spent fuel pool O&M and EP fees, but excludes program management costs (staffing), security and other related costs

[3] Columns may not add due to rounding

1. INTRODUCTION

This report presents estimates of the cost to decommission the Monticello Nuclear Generating Plant (Monticello) and the operation and eventual decommissioning of the on-site Independent Spent Fuel Storage Installation (ISFSI) for the selected decommissioning scenarios following the scheduled cessation of plant operations. The estimates are designed to provide Xcel Energy with the information to assess its current decommissioning liability, as it relates to Monticello.

The analysis relies upon site-specific, technical information from an earlier evaluation prepared in 2014, [1]* updated to reflect current assumptions pertaining to the disposition of the nuclear plant and relevant industry experience in undertaking such projects. The costs are based on several key assumptions in areas of regulation, component characterization, high-level radioactive waste management, low-level radioactive waste disposal, performance uncertainties (contingency) and site restoration requirements.

The analysis is not a detailed engineering evaluation, but an estimate prepared in advance of the detailed engineering required to carry out the decommissioning of the nuclear unit. It may also not reflect the actual plan to decommission Monticello; the plan may differ from the assumptions made in this analysis based on facts that exist at the time of decommissioning.

The 2014 plant inventory was reviewed for this analysis. It serves as the basis for the decontamination and dismantling requirements, cost, and the decommissioning waste streams. The review confirmed that there were no substantive changes to the configuration of the plant or site facilities that would impact decommissioning over the last three years. Removal of new FLEX facilities was included.

1.1 OBJECTIVES OF STUDY

The objectives of this study are to prepare comprehensive estimates of the cost to decommission Monticello, to provide a sequence or schedule for the associated activities, and to develop waste stream projections from the decontamination and dismantling activities.

The operating license was originally issued for the plant on September 8th, 1970, and was valid for a period of 40 years. In early 2005, Nuclear Management Company (as agent for Xcel Energy), submitted an application for

* Annotated references for citations in Sections 1-6 are provided in Section 7

a renewed license (i.e., 20 year extension). The application was approved by the NRC in November 2006. Therefore, for the purposes of this study, the final shutdown date (license expiration) for Monticello is September 8th, 2030, assuming a 60-year operating life (the current operating license's expiration date).

1.2 SITE DESCRIPTION

Monticello is located on the Mississippi River within the city limits of Monticello, in Wright County, Minnesota. The plant is located approximately 30 miles northwest of the Minneapolis-St. Paul area.

The Nuclear Steam Supply System (NSSS) consists of a single cycle, forced circulation, low power density boiling water reactor. The reactor recirculation system is comprised of the reactor vessel; the two loop reactor recirculation system with its pumps, pipes, and valves; the main steam piping up to the main steam isolation valves; and the reactor auxiliary systems piping. The system is housed within a "containment system," consisting of a steel light bulb-shaped drywell, a steel doughnut-shaped pressure suppression chamber, and interconnecting vent pipes. This system provides the first containment barrier surrounding the reactor vessel and reactor primary system. The reactor building provides secondary containment and is designed as a controlled leakage structure.

The saturated steam leaving the reactor vessel flows through the four main steam lines to the main turbine located in the turbine building. After passing through the main turbine, low-pressure steam is condensed, the non-condensable gases are removed, and the condensate is demineralized before being returned to the reactor vessel through the reactor feedwater system heaters. The turbine-generator system converts the thermodynamic energy of the steam into electrical energy. The unit's turbine-generator consists of one single-flow, high-pressure, and two double-flow, low-pressure turbines driving a direct-coupled generator at 1800 rpm. Heat rejected in the main condenser is removed by the circulating water system.

The circulating water system has been designed for open cycle once-through cooling towers, closed cycle with cooling towers, or for variations of these modes, i.e., partial recirculation. The system for open cycle operation consists of an intake structure with two half-capacity circulating water pumps, piping river water through the condenser to a discharge structure where the water enters a 1000-foot long canal that returns the water to the river downstream from the intake. Two induced-draft cooling towers are used during the open

and closed cycle operations. Cooled effluent returns by gravity to the intake structure from the cooling tower basins.

1.3 REGULATORY GUIDANCE

The Nuclear Regulatory Commission (NRC or Commission) provided initial decommissioning requirements in its rule "General Requirements for Decommissioning Nuclear Facilities," issued in June 1988.[2] This rule set forth financial criteria for decommissioning licensed nuclear power facilities. The regulation addressed decommissioning planning needs, timing, funding methods, and environmental review requirements. The intent of the rule was to ensure that decommissioning would be accomplished in a safe and timely manner and that adequate funds would be available for this purpose. Subsequent to the rule, the NRC issued Regulatory Guide 1.159, "Assuring the Availability of Funds for Decommissioning Nuclear Reactors,[3]" which provided additional guidance to the licensees of nuclear facilities on the financial methods acceptable to the NRC staff for complying with the requirements of the rule. The regulatory guide addressed the funding requirements and provided guidance on the content and form of the financial assurance mechanisms indicated in the rule.

The rule defined three decommissioning alternatives as being acceptable to the NRC: DECON, SAFSTOR, and ENTOMB. The DECON alternative assumes that any contaminated or activated portion of the plant's systems, structures, and facilities are removed or decontaminated to levels that permit the site to be released for unrestricted use shortly after the cessation of plant operations while the SAFSTOR and ENTOMB alternatives defer the process.

The rule also placed limits on the time allowed to complete the decommissioning process. For the SAFSTOR alternative, the process is restricted in overall duration to 60 years, unless it can be shown that a longer duration is necessary to protect public health and safety. The guidelines for ENTOMB are similar, providing the NRC with both sufficient leverage and flexibility to ensure that these deferred options are only used in situations where it is reasonable and consistent with the definition of decommissioning. At the conclusion of a 50 to 60-year dormancy period (or longer for ENTOMB if the NRC approves such a case), the site would still require significant remediation to meet the unrestricted release limits for license termination.

The ENTOMB alternative has not been viewed as a viable option for power reactors due to the significant time required to isolate the long-lived radionuclides for decay to permissible levels. However, with rulemaking permitting the controlled release of a site, [4] the NRC did re-evaluate the

alternative. The resulting feasibility study, based upon an assessment by Pacific Northwest National Laboratory, concluded that the method did have conditional merit for some, if not most reactors. The staff also found that additional rulemaking would be needed before this option could be treated as a generic alternative.

The NRC had considered rulemaking to alter the 60-year time for completing decommissioning and to clarify the use of engineered barriers for reactor entombments.[5] However, the NRC's staff has recommended that rulemaking be deferred, based upon several factors, e.g., no licensee has committed to pursuing the entombment option, the unresolved issues associated with the disposition of greater-than-Class C material (GTCC), and the NRC's current priorities, at least until after the additional research studies are complete. The Commission concurred with the staff's recommendation. In a draft regulatory basis document published in March 2017 in support of rulemaking that would amend NRC regulations concerning nuclear plant decommissioning, the NRC staff proposes removing any discussion of the ENTOMB option from existing guidance documents since the method is not deemed practically feasible.

In 1996, the NRC published revisions to the general requirements for decommissioning nuclear power plants. [6] When the regulations were originally adopted in 1988, it was assumed that the majority of licensees would decommission at the end of the facility's operating licensed life. Since that time, several licensees permanently and prematurely ceased operations. Exemptions from certain operating requirements were required once the reactor was defueled to facilitate the decommissioning. Each case was handled individually, without clearly defined generic requirements. The NRC amended the decommissioning regulations in 1996 to clarify ambiguities and codify procedures and terminology as a means of enhancing efficiency and uniformity in the decommissioning process. The new amendments allow for greater public participation and better define the transition process from operations to decommissioning.

Under the revised regulations, licensees will submit written certification to the NRC within 30 days after permanent shutdown. Certification will also be required once the fuel is permanently removed from the reactor vessel. Submittal of these notices will entitle the licensee to a fee reduction and eliminate the obligation to follow certain requirements needed only during operation of the reactor. Within two years of submitting notice of permanent cessation of operations, the licensee is required to submit a Post-Shutdown Decommissioning Activities Report (PSDAR) to the NRC. The PSDAR describes the planned decommissioning activities, the associated sequence and schedule, and an estimate of expected costs. Prior to completing

decommissioning, the licensee is required to submit applications to the NRC to terminate the license, which will include a License Termination Plan (LTP).

In 2011, the NRC published amended regulations to improve decommissioning planning and thereby reduce the likelihood that any current operating facility will become a legacy site.[7] The amended regulations require licensees to conduct their operations to minimize the introduction of residual radioactivity into the site, which includes the site's subsurface soil and groundwater. Licensees also may be required to perform site surveys to determine whether residual radioactivity is present in subsurface areas and to keep records of these surveys with records important for decommissioning. The amended regulations require licensees to report additional details in their decommissioning cost estimate as well as requiring additional financial reporting and assurances. These additional details, including an ISFSI decommissioning estimate, are included in this analysis.

1.3.1 High-Level Radioactive Waste Management

Congress passed the "Nuclear Waste Policy Act" [8] (NWPA) in 1982, assigning the federal government's long-standing responsibility for disposal of the spent nuclear fuel created by the commercial nuclear generating plants to the DOE. The NWPA provided that DOE would enter into contracts with utilities in which DOE would promise to take the utilities' spent fuel and high-level radioactive waste and utilities would pay the cost of the disposition services for that material. NWPA, along with the individual contracts with the utilities, specified that the DOE was to begin accepting spent fuel by January 31, 1998.

Since the original legislation, the DOE has announced several delays in the program schedule. By January 1998, the DOE had failed to accept any spent fuel or high level waste, as required by the NWPA and utility contracts. Delays continue and, as a result, generators have initiated legal action against the DOE in an attempt to obtain compensation for DOE's partial breach of contract. To date no spent fuel has been accepted from commercial generating sites for disposal.

In 2010, the Obama Administration appointed a Blue Ribbon Commission on America's Nuclear Future (Blue Ribbon Commission) to make recommendations for a new plan for nuclear waste disposal. The Blue Ribbon Commission's charter includes a requirement that it consider "[o]ptions for safe storage of used nuclear fuel while final disposition pathways are selected and deployed."[9]

On January 26, 2012, the Blue Ribbon Commission issued its "Report to the Secretary of Energy" containing a number of recommendations on nuclear waste disposal. Two of the recommendations that may impact decommissioning planning are:

- "[T]he United States [should] establish a program that leads to the timely development of one or more consolidated storage facilities"[10]
- "[T]he United States should undertake an integrated nuclear waste management program that leads to the timely development of one or more permanent deep geological facilities for the safe disposal of spent fuel and high-level nuclear waste."

In January 2013, the DOE issued the "Strategy for the Management and Disposal of Used Nuclear Fuel and High-Level Radioactive Waste," in response to the recommendations made by the Blue Ribbon Commission and as "a framework for moving toward a sustainable program to deploy an integrated system capable of transporting, storing, and disposing of used nuclear fuel..." [11] This document states:

"With the appropriate authorizations from Congress, the Obama Administration planned to implement a program over the next 10 years that would have:

- Sites, designs and licenses, constructs and begins operations of a pilot interim storage facility by 2021 with an initial focus on accepting used nuclear fuel from shut-down reactor sites;
- Advances toward the siting and licensing of a larger interim storage facility to be available by 2025 that will have sufficient capacity to provide flexibility in the waste management system and allows for acceptance of enough used nuclear fuel to reduce expected government liabilities; and
- Makes demonstrable progress on the siting and characterization of repository sites to facilitate the availability of a geologic repository by 2048."

The NRC's review of DOE's license application to construct a geologic repository at Yucca Mountain was suspended in 2011 when the Obama Administration slashed the budget for completing that work. However, the US Court of Appeals for the District of Columbia Circuit issued a writ of mandamus (in August 2013) [12] ordering NRC to comply with federal law and restart its review of DOE's Yucca Mountain repository

license application to the extent of previously appropriated funding for the review. That review is now complete with the publication of the five-volume safety evaluation report. A supplement to DOE's environmental impact statement and an adjudicatory hearing on the contentions filed by interested parties must be completed before a licensing decision can be made.

The state of Minnesota directed the Public Utilities Commission, "when considering approval of a plan for the accrual of funds for the decommissioning of nuclear facilities" …to "include an evaluation of the costs, if any, arising from storage of used nuclear fuel that may be incurred by the state of Minnesota, and any tribal community, county, city, or township where used nuclear fuel is located following the cessation of operations at a nuclear plant."[13]

The state of Minnesota statute also prescribed the parameters to be used in evaluating spent fuel management costs. "To assist the commission in making the determination … the filing shall provide cost estimates, including ratepayer impacts, assuming used nuclear fuel will be stored in the state for 60 years, 100 years, and 200 years following the cessation of operation of the nuclear plant."

Xcel Energy's current spent fuel management plan for the Monticello spent fuel is based in general upon:

1) Fuel transferred from the pool to the ISFSI within 5 years of shutdown;
2) Exchange of Monticello and Prairie Island spent fuel acceptance rights to best manage the overall cost of spent fuel storage for both plants;
3) Fuel will be shipped in the existing NUHOMS DSCs (Scenarios 1, 2, 6, and 7); the canisters and NUHOMS are periodically replaced in Scenarios 3, 4 and 5. Canisters that are unloaded in the spent fuel transfer operation will be surveyed for neutron activation.
4) As an allowance, some of these canisters and NUHOMS modules from the first off-load operation are assumed to be mildly neutron activated and therefore must be disposed of as radioactive waste.

The NRC requires that licensees establish a program to manage and provide funding for the caretaking of all irradiated fuel at the reactor

site until title of the fuel is transferred to the Secretary of Energy, pursuant to 10 CFR Part 50.54(bb). [14] This requirement is prepared for through inclusion of certain cost elements in the decommissioning estimates, for example, associated with the isolation and continued operation of the spent fuel pool and the ISFSI.

The spent fuel pool is expected to contain freshly discharged assemblies (from the most recent refueling cycles) as well as the final reactor core at shutdown. In the DECON and SAFSTOR scenarios, the assemblies are packaged into dry shielded canisters (DSCs) over the first five years after shutdown for transfer to the ISFSI for interim storage. It is assumed that this period provides the necessary cooling for the final core to meet the transport and/or storage requirements for decay heat.

An ISFSI, operated under a Part 50 General License (in accordance with 10 CFR 72, Subpart K [15]), has been constructed to support continued plant operations. The facility is assumed to be expanded to support decommissioning. This will allow decommissioning activities to proceed within the reactor building.

DOE has breached its obligations to remove fuel from reactor sites, and has also failed to provide the plant owners with information about how it will ultimately perform. DOE officials have stated that DOE does not have an obligation to accept already-canistered fuel without an amendment to DOE's contracts with plant licensees to remove the fuel (the "Standard Contract"), but DOE has not explained what any such amendment would involve. Consequently, Xcel Energy has no information or expectations on how DOE will remove fuel from the site in the future. In the absence of information about how DOE will perform, and for purposes of this analysis only, it is assumed that DOE will accept already-canistered fuel. If this assumption is incorrect, it is assumed that DOE will have liability for costs incurred to transfer the fuel to DOE-supplied containers.

Xcel Energy's position is that the DOE has a contractual obligation to accept Monticello's fuel earlier than the projections set out above, consistent with its contract commitments. No assumption made in this study should be interpreted to be inconsistent with this claim. However, including the cost of storing spent fuel in this study is appropriate to ensure the availability of sufficient decommissioning funds at the end of the station's life if the DOE has not met its obligation. The cost for the interim storage of spent fuel has been calculated and is separately presented as "Spent Fuel Management" expenditures in this report.

1.3.2 Low-Level Radioactive Waste Disposal

The contaminated and activated material generated in the decontamination and dismantling of a commercial nuclear reactor is classified as low-level (radioactive) waste, although not all of the material is suitable for "shallow-land" disposal. With the passage of the "Low-Level Radioactive Waste Policy Act" in 1980, [16] and its Amendments of 1985, [17] the states became ultimately responsible for the disposition of low-level radioactive waste generated within their own borders. It was expected that groups of states would combine together to jointly deal with their radioactive wastes; these organizations are referred to as waste disposal compacts.

With the exception of Texas, no new compact facilities have been successfully sited, licensed, and constructed. The Texas Compact disposal facility is now operational and waste is being accepted from generators within the Compact by the operator, Waste Control Specialists (WCS). The facility is also able to accept limited quantities of non-Compact waste.

Disposition of the various waste streams produced by the decommissioning process considered all options and services currently available to Xcel Energy. The majority of the low-level radioactive waste designated for direct disposal (Class A [18]) can be sent to Energy*Solutions*' facility in Clive, Utah. Therefore, disposal costs for Class A waste were based upon representative rates. This facility is not licensed to receive the higher activity portion (Classes B and C) of the decommissioning waste stream.

The Texas facility is licensed to receive the higher activity waste forms (Classes B and C). As such, for this analysis, disposal costs for the Class B and C waste were based upon the preliminary and indicative information on the cost for such from WCS.

The dismantling of the components residing closest to the reactor core generates radioactive waste considered unsuitable for shallow-land disposal (i.e., low-level radioactive waste with concentrations of radionuclides that exceed the limits established by the NRC for Class C radioactive waste (GTCC)). The Low-Level Radioactive Waste Policy Amendments Act of 1985 assigned the federal government the responsibility for the disposal of this material. The Act also stated that the beneficiaries of the activities resulting in the generation of such radioactive waste bear all reasonable costs of disposing of such waste. However, to date, the federal government has not identified a cost for disposing of GTCC or a schedule for acceptance.

For purposes of this analysis, the GTCC radioactive waste is assumed to be packaged and disposed of in a similar manner as high-level waste (i.e., in a geologic repository) and at a cost equivalent to that envisioned for the spent fuel. The GTCC is packaged in the same canisters used for spent fuel and either stored on site or shipped directly to a DOE facility as it is generated (depending upon the timing of the decommissioning and whether the spent fuel has been removed from the site prior to the start of decommissioning).

A significant portion of the metallic waste material generated during decommissioning may only be potentially contaminated by radioactive materials. This waste can be surveyed on site or shipped off site to licensed facilities for further analysis, for processing and/or for conditioning/recovery. Reduction in the volume of low-level radioactive waste requiring disposal in a licensed low-level radioactive waste disposal facility can be accomplished through a variety of methods, including analyses and surveys or decontamination to isolate the portion of waste that does not require disposal as radioactive waste, compaction, incineration or metal melt. The estimates reflect the savings from waste recovery/volume reduction.

1.3.3 Radiological Criteria for License Termination

In 1997, the NRC published Subpart E, "Radiological Criteria for License Termination," [19] amending 10 CFR §20. This subpart provides radiological criteria for releasing a facility for unrestricted use. The regulation states that the site can be released for unrestricted use if radioactivity levels are such that the average member of a critical group would not receive a Total Effective Dose Equivalent (TEDE) in excess of 25 millirem per year, and provided that residual radioactivity has been reduced to levels that are As Low As Reasonably Achievable (ALARA). The decommissioning estimates for Monticello assume that the site will be remediated to a residual level consistent with the NRC-prescribed level for radioactive material.

It should be noted that the NRC and the Environmental Protection Agency (EPA) differ on the amount of residual radioactivity considered acceptable in site remediation. The EPA has two limits that apply to radioactive materials. An EPA limit of 15 millirem per year is derived from criteria established by the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA or Superfund). [20] An additional and separate limit of 4 millirem per year, as defined in 40 CFR §141.66, is applied to drinking water. [21]

On October 9, 2002, the NRC signed an agreement with the EPA on the radiological decommissioning and decontamination of NRC-licensed sites. The Memorandum of Understanding (MOU) [22] provides that EPA will defer exercise of authority under CERCLA for the majority of facilities decommissioned under NRC authority. The MOU also includes provisions for NRC and EPA consultation for certain sites when, at the time of license termination, (1) groundwater contamination exceeds EPA-permitted levels; (2) NRC contemplates restricted release of the site; and/or (3) residual radioactive soil concentrations exceed levels defined in the MOU.

The MOU does not impose any new requirements on NRC licensees and should reduce the involvement of the EPA with NRC licensees who are decommissioning. Most sites are expected to meet the NRC criteria for unrestricted use, and the NRC believes that only a few sites will have groundwater or soil contamination in excess of the levels specified in the MOU that trigger consultation with the EPA. However, if there are other hazardous materials on the site, the EPA may be involved in the cleanup. As such, the possibility of dual regulation remains for certain licensees. The present study does not include any costs for this occurrence.

FIGURE 1.1
MONTICELLO NUCLEAR GENERATING PLANT
GENERAL PLAN

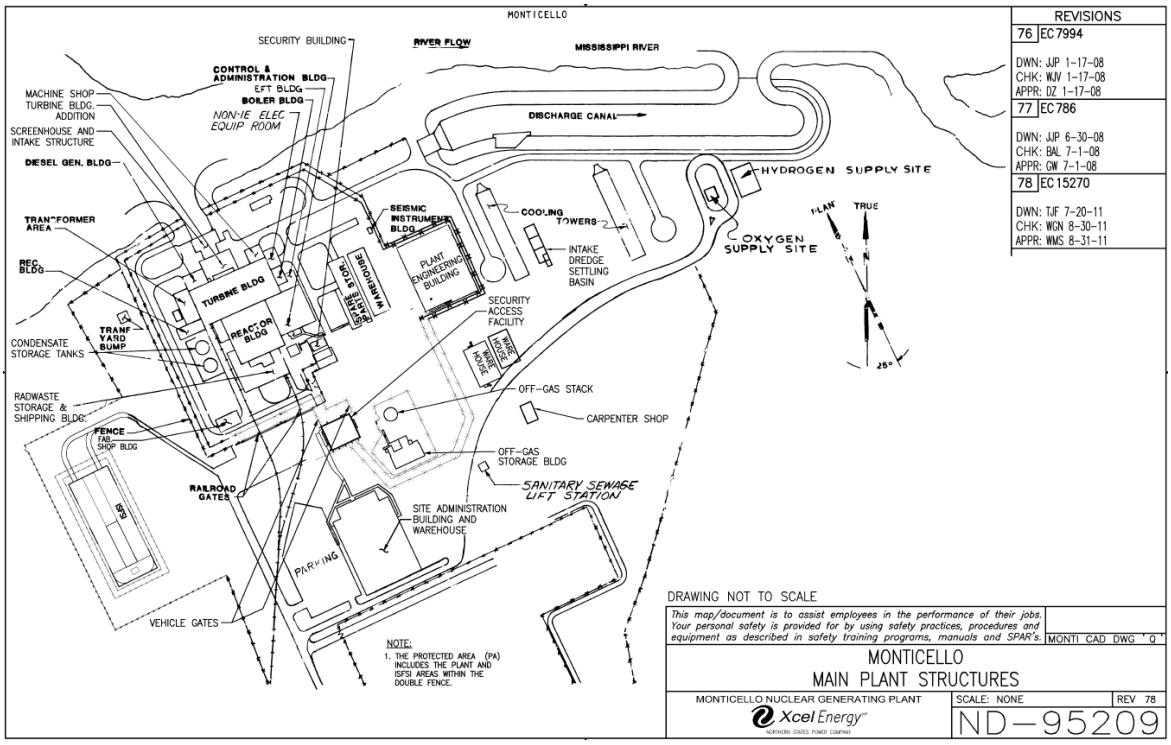
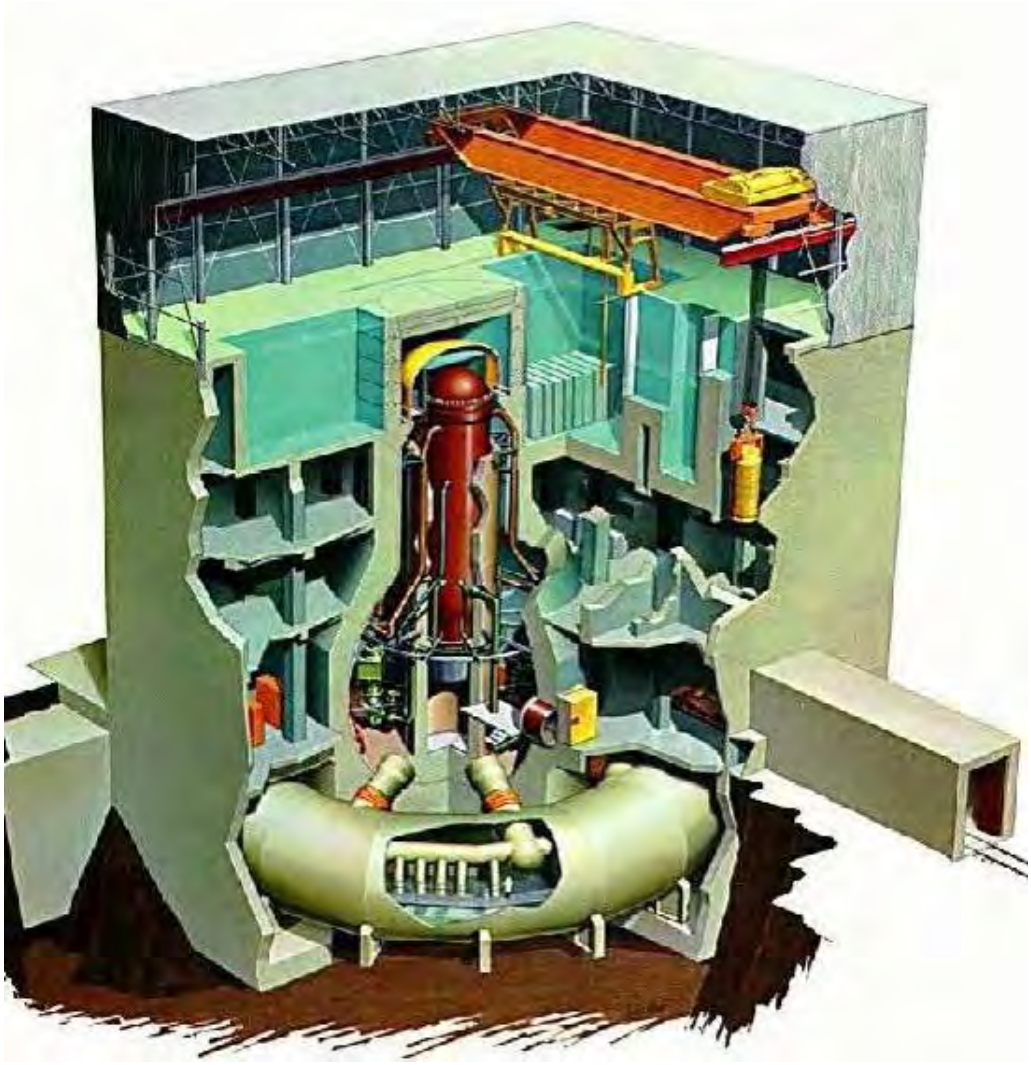


FIGURE 1.2
MONTICELLO NUCLEAR GENERATING PLANT
AERIAL VIEW

FIGURE 1.3
MONTICELLO NUCLEAR GENERATING PLANT
REACTOR BUILDING SECTION



2. DECOMMISSIONING ALTERNATIVES

Detailed cost estimates were developed to decommission Monticello based upon the approved decommissioning alternatives: DECON and SAFSTOR. Although the alternatives differ with respect to technique, process, cost, and schedule, they attain the same result: the ultimate release of the site for unrestricted use.

The following scenarios were evaluated and are intended to bound the liability associated with the removal of spent fuel from the site. The current operating license expires in 2030. The scenarios consist of five DECON scenarios, with differing spent fuel management assumptions, but essentially no changes to the decommissioning costs and timing of the power block. There are also two SAFSTOR scenarios (Scenarios 6 and 7) each corresponding to the first two DECON scenario spent fuel management assumptions. The spent fuel in the plant's spent fuel storage pool is transferred to the ISFSI within the first five years. The equipment, structures, and portions of the plant containing radioactive contaminants are removed or decontaminated to a level that permits the facility to be released for unrestricted use. Non-essential structures are then demolished. Spent fuel storage operations continue at the ISFSI until the transfer of the fuel to the DOE is completed (2062 in Scenarios 1 & 6, 2090 in Scenarios 2, 5 & 7, 2130 in Scenario 3, and 2230 in Scenario 4).

Scenario	1st Spent Fuel Canister Replacement	1st Spent Fuel Assembly Removed from Monticello*	Last Spent Fuel Assembly Removed from Monticello	Scenario Identification
1	n/a	2042	2062	DECON with 32 Year DFS+
2	n/a	2078	2090	DECON with 60 Year DFS
3	2058	2118	2130	DECON with 100 Year DFS
4	2058	2218	2230	DECON with 200 Year DFS
5	2058	2078	2090	DECON with 60 Year DFS and recasking
6	n/a	2042	2062	SAFSTOR with 32 Year DFS
7	n/a	2078	2090	SAFSTOR with 60 Year DFS

* Spent fuel stored at Morris is removed prior to fuel stored at the Monticello site.
+ Dry Fuel Storage

For Scenarios 2 and 7, although they provide a total fuel storage period of 60 years following plant shutdown, Xcel Energy directed TLG Services to not include the cost of transferring the spent fuel in dry storage to new canisters at 50 years after plant shutdown. The assumption to not transfer spent fuel at 50 years following plant shutdown in Scenarios 2 and 7 was premised on the likelihood that the life of the canisters could be successfully managed for an additional 10 years.

In Scenarios 3, 4 and 5, the DSCs are assumed to be replaced after fifty years of use. Since the reactor building spent fuel storage pool and fuel handling facilities are removed by the year 2038, a dry fuel transfer facility is assumed to be constructed on site to perform the transfers from the old to the new DSCs. For Scenarios 3 and 5, only one such transfer is needed over the time frame assumed (some fuel canisters in Scenario 5 will not require recasking). For Scenario 4, the spent fuel will be transferred three times following initial placement in the ISFSI.

The following sections describe the basic activities associated with each alternative. Although detailed procedures for each activity identified are not provided, and the actual sequence of work may vary, the activity descriptions provide a basis not only for estimating but also for the expected scope of work (i.e., engineering and planning at the time of decommissioning).

The conceptual approach that the NRC has described in its regulations divides decommissioning into three phases. The initial phase commences with the effective date of permanent cessation of operations and involves the transition of both plant and licensee from reactor operations (i.e., power production) to facilitate de-activation and closure. During the first phase, notification is to be provided to the NRC certifying the permanent cessation of operations and the removal of fuel from the reactor vessel. The licensee would then be prohibited from reactor operation.

The second phase encompasses activities during the storage period or during major decommissioning activities, or a combination of the two. The third phase pertains to the activities involved in license termination. The decommissioning estimates developed for Monticello are also divided into phases or periods; however, demarcation of the phases is based upon major milestones within the project or significant changes in the projected expenditures.

2.1 DECON

The DECON alternative, as defined by the NRC, is "the alternative in which the equipment, structures, and portions of a facility and site containing radioactive contaminants are removed or decontaminated to a level that permits the property to be released for unrestricted use shortly after cessation of operations." This study does not address the cost to dispose of the spent fuel

residing at the site; such costs are funded through a surcharge on electrical generation. However, the study does estimate the costs incurred with the interim on-site storage of the fuel pending shipment by the DOE to an off-site disposal facility. Those costs are separately presented as "Spent Fuel Management" expenditures in this report.

2.1.1 Period 1 - Preparations

In anticipation of the cessation of plant operations, detailed preparations are undertaken to provide a smooth transition from plant operations to site decommissioning. Through implementation of a staffing transition plan, the organization required to manage the intended decommissioning activities is assembled from available plant staff and outside resources. Preparations include the planning for permanent defueling of the reactor, revision of technical specifications applicable to the operating conditions and requirements, a characterization of the facility and major components, and the development of the PSDAR.

Engineering and Planning

The PSDAR, required prior to, or within two years of permanent cessation of operations, provides a description of the licensee's planned decommissioning activities, a timetable, a site-specific decommissioning cost estimate, and the associated financial requirements of the intended decommissioning program. Upon receipt of the PSDAR, the NRC will make the document available to the public for comment in a local meeting to be held in the vicinity of the reactor site. Ninety days following submittal and NRC receipt of the PSDAR, the licensee may begin to perform major decommissioning activities under a modified 10 CFR §50.59 procedure, (10 CFR §50.59 establishes the conditions under which licensees may make changes to the facility or procedures and conduct test or experiments, i.e., without prior NRC approval). Major activities are defined as any activity that results in permanent removal of major radioactive components, permanently modifies the structure of the containment, or results in dismantling components (for shipment) containing GTCC, as defined by 10 CFR §61. Major components are further defined as comprising the reactor vessel and internals, large bore reactor recirculation system piping, and other large components that are radioactive. The NRC includes the following additional criteria for use of the §50.59 process in decommissioning. The proposed activity must not:

- foreclose release of the site for possible unrestricted use,
- significantly increase decommissioning costs,
- cause any significant environmental impact not previously reviewed, or
- result in there no longer being reasonable assurance that adequate funds will be available for decommissioning

Existing operational technical specifications are reviewed and modified to reflect plant conditions and the safety concerns associated with permanent cessation of operations. The environmental impact associated with the planned decommissioning activities is also considered. Typically, a licensee will not be allowed to proceed if the consequences of a particular decommissioning activity are greater than that bounded by previously evaluated environmental assessments or impact statements. In this instance, the licensee would have to submit a license amendment for the specific activity and update the environmental report.

The decommissioning program outlined in the PSDAR will be designed to accomplish the required tasks within the ALARA guidelines (as defined in 10 CFR §20) for protection of personnel from exposure to radiation hazards. It will also address the continued protection of the health and safety of the public and the environment during the dismantling activity. Consequently, with the development of the PSDAR, activity specifications, cost-benefit and safety analyses, and work packages and procedures, would be assembled to support the proposed decontamination and dismantling activities.

Site Preparations

Following final plant shutdown, and in preparation for actual decommissioning activities, the following activities are initiated:

- Characterization of the site and surrounding environs. This includes radiation surveys of work areas, major components (including the reactor vessel and its internals), internal piping, and primary shield cores.
- An ISFSI has been constructed to support continued plant operation and will need to be expanded following the cessation of operations to offload the spent fuel pool in support of the decommissioning program.

- Isolation of the spent fuel storage pool and fuel handling systems, such that decommissioning operations can commence on the balance of the plant. Decommissioning operations are scheduled around the fuel handling area to optimize the overall project schedule. It is assumed that the fuel pool remains operational for the transfer of fuel for approximately five years following the cessation of operations.
- Specification of transport and disposal requirements for activated materials and/or hazardous materials, including shielding and waste stabilization.
- Development of procedures for occupational exposure control, control and release of liquid and gaseous effluent, processing of radwaste (including dry-active waste, resins, filter media, metallic and non-metallic components generated in decommissioning), site security and emergency programs, and industrial safety.

2.1.2 Period 2 - Decommissioning Operations

This period includes the physical decommissioning activities associated with the removal and disposal of contaminated and activated components and structures, including the successful amendment of the 10 CFR §50 operating license (releasing the site, exclusive of the ISFSI). Significant decommissioning activities in this phase include:

- Construction of temporary facilities and/or modification of existing facilities to support dismantling activities. This may include a centralized processing area to facilitate equipment removal and component preparations for off-site disposal.
- Reconfiguration and modification of site structures and facilities as needed to support decommissioning operations. This may include the upgrading of roads (on- and off-site) to facilitate hauling and transport. Modifications may be required to the containment structure to facilitate access of large/heavy equipment. Modifications may also be required to the refueling area of the reactor building to support the segmentation of the reactor vessel internals and component extraction.
- Transfer of the spent fuel from the storage pool to the ISFSI pad for interim storage.
- Design and fabrication of temporary and permanent shielding to support removal and transportation activities, construction of

contamination control envelopes, and the procurement of specialty tooling.

- Procurement (lease or purchase) of shipping canisters, cask liners, and industrial packages.
- Decontamination of components and piping systems as required to control (minimize) worker exposure.
- Removal of piping and components no longer essential to support decommissioning operations.
- Transfer of the steam separator and dryer assemblies to the dryer-separator pool for segmentation. Segmentation by weight and activity maximizes the loading of the shielded transport casks. The operations are conducted under water using remotely operated tooling and contamination controls.
- Disconnection of the control blades from the drives on the vessel lower head. Blades are transferred to the spent fuel pool for packaging.
- Disassembly, segmentation, and packaging of the core shroud and in-core guide tubes. Some of the material is expected to exceed Class C disposal requirements. As such, those segments are packaged in modified fuel storage canisters for geologic disposal.
- Removal and segmentation of the remaining internals including the jet pump assemblies, fuel support castings, and core plate assembly.
- Removal of spent fuel storage racks from spent fuel pool, and cleanup of spent fuel pool.
- Draining and decontamination of the reactor well and the permanent sealing of the spent fuel transfer gate. Installation of a shielded platform for segmentation of the reactor vessel. Cutting operations are performed in air using remotely operated equipment within a contamination control envelope, with the water level maintained just below the cut to minimize the working area dose rates. Sections are transferred to the dryer-separator pool for packaging and interim storage.
- Disconnection of the control rod drives and instrumentation tubes from the reactor vessel lower head. The lower reactor head and vessel supporting structure are then segmented.
- Removal of the reactor recirculation pumps. Exterior surfaces are decontaminated and openings covered. Components can serve as

their own burial containers provided that all penetrations are properly sealed.

- Demolition of the sacrificial shield wall activated concrete by controlled demolition.
- Spent fuel storage operations continue throughout the active decommissioning period.

At least two years prior to the anticipated date of license termination, an LTP is required. Submitted as a supplement to the Final Safety Analysis Report (FSAR) or its equivalent, the plan must include: a site characterization, description of the remaining dismantling activities, plans for site remediation, procedures for the final radiation survey, designation of the end use of the site, an updated cost estimate to complete the decommissioning, and any associated environmental concerns. The NRC will notice the receipt of the plan, make the plan available for public comment, and schedule a local meeting. LTP approval will be subject to any conditions and limitations as deemed appropriate by the Commission. The licensee may then commence with the final remediation of site facilities and services, including:

- Removal of remaining plant systems and associated components as they become nonessential to the decommissioning program or worker health and safety (e.g., waste collection and treatment systems, electrical power and ventilation systems).
- Removal of the steel liners from the drywell, disposing of the activated and contaminated sections as radioactive waste. Removal of any activated/contaminated concrete.
- Removal of the steel liners from the dryer/separator pool, reactor well, and spent fuel storage pool.
- Surveys of the decontaminated areas of the containment structure.
- Removal of the contaminated equipment and material from the turbine and radwaste buildings, and any other contaminated facility. Use radiation and contamination control techniques until radiation surveys indicate that the structures can be released for unrestricted access and conventional demolition. This activity may necessitate the dismantling and disposition of most of the systems and components (both clean and contaminated) located within these buildings. This activity will facilitate surface decontamination and subsequent verification surveys required prior to obtaining release for demolition.

- Removal of the remaining components, equipment, and plant services in support of the area release survey(s).
- Routing of material removed in the decontamination and dismantling to a central processing area. Material certified to be free of contamination is released for unrestricted disposition, e.g., as scrap, recycle, or general disposal. Contaminated material is characterized and segregated for additional off-site processing (disassembly, chemical cleaning, volume reduction, and waste treatment), and/or packaged for controlled disposal at a low-level radioactive waste disposal facility.

Incorporated into the LTP is the Final Survey Plan. This plan identifies the radiological surveys to be performed once the decontamination activities are completed and is developed using the guidance provided in the "Multi-Agency Radiation Survey and Site Investigation Manual (MARSSIM)."[23] This document incorporates the statistical approaches to survey design and data interpretation used by the EPA. It also identifies commercially available instrumentation and procedures for conducting radiological surveys. Use of this guidance ensures that the surveys are conducted in a manner that provides a high degree of confidence that applicable NRC criteria are satisfied. Once the survey is complete, the results are provided to the NRC in a format that can be verified. The NRC then reviews and evaluates the information, performs an independent confirmation of radiological site conditions, and makes a determination on the requested change to the operating license (that would release the property, exclusive of the ISFSI, for unrestricted use).

The NRC will amend the operating license to reduce the licensed area to the ISFSI area if it determines that site remediation has been performed in accordance with the LTP, and that the terminal radiation survey and associated documentation demonstrate that the property (exclusive of the ISFSI) is suitable for release.

2.1.3 Period 3 - Site Restoration

Following completion of decommissioning operations, site restoration activities will begin. Efficient removal of the contaminated materials and verification that residual radionuclide concentrations are below the NRC limits will result in substantial damage to many of the structures. Although performed in a controlled and safe manner, blasting, coring, drilling, scarification (surface removal), and the other decontamination activities will substantially degrade power block structures including the reactor, turbine and radwaste buildings. Under certain

circumstances, verifying that subsurface radionuclide concentrations meet NRC site release requirements will require removal of grade slabs and lower floors, potentially weakening footings and structural supports. This removal activity will be necessary for those facilities and plant areas where historical records, when available, indicate the potential for radionuclides having been present in the soil, where system failures have been recorded, or where it is required to confirm that subsurface process and drain lines were not breached over the operating life of the station.

Dismantling of site structures following decommissioning is clearly the most appropriate and cost-effective option. It is unreasonable to anticipate that these structures would be repaired and preserved after the radiological contamination is removed. The effort to dismantle site structures with a work force already mobilized on site is more efficient than if the process were deferred. Site facilities quickly degrade without maintenance, adding additional expense and creating potential hazards to the public as well as to future workers. Abandonment creates a breeding ground for vermin infestation as well as other biological hazards.

This cost study presumes that non-essential structures and site facilities are dismantled as a continuation of the decommissioning activity. Foundations and exterior walls are completely removed, including foundations and basemats, as required by Minnesota regulations. [24] Site areas affected by the dismantling activities are restored and the plant area graded as required to prevent ponding, establish erosion control by the planting of native vegetation, and inhibit the refloating of subsurface materials.

Non-contaminated concrete rubble produced by demolition activities is processed to remove reinforcing steel and miscellaneous embedments. All non-contaminated materials are trucked to an off-site area for disposal as construction debris. Subgrade voids are backfilled with clean construction fill, suitable under Minnesota regulations.

2.1.4 ISFSI Operations and Decommissioning

The ISFSI will continue to operate under a general license (10 CFR §50) following the amendment of the operating license to release the adjacent (power block) property. Assuming that Monticello spent fuel shipments begin in 2042, the process is not expected to be completed until 2062 (Scenario 1). Any delay in the transfer process, for example, due to a

delay in the scheduled opening of the geologic repository, a slower acceptance rate, or a combination of both, can result in a longer on-site residence time for the fuel discharge from the reactor, as well as additional caretaking expenses. Scenarios 3 and 4 address extended delay periods. Scenarios 3, 4 and 5 also reflect an assumption that the spent fuel DSCs will need to be replaced every fifty years.

The assumed design for the ISFSI is based upon the use of a multi-purpose dry shielded storage canister and a horizontal storage module for pad storage.

At the conclusion of the spent fuel transfer process, the ISFSI will be decommissioned. The Commission will terminate the license if it determines that the remediation of the ISFSI has been performed in accordance with an ISFSI license termination plan and that the final radiation survey and associated documentation demonstrate that the facility is suitable for release. Once the requirements are satisfied, the NRC can terminate the license for the ISFSI.

For purposes of this cost analysis, it is assumed that once the DSCs containing the spent fuel assemblies have been removed, any required decontamination is performed on the storage overpacks (some minor neutron-induced activation is assumed), and the license for the facility terminated, the concrete overpacks can be dismantled using conventional techniques for the demolition of reinforced concrete. The concrete storage pad is then removed and the area regraded. This topic is discussed in greater detail in section 3.4.1.

2.2 SAFSTOR

The NRC defines SAFSTOR as "the alternative in which the nuclear facility is placed and maintained in a condition that allows the nuclear facility to be safely stored and subsequently decontaminated (deferred decontamination) to levels that permit release for unrestricted use." The facility is left intact (during the dormancy period), with structures maintained in a sound condition. Systems not required to operate in support of the spent fuel pool or site surveillance and security are drained, de-energized, and secured. Minimal cleaning/removal of loose contamination and/or fixation and sealing of remaining contamination are performed. Access to contaminated areas is secured to provide controlled access for inspection and maintenance.

The engineering and planning requirements are similar to those for the DECON alternative. Site preparations are also similar to those for the DECON

alternative. However, with the exception of the required radiation surveys and site characterizations, the mobilization and preparation of site facilities is less extensive.

2.2.1 Period 1 - Preparations

Preparations for long-term storage include the planning for permanent defueling of the reactor, revision of technical specifications appropriate to the operating conditions and requirements, a characterization of the facility and major components, and the development of the PSDAR.

The process of placing the plant in safe-storage includes, but is not limited to, the following activities:

- Isolation of the spent fuel storage services and fuel handling systems located in the reactor building so that safe-storage operations may commence on the balance of the plant. This activity may be carried out by plant personnel in accordance with existing operating technical specifications. Activities are scheduled around the fuel handling systems to the greatest extent possible.
- Draining and de-energizing of the non-contaminated systems not required to support continued site operations or maintenance.
- Disposing of contaminated filter elements and resin beds not required for processing wastes from layup activities for future operations.
- Draining of the reactor vessel, with the internals left in place and the vessel head secured.
- Draining and de-energizing non-essential, contaminated systems with decontamination as required for future maintenance and inspection.
- Preparing lighting and alarm systems whose continued use is required; de-energizing portions of fire protection, electric power, and HVAC systems whose continued use is not required.
- Cleaning of the loose surface contamination from building access pathways.
- Performing an interim radiation survey of plant, posting warning signs where appropriate.
- Erecting physical barriers and/or securing all access to radioactive or contaminated areas, except as required for inspection and maintenance.

- Installing security and surveillance monitoring equipment and relocating security fence around secured structures, as required.

2.2.2 Period 2 - Dormancy

The second phase identified by the NRC in its rule addresses licensed activities during a storage period and is applicable to the dormancy phases of the deferred decommissioning alternatives. Dormancy activities include a 24-hour security force, preventive and corrective maintenance on security systems, area lighting, general building maintenance, heating and ventilation of buildings, routine radiological inspections of contaminated structures, maintenance of structural integrity, and a site environmental and radiation monitoring program. Resident maintenance personnel perform equipment maintenance, inspection activities, routine services to maintain safe conditions, adequate lighting, heating, and ventilation, and periodic preventive maintenance on essential site services.

An environmental surveillance program is carried out during the dormancy period to ensure that releases of radioactive material to the environment are prevented and/or detected and controlled. Appropriate emergency procedures are established and initiated for potential releases that exceed prescribed limits. The environmental surveillance program constitutes an abbreviated version of the program in effect during normal plant operations.

Security during the dormancy period is conducted primarily to protect the spent nuclear fuel while it is on site, prevent unauthorized entry, and to protect the public from the consequences of their own actions. The security fence, sensors, alarms, and other surveillance equipment provide security. Fire and radiation alarms are also monitored and maintained. While remote surveillance is an option, it does not offer the immediate response time of a physical presence.

During Scenario 6, the transfer of the spent fuel to a DOE facility continues during this period until complete. In Scenario 7, ISFSI operations and fuel transfer to the DOE continue through delayed decommissioning.

The length of the dormancy period is such that decommissioning (license termination) of the station (excluding the ISFSI) is accomplished within 60 years of final shutdown. The Scenario 6 SAFSTOR has the site remain in dormancy following spent fuel removal to the maximum

extent possible, such that the license is terminated within the required 60-year time period.

It is required that the licensee submit an application to terminate the license, along with a LTP (described in Section 2.1.2), thereby initiating the third phase.

2.2.3 Periods 3 and 4 - Delayed Decommissioning

Prior to the commencement of decommissioning operations, preparations are undertaken to reactivate site services and prepare for decommissioning. Preparations include engineering and planning, a detailed site characterization, and the assembly of a decommissioning management organization. Final planning for activities and the writing of activity specifications and detailed procedures are also initiated at this time.

Much of the work in developing a termination plan is relevant to the development of the detailed engineering plans and procedures. The activities associated with this phase and the follow-on decontamination and dismantling processes are detailed in Sections 2.1.1 and 2.1.2. The primary difference between the sequences anticipated for the DECON and SAFSTOR scenarios is the absence, in the latter, of any constraint on the availability of the fuel storage pool located within the reactor building for decommissioning.

For Scenario 7, final fuel shipment occurs during Period 4f, the Final Survey period. ISFSI decommissioning begins immediately upon completion of final shipment of the spent fuel and GTCC canisters.

Variations in the length of the dormancy period are expected to have some effect upon the quantities of radioactive wastes generated from system and structure removal operations. However, given the levels of radioactivity and spectrum of radionuclides expected from approximately sixty years of plant operation, no plant process system identified as being contaminated upon final shutdown will become releasable due to the decay period alone. (i.e., there is no significant reduction in the waste generated from the decommissioning activities). Due to the lower activity levels, a greater percentage of the waste volume can be designated for off-site processing and recovery.

The delay in decommissioning also yields lower working area radiation levels. As such, the estimate for the delayed scenarios incorporate

reduced ALARA controls for the SAFSTOR's lower occupational exposure potential.

Although the initial radiation levels due to ^{60}Co will substantially decrease during the dormancy period, the internal components of the reactor vessel will still exhibit sufficiently high radiation dose rates to require remote sectioning under water due to the presence of long-lived radionuclides such as ^{94}Nb, ^{59}Ni, and ^{63}Ni. Therefore, the dismantling procedures described for the DECON alternative would still be employed during this scenario. Portions of the sacrificial shield wall will still be radioactive due to the presence of activated trace elements with long half-lives (^{152}Eu and ^{154}Eu). Decontamination will require controlled removal and disposal. It is assumed that radioactive corrosion products on inner surfaces of piping and components will not have decayed to levels that will permit unrestricted use or allow conventional removal. These systems and components will be surveyed as they are removed and disposed of in accordance with the existing radioactive release criteria.

2.2.4 Period 5 - Site Restoration

Following completion of decommissioning operations, site-restoration activities can begin. Dismantling, as a continuation of the decommissioning process, is a cost-effective option, as described in Section 2.1.3. The basis for the dismantling cost in this scenario is consistent with that described for DECON, presuming the removal of structures and site facilities to include the existing foundations and basemats, and the limited restoration of the site.

3. COST ESTIMATES

The cost estimates prepared for decommissioning Monticello consider the unique features of the site, including the NSSS, power generation systems, support services, site buildings, and ancillary facilities. The basis of the estimates, including the sources of information relied upon, the estimating methodology employed, site-specific considerations, and other pertinent assumptions, is described in this section.

3.1 BASIS OF ESTIMATES

The estimates were developed using the site-specific, technical information from the 2014 analysis. The plant inventory, the basis for the decontamination and dismantling requirements and cost, and the decommissioning waste streams, was reviewed for this analysis; no substantive changes were identified over the three-year period to the configuration of the plant or site facilities that would impact decommissioning. The site-specific considerations and assumptions used in the previous evaluation were also revisited; no necessary modifications were identified. Modifications such as new FLEX facilities were incorporated where new information was available or experience from ongoing decommissioning programs provided viable alternatives or improved processes.

3.2 METHODOLOGY

The methodology used to develop the estimates follows the basic approach originally presented in the AIF/NESP-036 study report, "Guidelines for Producing Commercial Nuclear Power Plant Decommissioning Cost Estimates,"[25] and the DOE "Decommissioning Handbook."[26] These documents present a unit factor method for estimating decommissioning activity costs, which simplifies the estimating calculations. Unit factors for concrete removal ($/cubic yard), steel removal ($/ton), and cutting costs ($/inch) were developed using local labor rates. The activity-dependent costs were estimated with the item quantities (cubic yards and tons), developed from plant drawings and inventory documents. Removal rates and material costs for the conventional disposition of components and structures relied upon information available in the industry publication, "Building Construction Cost Data," published by RSMeans. [27]

The unit factor method provides a demonstrable basis for establishing reliable cost estimates. The detail provided in the unit factors, including activity duration, labor costs (by craft), and equipment and consumable costs, ensures

that essential elements have not been omitted. Appendix A presents the detailed development of a typical unit factor. Appendix B provides the values contained within one set of factors developed for this analysis.

Regulatory Guide 1.184 [28] describes the methods and procedures that are acceptable to the NRC staff for implementing the requirements that relate to the initial activities and the major phases of the decommissioning process. The costs and schedules presented in this analysis follow the general guidance and sequence in the regulations. The format and content of the estimates is also consistent with the recommendations of Regulatory Guide 1.202. [29]

This analysis reflects lessons learned from TLG's involvement in the Shippingport Station Decommissioning Project, completed in 1989, as well as the decommissioning of the Cintichem reactor, hot cells, and associated facilities, completed in 1997. In addition, the planning and engineering for the Pathfinder, Shoreham, Rancho Seco, Trojan, Yankee Rowe, Big Rock Point, Maine Yankee, Humboldt Bay-3, Oyster Creek, Connecticut Yankee, Crystal River, Vermont Yankee and Fort Calhoun nuclear units have provided additional insight into the process, the regulatory aspects, and the technical challenges of decommissioning commercial nuclear units.

Work Difficulty Factors

TLG has historically applied work difficulty adjustment factors (WDFs) to account for the inefficiencies in working in a power plant environment. WDFs were assigned to each unique set of unit factors, commensurate with the inefficiencies associated with working in confined, hazardous environments. The ranges used for the WDFs are as follows:

- Access Factor 10% to 20%
- Respiratory Protection Factor 10% to 50%
- Radiation/ALARA Factor 10% to 40%
- Protective Clothing Factor 10% to 30%
- Work Break Factor 8.33%

The factors and their associated range of values were developed in conjunction with the AIF/NESP-036 study. The application of the factors is discussed in more detail in that publication.

Scheduling Program Durations

The unit factors, adjusted by the WDFs as described above, are applied against the inventory of materials to be removed in the radiologically controlled areas.

The resulting man-hours, or crew-hours, are used in the development of the decommissioning program schedule, using resource loading and event sequencing considerations. The scheduling of conventional removal and dismantling activities are based upon productivity information available from the RSMeans "Building Construction Cost Data" publication. Dismantling of the fuel handing systems and decontamination of the spent fuel pool is also dependent upon the timetable for the transfer of the spent fuel assemblies from the pool to the ISFSI or the DOE.

The program schedule is used to determine the period-dependent costs for program management, administration, field engineering, equipment rental, contracted services, etc. The study relies upon regional or site-specific salary and wage rates for the personnel associated with the intended program.

3.3 FINANCIAL COMPONENTS OF THE COST MODEL

TLG's proprietary decommissioning cost model, DECCER, produces a number of distinct cost elements. These direct expenditures, however, do not comprise the total cost to accomplish the project goal, i.e., license termination and site restoration.

3.3.1 Contingency

Inherent in any cost estimate that does not rely on historical data is the inability to specify the precise source of costs imposed by factors such as tool breakage, accidents, illnesses, weather delays, and labor stoppages. In the DECCER cost model, contingency fulfills this role. Contingency is added to each line item to account for costs that are difficult or impossible to develop analytically. Such costs are historically inevitable over the duration of a job of this magnitude; therefore, this cost analysis includes funds to cover these types of expenses.

The activity- and period-dependent costs are combined to develop the total decommissioning cost. A contingency is then applied on a line-item basis, using one or more of the contingency types listed in the AIF/NESP-036 study. "Contingencies" are defined in the American Association of Cost Engineers "Project and Cost Engineers' Handbook"[30] as "specific provision for unforeseeable elements of cost within the defined project scope; particularly important where previous experience relating estimates and actual costs has shown that unforeseeable events which will increase costs are likely to occur." The cost elements in this analysis are based upon ideal conditions and maximum efficiency; therefore, consistent with industry practice, a

contingency factor has been applied. In the AIF/NESP-036 study, the types of unforeseeable events that are likely to occur in decommissioning are discussed and guidelines are provided for percentage contingency in each category. It should be noted that contingency, as used in this analysis, does not account for price escalation and inflation in the cost of decommissioning over the remaining operating life of the station.

The use and role of contingency within decommissioning estimates is not a "safety factor issue." Safety factors provide additional security and address situations that may never occur. Contingency funds are expected to be fully expended throughout the program. They also provide assurance that sufficient funding is available to accomplish the intended tasks. An estimate without contingency, or from which contingency has been removed, can disrupt the orderly progression of events and jeopardize a successful conclusion to the decommissioning process.

For example, the most technologically challenging task in decommissioning a commercial nuclear plant is the disposition of the reactor vessel and internal components, now highly radioactive after a lifetime of exposure to core activity. The disposition of these components forms the basis of the critical path (schedule) for decommissioning operations. Cost and schedule are interdependent, and any deviation in schedule has a significant impact on cost for performing a specific activity.

Disposition of the reactor vessel internals involves the underwater cutting of complex components that are highly radioactive. Costs are based upon optimum segmentation, handling, and packaging scenarios. The schedule is primarily dependent upon the turnaround time for the heavily shielded shipping casks, including preparation, loading, and decontamination of the containers for transport. The number of casks required is a function of the pieces generated in the segmentation activity, a value calculated on optimum performance of the tooling employed in cutting the various subassemblies. The expected optimization, however, may not be achieved, resulting in delays and additional program costs. For this reason, contingency must be included to mitigate the consequences of the expected inefficiencies inherent in this complex activity, along with related concerns associated with the operation of highly specialized tooling, field conditions, and water clarity.

Contingency funds are an integral part of the total cost to complete the decommissioning process. Exclusion of this component puts at risk a successful completion of the intended tasks and, potentially, subsequent related activities. For this study, TLG examined the major activity-related problems (decontamination, segmentation, equipment handling, packaging, transport, and waste disposal) that necessitate a contingency. Individual activity contingencies ranged from 10% to 75%, depending on the degree of difficulty judged to be appropriate from TLG's actual decommissioning experience. The contingency values used in this study are as follows:

Decontamination	50%
Contaminated Component Removal	25%
Contaminated Component Packaging	10%
Contaminated Component Transport	15%
Low-Level Radioactive Waste Disposal	25%
Reactor Segmentation	75%
NSSS Component Removal	25%
Reactor Waste Packaging	25%
Reactor Waste Transport	25%
Reactor Vessel Component Disposal	50%
GTCC Disposal	15%
Non-Radioactive Component Removal	15%
Heavy Equipment and Tooling	15%
Supplies	25%
Engineering	15%
Energy	15%
Characterization and Termination Surveys	30%
Construction	15%
Taxes and Fees	10%
Insurance	10%
Staffing	15%
Spent Fuel Storage (Dry) Systems	15%
Spent Fuel Transfer Costs	15%
Operations and Maintenance Expenses	15%
ISFSI Decommissioning	25%

The contingency values are applied to the appropriate components of the estimates on a line item basis. A composite value is then reported at the

end of each detailed estimate (as provided in Appendices C through I). Appendix J, the ISFSI decommissioning calculation, uses a flat 25% contingency added at the end of the calculation.

3.3.2 Financial Risk

In addition to the routine uncertainties addressed by contingency, another cost element that is sometimes necessary to consider when bounding decommissioning costs relates to uncertainty, or risk. Examples can include changes in work scope, pricing, job performance, and other variations that could conceivably, but not necessarily, occur. Consideration is sometimes necessary to generate a level of confidence in the estimate, within a range of probabilities. TLG considers these types of costs under the broad term "financial risk." Included within the category of financial risk are:

- Transition activities and costs: ancillary expenses associated with eliminating 50% to 80% of the site labor force shortly after the cessation of plant operations, added cost for worker separation packages throughout the decommissioning program, national or company-mandated retraining, and retention incentives for key personnel.
- Delays in approval of the decommissioning plan due to intervention, public participation in local community meetings, legal challenges, and national and local hearings.
- Changes in the project work scope from the baseline estimate, involving the discovery of unexpected levels of contaminants, contamination in places not previously expected, contaminated soil previously undiscovered (either radioactive or hazardous material contamination), variations in plant inventory or configuration not indicated by the as-built drawings.
- Regulatory changes (e.g., affecting worker health and safety, site release criteria, waste transportation, and disposal).
- Policy decisions altering national commitments (e.g., in the ability to accommodate certain waste forms for disposition) or in the timetable for such, for example, the start and rate of acceptance of spent fuel by the DOE.
- Pricing changes for basic inputs such as labor, energy, materials, and disposal. Items subject to widespread price competition (such as materials) may not show significant variation; however, others such

as waste disposal could exhibit large pricing uncertainties, particularly in markets where limited access to services is available.

This cost study does not add any additional costs to the estimate for financial risk, since there is insufficient historical data from which to project future liabilities. Consequently, the areas of uncertainty or risk are revisited periodically and addressed through repeated revisions or updates of the base estimates.

3.4 SITE-SPECIFIC CONSIDERATIONS

There are a number of site-specific considerations that affect the method for dismantling and removal of equipment from the site and the degree of restoration required. The cost impacts of the considerations identified below are included in this cost study.

3.4.1 Spent Fuel Management

The cost to dispose of spent fuel generated from plant operations is not reflected within the estimates to decommission Monticello. Ultimate disposition of the spent fuel is within the province of the DOE's Waste Management System, as defined by the Nuclear Waste Policy Act. As such, the disposal cost was financed by a 1 mill/kWhr surcharge paid into the DOE's waste fund during operations. On November 19, 2013, the U.S. Court of Appeals for the D.C. Circuit ordered the Secretary of the Department of Energy to suspend collecting annual fees for nuclear waste disposal from nuclear power plant operators until the DOE has conducted a legally adequate fee assessment.

The NRC does, however, require licensees to establish a program to manage and provide funding for the management of all irradiated fuel at the reactor site until title of the fuel is transferred to the Secretary of Energy. This requirement is prepared for through inclusion of certain high-level waste cost elements within the estimates, as described below.

Xcel Energy's current spent fuel management plan for the Monticello spent fuel is based in general upon:

1) Fuel transferred from the pool to the ISFSI within 5 years of shutdown;
2) Exchange of Monticello and Prairie Island spent fuel acceptance rights to best manage the overall cost of spent fuel storage for both plants;

3) Currently Monticello is storing 1,058 fuel assemblies at the Morris Operation facility of GE Hitachi Nuclear Energy in Morris, Illinois. These assemblies will be shipped for final disposal to DOE prior to removal of fuel from the Monticello site.

4) Fuel will be shipped in the existing NUHOMS DSCs (Scenarios 1, 2, 6, and 7); the canisters and NUHOMS are periodically replaced in Scenarios 3, 4 and 5. Canisters that are unloaded in the spent fuel transfer operation will be surveyed for neutron activation.

5) As an allowance, some of these canisters and NUHOMS modules from the first off-load operation are assumed to be mildly neutron activated and therefore must be disposed of as radioactive waste.

This analysis assumes that the existing ISFSI is modified at the cessation of plant operations to accommodate the fuel present in the storage pool at shutdown.

The DOE's repository program assumes that spent fuel will be accepted for disposal from the nation's commercial nuclear plants in the order (the "queue") in which it was removed from service ("oldest fuel first").[31] Repository operations were based upon annual industry-wide receipt of 400 Metric Tons Heavy Metal (MTHM) in the first year of operation, a total of 3,800 MTHM in years 2 through 4 and 3,000 MTHM for year 5 and beyond.[32] This logic supports the spent fuel schedules for Scenarios 1 and 6. All other spent fuel scenarios are consistent with those identified by the Minnesota PSC.

Operation and maintenance costs for the spent fuel pool and ISFSI are included within the estimates and address the costs for staffing the facility, as well as security, insurance, and licensing fees. The estimates also include the costs to purchase, load, and transfer the NUHOMs DSCs from the pool to the ISFSI. Costs are also provided for the final disposition of the ISFSI once the transfer of the DSCs from the ISFSI to the DOE is complete.

Storage Canister Design

The design and capacity of the ISFSI is based upon the Transnuclear NUHOMS system (with a 61-fuel assembly capacity). The system consists of a multi-purpose (storage and transport) dry shielded storage canister (DSC) and a horizontal storage module (HSM). The existing

DSCs and HSMs will remain in the ISFSI until either shipment to the DOE, or until recasked.

Canister Loading and Transfer

The estimates include an average cost of $750,000 for the labor to load/transport the spent fuel from the pool to the ISFSI pad. For estimating purposes an allowance of $332,800 is used for the cost to transfer each fuel canister from the ISFSI pad to the DOE transport vehicle.

Operations and Maintenance

An annual cost (excluding labor) of approximately $803,000 and $103,000 are used for operation and maintenance of the spent fuel pool and the ISFSI, respectively.

At shutdown, the spent fuel pool is expected to contain freshly discharged assemblies (from the most recent refueling cycles). Over the next five years the assemblies are packaged into DSCs for transfer to the ISFSI for transfer to the DOE. It is assumed that the five years provides the necessary cooling period for the final core to meet the decay heat requirements for dry storage. Once the pool is emptied, the spent fuel storage and handling facilities are available for decommissioning.

Replacement of DSCs during ISFSI fuel storage period

Scenarios 1, 2, 6, and 7 do not assume any replacement of the spent fuel storage DSCs (recasking).

Three of the cost estimates, Scenarios 3, 4 and 5, include costs to recask the spent fuel, based upon an assumption that the DSC has a limited lifetime of approximately 50 years.

Scenario 3, which is 100 years (nominally) in length, considers a single repackaging effort for each DSC in the ISFSI.

Scenario 4, which is a (nominal) 200-year scenario, assumes that when any DSC in the ISFSI reaches the 50 years of storage milestone, the DSC is replaced. In Scenario 4, the fuel will be recasked three times following final shutdown of Monticello.

Scenario 5, which is 60 years (nominally) in length, considers a single repackaging effort for each DSC in the ISFSI. Not all fuel will be recasked.

Since the reactor building, spent fuel storage pool, and fuel handling facilities are removed by the year 2038, a dry fuel transfer facility is assumed to be constructed on site to perform the transfers from the old to the new DSCs. Scenarios 3, 4 and 5 include the cost to construct such a transfer facility, as well as additional staffing positions for support of the dry transfer activities, and additional NRC oversight associated with the transfer operations. The decommissioning of this transfer facility is also included in Scenarios 3, 4 and 5.

ISFSI Decommissioning

In accordance with 10 CFR §72.30, licensees must have a proposed decommissioning plan for the ISFSI site and facilities that includes a cost estimate for the plan. The plan should contain sufficient information on the proposed practices and procedures for the decontamination of the ISFSI and for the disposal of residual radioactive materials after all spent fuel, high-level radioactive waste, and reactor-related GTCC waste have been removed.

The NUHOMS multi-purpose dry shielded storage canister with a horizontal, reinforced concrete storage module is used as a basis for the ISFSI decommissioning cost analyses. The modules are assumed to have some level of neutron-induced activation, as a result of the long-term storage of the fuel, i.e., to levels exceeding free-release limits. As an allowance, 8 modules are assumed to require remediation, equivalent to the number of modules required to accommodate the final core offload at Monticello (484 assemblies). The cost of the disposition of this material, as well as the demolition of the ISFSI facility, is included in the estimates.

In accordance with the specific requirements of 10 CFR §72.30 for the ISFSI work scope, the cost estimate for decommissioning the ISFSI reflects: 1) the cost of an independent contractor performing the decommissioning activities; 2) an adequate contingency factor; and 3) the cost of meeting the criteria for unrestricted use. The cost summary for decommissioning the ISFSI is presented in Appendix J. It contains four different scenarios reflecting the different number of casks present at the end of the ISFSI operations. The demolition of the ISFSI for all seven scenarios is reflected within the estimates.

GTCC

The dismantling of the reactor internals is expected to generate radioactive waste considered unsuitable for shallow land disposal (i.e., low-level radioactive waste with concentrations of radionuclides that exceed the limits established by the NRC for Class C radioactive waste (GTCC)). The Low-Level Radioactive Waste Policy Amendments Act of 1985 assigned the federal government the responsibility for the disposal of this material. The Act also stated that the beneficiaries of the activities resulting in the generation of such radioactive waste bear all reasonable costs of disposing of such waste. [33]

Although the material is not classified as high-level waste, federal regulations under the Act designate that disposal of this material is a federal responsibility under Section 3(b)(1)(D). However, the DOE has not been forthcoming with an acceptance criteria or disposition schedule for this material, and numerous questions remain as to the ultimate disposal cost and waste form requirements.

As such, for purposes of this study, the GTCC has been packaged and disposed of in the same manner as high-level waste, at a cost equivalent to that envisioned for the spent fuel. The number of DSCs required and the packaged volume for GTCC was based upon experience at Maine Yankee (e.g., the constraints on loading as identified in the canister's certificate of compliance), but adjusted for the increased spent fuel capacity of the current DSCs.

It is assumed that the DOE would not accept this waste prior to completing the transfer of spent fuel. Therefore, until such time the DOE is ready to accept GTCC waste, it is reasonable to assume that this material would remain in storage at Monticello (for the DECON alternatives). In the SAFSTOR alternatives, the GTCC material is shipped directly to a DOE facility as it is generated. GTCC costs have been segregated and included within the "License Termination" expenditures.

3.4.2 Reactor Vessel and Internal Components

The NSSS (reactor vessel and reactor recirculation system components) will be decontaminated using chemical agents prior to the start of cutting operations (for DECON alternative only).

The reactor pressure vessel and internal components are segmented for disposal in shielded, reusable transportation casks. Segmentation is performed underwater in the dryer-separator pool, where a turntable and remote cutter are installed. The vessel is segmented in place, using a mast-mounted cutter supported off the lower head and directed from a shielded work platform installed overhead in the reactor well. Transportation cask specifications and transportation regulations dictate the segmentation and packaging methodology.

Intact disposal of reactor vessel shells has been successfully demonstrated at several of the sites that have been decommissioned. Access to navigable waterways has allowed these large packages to be transported to the Barnwell disposal site with minimal overland travel. Intact disposal of the reactor vessel and internal components can provide savings in cost and worker exposure by eliminating the complex segmentation requirements, isolation of the GTCC material, and transport/storage of the resulting waste packages. Portland General Electric (PGE) was able to dispose of the Trojan reactor as an intact package (including the internals). However, its location on the Columbia River simplified the transportation analysis since:

- the reactor package could be secured to the transport vehicle for the entire journey, i.e., the package was not lifted during transport,
- there were no man-made or natural terrain features between the plant site and the disposal location that could produce a large drop, and
- transport speeds were very low, limited by the overland transport vehicle and the river barge.

As a member of the Northwest Compact, PGE had a site available for disposal of the package - the US Ecology facility in Washington State. The characteristics of this arid site proved favorable in demonstrating compliance with land disposal regulations.

It is not known whether this option will be available when Monticello ceases operation. Future viability of this option will depend upon the ultimate location of the disposal site, as well as the disposal site licensee's ability to accept highly radioactive packages and effectively isolate them from the environment. Additionally, with BWRs, the diameter of the reactor vessel may severely limit overland transport.

Consequently, the study assumes the reactor vessel will require segmentation, as a bounding condition.

3.4.3 Primary System Components

Reactor recirculation piping is cut from the reactor vessel once the water level in the vessel (used for personnel shielding during dismantling and cutting operations in and around the vessel) is dropped below the nozzle zone. The piping is boxed and transported by shielded van. The reactor recirculation pumps and motors are lifted out intact, packaged, and transported for processing and/or disposal.

3.4.4 Main Turbine and Condenser

The main turbine will be dismantled using conventional maintenance procedures. The turbine rotors and shafts will be removed to a laydown area. The lower turbine casings will be removed from their anchors by controlled demolition. The main condensers will also be disassembled and moved to a laydown area. Material is then prepared for transportation to an off-site recycling facility where it will be surveyed and designated for either decontamination or volume reduction, or controlled disposal. Components will be packaged and readied for transport in accordance with the intended disposition.

3.4.5 Transportation Methods

Contaminated piping, components, and structural material other than the highly activated reactor vessel and internal components will qualify as LSA-I, II or III or Surface Contaminated Object, SCO-I or II, as described in Title 49. [34] The contaminated material will be packaged in Industrial Packages (IP-1, IP-2, or IP-3, as defined in subpart 173.411) for transport unless demonstrated to qualify as their own shipping containers. The reactor vessel and internal components are expected to be transported in accordance with 10 CFR Part 71, as Type B. It is conceivable that the reactor, due to its limited specific activity, could qualify as LSA II or III. However, the high radiation levels on the outer surface would require that additional shielding be incorporated within the packaging so as to attenuate the dose to levels acceptable for transport.

Any fuel cladding failure that occurred during the lifetime of the plant is assumed to have released fission products at sufficiently low levels that the buildup of quantities of long-lived isotopes (e.g., ^{137}Cs, ^{90}Sr, or

transuranics) has been prevented from reaching levels exceeding those that permit the major reactor components to be shipped under current transportation regulations and disposal requirements.

Transport of the highly activated metal, produced in the segmentation of the reactor vessel and internal components, will be by shielded truck cask. Cask shipments may exceed 95,000 pounds, including vessel segment(s), supplementary shielding, cask tie-downs, and tractor-trailer. The maximum level of activity per shipment assumed permissible was based upon the license limits of the available shielded transport casks. The segmentation scheme for the vessel and internal segments is designed to meet these limits.

Transportation costs for Class A radioactive material requiring controlled disposal are based upon the mileage to the Energy*Solutions* facility in Clive, Utah. Transportation costs for the higher activity Class B and C radioactive material are based upon the mileage to the WCS facility in Andrews County, Texas. The transportation cost for the GTCC material is assumed to be contained within the disposal cost. Transportation costs for off-site waste processing are based upon the mileage to Oak Ridge, Tennessee. Truck transport costs were estimated using published tariffs from Tri-State Motor Transit. [35]

3.4.6 Low-Level Radioactive Waste Disposal

To the greatest extent practical, metallic material generated in the decontamination and dismantling processes is processed to reduce the total cost of controlled disposal. Material meeting the regulatory and/or site release criterion, is released as scrap, requiring no further cost consideration. Conditioning (preparing the material to meet the waste acceptance criteria of the disposal site) and recovery of the waste stream is performed off site at a licensed processing center. Any material leaving the site is subject to a survey and release charge, at a minimum.

The mass of radioactive waste generated during the various decommissioning activities at the site is shown on a line-item basis in the detailed Appendices C through J, and summarized in Section 5. The quantified waste summaries shown in these tables are consistent with 10 CFR Part 61 classifications. Commercially available steel containers are presumed to be used for the disposal of piping, small components, and concrete. Larger components can serve as their own containers, with proper closure of all openings, access ways, and penetrations. The volumes are calculated based on the exterior package dimensions for

containerized material or a specific calculation for components serving as their own waste containers.

The more highly activated reactor components will be shipped in reusable, shielded truck casks with disposable liners. In calculating disposal costs, the burial fees are applied against the liner volume and weight, with surcharges added for the special handling requirements and the radiological characteristics of the payload. Packaging efficiencies are lower for the highly activated materials (greater than Type A quantity waste), where high concentrations of gamma-emitting radionuclides limit the capacity of the shipping canisters.

The cost to dispose of the lowest level and majority of the material generated from the decontamination and dismantling activities is based upon representative costs for disposal at Energy*Solutions* facility in Clive, Utah. Disposal costs for the higher activity waste (Class B and C) were based upon preliminary and indicative information from WCS for the Andrews County facility

Material exceeding Class C limits (limited to material closest to the reactor core and comprising less than 1% of the total waste volume) is generally not suitable for shallow-land disposal. This material is packaged in the same multipurpose canisters used for spent fuel storage/transport, for eventual transfer to the DOE for disposal.

3.4.7 Site Conditions Following Decommissioning

The NRC will amend or terminate the unit license if it determines that site remediation has been performed in accordance with the license termination plan, and that the terminal radiation survey and associated documentation demonstrate that the facility is suitable for release. The NRC's involvement in the decommissioning process will end at this point. Building codes and environmental regulations will dictate the next step in the decommissioning process, as well as Xcel Energy's own future plans for the site, e.g., the electrical switchyard will remain in support of the regional transmission and distribution system.

Asphalt surfaces in the immediate vicinity of site buildings are broken up and the material disposed of as construction debris. The site access road will remain.

Only existing site structures are considered in the dismantling cost. All subgrade structures are removed. The voids are backfilled with clean

debris and capped with soil. The site is then re-graded to conform to the adjacent landscape. Vegetation is established to inhibit erosion. These "non-radiological costs" are included in the total cost of decommissioning.

Bulk excavation of soil and material in the immediate vicinity of the reactor building is included to remove various duct banks, catch basins, and underground utilities that may exist.

The estimates do not assume the remediation of any significant volume of contaminated soil. This assumption may be affected by continued plant operations and/or future regulatory actions, such as the development of site-specific release criteria.

3.5 ASSUMPTIONS

The following are the major assumptions made in the development of the estimates for decommissioning the site.

3.5.1 Estimating Basis

The study follows the principles of ALARA through the use of work duration adjustment factors. These factors address the impact of activities such as radiological protection instruction, mock-up training, and the use of respiratory protection and protective clothing. The factors lengthen a task's duration, increasing costs and lengthening the overall schedule. ALARA planning is considered in the costs for engineering and planning, and in the development of activity specifications and detailed procedures. Changes to worker exposure limits may impact the decommissioning cost and project schedule.

3.5.2 Labor Costs

For purposes of this analysis, it is assumed that Xcel Energy will hire a Decommissioning Operations Contractor (DOC) to manage the decommissioning. Xcel Energy will provide site security, radiological health and safety, quality assurance and overall site administration during the decommissioning and demolition phases. Contract personnel will provide engineering services (e.g., for preparing the activity specifications, work procedures, neutron activation, and structural analyses) under the direction of Xcel Energy.

Utility labor costs were provided by Xcel Energy. Average costs were provided by department or work group and included payroll overheads. Decommissioning Operations Contractor (DOC) labor costs were based on utility labor costs with modified markups to account for employee benefits, DOC overhead and profit.

The craft labor required to decontaminate and dismantle the nuclear station will be acquired through standard site contracting practices. Craft labor costs were based upon information from Xcel Energy. Craft labor costs include applicable overheads and profit.

Security, while reduced from operating levels, is maintained throughout the decommissioning for access control, material control, and to safeguard the spent fuel.

Staffing levels are assigned by sub-period and functional area. The types of positions and staffing levels are adjusted based upon the type of activity occurring in each sub-period.

Representative profiles of the staffing level for decommissioning, including contractors and craft, is provided in Figures 3.1 and 3.2 for the DECON (Scenario 2) and SAFSTOR (Scenario 7) estimates. Utility staffing levels will gradually decrease after completing the removal of physical systems. Staffing levels and management support will vary based upon the amount and type of decommissioning work. Craft manpower levels decrease after systems removal and structures decontamination and drop substantially during the delay period and the license termination survey period. However, craft levels increase again during the site restoration period due to the work associated with structures demolition.

Security, while reduced from operating levels, is maintained throughout the decommissioning for access control, material control, and to safeguard the spent fuel (in accordance with the requirements of 10 CFR Part 37, Part 72, and Part 73). Once the fuel has been transferred to the DOE, the security organization will be reduced to Part 37 requirements for Scenario 6.

3.5.3 Design Conditions

Any fuel cladding failure that occurred during the lifetime of the plant is assumed to have released fission products at sufficiently low levels that the buildup of quantities of long-lived isotopes (e.g., ^{137}Cs, ^{90}Sr, or transuranics) has been prevented from reaching levels exceeding those that permit the major NSSS components to be shipped under current transportation regulations and disposal requirements.

The curie contents of the vessel and internals at final shutdown are derived from those listed in NUREG/CR-3474.[36] Actual estimates are derived from the curie/gram values contained therein and adjusted for the different mass of the Monticello components, projected operating life, and different periods of decay. Additional short-lived isotopes were derived from NUREG/CR-0130[37] and NUREG/CR-0672, [38] and benchmarked to the long-lived values from NUREG/CR-3474.

The disposal cost for the control blades removed from the vessel with the final core load was included within the estimates. Control blade residence time in the reactor is assumed to be controlled such that the blades do not become GTCC material. Disposition of any blades stored in the pool from operations was considered an operating expense and therefore not accounted for in the estimates.

Neutron activation of the reactor building structure is confined to the reactor sacrificial shield.

3.5.4 General

Transition Activities

Existing warehouses will be cleared of non-essential material and remain for use by Xcel Energy and subcontractors. The plant's operating staff will perform the following activities at no additional cost or credit to the project during the transition period:

- Drain and collect fuel oils, lubricating oils, and transformer oils for recycle and/or sale.
- Drain and collect acids, caustics, and other chemical stores for recycle and/or sale.
- Processes operating waste inventories, i.e., the estimates do not address the disposition of any legacy wastes; the disposal of

operating wastes during this initial period is not considered a decommissioning expense.

Scrap and Salvage

The existing plant equipment is considered obsolete and suitable for scrap as deadweight quantities only. Xcel Energy will make economically reasonable efforts to salvage equipment following final plant shutdown. However, dismantling techniques assumed by TLG for equipment in this analysis are not consistent with removal techniques required for salvage (resale) of equipment. Experience has indicated that some buyers wanted equipment stripped down to very specific requirements before they would consider purchase. This required expensive rework after the equipment had been removed from its installed location. Since placing a salvage value on this machinery and equipment would be speculative, and the value would be small in comparison to the overall decommissioning expenses, this analysis does not attempt to quantify the possible salvage value that Xcel Energy may realize based upon those efforts.

It is assumed, for purposes of this analysis, that any value received from the sale of scrap generated in the dismantling process would be offset by the on-site processing costs. The dismantling techniques assumed in the decommissioning estimates do not include the additional cost for size reduction and preparation to meet "furnace ready" conditions. For example, the recovery of copper from electrical cabling may require the removal and disposition of any contaminated insulation, an added expense. With a volatile market, the potential profit margin in scrap recovery is highly speculative, regardless of the ability to free release this material. This assumption is an implicit recognition of scrap value in the disposal of clean metallic waste at no additional cost to the project.

Furniture, tools, mobile equipment such as forklifts, trucks, bulldozers, and other property will be removed at no cost or credit to the decommissioning project. Disposition may include relocation to other facilities. Spare parts will also be made available for alternative use.

The concrete debris resulting from building demolition activities is crushed on site to reduce the size of the debris. The resulting crushed concrete is disposed offsite as construction debris. The rebar removed from the concrete crushing process is disposed of as scrap steel in a similar fashion as other scrap metal as discussed previously.

Energy

For estimating purposes, the plant is assumed to be de-energized, with the exception of those facilities associated with spent fuel storage. Replacement power costs are used for the cost of energy consumption during decommissioning for tooling, lighting, ventilation, and essential services.

Emergency Planning

FEMA and state fees associated with emergency planning are assumed to continue for approximately 18 months following the cessation of operations. At this time, the FEMA fees are discontinued. The timing is based upon the anticipated condition of the spent fuel (i.e., the hottest spent fuel assemblies are assumed to be cool enough that no substantial Zircaloy oxidation and off-site event would occur with the loss of spent fuel pool water). State and local fees are continued until all spent fuel is transferred out of the spent fuel pool.

Insurance

Costs for continuing coverage (nuclear liability and property insurance) following cessation of plant operations and during decommissioning are included and based upon current operating premiums. Reductions in premiums throughout the decommissioning process are based upon guidance provided by Xcel Energy. Reductions in premiums, throughout the decommissioning process, are based upon the guidance provided in SECY-00-0145, "Integrated Rulemaking Plan for Nuclear Power Plant Decommissioning."[39] The NRC's financial protection requirements are based on various reactor (and spent fuel) configurations.

Taxes

Property taxes are included for all decommissioning periods. Xcel Energy provided a schedule of decreasing tax payments against the current tax assessment. These payments are maintained for the balance of the decommissioning program.

NRC Fees

These estimates include charges from the NRC to support the Monticello decommissioning program. Charges are included for the yearly license held by Xcel Energy for the Part 50 license, as well as engineering

support charges by the NRC to review activities at the site. The Part 50 license fee for a reactor in a decommissioning or possession-only status and which has spent fuel onsite is $194 thousand per year. Once the reactor has been decommissioned, the site Part 50 license continues at the same fee until final removal of the spent fuel. The hourly rate for NRC review is $267.00. The level of effort of NRC participation is commensurate with the decommissioning alternative and schedule.

Disposal of Processed Water

This estimate assumes that processed water which meets state and federal release limits can be disposed of without additional cost.

Site Modifications

The perimeter fence and in-plant security barriers will be moved, as appropriate, to conform to the Site Security Plan in force during the various stages of the project.

Minnesota state regulations regarding concrete

This estimate complies with the Minnesota state regulations regarding the removal of all subterranean concrete during demolition, plus the survey and confirmation of the suitability of the clean fill used for backfill of the subgrade structures following concrete removal.

3.6 COST ESTIMATE SUMMARY

The estimates presented in this document reflects the total cost to decontaminate the nuclear units, manage the spent fuel until the DOE is able to complete the transfer to a federal facility, dismantle the plant and restore the site for alternative use.

Schedules of expenditures are provided in Tables 3.1 through 3.7. The tables delineate the cost contributors by year of expenditures as well as cost contributor (e.g., labor, materials, and waste disposal).

Additional tables in Appendices C through I provide detailed costs elements. The cost elements are also assigned to one of three subcategories: “License Termination,” “Spent Fuel Management,” and “Site Restoration.” The subcategory “License Termination” is used to accumulate costs that are consistent with “decommissioning” as defined by the NRC in its financial assurance regulations (i.e., 10 CFR §50.75). In situations where the long-term

management of spent fuel is not an issue, the cost reported for this subcategory is generally sufficient to terminate the unit's operating license, recognizing that there may be some additional cost impact from spent fuel management.
The "Spent Fuel Management" subcategory contains costs associated with the containerization and transfer of spent fuel from the pool to the DOE or to the ISFSI for interim storage, and the transfer of the multipurpose canisters from the ISFSI to the DOE. Costs are also included for the operations of the pool and management of the ISFSI until such time that the transfer of all fuel from this facility to an off-site location (e.g., interim storage facility) is complete.

"Site Restoration" is used to capture costs associated with the dismantling and demolition of buildings and facilities demonstrated to be free from contamination. This includes structures never exposed to radioactive materials, as well as those facilities that have been decontaminated to appropriate levels. Structures are completely removed, including foundations and basemats and backfilled to conform to local grade.

As discussed in Section 3.4.1, it is assumed that the DOE will not accept the GTCC waste prior to completing the transfer of spent fuel. Therefore, the cost of GTCC disposal is shown in the final year of ISFSI operation (for the DECON alternative). While designated for disposal at a federal facility along with the spent fuel, GTCC waste is still classified as low-level radioactive waste and, as such, included as a "License Termination" expense.

Decommissioning costs are reported in 2017 dollars. Costs are not inflated, escalated, or discounted over the period of expenditure (or projected lifetime of the plant).

TABLE 3.1
SCENARIO 1: DECON WITH 32 YEAR DFS
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2030	22,829	6,415	627	20	7,049	36,939
2031	72,400	7,603	2,616	913	31,779	115,311
2032	78,460	28,886	2,284	40,103	30,941	180,673
2033	78,072	37,838	1,749	34,741	24,053	176,453
2034	66,364	7,235	1,492	9,590	20,527	105,209
2035	86,863	81,152	1,273	13,277	17,396	199,960
2036	50,291	3,982	573	9,360	6,723	70,929
2037	34,607	10,274	237	9	3,627	48,754
2038	29,565	11,366	184	0	3,515	44,629
2039	5,908	0	0	0	2,334	8,243
2040	5,925	0	0	0	2,341	8,265
2041	5,908	0	0	0	2,334	8,243
2042	6,004	287	0	0	2,334	8,625
2043	6,195	861	0	0	2,334	9,391
2044	6,116	574	0	0	2,341	9,031
2045	6,100	574	0	0	2,334	9,008
2046	6,483	1,722	0	0	2,334	10,539
2047	6,387	1,435	0	0	2,334	10,156
2048	7,067	3,426	0	0	2,341	12,834
2049	6,387	1,435	0	0	2,334	10,156
2050	6,195	861	0	0	2,334	9,391
2051	6,100	574	0	0	2,334	9,008
2052	6,212	861	0	0	2,341	9,413
2053	6,100	574	0	0	2,334	9,008
2054	6,100	574	0	0	2,334	9,008
2055	6,195	861	0	0	2,334	9,391
2056	6,116	574	0	0	2,341	9,031
2057	6,100	574	0	0	2,334	9,008
2058	6,195	861	0	0	2,334	9,391
2059	6,291	1,148	0	0	2,334	9,774

TABLE 3.1 (continued)
SCENARIO 1: DECON WITH 32 YEAR DFS
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2060	6,116	574	0	0	2,341	9,031
2061	6,291	1,148	0	0	2,334	9,774
2062	6,291	1,148	0	0	2,334	9,774
2063	2,248	3,118	33	10,073	11,731	27,203
Total	670,480	218,520	11,068	118,086	213,400	1,231,552

Note: Columns may not add due to rounding

TABLE 3.2
SCENARIO 2: DECON WITH 60 YEAR DFS
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2030	21,104	1,240	627	20	7,049	30,039
2031	72,416	7,653	2,616	913	31,779	115,378
2032	78,476	28,935	2,284	40,103	30,941	180,740
2033	78,663	39,613	1,749	34,741	24,053	178,819
2034	66,380	7,285	1,492	9,590	20,527	105,275
2035	86,880	81,202	1,273	13,277	17,396	200,027
2036	50,308	4,032	573	9,360	6,723	70,996
2037	34,623	10,324	237	9	3,627	48,820
2038	29,581	11,416	184	0	3,500	44,680
2039	5,925	50	0	0	2,137	8,112
2040	5,941	50	0	0	2,143	8,134
2041	5,925	50	0	0	2,137	8,112
2042	5,925	50	0	0	2,137	8,112
2043	5,925	50	0	0	2,137	8,112
2044	5,941	50	0	0	2,143	8,134
2045	5,925	50	0	0	2,137	8,112
2046	5,925	50	0	0	2,137	8,112
2047	5,925	50	0	0	2,137	8,112
2048	6,605	2,041	0	0	2,143	10,789
2049	5,925	50	0	0	2,137	8,112
2050	7,418	4,529	0	0	2,137	14,085
2051	7,418	4,529	0	0	2,137	14,085
2052	8,297	7,117	0	0	2,143	17,557
2053	8,928	9,058	0	0	2,137	20,122
2054	7,634	5,176	0	0	2,137	14,947
2055	8,712	8,411	0	0	2,137	19,260
2056	9,159	9,704	0	0	2,143	21,007
2057	5,908	0	0	0	2,137	8,046
2058	5,908	0	0	0	2,137	8,046
2059	5,908	0	0	0	2,137	8,046

TABLE 3.2 (continued)
SCENARIO 2: DECON WITH 60 YEAR DFS
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2060	5,925	0	0	0	2,143	8,068
2061	5,908	0	0	0	2,137	8,046
2062	5,908	0	0	0	2,137	8,046
2063	5,908	0	0	0	2,137	8,046
2064	5,925	0	0	0	2,143	8,068
2065	5,908	0	0	0	2,137	8,046
2066	5,908	0	0	0	2,137	8,046
2067	5,908	0	0	0	2,137	8,046
2068	5,925	0	0	0	2,143	8,068
2069	5,908	0	0	0	2,137	8,046
2070	5,908	0	0	0	2,137	8,046
2071	5,908	0	0	0	2,137	8,046
2072	5,925	0	0	0	2,143	8,068
2073	5,908	0	0	0	2,137	8,046
2074	5,908	0	0	0	2,137	8,046
2075	5,908	0	0	0	2,137	8,046
2076	5,925	0	0	0	2,143	8,068
2077	5,908	0	0	0	2,137	8,046
2078	6,387	1,435	0	0	2,122	9,944
2079	6,483	1,722	0	0	2,122	10,327
2080	6,403	1,435	0	0	2,128	9,966
2081	6,387	1,435	0	0	2,122	9,944
2082	6,387	1,435	0	0	2,122	9,944
2083	6,483	1,722	0	0	2,122	10,327
2084	6,403	1,435	0	0	2,128	9,966
2085	6,387	1,435	0	0	2,122	9,944
2086	6,387	1,435	0	0	2,122	9,944
2087	6,483	1,722	0	0	2,122	10,327
2088	7,067	3,426	0	0	2,128	12,621
2089	6,387	1,435	0	0	2,122	9,944

TABLE 3.2 (continued)
SCENARIO 2: DECON WITH 60 YEAR DFS
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2090	6,100	574	0	0	2,122	8,796
2091	2,035	3,143	33	10,073	11,706	26,990
Total	851,819	266,556	11,068	118,086	268,321	1,515,850

Note: Columns may not add due to rounding

TABLE 3.3
SCENARIO 3: DECON WITH 100 YEAR DFS
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2030	21,104	1,240	627	20	7,049	30,039
2031	72,416	7,653	2,616	913	31,779	115,378
2032	81,871	39,120	2,284	40,103	30,941	194,319
2033	78,663	39,613	1,749	34,741	24,053	178,819
2034	66,380	7,285	1,492	9,590	20,527	105,275
2035	86,880	81,202	1,273	13,277	17,396	200,027
2036	50,308	4,032	573	9,360	6,723	70,996
2037	34,756	10,324	237	9	3,627	48,953
2038	29,828	11,416	184	0	3,495	44,922
2039	7,165	50	0	0	2,075	9,290
2040	7,184	50	0	0	2,081	9,315
2041	7,165	50	0	0	2,075	9,290
2042	7,165	50	0	0	2,075	9,290
2043	7,165	50	0	0	2,075	9,290
2044	7,184	50	0	0	2,081	9,315
2045	7,165	50	0	0	2,075	9,290
2046	7,165	50	0	0	2,075	9,290
2047	7,165	50	0	0	2,075	9,290
2048	7,848	2,041	0	0	2,081	11,970
2049	7,165	50	0	0	2,075	9,290
2050	8,658	4,529	0	0	2,075	15,263
2051	8,658	4,529	0	0	2,075	15,263
2052	8,677	4,529	0	0	2,081	15,288
2053	8,658	4,529	0	0	2,075	15,263
2054	8,658	4,529	0	0	2,075	15,263
2055	8,658	4,529	0	0	2,075	15,263
2056	8,677	4,529	0	0	2,081	15,288
2057	8,658	4,529	0	0	2,075	15,263
2058	14,754	22,819	0	0	2,075	39,648
2059	8,658	4,529	0	0	2,075	15,263

TABLE 3.3 (continued)
SCENARIO 3: DECON WITH 100 YEAR DFS
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2060	8,677	4,529	0	0	2,081	15,288
2061	8,658	4,529	0	0	2,075	15,263
2062	8,658	4,529	0	0	2,075	15,263
2063	8,658	4,529	0	0	2,075	15,263
2064	8,677	4,529	0	0	2,081	15,288
2065	8,658	4,529	0	0	2,075	15,263
2066	12,316	15,503	0	0	2,075	29,894
2067	8,658	4,529	0	0	2,075	15,263
2068	17,212	30,134	0	0	2,081	49,428
2069	8,658	4,529	0	0	2,075	15,263
2070	8,658	4,529	0	0	2,075	15,263
2071	8,658	4,529	0	0	2,075	15,263
2072	8,677	4,529	0	0	2,081	15,288
2073	8,658	4,529	0	0	2,075	15,263
2074	8,658	4,529	0	0	2,075	15,263
2075	8,658	4,529	0	0	2,075	15,263
2076	8,677	4,529	0	0	2,081	15,288
2077	8,658	4,529	0	0	2,075	15,263
2078	8,658	4,529	0	0	2,075	15,263
2079	8,658	4,529	0	0	2,075	15,263
2080	8,677	4,529	0	0	2,081	15,288
2081	8,658	4,529	0	0	2,075	15,263
2082	8,658	4,529	0	0	2,075	15,263
2083	8,658	4,529	0	0	2,075	15,263
2084	8,677	4,529	0	0	2,081	15,288
2085	8,658	4,529	0	0	2,075	15,263
2086	8,658	4,529	0	0	2,075	15,263
2087	8,658	4,529	0	0	2,075	15,263
2088	9,341	6,520	0	0	2,081	17,942
2089	8,658	4,529	0	0	2,075	15,263

TABLE 3.3 (continued)
SCENARIO 3: DECON WITH 100 YEAR DFS
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2090	8,658	4,529	0	0	2,075	15,263
2091	8,658	4,529	0	0	2,075	15,263
2092	9,540	7,117	0	0	2,081	18,738
2093	10,167	9,058	0	0	2,075	21,300
2094	8,873	5,176	0	0	2,075	16,125
2095	31,289	72,423	0	9,072	2,075	114,859
2096	10,402	9,704	0	0	2,081	22,188
2097	7,148	0	0	0	2,075	9,223
2098	7,148	0	0	0	2,075	9,223
2099	7,148	0	0	0	2,075	9,223
2100	7,148	0	0	0	2,075	9,223
2101	7,148	0	0	0	2,075	9,223
2102	7,148	0	0	0	2,075	9,223
2103	7,148	0	0	0	2,075	9,223
2104	7,168	0	0	0	2,081	9,249
2105	7,148	0	0	0	2,075	9,223
2106	7,148	0	0	0	2,075	9,223
2107	7,148	0	0	0	2,075	9,223
2108	13,264	18,289	0	0	2,081	33,634
2109	7,148	0	0	0	2,075	9,223
2110	7,148	0	0	0	2,075	9,223
2111	7,148	0	0	0	2,075	9,223
2112	7,168	0	0	0	2,081	9,249
2113	7,148	1,664	0	0	9,610	18,422
2114	7,148	0	0	0	2,075	9,223
2115	7,148	0	0	0	2,075	9,223
2116	10,825	10,973	0	0	2,081	23,880
2117	7,148	0	0	0	2,075	9,223
2118	14,922	27,040	0	0	2,122	44,084
2119	6,483	1,722	0	0	2,122	10,327

TABLE 3.3 (continued)
SCENARIO 3: DECON WITH 100 YEAR DFS
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2120	6,403	1,435	0	0	2,128	9,966
2121	6,387	1,435	0	0	2,122	9,944
2122	6,387	1,435	0	0	2,122	9,944
2123	6,483	1,722	0	0	2,122	10,327
2124	6,403	1,435	0	0	2,128	9,966
2125	6,387	1,435	0	0	2,122	9,944
2126	6,387	1,435	0	0	2,122	9,944
2127	6,483	1,722	0	0	2,122	10,327
2128	7,067	3,426	0	0	2,128	12,621
2129	6,387	1,435	0	0	2,122	9,944
2130	6,100	574	0	0	2,122	8,796
2131	2,028	1,499	33	260	3,230	7,051
Total	1,309,028	633,674	11,068	117,345	348,021	2,419,136

Note: Columns may not add due to rounding

TABLE 3.4
SCENARIO 4: DECON WITH 200 YEAR DFS
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2030	21,104	1,240	627	20	7,049	30,039
2031	72,416	7,653	2,616	913	31,779	115,378
2032	81,871	39,120	2,284	40,103	30,941	194,319
2033	78,663	39,613	1,749	34,741	24,053	178,819
2034	66,380	7,285	1,492	9,590	20,527	105,275
2035	86,880	81,202	1,273	13,277	17,396	200,027
2036	50,308	4,032	573	9,360	6,723	70,996
2037	34,756	10,324	237	9	3,627	48,953
2038	29,828	11,416	184	0	3,492	44,919
2039	7,165	50	0	0	2,037	9,251
2040	7,184	50	0	0	2,043	9,277
2041	7,165	50	0	0	2,037	9,251
2042	7,165	50	0	0	2,037	9,251
2043	7,165	50	0	0	2,037	9,251
2044	7,184	50	0	0	2,043	9,277
2045	7,165	50	0	0	2,037	9,251
2046	7,165	50	0	0	2,037	9,251
2047	7,165	50	0	0	2,037	9,251
2048	7,848	2,041	0	0	2,043	11,931
2049	7,165	50	0	0	2,037	9,251
2050	8,658	4,529	0	0	2,037	15,224
2051	8,658	4,529	0	0	2,037	15,224
2052	8,677	4,529	0	0	2,043	15,249
2053	8,658	4,529	0	0	2,037	15,224
2054	8,658	4,529	0	0	2,037	15,224
2055	8,658	4,529	0	0	2,037	15,224
2056	8,677	4,529	0	0	2,043	15,249
2057	8,658	4,529	0	0	2,037	15,224
2058	14,754	22,819	0	0	2,037	39,610
2059	8,658	4,529	0	0	2,037	15,224

TABLE 3.4 (continued)
SCENARIO 4: DECON WITH 200 YEAR DFS
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2060	8,677	4,529	0	0	2,043	15,249
2061	8,658	4,529	0	0	2,037	15,224
2062	8,658	4,529	0	0	2,037	15,224
2063	8,658	4,529	0	0	2,037	15,224
2064	8,677	4,529	0	0	2,043	15,249
2065	8,658	4,529	0	0	2,037	15,224
2066	12,316	15,503	0	0	2,037	29,855
2067	8,658	4,529	0	0	2,037	15,224
2068	17,212	30,134	0	0	2,043	49,389
2069	8,658	4,529	0	0	2,037	15,224
2070	8,658	4,529	0	0	2,037	15,224
2071	8,658	4,529	0	0	2,037	15,224
2072	8,677	4,529	0	0	2,043	15,249
2073	8,658	4,529	0	0	2,037	15,224
2074	8,658	4,529	0	0	2,037	15,224
2075	8,658	4,529	0	0	2,037	15,224
2076	8,677	4,529	0	0	2,043	15,249
2077	8,658	4,529	0	0	2,037	15,224
2078	8,658	4,529	0	0	2,037	15,224
2079	8,658	4,529	0	0	2,037	15,224
2080	8,677	4,529	0	0	2,043	15,249
2081	8,658	4,529	0	0	2,037	15,224
2082	8,658	4,529	0	0	2,037	15,224
2083	8,658	4,529	0	0	2,037	15,224
2084	8,677	4,529	0	0	2,043	15,249
2085	8,658	4,529	0	0	2,037	15,224
2086	8,658	4,529	0	0	2,037	15,224
2087	8,658	4,529	0	0	2,037	15,224
2088	9,341	6,520	0	0	2,043	17,904
2089	8,658	4,529	0	0	2,037	15,224

TABLE 3.4 (continued)
SCENARIO 4: DECON WITH 200 YEAR DFS
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2090	8,658	4,529	0	0	2,037	15,224
2091	8,658	4,529	0	0	2,037	15,224
2092	8,677	4,529	0	0	2,043	15,249
2093	8,658	4,529	0	0	2,037	15,224
2094	8,658	4,529	0	0	2,037	15,224
2095	29,995	68,541	0	9,072	2,037	109,645
2096	8,677	4,529	0	0	2,043	15,249
2097	8,658	4,529	0	0	2,037	15,224
2098	8,658	4,529	0	0	2,037	15,224
2099	8,658	4,529	0	0	2,037	15,224
2100	8,658	4,529	0	0	2,037	15,224
2101	8,658	4,529	0	0	2,037	15,224
2102	8,658	4,529	0	0	2,037	15,224
2103	8,658	4,529	0	0	2,037	15,224
2104	8,677	4,529	0	0	2,043	15,249
2105	8,658	4,529	0	0	2,037	15,224
2106	8,658	4,529	0	0	2,037	15,224
2107	8,658	4,529	0	0	2,037	15,224
2108	14,774	22,819	0	0	2,043	39,635
2109	8,658	4,529	0	0	2,037	15,224
2110	8,658	4,529	0	0	2,037	15,224
2111	8,658	4,529	0	0	2,037	15,224
2112	8,677	4,529	0	0	2,043	15,249
2113	8,658	4,529	0	0	2,037	15,224
2114	8,658	4,529	0	0	2,037	15,224
2115	8,658	4,529	0	0	2,037	15,224
2116	12,335	15,503	0	0	2,043	29,881
2117	8,658	4,529	0	0	2,037	15,224
2118	17,193	30,134	0	0	2,037	49,364
2119	8,658	4,529	0	0	2,037	15,224

TABLE 3.4 (continued)
SCENARIO 4: DECON WITH 200 YEAR DFS
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2120	8,677	4,529	0	0	2,043	15,249
2121	8,658	4,529	0	0	2,037	15,224
2122	8,658	4,529	0	0	2,037	15,224
2123	8,658	4,529	0	0	2,037	15,224
2124	8,677	4,529	0	0	2,043	15,249
2125	8,658	4,529	0	0	2,037	15,224
2126	8,658	4,529	0	0	2,037	15,224
2127	8,658	4,529	0	0	2,037	15,224
2128	9,341	6,520	0	0	2,043	17,904
2129	8,658	4,529	0	0	2,037	15,224
2130	8,658	4,529	0	0	2,037	15,224
2131	8,658	4,529	0	0	2,037	15,224
2132	8,677	4,529	0	0	2,043	15,249
2133	8,658	4,529	0	0	2,037	15,224
2134	8,658	4,529	0	0	2,037	15,224
2135	8,658	4,529	0	0	2,037	15,224
2136	8,677	4,529	0	0	2,043	15,249
2137	8,658	4,529	0	0	2,037	15,224
2138	8,658	4,529	0	0	2,037	15,224
2139	8,658	4,529	0	0	2,037	15,224
2140	8,677	4,529	0	0	2,043	15,249
2141	8,658	4,529	0	0	2,037	15,224
2142	8,658	4,529	0	0	2,037	15,224
2143	8,658	4,529	0	0	2,037	15,224
2144	8,677	4,529	0	0	2,043	15,249
2145	29,995	68,541	0	0	2,037	100,574
2146	8,658	4,529	0	0	2,037	15,224
2147	8,658	4,529	0	0	2,037	15,224
2148	8,677	4,529	0	0	2,043	15,249
2149	8,658	4,529	0	0	2,037	15,224

TABLE 3.4 (continued)
SCENARIO 4: DECON WITH 200 YEAR DFS
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2150	8,658	4,529	0	0	2,037	15,224
2151	8,658	4,529	0	0	2,037	15,224
2152	8,677	4,529	0	0	2,043	15,249
2153	8,658	4,529	0	0	2,037	15,224
2154	8,658	4,529	0	0	2,037	15,224
2155	8,658	4,529	0	0	2,037	15,224
2156	8,677	4,529	0	0	2,043	15,249
2157	8,658	4,529	0	0	2,037	15,224
2158	14,754	22,819	0	0	2,037	39,610
2159	8,658	4,529	0	0	2,037	15,224
2160	8,677	4,529	0	0	2,043	15,249
2161	8,658	4,529	0	0	2,037	15,224
2162	8,658	4,529	0	0	2,037	15,224
2163	8,658	4,529	0	0	2,037	15,224
2164	8,677	4,529	0	0	2,043	15,249
2165	8,658	4,529	0	0	2,037	15,224
2166	12,316	15,503	0	0	2,037	29,855
2167	8,658	4,529	0	0	2,037	15,224
2168	17,876	32,125	0	0	2,043	52,044
2169	8,658	4,529	0	0	2,037	15,224
2170	8,658	4,529	0	0	2,037	15,224
2171	8,658	4,529	0	0	2,037	15,224
2172	8,677	4,529	0	0	2,043	15,249
2173	8,658	4,529	0	0	2,037	15,224
2174	8,658	4,529	0	0	2,037	15,224
2175	8,658	4,529	0	0	2,037	15,224
2176	8,677	4,529	0	0	2,043	15,249
2177	8,658	4,529	0	0	2,037	15,224
2178	8,658	4,529	0	0	2,037	15,224
2179	8,658	4,529	0	0	2,037	15,224

TABLE 3.4 (continued)
SCENARIO 4: DECON WITH 200 YEAR DFS
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2180	8,677	4,529	0	0	2,043	15,249
2181	8,658	4,529	0	0	2,037	15,224
2182	8,658	4,529	0	0	2,037	15,224
2183	8,658	4,529	0	0	2,037	15,224
2184	8,677	4,529	0	0	2,043	15,249
2185	8,658	4,529	0	0	2,037	15,224
2186	8,658	4,529	0	0	2,037	15,224
2187	8,658	4,529	0	0	2,037	15,224
2188	8,677	4,529	0	0	2,043	15,249
2189	8,658	4,529	0	0	2,037	15,224
2190	8,658	4,529	0	0	2,037	15,224
2191	8,658	4,529	0	0	2,037	15,224
2192	9,540	7,117	0	0	2,043	18,699
2193	10,167	9,058	0	0	2,037	21,262
2194	8,873	5,176	0	0	2,037	16,087
2195	31,289	72,423	0	0	2,037	105,749
2196	10,402	9,704	0	0	2,043	22,149
2197	7,148	0	0	0	2,037	9,185
2198	7,148	0	0	0	2,037	9,185
2199	7,148	0	0	0	2,037	9,185
2200	7,148	0	0	0	2,037	9,185
2201	7,148	0	0	0	2,037	9,185
2202	7,148	0	0	0	2,037	9,185
2203	7,148	0	0	0	2,037	9,185
2204	7,168	0	0	0	2,043	9,210
2205	7,148	0	0	0	2,037	9,185
2206	7,148	0	0	0	2,037	9,185
2207	7,148	0	0	0	2,037	9,185
2208	13,928	20,280	0	0	2,043	36,250
2209	7,148	0	0	0	2,037	9,185

TABLE 3.4 (continued)
SCENARIO 4: DECON WITH 200 YEAR DFS
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2210	7,148	0	0	0	2,037	9,185
2211	7,148	0	0	0	2,037	9,185
2212	7,168	0	0	0	2,043	9,210
2213	7,148	1,664	0	0	9,572	18,384
2214	7,148	0	0	0	2,037	9,185
2215	7,148	0	0	0	2,037	9,185
2216	10,825	10,973	0	0	2,043	23,841
2217	7,148	0	0	0	2,037	9,185
2218	14,922	27,040	0	0	2,122	44,084
2219	6,483	1,722	0	0	2,122	10,327
2220	6,403	1,435	0	0	2,128	9,966
2221	6,387	1,435	0	0	2,122	9,944
2222	6,387	1,435	0	0	2,122	9,944
2223	6,483	1,722	0	0	2,122	10,327
2224	6,403	1,435	0	0	2,128	9,966
2225	6,387	1,435	0	0	2,122	9,944
2226	6,387	1,435	0	0	2,122	9,944
2227	6,483	1,722	0	0	2,122	10,327
2228	6,403	1,435	0	0	2,128	9,966
2229	6,387	1,435	0	0	2,122	9,944
2230	6,100	574	0	0	2,122	8,796
2231	2,028	1,499	33	260	3,230	7,051
Total	2,255,856	1,328,352	11,068	117,345	548,823	4,261,444

Note: Columns may not add due to rounding

TABLE 3.5
SCENARIO 5: DECON WITH 60 YEAR DFS WITH RECASKING
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2030	21,104	1,240	627	20	7,049	30,039
2031	72,416	7,653	2,616	913	31,779	115,378
2032	81,871	39,120	2,284	40,103	30,941	194,319
2033	78,663	39,613	1,749	34,741	24,053	178,819
2034	66,380	7,285	1,492	9,590	20,527	105,275
2035	86,880	81,202	1,273	13,277	17,396	200,027
2036	50,308	4,032	573	9,360	6,723	70,996
2037	34,623	10,324	237	9	3,627	48,820
2038	29,581	11,416	184	0	3,500	44,680
2039	5,925	50	0	0	2,137	8,112
2040	5,941	50	0	0	2,143	8,134
2041	5,925	50	0	0	2,137	8,112
2042	5,925	50	0	0	2,137	8,112
2043	5,925	50	0	0	2,137	8,112
2044	5,941	50	0	0	2,143	8,134
2045	5,925	50	0	0	2,137	8,112
2046	5,925	50	0	0	2,137	8,112
2047	5,925	50	0	0	2,137	8,112
2048	6,605	2,041	0	0	2,143	10,789
2049	5,925	50	0	0	2,137	8,112
2050	7,418	4,529	0	0	2,137	14,085
2051	7,418	4,529	0	0	2,137	14,085
2052	8,297	7,117	0	0	2,143	17,557
2053	8,928	9,058	0	0	2,137	20,122
2054	7,634	5,176	0	0	2,137	14,947
2055	8,712	8,411	0	0	2,137	19,260
2056	9,159	9,704	0	0	2,143	21,007
2057	5,908	0	0	0	2,137	8,046
2058	12,005	18,289	0	0	2,137	32,431
2059	5,908	0	0	0	2,137	8,046

TABLE 3.5 (continued)
SCENARIO 5: DECON WITH 60 YEAR DFS WITH RECASKING
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2060	5,925	0	0	0	2,143	8,068
2061	5,908	0	0	0	2,137	8,046
2062	5,908	0	0	0	2,137	8,046
2063	5,908	0	0	0	2,137	8,046
2064	5,925	0	0	0	2,143	8,068
2065	5,908	0	0	0	2,137	8,046
2066	9,566	10,973	0	0	2,137	22,677
2067	5,908	0	0	0	2,137	8,046
2068	14,460	25,605	0	0	2,143	42,208
2069	5,908	0	0	0	2,137	8,046
2070	5,908	0	0	0	2,137	8,046
2071	5,908	0	0	0	2,137	8,046
2072	5,925	0	0	0	2,143	8,068
2073	5,908	0	0	0	2,137	8,046
2074	5,908	0	0	0	2,137	8,046
2075	5,908	0	0	0	2,137	8,046
2076	5,925	0	0	0	2,143	8,068
2077	5,908	0	0	0	2,137	8,046
2078	6,387	1,435	0	0	2,122	9,944
2079	6,483	1,722	0	0	2,122	10,327
2080	6,403	1,435	0	0	2,128	9,966
2081	6,387	1,435	0	0	2,122	9,944
2082	6,387	1,435	0	0	2,122	9,944
2083	6,483	1,722	0	0	2,122	10,327
2084	6,403	1,435	0	0	2,128	9,966
2085	6,387	1,435	0	0	2,122	9,944
2086	6,387	1,435	0	0	2,122	9,944
2087	6,483	1,722	0	0	2,122	10,327
2088	7,067	3,426	0	0	2,128	12,621
2089	6,387	1,435	0	0	2,122	9,944

TABLE 3.5 (continued)
SCENARIO 5: DECON WITH 60 YEAR DFS WITH RECASKING
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2090	6,100	2,238	0	0	9,657	17,995
2091	2,067	1,493	33	10,097	4,175	17,866
Total	873,536	331,622	11,068	118,110	268,325	1,602,660

Note: Columns may not add due to rounding

TABLE 3.6
SCENARIO 6: SAFSTOR WITH 32 YEAR DFS
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2030	19,484	6,243	627	20	7,049	33,423
2031	63,214	6,306	1,989	941	37,537	109,988
2032	30,082	1,835	695	420	18,964	51,996
2033	29,420	15,975	398	23	17,697	63,513
2034	24,245	450	398	23	17,697	42,813
2035	43,919	74,367	335	20	13,362	132,002
2036	8,465	315	199	11	3,948	12,939
2037	8,442	314	199	11	3,938	12,904
2038	8,442	314	199	11	3,938	12,904
2039	8,442	314	199	11	3,938	12,904
2040	8,465	315	199	11	3,948	12,939
2041	8,442	314	199	11	3,938	12,904
2042	8,537	601	199	11	3,938	13,287
2043	8,729	1,175	199	11	3,938	14,052
2044	8,656	889	199	11	3,948	13,705
2045	8,633	888	199	11	3,938	13,669
2046	9,016	2,037	199	11	3,938	15,200
2047	8,920	1,750	199	11	3,938	14,818
2048	9,607	3,741	199	11	3,948	17,507
2049	8,920	1,750	199	11	3,938	14,818
2050	8,729	1,175	199	11	3,938	14,052
2051	8,633	888	199	11	3,938	13,669
2052	8,752	1,176	199	11	3,948	14,087
2053	8,633	888	199	11	3,938	13,669
2054	8,633	888	199	11	3,938	13,669
2055	8,729	1,175	199	11	3,938	14,052
2056	8,656	889	199	11	3,948	13,705
2057	8,633	888	199	11	3,938	13,669
2058	8,729	1,175	199	11	3,938	14,052
2059	8,825	1,463	199	11	3,938	14,435

TABLE 3.6 (continued)
SCENARIO 6: SAFSTOR WITH 32 YEAR DFS
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2060	8,656	889	199	11	3,948	13,705
2061	8,825	1,463	199	11	3,938	14,435
2062	8,825	1,463	199	11	3,938	14,435
2063	1,610	307	199	10	3,900	6,026
2064	1,614	308	199	10	3,910	6,042
2065	1,610	307	199	10	3,900	6,026
2066	1,610	307	199	10	3,900	6,026
2067	1,610	307	199	10	3,900	6,026
2068	1,614	308	199	10	3,910	6,042
2069	1,610	307	199	10	3,900	6,026
2070	1,610	307	199	10	3,900	6,026
2071	1,610	307	199	10	3,900	6,026
2072	1,614	308	199	10	3,910	6,042
2073	1,610	307	199	10	3,900	6,026
2074	1,610	307	199	10	3,900	6,026
2075	1,610	307	199	10	3,900	6,026
2076	1,614	308	199	10	3,910	6,042
2077	1,610	307	199	10	3,900	6,026
2078	1,610	307	199	10	3,900	6,026
2079	1,610	307	199	10	3,900	6,026
2080	1,614	308	199	10	3,910	6,042
2081	1,610	307	199	10	3,900	6,026
2082	1,610	307	199	10	3,900	6,026
2083	1,610	307	199	10	3,900	6,026
2084	1,614	308	199	10	3,910	6,042
2085	40,842	4,857	1,921	65	4,033	51,718
2086	48,428	16,050	1,943	18,529	8,986	93,937
2087	52,120	25,292	1,848	37,180	14,229	130,670
2088	46,773	7,413	1,496	13,385	7,493	76,560
2089	45,679	7,004	1,417	13,353	7,627	75,081

TABLE 3.6 (continued)
SCENARIO 6: SAFSTOR WITH 32 YEAR DFS
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2090	28,929	5,553	335	9,189	7,305	51,311
2091	21,064	13,889	199	0	2,029	37,181
2092	8,829	5,822	83	0	851	15,585
Total	773,451	226,950	23,440	93,680	357,105	1,474,626

Note: Columns may not add due to rounding

TABLE 3.7
SCENARIO 7: SAFSTOR WITH 60 YEAR DFS
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2030	17,759	1,068	627	20	7,049	26,523
2031	63,231	6,356	1,989	941	37,537	110,054
2032	30,099	1,885	695	420	18,964	52,063
2033	30,012	17,750	398	23	17,697	65,880
2034	24,262	500	398	23	17,697	42,880
2035	43,936	74,416	335	20	13,362	132,069
2036	8,481	365	199	11	3,948	13,005
2037	8,458	364	199	11	3,938	12,970
2038	8,458	364	199	11	3,938	12,970
2039	8,458	364	199	11	3,938	12,970
2040	8,481	365	199	11	3,948	13,005
2041	8,458	364	199	11	3,938	12,970
2042	8,458	364	199	11	3,938	12,970
2043	8,458	364	199	11	3,938	12,970
2044	8,481	365	199	11	3,948	13,005
2045	8,458	364	199	11	3,938	12,970
2046	8,458	364	199	11	3,938	12,970
2047	8,458	364	199	11	3,938	12,970
2048	9,145	2,356	199	11	3,948	15,660
2049	8,458	364	199	11	3,938	12,970
2050	9,952	4,844	199	11	3,938	18,943
2051	9,952	4,844	199	11	3,938	18,943
2052	10,837	7,432	199	11	3,948	22,428
2053	11,461	9,372	199	11	3,938	24,980
2054	10,167	5,491	199	11	3,938	19,805
2055	11,245	8,725	199	11	3,938	24,118
2056	11,700	10,020	199	11	3,948	25,878
2057	8,442	314	199	11	3,938	12,904
2058	8,442	314	199	11	3,938	12,904
2059	8,442	314	199	11	3,938	12,904

TABLE 3.7 (continued)
SCENARIO 7: SAFSTOR WITH 60 YEAR DFS
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

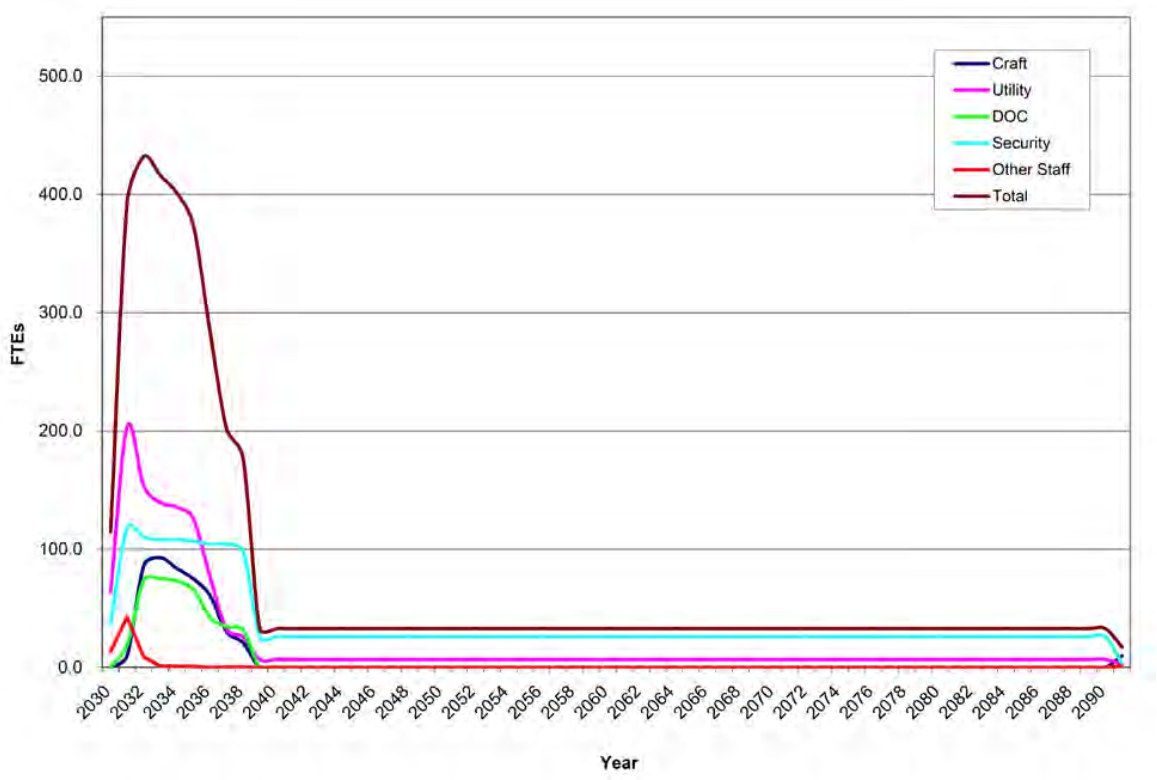
Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2060	8,465	315	199	11	3,948	12,939
2061	8,442	314	199	11	3,938	12,904
2062	8,442	314	199	11	3,938	12,904
2063	8,442	314	199	11	3,938	12,904
2064	8,465	315	199	11	3,948	12,939
2065	8,442	314	199	11	3,938	12,904
2066	8,442	314	199	11	3,938	12,904
2067	8,442	314	199	11	3,938	12,904
2068	8,465	315	199	11	3,948	12,939
2069	8,442	314	199	11	3,938	12,904
2070	8,442	314	199	11	3,938	12,904
2071	8,442	314	199	11	3,938	12,904
2072	8,465	315	199	11	3,948	12,939
2073	8,442	314	199	11	3,938	12,904
2074	8,442	314	199	11	3,938	12,904
2075	8,442	314	199	11	3,938	12,904
2076	8,465	315	199	11	3,948	12,939
2077	8,442	314	199	11	3,938	12,904
2078	8,920	1,750	199	11	3,938	14,817
2079	9,016	2,037	199	11	3,938	15,200
2080	8,943	1,750	199	11	3,948	14,853
2081	8,920	1,750	199	11	3,938	14,817
2082	8,920	1,750	199	11	3,938	14,817
2083	9,016	2,037	199	11	3,938	15,200
2084	8,943	1,750	199	11	3,948	14,853
2085	46,126	6,293	1,921	66	4,034	58,440
2086	53,631	17,486	1,943	18,529	8,987	100,577
2087	57,419	27,016	1,848	37,180	14,229	137,692
2088	52,653	10,840	1,496	13,385	7,493	85,867
2089	50,914	8,441	1,417	13,353	7,631	81,755

TABLE 3.7 (continued)
SCENARIO 7: SAFSTOR WITH 60 YEAR DFS
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2090	32,668	6,135	335	9,190	7,341	55,669
2091	21,071	13,904	199	0	2,029	37,203
2092	8,833	5,828	83	0	851	15,595
Total	967,172	275,164	23,440	93,701	357,978	1,717,454

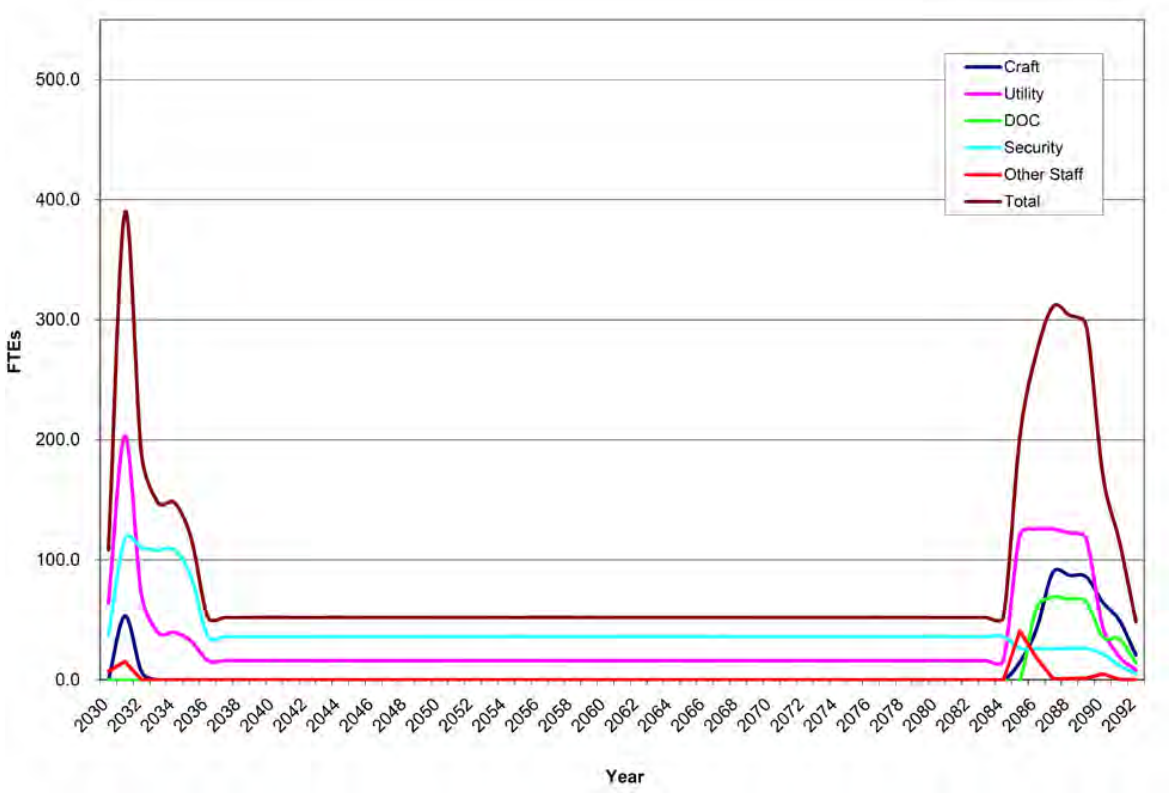
Note: Columns may not add due to rounding

FIGURE 3.1
SCENARIO 2: DECON WITH 60 YEAR DFS
MONTICELLO NUCLEAR GENERATING PLANT
MANPOWER LEVELS



Note that the labor hour basis of this chart was taken from Appendix D; however not all line items in Appendix D have labor hour values available (e.g. spent fuel canister loading estimates from Xcel Energy)

FIGURE 3.2
SCENARIO 7: SAFSTOR WITH 60 YEAR DFS
MONTICELLO NUCLEAR GENERATING PLANT
MANPOWER LEVELS



Note that the labor hour basis of this chart was taken from Appendix I; however not all line items in Appendix I have labor hour values available (e.g. spent fuel canister loading estimates from Xcel Energy)

4. SCHEDULE ESTIMATE

The schedules for the decommissioning scenarios considered in this study follow the sequence presented in the AIF/NESP-036 study, with minor changes to reflect recent experience and site-specific constraints. In addition, the scheduling has been revised to reflect the spent fuel management plans described in Section 3.4.1.

A schedule or sequence of activities for the DECON alternative is presented in Figure 4.1. The schedule is also representative of the work activities identified in the delayed dismantling scenarios, absent any spent fuel constraints. The scheduling sequence is based on the fuel being removed from the spent fuel pool within the first five years after operations cease. The key activities listed in the schedule do not reflect a one-to-one correspondence with those activities in the cost tables, but reflect dividing some activities for clarity and combining others for convenience. The schedule was prepared using the "Microsoft Project Professional" computer software. [40]

4.1 SCHEDULE ESTIMATE ASSUMPTIONS

The schedule reflects the results of a precedence network developed for the site decommissioning activities, i.e., a PERT (Program Evaluation and Review Technique) Software Package. The work activity durations used in the precedence network reflect the actual man-hour estimates from the cost table, adjusted by stretching certain activities over their slack range and shifting the start and end dates of others. The following assumptions were made in the development of the decommissioning schedule:

- The reactor building is isolated until such time that all spent fuel has been discharged from the storage pool to the DOE or to the ISFSI. Decontamination and dismantling of the spent fuel storage pool is initiated once the transfer of spent fuel is complete (DECON option).
- All work (except vessel and internals removal) is performed during an 8-hour workday, 5 days per week, with no overtime. There are eleven paid holidays per year.
- Reactor and internals removal activities are performed by using separate crews for different activities working on different shifts, with a corresponding backshift charge for the second shift.
- Multiple crews work parallel activities to the maximum extent possible, consistent with optimum efficiency, adequate access for cutting, removal and laydown space, and with the stringent safety measures necessary during demolition of heavy components and structures.

- For plant systems removal, the systems with the longest removal durations in areas on the critical path are considered to determine the duration of the activity.

4.2 PROJECT SCHEDULE

The period-dependent costs presented in the detailed cost tables are based upon the durations developed in the schedules for decommissioning Monticello. Durations are established between several milestones in each project period; these durations are used to establish a critical path for the entire project. In turn, the critical path duration for each period is used as the basis for determining the period-dependent costs. A second parallel path is also shown for the spent fuel cooling period, which determines the release of the reactor building for final decontamination.

Project timelines are provided in Figures 4.2 through 4.8, with milestone dates based on a 2030 shutdown date. The fuel pool is emptied approximately five years after shutdown, while ISFSI operations continue until the DOE completes the transfer of assemblies. Deferred decommissioning operations in the SAFSTOR scenarios are assumed to commence so that the operating license is terminated within a 60-year period from the cessation of operations.

FIGURE 4.1
DECON ACTIVITY SCHEDULE

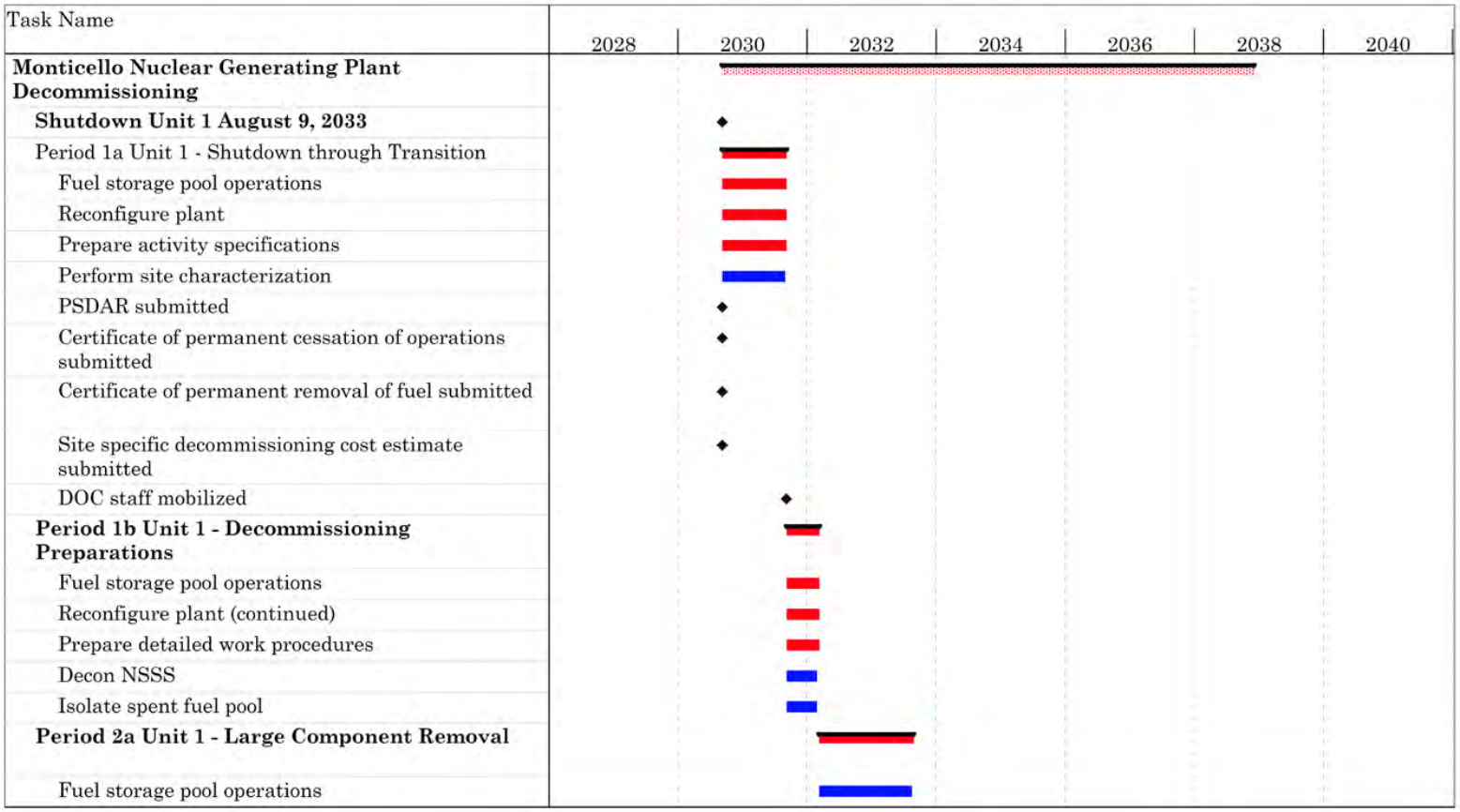


FIGURE 4.1 (continued)
DECON ACTIVITY SCHEDULE

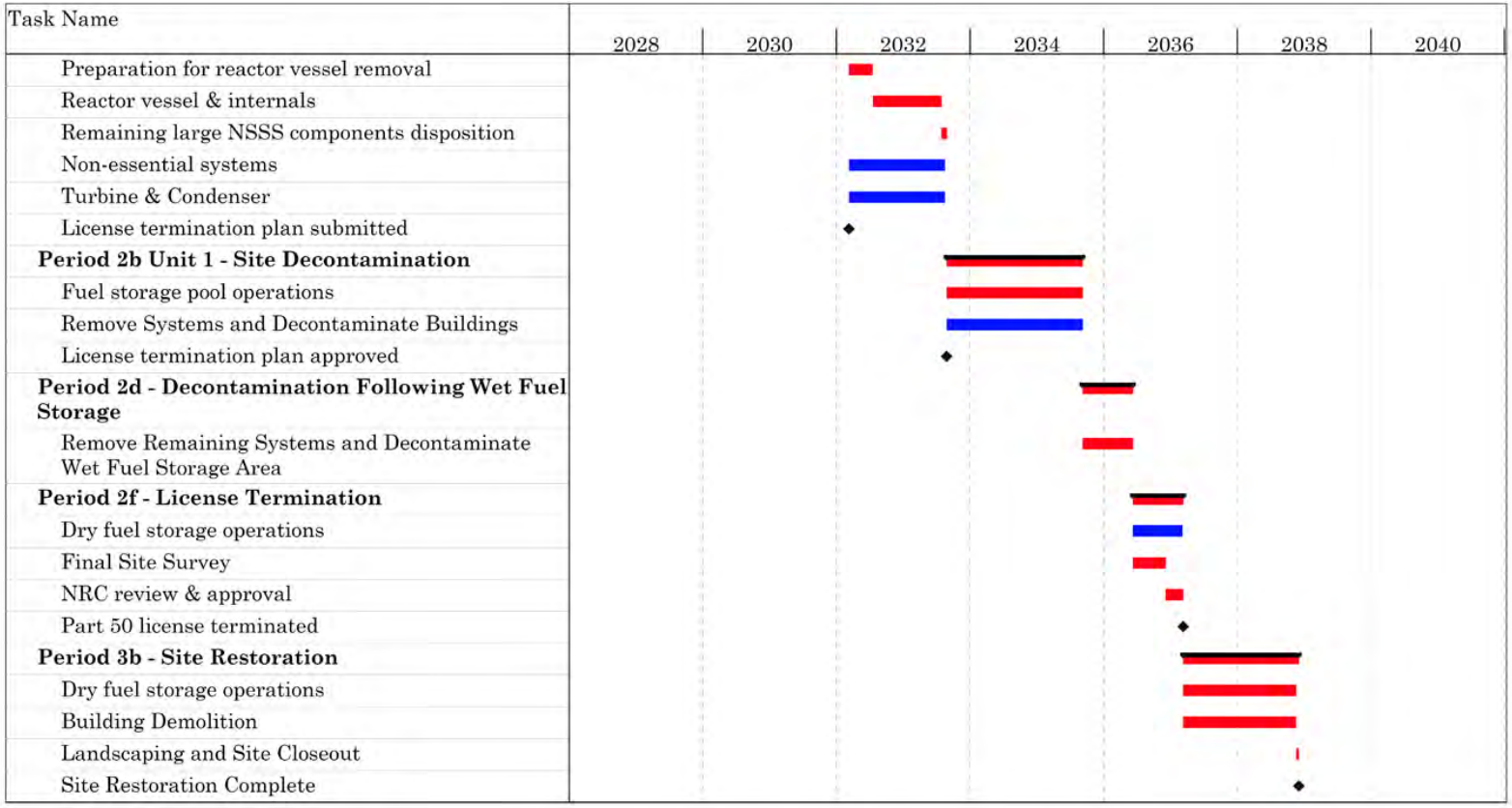


FIGURE 4.1 (continued)
LEGEND

1. Red scheduling bars indicate critical path activities
2. Blue scheduling bars associated with non-critical path activities
3. Diamond symbols indicate major milestones

FIGURE 4.2
SCENARIO 1: DECON WITH 32 YEAR DFS
DECOMMISSIONING TIMELINE
(not to scale)

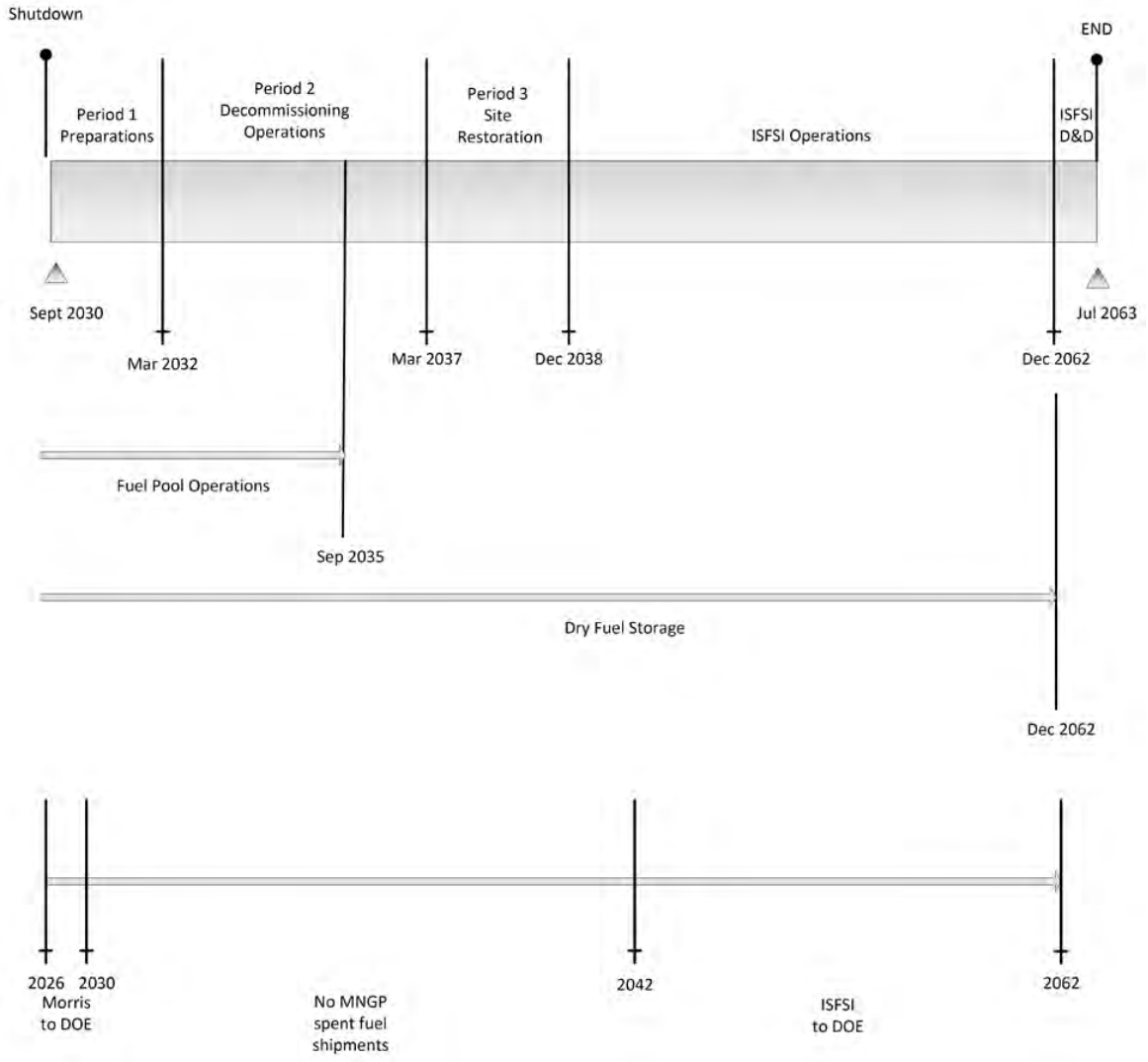


FIGURE 4.3
SCENARIO 2: DECON WITH 60 YEAR DFS
DECOMMISSIONING TIMELINE
(not to scale)

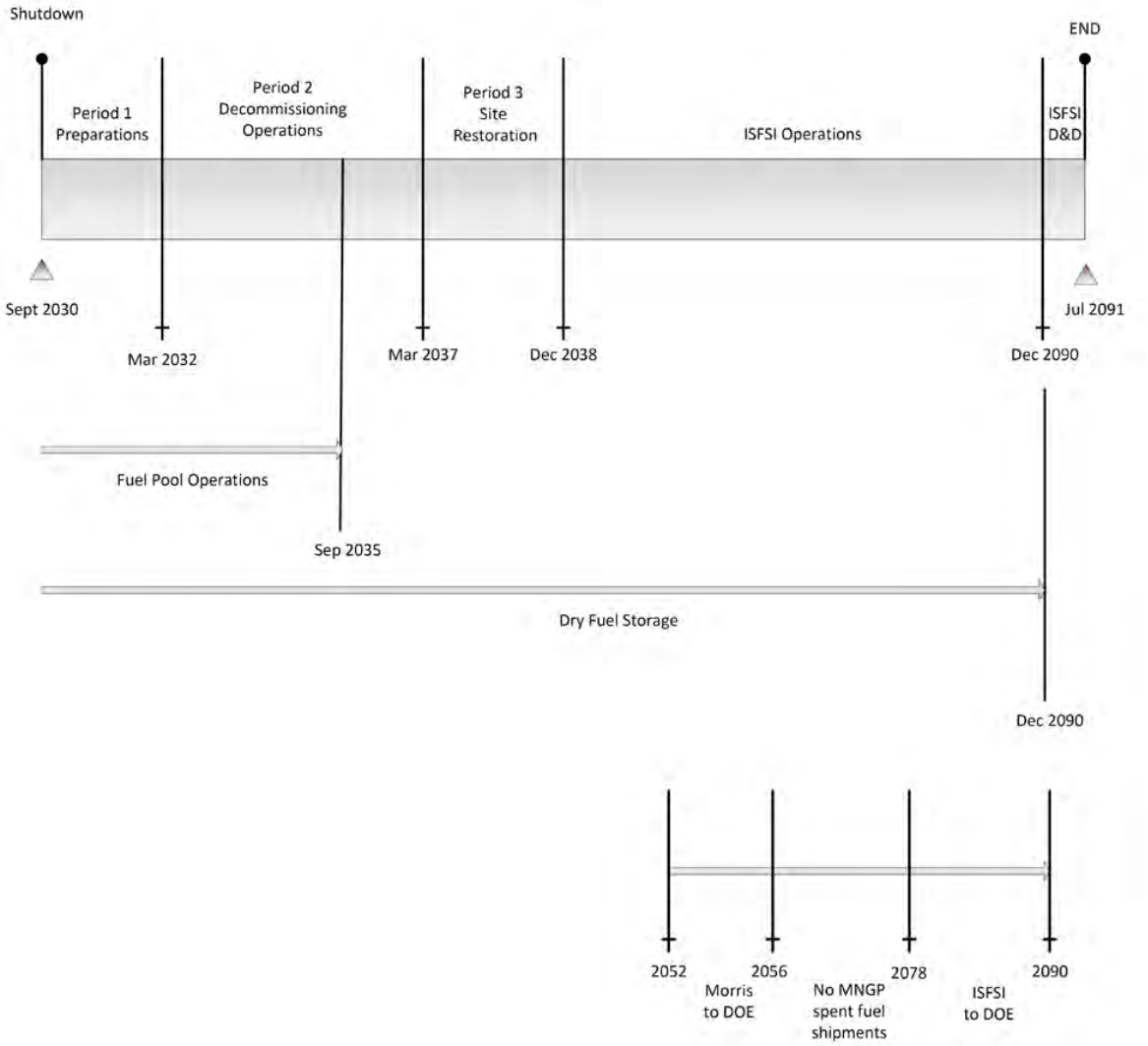


FIGURE 4.4
SCENARIO 3: DECON WITH 100 YEAR DFS
DECOMMISSIONING TIMELINE
(not to scale)

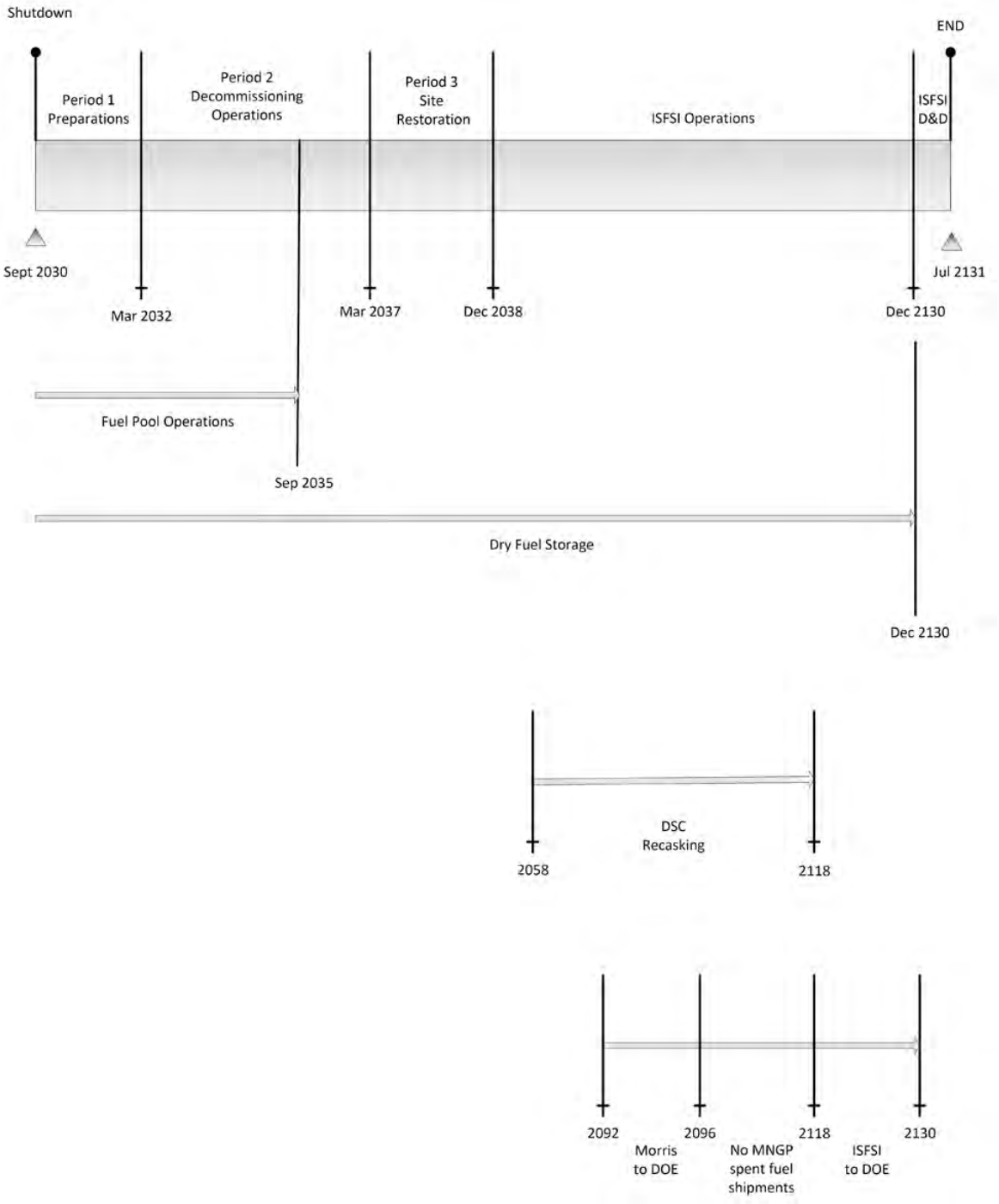


FIGURE 4.5
SCENARIO 4: DECON WITH 200 YEAR DFS
DECOMMISSIONING TIMELINE
(not to scale)

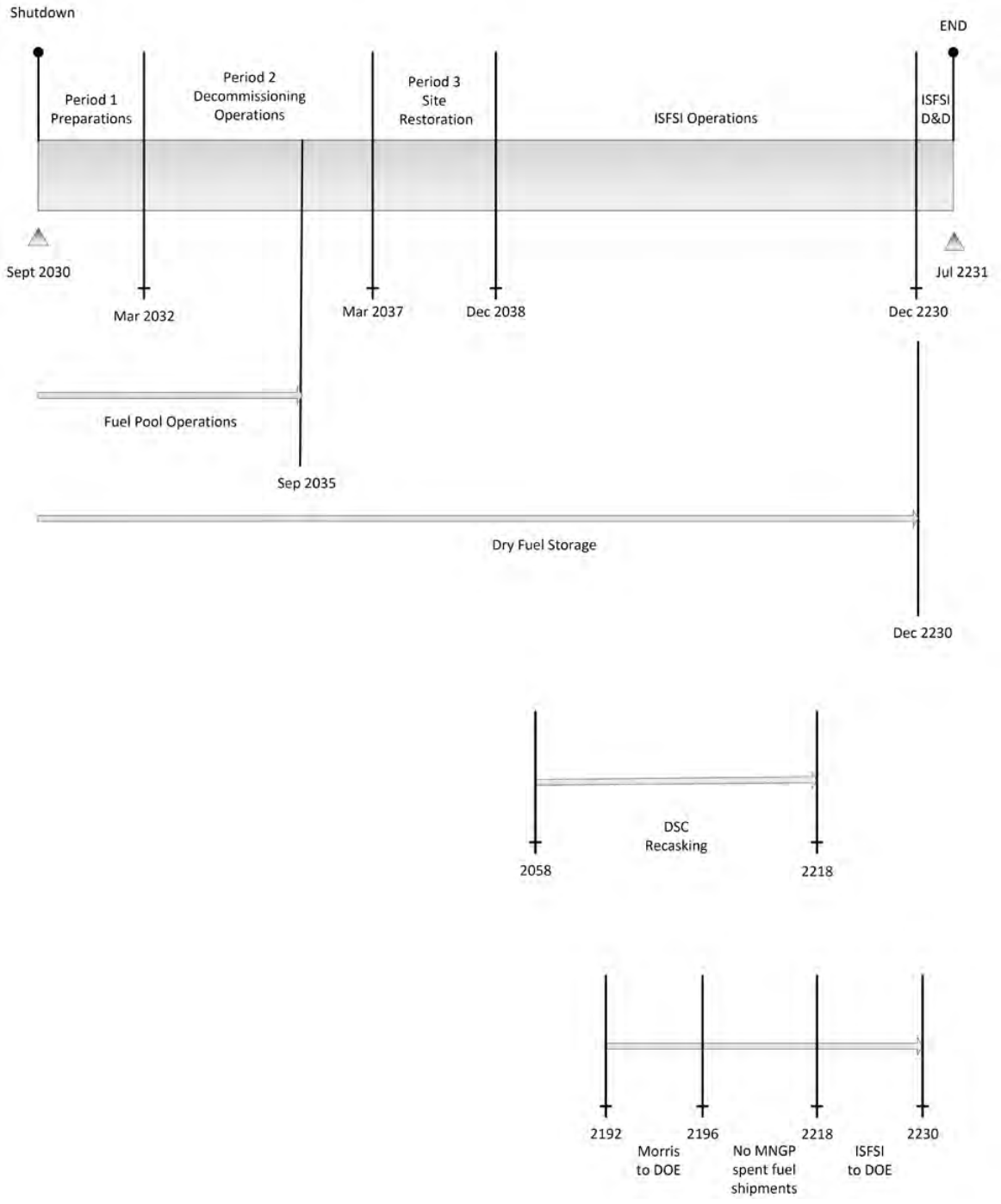


FIGURE 4.6
SCENARIO 5: DECON WITH 60 YEAR DFS WITH RECASKING
DECOMMISSIONING TIMELINE
(not to scale)

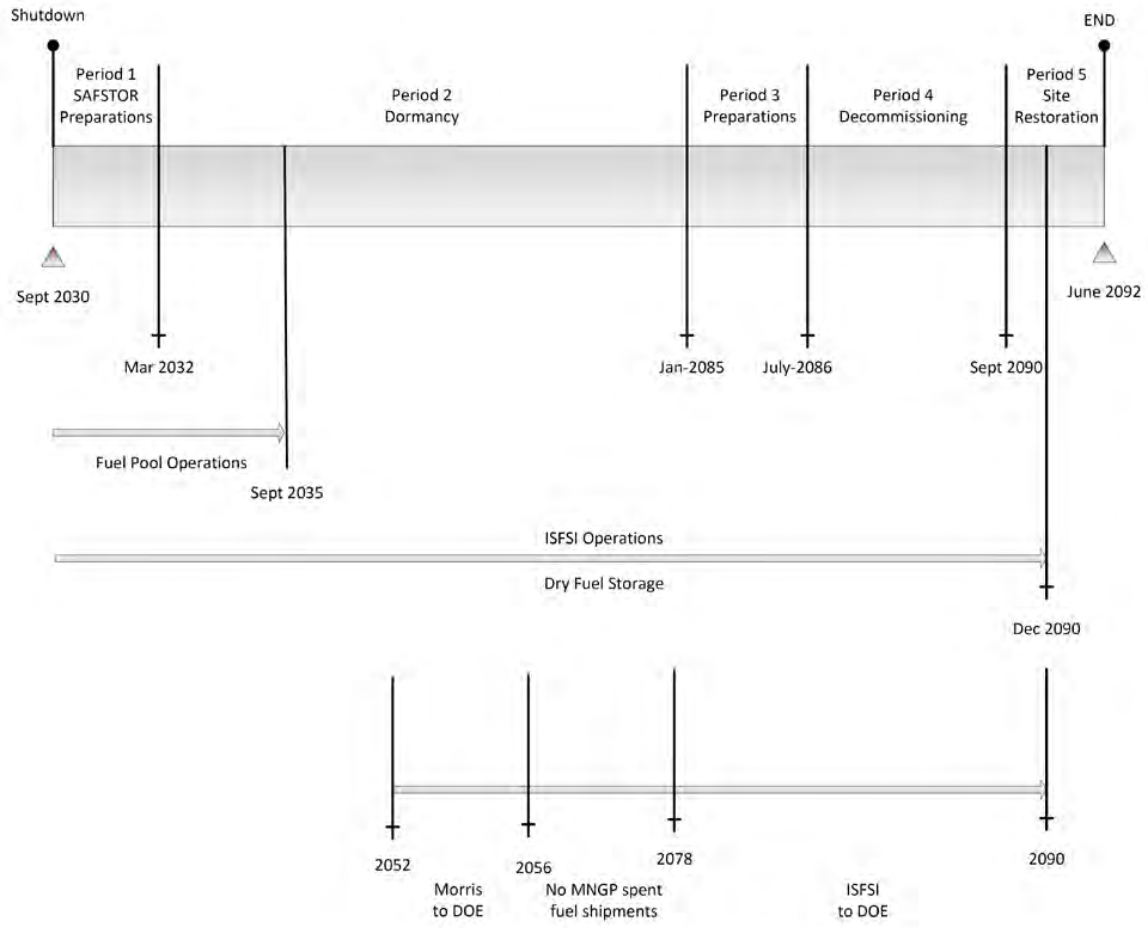


FIGURE 4.7
SCENARIO 6: SAFSTOR WITH 32 YEAR DFS
DECOMMISSIONING TIMELINE
(not to scale)

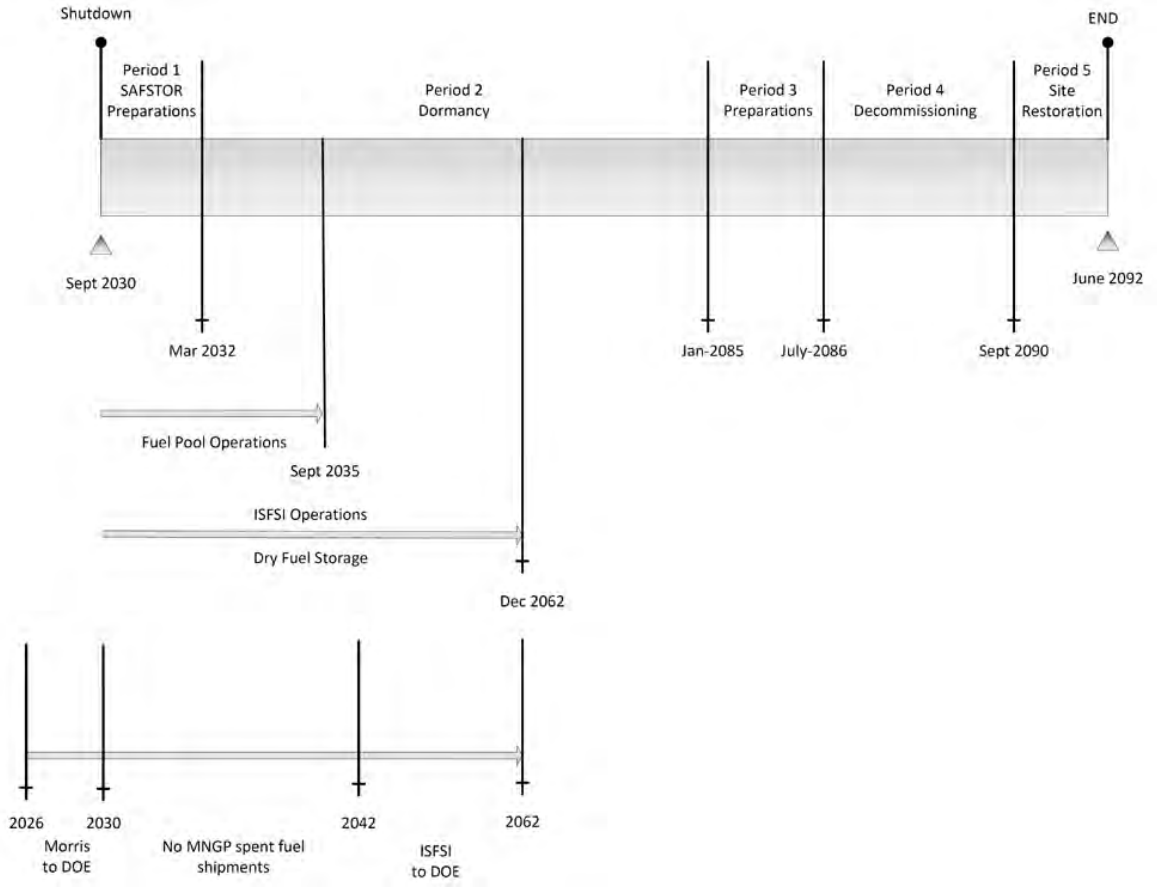
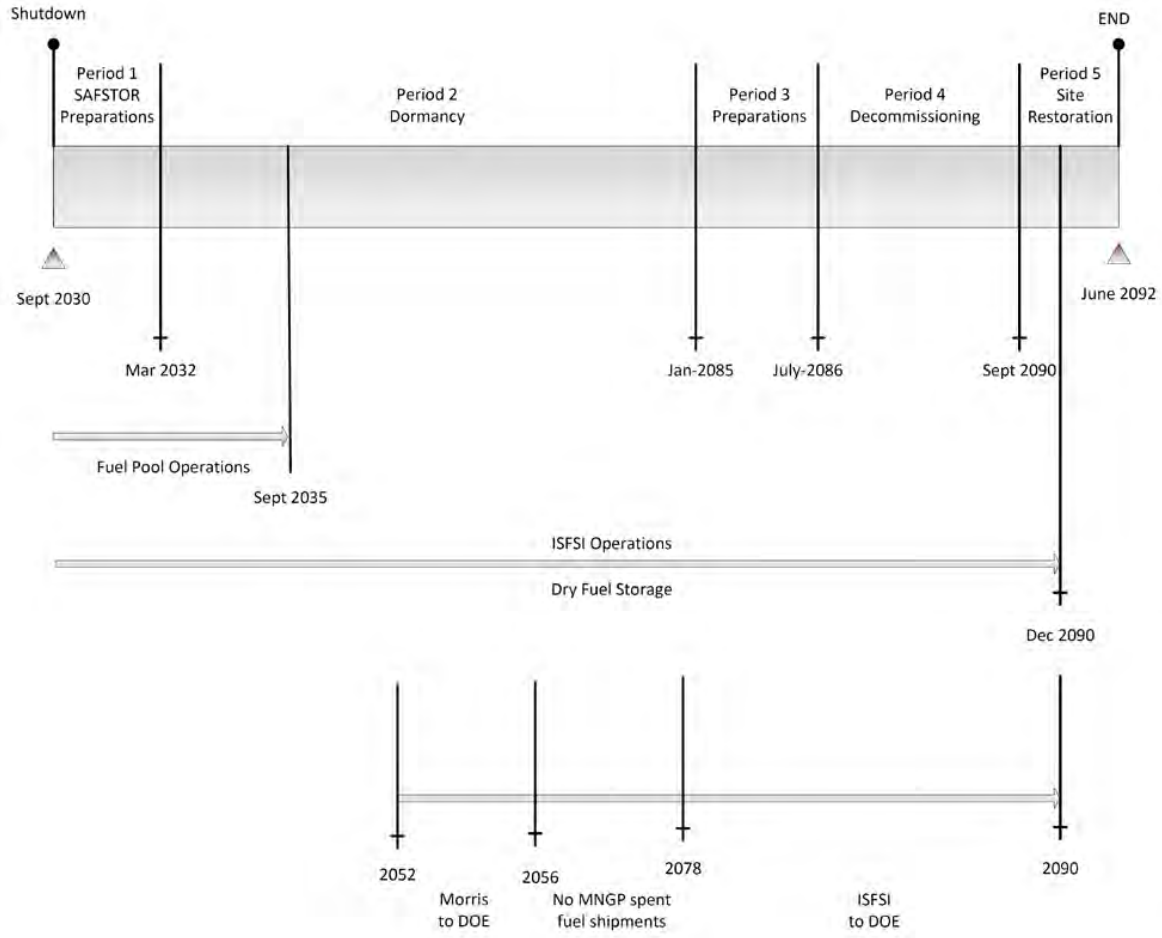


FIGURE 4.8
SCENARIO 7: SAFSTOR WITH 60 YEAR DFS
DECOMMISSIONING TIMELINE
(not to scale)



5. RADIOACTIVE WASTES

The objectives of the decommissioning process are the removal of all radioactive material from the site that would restrict its future use and the termination of the NRC license. This currently requires the remediation of all radioactive material at the site in excess of applicable legal limits. Under the Atomic Energy Act, [41] the NRC is responsible for protecting the public from sources of ionizing radiation. Title 10 of the Code of Federal Regulations delineates the production, utilization, and disposal of radioactive materials and processes. In particular, Part 71 defines radioactive material as it pertains to transportation and Part 61 specifies its disposition.

Most of the materials being transported for controlled burial are categorized as Low Specific Activity (LSA) or Surface Contaminated Object (SCO) materials containing Type A quantities, as defined in 49 CFR Parts 173-178. Shipping containers are required to be Industrial Packages (IP-1, IP-2 or IP-3, as defined in 10 CFR §173.411). For this study, commercially available steel containers are presumed to be used for the disposal of piping, small components, and concrete. Larger components can serve as their own containers, with proper closure of all openings, access ways, and penetrations.

The destinations for the various waste streams from decommissioning are identified in Figures 5.1 and 5.2. The volumes of radioactive waste generated during the various decommissioning activities at the site are shown on a line-item basis in Appendices C through J and summarized in Tables 5.1 through 5.7. The quantified waste volume summaries shown in these tables are consistent with §61 classifications. The volumes are calculated based on the exterior dimensions for containerized material and on the displaced volume of components serving as their own waste containers.

The reactor vessel and internals are categorized as large quantity shipments and, accordingly, will be shipped in reusable, shielded truck casks with disposable liners. In calculating disposal costs, the burial fees are applied against the liner volume, as well as the special handling requirements of the payload. Packaging efficiencies are lower for the highly activated materials (greater than Type A quantity waste), where high concentrations of gamma-emitting radionuclides limit the capacity of the shipping canisters.

No process system containing/handling radioactive substances at shutdown is presumed to meet material release criteria by decay alone, i.e., systems radioactive at shutdown will still be radioactive over the time period during which the decommissioning is accomplished, due to the presence of long-lived radionuclides.

While the dose rates decrease with time, radionuclides such as ^{137}Cs will still control the disposition requirements.

The waste material generated in the decontamination and dismantling of Monticello is primarily generated during Period 2 of the DECON alternatives and Period 4 of the SAFSTOR alternatives. Material that is considered potentially contaminated when removed from the radiologically controlled area is sent to processing facilities in Tennessee for conditioning and disposal. Heavily contaminated components and activated materials are routed for controlled disposal. The disposal volumes reported in the tables reflect the savings resulting from reprocessing and recycling.

Disposal fees are calculated using representative costs, with surcharges added for the highly activated components, for example, generated in the segmentation of the reactor vessel. The cost to dispose of the majority of the material generated from the decontamination and dismantling activities is based upon representative rates.

Energy*Solutions* is not able to accept the higher activity waste (Class B and C) generated in the decontamination of the NSSS and segmentation of the components closest to the core. Waste disposal costs for the higher activity waste (Class B and C) are based upon preliminary and indicative information on the cost for such from WCS.

A small quantity of material generated during the Monticello decommissioning will not be considered suitable for near-surface disposal, and is assumed to be disposed of in a geologic repository, in a manner similar to that envisioned for spent fuel disposal. Such material, known as Greater-Than-Class-C or GTCC material, is estimated to require four spent fuel storage canisters (or the equivalent) to dispose of the most radioactive portions of the reactor vessel internals. The volume and weight reported in Tables 5.1 through 5.7 represent the packaged weight and volume of the spent fuel storage canisters.

FIGURE 5.1
RADIOACTIVE WASTE DISPOSITION

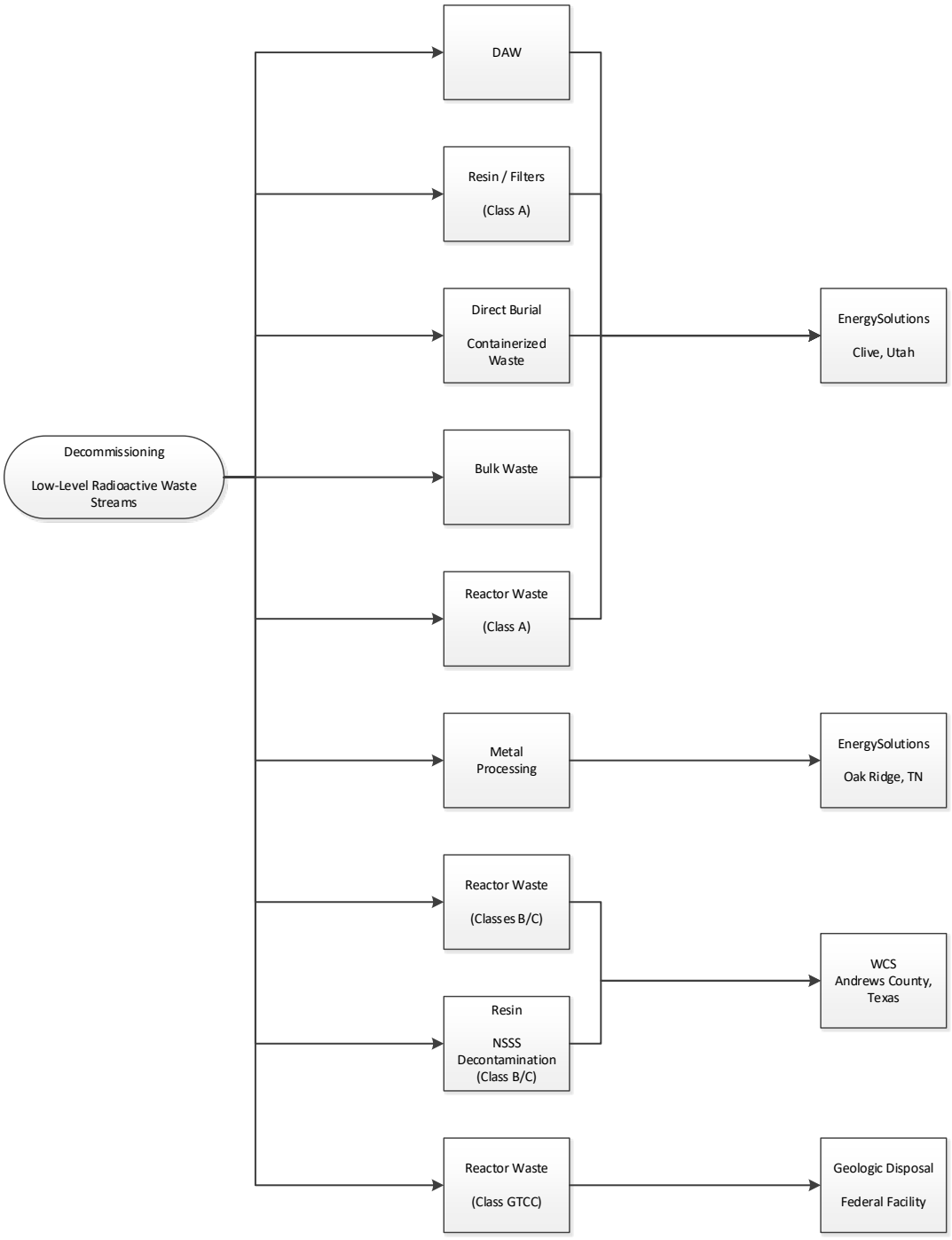
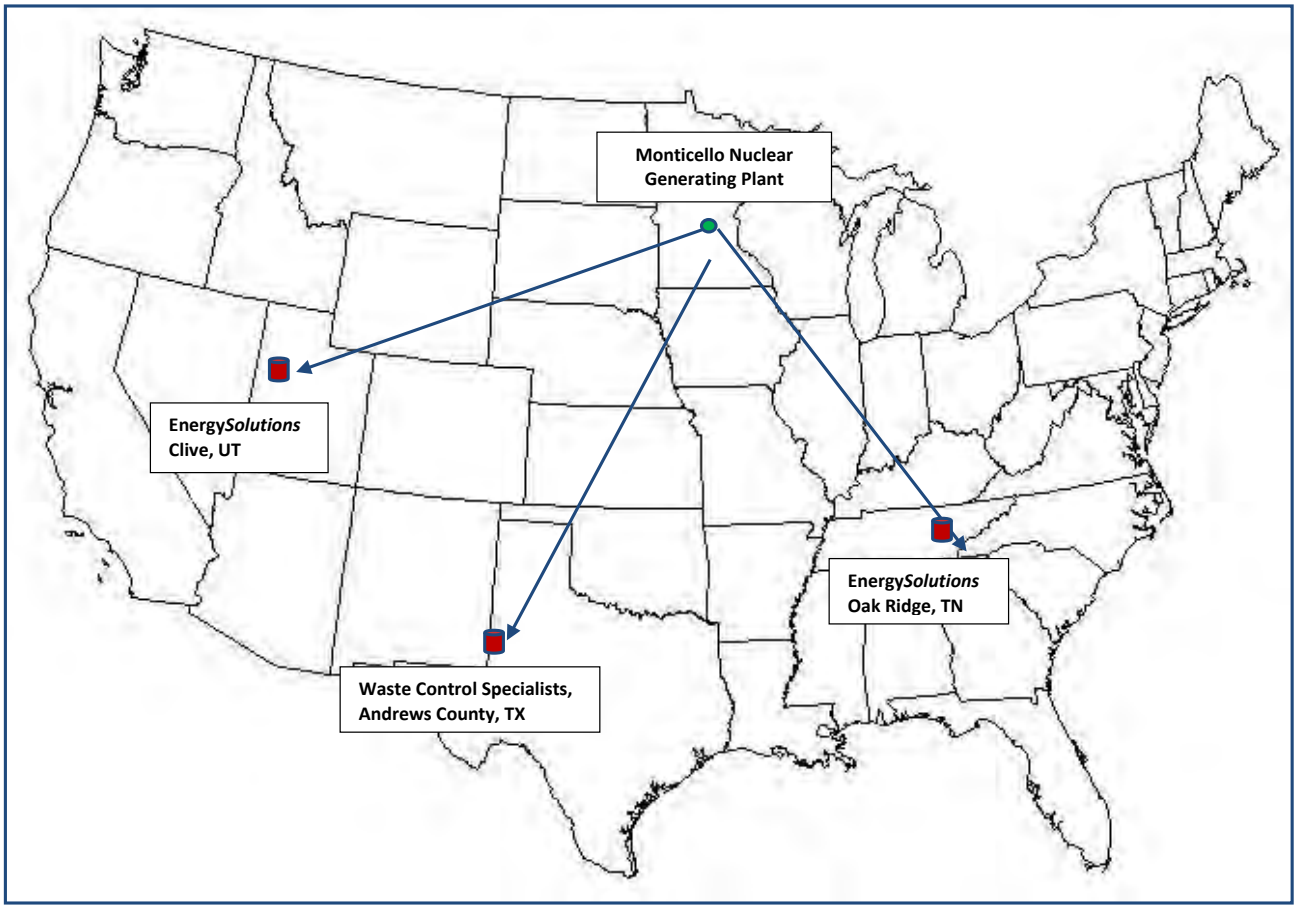


FIGURE 5.2
DECOMMISSIONING WASTE DESTINATIONS
RADIOLOGICAL



The figure indicates the destinations for the low-level radioactive waste designated for direct disposal (Clive, Utah) and processing/recovery (Oak Ridge, Tennessee).

Disposition of the Class B and C low-level radioactive waste will be at the Waste Control Specialists site in Andrews County, Texas.

Disposal options (and destinations) for GTCC are still being evaluated.

TABLE 5.1
SCENARIO 1: DECON WITH 32 YEAR DFS
DECOMMISSIONING WASTE SUMMARY

Waste	Cost Basis	Class [1]	Waste Volume (cubic feet)	Mass (pounds)
Low-Level Radioactive Waste (near-surface disposal)	Energy*Solutions* Containerized	A	124,968	7,403,271
	Energy*Solutions* Bulk	A	78,091	5,653,134
	Future LLRW Disposal Facility (Proxy)	B	1,711	185,173
	Future LLRW Disposal Facility (Proxy)	C	1,010	79,764
Greater than Class C (geologic repository)	Spent Fuel Equivalent	GTCC	1,547	311,184
Total [2]			207,327	13,632,526
Processed/Conditioned (off-site recycling center)	Recycling Vendors	A	288,153	12,124,710
Scrap Metal				45,392,000

[1] Waste is classified according to the requirements as delineated in Title 10 CFR, Part 61.55
[2] Columns may not add due to rounding

TABLE 5.2
SCENARIO 2: DECON WITH 60 YEAR DFS
DECOMMISSIONING WASTE SUMMARY

Waste	Cost Basis	Class [1]	Waste Volume (cubic feet)	Mass (pounds)
Low-Level Radioactive Waste (near-surface disposal)	Energy*Solutions* Containerized	A	124,968	7,403,271
	Energy*Solutions* Bulk	A	78,091	5,653,134
	Future LLRW Disposal Facility (Proxy)	B	1,711	185,173
	Future LLRW Disposal Facility (Proxy)	C	1,010	79,764
Greater than Class C (geologic repository)	Spent Fuel Equivalent	GTCC	1,547	311,184
Total [2]			207,327	13,632,526
Processed/Conditioned (off-site recycling center)	Recycling Vendors	A	288,153	12,124,710
Scrap Metal				45,392,000

[1] Waste is classified according to the requirements as delineated in Title 10 CFR, Part 61.55
[2] Columns may not add due to rounding

TABLE 5.3
SCENARIO 3: DECON WITH 100 YEAR DFS
DECOMMISSIONING WASTE SUMMARY

Waste	Cost Basis	Class [1]	Waste Volume (cubic feet)	Mass (pounds)
Low-Level Radioactive Waste (near-surface disposal)	Energy*Solutions* Containerized	A	144,351	8,515,592
	Energy*Solutions* Bulk	A	55,265	2,218,598
	Future LLRW Disposal Facility (Proxy)	B	1,711	185,173
	Future LLRW Disposal Facility (Proxy)	C	1,010	79,764
Greater than Class C (geologic repository)	Spent Fuel Equivalent	GTCC	1,547	311,184
Total [2]			203,884	11,310,311
Processed/Conditioned (off-site recycling center)	Recycling Vendors	A	288,153	12,124,710
Scrap Metal				45,392,000

[1] Waste is classified according to the requirements as delineated in Title 10 CFR, Part 61.55
[2] Columns may not add due to rounding

TABLE 5.4
SCENARIO 4: DECON WITH 200 YEAR DFS
DECOMMISSIONING WASTE SUMMARY

Waste	Cost Basis	Class [1]	Waste Volume (cubic feet)	Mass (pounds)
Low-Level Radioactive Waste (near-surface disposal)	Energy*Solutions* Containerized	A	144,351	8,515,592
	Energy*Solutions* Bulk	A	55,265	2,218,598
	Future LLRW Disposal Facility (Proxy)	B	1,711	185,173
	Future LLRW Disposal Facility (Proxy)	C	1,010	79,764
Greater than Class C (geologic repository)	Spent Fuel Equivalent	GTCC	1,547	311,184
Total [2]			203,884	11,310,311
Processed/Conditioned (off-site recycling center)	Recycling Vendors	A	288,153	12,124,710
Scrap Metal				45,392,000

[1] Waste is classified according to the requirements as delineated in Title 10 CFR, Part 61.55
[2] Columns may not add due to rounding

TABLE 5.5
SCENARIO 5: DECON WITH 60 YEAR DFS WITH RECASKING
DECOMMISSIONING WASTE SUMMARY

Waste	Cost Basis	Class [1]	Waste Volume (cubic feet)	Mass (pounds)
Low-Level Radioactive Waste (near-surface disposal)	Energy*Solutions* Containerized	A	124,968	7,403,271
	Energy*Solutions* Bulk	A	78,280	5,669,770
	Future LLRW Disposal Facility (Proxy)	B	1,711	185,173
	Future LLRW Disposal Facility (Proxy)	C	1,010	79,764
Greater than Class C (geologic repository)	Spent Fuel Equivalent	GTCC	1,547	311,184
Total [2]			207,517	13,649,162
Processed/Conditioned (off-site recycling center)	Recycling Vendors	A	288,153	12,124,710
Scrap Metal				45,392,000

[1] Waste is classified according to the requirements as delineated in Title 10 CFR, Part 61.55
[2] Columns may not add due to rounding

TABLE 5.6
SCENARIO 6: SAFSTOR WITH 32 YEAR DFS
DECOMMISSIONING WASTE SUMMARY

Waste	Cost Basis	Class [1]	Waste Volume (cubic feet)	Mass (pounds)
Low-Level Radioactive Waste (near-surface disposal)	Energy*Solutions* Containerized	A	51,704	3,350,492
	Energy*Solutions* Bulk	A	98,724	6,508,668
	Future LLRW Disposal Facility (Proxy)	B	1,127	99,260
	Future LLRW Disposal Facility (Proxy)	C	643	71,913
Greater than Class C (geologic repository)	Spent Fuel Equivalent	GTCC	1,547	311,184
Total [2]			153,744	10,341,518
Processed/Conditioned (off-site recycling center)	Recycling Vendors	A	340,130	14,284,870
Scrap Metal				45,392,000

[1] Waste is classified according to the requirements as delineated in Title 10 CFR, Part 61.55
[2] Columns may not add due to rounding

TABLE 5.7
SCENARIO 7: SAFSTOR WITH 60 YEAR DFS
DECOMMISSIONING WASTE SUMMARY

Waste	Cost Basis	Class [1]	Waste Volume (cubic feet)	Mass (pounds)
Low-Level Radioactive Waste (near-surface disposal)	Energy*Solutions* Containerized	A	51,704	3,350,492
	Energy*Solutions* Bulk	A	98,926	6,512,710
	Future LLRW Disposal Facility (Proxy)	B	1,127	99,260
	Future LLRW Disposal Facility (Proxy)	C	643	71,913
Greater than Class C (geologic repository)	Spent Fuel Equivalent	GTCC	1,547	311,184
Total [2]			153,946	10,345,560
Processed/Conditioned (off-site recycling center)	Recycling Vendors	A	340,130	14,284,870
Scrap Metal				45,392,000

[1] Waste is classified according to the requirements as delineated in Title 10 CFR, Part 61.55
[2] Columns may not add due to rounding

6. RESULTS

This report presents estimates of the cost to decommission Monticello for the selected decommissioning scenarios following the cessation of plant operations. The estimates are based on numerous fundamental assumptions, including regulatory requirements, project contingencies, low-level radioactive waste disposal practices, high-level radioactive waste management options, and site restoration requirements. While not an engineering study, the estimates provide Xcel Energy with sufficient information to assess their financial obligations, as they pertain to the eventual decommissioning of the nuclear station.

The decommissioning scenarios assume continued operation of the station's spent fuel pool for a minimum of five years following the cessation of operations for continued cooling of the assemblies. The existing ISFSI is expanded to accommodate the spent fuel, once sufficiently cooled, until such time that the DOE can complete the transfer of the assemblies to its repository.

The cost projected to promptly decommission the station, restore the site, and manage the spent fuel is estimated to be $1.516 billion (2017 dollars). The majority of this cost (approximately 50.1%) is associated with the physical decontamination and dismantling of the nuclear plant so that the operating license can be terminated. Another 45.2% is associated with the management, interim storage, and eventual transfer of the spent fuel. The remaining 4.7% is for the demolition of the designated structures and limited restoration of the site.

The primary cost contributors, identified in Tables 6.1 through 6.7, are either labor-related or associated with the management and disposition of the spent fuel or radioactive waste. Program management (including security) is the largest single contributor to the overall cost. The magnitude of the expense is a function of both the size of the organization required to manage the decommissioning, as well as the duration of the program. It is assumed, for purposes of this analysis, that Xcel Energy will hire a contractor to manage the decommissioning labor force. The size and composition of the management organizations varies with the decommissioning phase and associated site activities. However, once the operating license is amended or terminated, the staff is substantially reduced for the conventional demolition and restoration of the site, and the long-term care of the spent fuel (for the DECON alternative).

As described in this report, the spent fuel pool will remain operational for a minimum of five years following the cessation of operations. The pool will be isolated and an independent spent fuel island created. This will allow decommissioning operations to proceed in and around the pool areas. Over the five

year period, the spent fuel will be packaged into transportable canisters for future loading into a DOE-provided transport cask or relocation to the ISFSI (DECON and both SAFSTOR alternatives). The canisters will be stored in horizontal storage casks at the ISFSI until the DOE is able to receive them. Dry storage of the fuel provides additional flexibility in the event the DOE is not able to meet the current timetable for completing the transfer of assemblies to an off-site facility and minimizes the associated caretaking expenses.

The cost for waste disposal includes only those costs associated with the controlled disposition of the low-level radioactive waste generated from decontamination and dismantling activities, including plant equipment and components, structural material, filters, resins and dry-active waste. As described in Section 5, disposition of the majority of the low-level radioactive material requiring controlled disposal is at the Energy*Solutions* facility, with higher-activity waste sent to the WCS facility. Highly activated components, requiring additional isolation from the environment (GTCC), are packaged for geologic disposal. The cost of geologic disposal is based upon a cost equivalent for spent fuel.

A significant portion of the metallic waste is designated for additional processing and treatment at an off-site facility. Processing reduces the volume of material requiring controlled disposal through such techniques and processes as survey and sorting, decontamination, and volume reduction. The material that cannot be unconditionally released is packaged for controlled disposal at one of the currently operating facilities. The cost identified in the summary tables for processing is all-inclusive, incorporating the ultimate disposition of the material.

Removal costs reflect the labor-intensive nature of the decommissioning process, as well as the management controls required to ensure a safe and successful program. Decontamination and packaging costs also have a large labor component that is based upon prevailing wages. Non-radiological demolition is a natural extension of the decommissioning process. The methods employed in decontamination and dismantling are generally destructive and indiscriminate in inflicting collateral damage. With a work force mobilized to support decommissioning operations, non-radiological demolition can be an integrated activity and a logical expansion of the work being performed in the process of terminating the operating license.

The reported cost for transport includes the tariffs and surcharges associated with moving large components and/or overweight shielded casks overland, as well as the general expense, e.g., labor and fuel, of transporting material to the destinations identified in this report. For purposes of this analysis, material is moved overland by truck.

Decontamination is used to reduce the plant's radiation fields and minimize worker exposure. Slightly contaminated material or material located within a contaminated area is sent to an off-site processing center, i.e., this analysis does not assume that contaminated plant components and equipment can be decontaminated for uncontrolled release in-situ. Centralized processing centers have proven to be a more economical means of handling the large volumes of material produced in the dismantling of a nuclear plant.

License termination survey costs are associated with the labor intensive and complex activity of verifying that contamination has been removed from the site to the levels specified by the regulating agency. This process involves a systematic survey of all remaining plant surface areas and surrounding environs, sampling, isotopic analysis, and documentation of the findings. The status of any plant components and materials not removed in the decommissioning process will also require confirmation and will add to the expense of surveying the facilities alone.

The remaining costs include allocations for heavy equipment and temporary services, as well as for other expenses such as regulatory fees and the premiums for nuclear insurance. While site operating costs are greatly reduced following the final cessation of plant operations, certain administrative functions do need to be maintained either at a basic functional or regulatory level.

TABLE 6.1
SCENARIO 1: DECON WITH 32 YEAR DFS
DECOMMISSIONING COST ELEMENTS
(thousands of 2017 dollars)

Cost Element	Total	Percentage
Decontamination	23,268	1.9
Removal	119,462	9.7
Packaging	26,800	2.2
Transportation	12,389	1.0
Waste Disposal	95,919	7.8
Off-site Waste Processing	29,702	2.4
Program Management [1]	303,532	24.6
Security	233,970	19.0
Spent Fuel Pool Isolation	13,445	1.1
Spent Fuel Storage (Direct Costs) [2]	197,448	16.0
Insurance and Regulatory Fees	33,282	2.7
Energy	11,068	0.9
Characterization and Licensing Surveys	28,626	2.3
Property Taxes	36,452	3.0
Miscellaneous Equipment	7,265	0.6
Railroad Track Maintenance	5,048	0.4
Retention and Severance	43,877	3.6
Security Modifications	10,000	0.8
Total [3]	1,231,552	100.0

Cost Element	Total	Percentage
NRC License Termination	759,294	61.7
Spent Fuel Management	400,983	32.6
Site Restoration	71,275	5.8
Total [3]	1,231,552	100.0

[1] Includes engineering

[2] Includes costs for the dry storage system components, spent fuel loading and transfer, spent fuel pool O&M and EP fees, but excludes program management costs (staffing), security and other related costs

[3] Columns may not add due to rounding

TABLE 6.2
SCENARIO 2: DECON WITH 60 YEAR DFS
DECOMMISSIONING COST ELEMENTS
(thousands of 2017 dollars)

Cost Element	Total	Percentage
Decontamination	23,268	1.5
Removal	119,501	7.9
Packaging	26,800	1.8
Transportation	12,389	0.8
Waste Disposal	95,919	6.3
Off-site Waste Processing	29,702	2.0
Program Management [1]	343,355	22.7
Security	359,469	23.7
Spent Fuel Pool Isolation	13,445	0.9
Spent Fuel Storage (Direct Costs) [2]	274,588	18.1
Insurance and Regulatory Fees	55,483	3.7
Energy	11,068	0.7
Characterization and Licensing Surveys	28,626	1.9
Property Taxes	52,336	3.5
Miscellaneous Equipment	7,265	0.5
Railroad Track Maintenance	8,759	0.6
Retention and Severance	43,877	2.9
Security Modifications	10,000	0.7
Total [3]	1,515,850	100.0

Cost Element	Total	Percentage
NRC License Termination	759,047	50.1
Spent Fuel Management	685,479	45.2
Site Restoration	71,324	4.7
Total [3]	1,515,850	100.0

[1] Includes engineering

[2] Includes costs for the dry storage system components, spent fuel loading and transfer, spent fuel pool O&M and EP fees, but excludes program management costs (staffing), security and other related costs

[3] Columns may not add due to rounding

TABLE 6.3
SCENARIO 3: DECON WITH 100 YEAR DFS
DECOMMISSIONING COST ELEMENTS
(thousands of 2017 dollars)

Cost Element	Total	Percentage
Decontamination	23,306	1.0
Removal	119,474	4.9
Packaging	26,803	1.1
Transportation	11,749	0.5
Waste Disposal	95,178	3.9
Off-site Waste Processing	29,702	1.2
Program Management [1]	498,687	20.6
Security	538,987	22.3
Spent Fuel Pool Isolation	13,445	0.6
Spent Fuel Storage (Direct Costs) [2]	784,638	32.4
Insurance and Regulatory Fees	87,239	3.6
Energy	11,068	0.5
Characterization and Licensing Surveys	28,626	1.2
Property Taxes	75,024	3.1
Miscellaneous Equipment	7,265	0.3
Railroad Track Maintenance	14,068	0.6
Retention and Severance	43,877	1.8
Security Modifications	10,000	0.4
Total [3]	2,419,136	100.0

Cost Element	Total	Percentage
NRC License Termination	748,156	30.9
Spent Fuel Management	1,599,295	66.1
Site Restoration	71,685	3.0
Total [3]	2,419,136	100.0

[1] Includes engineering

[2] Includes costs for the dry storage system components, spent fuel loading and transfer, spent fuel pool O&M and EP fees, but excludes program management costs (staffing), security and other related costs

[3] Columns may not add due to rounding

TABLE 6.4
SCENARIO 4: DECON WITH 200 YEAR DFS
DECOMMISSIONING COST ELEMENTS
(thousands of 2017 dollars)

Cost Element	Total	Percentage
Decontamination	23,306	0.5
Removal	119,474	2.8
Packaging	26,803	0.6
Transportation	11,749	0.3
Waste Disposal	95,178	2.2
Off-site Waste Processing	29,702	0.7
Program Management [1]	765,140	18.0
Security	987,801	23.2
Spent Fuel Pool Isolation	13,445	0.3
Spent Fuel Storage (Direct Costs) [2]	1,762,292	41.4
Insurance and Regulatory Fees	166,633	3.9
Energy	11,068	0.3
Characterization and Licensing Surveys	28,626	0.7
Property Taxes	131,743	3.1
Miscellaneous Equipment	7,265	0.2
Railroad Track Maintenance	27,341	0.6
Retention and Severance	43,877	1.0
Security Modifications	10,000	0.2
Total [3]	4,261,443	100.0

Cost Element	Total	Percentage
NRC License Termination	748,155	17.6
Spent Fuel Management	3,441,602	80.8
Site Restoration	71,685	1.7
Total [3]	4,261,443	100.0

[1] Includes engineering

[2] Includes costs for the dry storage system components, spent fuel loading and transfer, spent fuel pool O&M and EP fees, but excludes program management costs (staffing), security and other related costs

[3] Columns may not add due to rounding

TABLE 6.5
SCENARIO 5: DECON WITH 60 YEAR DFS WITH RECASKING
DECOMMISSIONING COST ELEMENTS
(thousands of 2017 dollars)

Cost Element	Total	Percentage
Decontamination	23,306	1.5
Removal	119,505	7.5
Packaging	26,805	1.7
Transportation	12,393	0.8
Waste Disposal	95,943	6.0
Off-site Waste Processing	29,702	1.9
Program Management [1]	343,355	21.4
Security	359,469	22.4
Spent Fuel Pool Isolation	13,445	0.8
Spent Fuel Storage (Direct Costs) [2]	361,324	22.5
Insurance and Regulatory Fees	55,483	3.5
Energy	11,068	0.7
Characterization and Licensing Surveys	28,626	1.8
Property Taxes	52,336	3.3
Miscellaneous Equipment	7,265	0.5
Railroad Track Maintenance	8,759	0.5
Retention and Severance	43,877	2.7
Security Modifications	10,000	0.6
Total [3]	1,602,660	100.0

Cost Element	Total	Percentage
NRC License Termination	759,122	47.4
Spent Fuel Management	772,214	48.2
Site Restoration	71,324	4.5
Total [3]	1,602,660	100.0

[1] Includes engineering

[2] Includes costs for the dry storage system components, spent fuel loading and transfer, spent fuel pool O&M and EP fees, but excludes program management costs (staffing), security and other related costs

[3] Columns may not add due to rounding

TABLE 6.6
SCENARIO 6: SAFSTOR WITH 32 YEAR DFS
DECOMMISSIONING COST ELEMENTS
(thousands of 2017 dollars)

Cost Element	Total	Percentage
Decontamination	25,220	1.7
Removal	122,447	8.3
Packaging	17,915	1.2
Transportation	8,026	0.5
Waste Disposal	66,222	4.5
Off-site Waste Processing	34,993	2.4
Program Management [1]	403,048	27.3
Security	236,063	16.0
Spent Fuel Pool Isolation	13,445	0.9
Spent Fuel Storage (Direct Costs) [2]	195,063	13.2
Insurance and Regulatory Fees	68,491	4.6
Energy	23,440	1.6
Characterization and Licensing Surveys	28,277	1.9
Property Taxes	148,737	10.1
Miscellaneous Equipment	20,825	1.4
Railroad Track Maintenance	8,536	0.6
Retention and Severance	43,877	3.0
Security Modifications	10,000	0.7
Total [3]	1,474,626	100.0

Cost Element	Total	Percentage
NRC License Termination	1,045,043	70.9
Spent Fuel Management	364,666	24.7
Site Restoration	64,917	4.4
Total [3]	1,474,626	100.0

[1] Includes engineering

[2] Includes costs for the dry storage system components, spent fuel loading and transfer, spent fuel pool O&M and EP fees, but excludes program management costs (staffing), security and other related costs

[3] Columns may not add due to rounding

TABLE 6.7
SCENARIO 7: SAFSTOR WITH 60 YEAR DFS
DECOMMISSIONING COST ELEMENTS
(thousands of 2017 dollars)

Cost Element	Total	Percentage
Decontamination	25,220	1.5
Removal	122,659	7.1
Packaging	17,920	1.0
Transportation	8,028	0.5
Waste Disposal	66,243	3.9
Off-site Waste Processing	34,993	2.0
Program Management [1]	430,133	25.0
Security	386,682	22.5
Spent Fuel Pool Isolation	13,445	0.8
Spent Fuel Storage (Direct Costs) [2]	259,117	15.1
Insurance and Regulatory Fees	69,323	4.0
Energy	23,440	1.4
Characterization and Licensing Surveys	28,277	1.6
Property Taxes	148,737	8.7
Miscellaneous Equipment	20,825	1.2
Railroad Track Maintenance	8,536	0.5
Retention and Severance	43,877	2.6
Security Modifications	10,000	0.6
Total [3]	1,717,454	100.0

Cost Element	Total	
NRC License Termination	1,099,775	64.0
Spent Fuel Management	552,724	32.2
Site Restoration	64,956	3.8
Total [3]	1,717,454	100.0

[1] Includes engineering costs

[2] Includes costs for the dry storage system components, spent fuel loading and transfer, spent fuel pool O&M and EP fees, but excludes program management costs (staffing), security and other related costs

[3] Columns may not add due to rounding

7. REFERENCES

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2. U.S. Code of Federal Regulations, Title 10, Parts 30, 40, 50, 51, 70 and 72, "General Requirements for Decommissioning Nuclear Facilities," Nuclear Regulatory Commission, 53 Fed. Reg. 24018, June 27, 198

3. U.S. Nuclear Regulatory Commission, Regulatory Guide 1.159, "Assuring the Availability of Funds for Decommissioning Nuclear Reactors," Rev. 2, October 2011 [Open]

4. U.S. Code of Federal Regulations, Title 10, Part 20, Subpart E, "Radiological Criteria for License Termination" [Open]

5. U.S. Code of Federal Regulations, Title 10, Parts 20 and 50, "Entombment Options for Power Reactors," Advance Notice of Proposed Rulemaking, 66 Fed. Reg. 52551, October 16, 2001 [Open]

6. U.S. Code of Federal Regulations, Title 10, Parts 2, 50 and 51, "Decommissioning of Nuclear Power Reactors," Nuclear Regulatory Commission, 61 Fed. Reg. 39278, July 29, 1996 [Open]

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15. U.S. Code of Federal Regulations, Title 10, Part 72, Subpart K, "General License for Storage of Spent Fuel at Power Reactor Sites" [Open]

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17. "Low-Level Radioactive Waste Policy Amendments Act of 1985," Public Law 99-240, January 15, 1986 [Open]

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30. Project and Cost Engineers' Handbook, Second Edition, p. 239, American Association of Cost Engineers, Marcel Dekker, Inc., New York, New York, 1984

31. DOE/RW-0351, "Civilian Radioactive Waste Management System Waste Acceptance System Requirements Document", Revision 5, May 31, 2007 [Open]

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APPENDIX A

UNIT COST FACTOR DEVELOPMENT

APPENDIX A
UNIT COST FACTOR DEVELOPMENT

Example: Unit Factor for Removal of Contaminated Heat Exchanger < 3,000 lbs.

1. SCOPE

Heat exchangers weighing < 3,000 lbs. will be removed in one piece using a crane or small hoist. They will be disconnected from the inlet and outlet piping. The heat exchanger will be sent to the waste processing area.

2. CALCULATIONS

Act ID	Activity Description	Activity Duration (minutes)	Critical Duration (minutes)*
a	Remove insulation	60	(b)
b	Mount pipe cutters	60	60
c	Install contamination controls	20	(b)
d	Disconnect inlet and outlet lines	60	60
e	Cap openings	20	(d)
f	Rig for removal	30	30
g	Unbolt from mounts	30	30
h	Remove contamination controls	15	15
i	Remove, wrap, send to waste processing area	60	60
	Totals (Activity/Critical)	355	255

Duration adjustment(s):	
+ Respiratory protection adjustment (50 of critical duration)	128
+ Radiation/ALARA adjustment (37.1 of critical duration)	95
Adjusted work duration	478
+ Protective clothing adjustment (30 of adjusted duration)	143
Productive work duration	621
+ Work break adjustment (8.33 of productive duration)	52
Total work duration (minutes)	673

***** Total duration = 11.217 hr *****

* alpha designators indicate activities that can be performed in parallel

APPENDIX A
(continued)

3. LABOR REQUIRED

Crew	Number	Duration (hours)	Rate ($/hr)	Cost
Laborers	3.00	11.217	$54.73	$1841.72
Craftsmen	2.00	11.217	$69.32	$1,555.12
Foreman	1.00	11.217	$72.53	$813.57
General Foreman	0.25	11.217	$74.83	$209.84
Fire Watch	0.05	11.217	$54.73	$30.70
Health Physics Technician	1.00	11.217	$76.50	$858.10
Total Labor Cost				$5,309.05

4. EQUIPMENT & CONSUMABLES COSTS

Equipment Costs	none
Consumables/Materials Costs	
• Universal Sorbent 50 @ $0.61 sq ft {1}	$30.50
• Tarpaulins (oil resistant/fire retardant) 50 @ $0.46/sq ft {2}	$23.00
• Gas torch consumables 1 @ $20.45/hr x 1 hr {3}	$20.45
Subtotal cost of equipment and materials	$73.95
Overhead & profit on equipment and materials @ 16.88%	$12.48
Total costs, equipment & material	$86.43

TOTAL COST:

Removal of contaminated heat exchanger <3000 pounds:	**$5,395.48**
Total labor cost:	$5,309.05
Total equipment/material costs:	$86.43
Total craft labor man-hours required per unit:	81.88

5. NOTES AND REFERENCES

- Work difficulty factors were developed in conjunction with the Atomic Industrial Forum's (now NEI) program to standardize nuclear decommissioning cost estimates and are delineated in Volume 1, Chapter 5 of the "Guidelines for Producing Commercial Nuclear Power Plant Decommissioning Cost Estimates," AIF/NESP-036, May 1986.

- References for equipment & consumables costs:

    1. www.mcmaster.com online catalog, McMaster Carr Spill Control (7193T88)
    2. R.S. Means (2017) Division 01 56, Section 13.60-0600, page 23
    3. R.S. Means (2017) Division 01 54 33, Section 40-6360, page 718

- Material and consumable costs were adjusted using the regional indices for Minneapolis, Minnesota.

APPENDIX B

UNIT COST FACTOR LISTING
(DECON: Power Block Structures Only)

APPENDIX B

UNIT COST FACTOR LISTING
(Power Block Structures Only)

Unit Cost Factor	Cost/Unit
Removal of clean instrument and sampling tubing, $/linear foot	0.59
Removal of clean pipe 0.25 to 2 inches diameter, $/linear foot	6.38
Removal of clean pipe >2 to 4 inches diameter, $/linear foot	9.07
Removal of clean pipe >4 to 8 inches diameter, $/linear foot	17.58
Removal of clean pipe >8 to 14 inches diameter, $/linear foot	34.02
Removal of clean pipe >14 to 20 inches diameter, $/linear foot	44.29
Removal of clean pipe >20 to 36 inches diameter, $/linear foot	65.15
Removal of clean pipe >36 inches diameter, $/linear foot	77.38
Removal of clean valve >2 to 4 inches	116.53
Removal of clean valve >4 to 8 inches	175.82
Removal of clean valve >8 to 14 inches	340.22
Removal of clean valve >14 to 20 inches	442.86
Removal of clean valve >20 to 36 inches	651.46
Removal of clean valve >36 inches	773.78
Removal of clean pipe hanger for small bore piping	40.73
Removal of clean pipe hanger for large bore piping	144.67
Removal of clean pump, <300 pound	297.76
Removal of clean pump, 300-1000 pound	821.40
Removal of clean pump, 1000-10,000 pound	3,244.34
Removal of clean pump, >10,000 pound	6,278.73
Removal of clean pump motor, 300-1000 pound	342.77
Removal of clean pump motor, 1000-10,000 pound	1,347.11
Removal of clean pump motor, >10,000 pound	3,030.99
Removal of clean heat exchanger <3000 pound	1,743.26
Removal of clean heat exchanger >3000 pound	4,394.19
Removal of clean feedwater heater/deaerator	12,379.20
Removal of clean moisture separator/reheater	25,438.07
Removal of clean tank, <300 gallons	382.87
Removal of clean tank, 300-3000 gallon	1,205.00
Removal of clean tank, >3000 gallons, $/square foot surface area	10.09

APPENDIX B

UNIT COST FACTOR LISTING
(Power Block Structures Only)

Unit Cost Factor	Cost/Unit
Removal of clean electrical equipment, <300 pound	160.89
Removal of clean electrical equipment, 300-1000 pound	558.06
Removal of clean electrical equipment, 1000-10,000 pound	1,116.13
Removal of clean electrical equipment, >10,000 pound	2,646.83
Removal of clean electrical transformer < 30 tons	1,838.18
Removal of clean electrical transformer > 30 tons	5,293.67
Removal of clean standby diesel generator, <100 kW	1,877.56
Removal of clean standby diesel generator, 100 kW to 1 MW	4,190.82
Removal of clean standby diesel generator, >1 MW	8,675.83
Removal of clean electrical cable tray, $/linear foot	15.16
Removal of clean electrical conduit, $/linear foot	6.63
Removal of clean mechanical equipment, <300 pound	160.89
Removal of clean mechanical equipment, 300-1000 pound	558.06
Removal of clean mechanical equipment, 1000-10,000 pound	1,116.13
Removal of clean mechanical equipment, >10,000 pound	2,646.83
Removal of clean HVAC equipment, <300 pound	194.55
Removal of clean HVAC equipment, 300-1000 pound	670.56
Removal of clean HVAC equipment, 1000-10,000 pound	1,336.42
Removal of clean HVAC equipment, >10,000 pound	2,646.83
Removal of clean HVAC ductwork, $/pound	0.63
Removal of contaminated instrument and sampling tubing, $/linear foot	1.99
Removal of contaminated pipe 0.25 to 2 inches diameter, $/linear foot	27.12
Removal of contaminated pipe >2 to 4 inches diameter, $/linear foot	46.23
Removal of contaminated pipe >4 to 8 inches diameter, $/linear foot	74.04
Removal of contaminated pipe >8 to 14 inches diameter, $/linear foot	144.12
Removal of contaminated pipe >14 to 20 inches diameter, $/linear foot	173.18
Removal of contaminated pipe >20 to 36 inches diameter, $/linear foot	239.68
Removal of contaminated pipe >36 inches diameter, $/linear foot	283.26
Removal of contaminated valve >2 to 4 inches	564.33
Removal of contaminated valve >4 to 8 inches	675.66

APPENDIX B

UNIT COST FACTOR LISTING
(Power Block Structures Only)

Unit Cost Factor	Cost/Unit
Removal of contaminated valve >8 to 14 inches	1,378.64
Removal of contaminated valve >14 to 20 inches	1,752.81
Removal of contaminated valve >20 to 36 inches	2,334.29
Removal of contaminated valve >36 inches	2,770.04
Removal of contaminated pipe hanger for small bore piping	188.44
Removal of contaminated pipe hanger for large bore piping	611.48
Removal of contaminated pump, <300 pound	1,205.97
Removal of contaminated pump, 300-1000 pound	2,758.03
Removal of contaminated pump, 1000-10,000 pound	8,850.61
Removal of contaminated pump, >10,000 pound	21,559.16
Removal of contaminated pump motor, 300-1000 pound	1,173.89
Removal of contaminated pump motor, 1000-10,000 pound	3,603.57
Removal of contaminated pump motor, >10,000 pound	8,090.51
Removal of contaminated heat exchanger <3000 pound	5,395.48
Removal of contaminated heat exchanger >3000 pound	15,648.23
Removal of contaminated feedwater heater/deaerator	38,068.15
Removal of contaminated moisture separator/reheater	82,788.96
Removal of contaminated tank, <300 gallons	2,004.39
Removal of contaminated tank, >300 gallons, $/square foot	38.67
Removal of contaminated electrical equipment, <300 pound	936.29
Removal of contaminated electrical equipment, 300-1000 pound	2,250.27
Removal of contaminated electrical equipment, 1000-10,000 pound	4,334.31
Removal of contaminated electrical equipment, >10,000 pound	8,447.10
Removal of contaminated electrical cable tray, $/linear foot	45.27
Removal of contaminated electrical conduit, $/linear foot	22.11
Removal of contaminated mechanical equipment, <300 pound	1,041.61
Removal of contaminated mechanical equipment, 300-1000 pound	2,484.99
Removal of contaminated mechanical equipment, 1000-10,000 pound	4,778.59
Removal of contaminated mechanical equipment, >10,000 pound	8,447.10
Removal of contaminated HVAC equipment, <300 pound	1,041.61

APPENDIX B

UNIT COST FACTOR LISTING
(Power Block Structures Only)

Unit Cost Factor	Cost/Unit
Removal of contaminated HVAC equipment, 300-1000 pound	2,484.99
Removal of contaminated HVAC equipment, 1000-10,000 pound	4,778.59
Removal of contaminated HVAC equipment, >10,000 pound	8,447.10
Removal of contaminated HVAC ductwork, $/pound	2.71
Removal/plasma arc cut of contaminated thin metal components, $/linear in.	4.89
Additional decontamination of surface by washing, $/square foot	10.12
Additional decontamination of surfaces by hydrolasing, $/square foot	43.37
Decontamination rig hook up and flush, $/ 250 foot length	8,781.13
Chemical flush of components/systems, $/gallon	20.62
Removal of clean standard reinforced concrete, $/cubic yard	76.85
Removal of grade slab concrete, $/cubic yard	87.42
Removal of clean concrete floors, $/cubic yard	431.26
Removal of sections of clean concrete floors, $/cubic yard	1,298.07
Removal of clean heavily rein concrete w/#9 rebar, $/cubic yard	111.01
Removal of contaminated heavily rein concrete w/#9 rebar, $/cubic yard	2,568.54
Removal of clean heavily rein concrete w/#18 rebar, $/cubic yard	150.46
Removal of contaminated heavily rein concrete w/#18 rebar, $/cubic yard	3,397.61
Removal heavily rein concrete w/#18 rebar & steel embedments, $/cubic yard	527.05
Removal of below-grade suspended floors, $/cubic yard	211.02
Removal of clean monolithic concrete structures, $/cubic yard	1,068.91
Removal of contaminated monolithic concrete structures, $/cubic yard	2,555.68
Removal of clean foundation concrete, $/cubic yard	840.09
Removal of contaminated foundation concrete, $/cubic yard	2,381.01
Explosive demolition of bulk concrete, $/cubic yard	56.88
Removal of clean hollow masonry block wall, $/cubic yard	26.93
Removal of contaminated hollow masonry block wall, $/cubic yard	72.18
Removal of clean solid masonry block wall, $/cubic yard	26.93
Removal of contaminated solid masonry block wall, $/cubic yard	72.18
Backfill of below-grade voids, $/cubic yard	32.27
Removal of subterranean tunnels/voids, $/linear foot	134.42

APPENDIX B

UNIT COST FACTOR LISTING
(Power Block Structures Only)

Unit Cost Factor	Cost/Unit
Placement of concrete for below-grade voids, $/cubic yard	151.11
Excavation of clean material, $/cubic yard	3.38
Excavation of contaminated material, $/cubic yard	48.96
Removal of clean concrete rubble (tipping fee included), $/cubic yard	27.80
Removal of contaminated concrete rubble, $/cubic yard	31.35
Removal of building by volume, $/cubic foot	0.35
Removal of clean building metal siding, $/square foot	1.63
Removal of contaminated building metal siding, $/square foot	5.82
Removal of standard asphalt roofing, $/square foot	2.79
Removal of transite panels, $/square foot	2.50
Scarifying contaminated concrete surfaces (drill & spall), $/square foot	15.10
Scabbling contaminated concrete floors, $/square foot	9.40
Scabbling contaminated concrete walls, $/square foot	25.13
Scabbling contaminated ceilings, $/square foot	86.52
Scabbling structural steel, $/square foot	7.77
Removal of clean overhead crane/monorail < 10 ton capacity	776.71
Removal of contaminated overhead crane/monorail < 10 ton capacity	2,303.06
Removal of clean overhead crane/monorail >10-50 ton capacity	1,864.11
Removal of contaminated overhead crane/monorail >10-50 ton capacity	5,526.42
Removal of polar crane > 50 ton capacity	7,769.78
Removal of gantry crane > 50 ton capacity	33,085.40
Removal of structural steel, $/pound	0.23
Removal of clean steel floor grating, $/square foot	5.62
Removal of contaminated steel floor grating, $/square foot	16.90
Removal of clean free standing steel liner, $/square foot	15.14
Removal of contaminated free standing steel liner, $/square foot	45.26
Removal of clean concrete-anchored steel liner, $/square foot	7.57
Removal of contaminated concrete-anchored steel liner, $/square foot	52.76
Placement of scaffolding in clean areas, $/square foot	17.30
Placement of scaffolding in contaminated areas, $/square foot	30.78

APPENDIX B

UNIT COST FACTOR LISTING
(Power Block Structures Only)

Unit Cost Factor	Cost/Unit
Landscaping with topsoil, $/acre	24,683.41
Cost of CPC B-88 LSA box & preparation for use	2,089.10
Cost of CPC B-25 LSA box & preparation for use	1,969.57
Cost of CPC B-12V 12 gauge LSA box & preparation for use	1,571.57
Cost of CPC B-144 LSA box & preparation for use	10,466.06
Cost of LSA drum & preparation for use	232.86
Cost of cask liner for CNSI 8 120A cask (resins)	12,441.18
Cost of cask liner for CNSI 8 120A cask (filters)	9,028.23
Decontamination of surfaces with vacuuming, $/square foot	0.96

APPENDIX C

DETAILED COST ANALYSIS

SCENARIO 1: DECON with 32 Year DFS

Table C
Monticello Nuclear Generating Plant
Scenario 1: DECON with 32 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
PERIOD 1a - Shutdown through Transition																					
Period 1a Direct Decommissioning Activities																					
1a.1.1	Prepare preliminary decommissioning cost	-	-	-	-	-	-	153	23	175	175	-	-	-	-	-	-	-	-	-	1,300
1a.1.2	Notification of Cessation of Operations									a											
1a.1.3	Remove fuel & source material									n/a											
1a.1.4	Notification of Permanent Defueling									a											
1a.1.5	Deactivate plant systems & process waste									a											
1a.1.6	Prepare and submit PSDAR	-	-	-	-	-	-	235	35	270	270	-	-	-	-	-	-	-	-	-	2,000
1a.1.7	Review plant dwgs & specs.	-	-	-	-	-	-	540	81	621	621	-	-	-	-	-	-	-	-	-	4,600
1a.1.8	Perform detailed rad survey									a											
1a.1.9	Estimate by-product inventory	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1a.1.10	End product description	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1a.1.11	Detailed by-product inventory	-	-	-	-	-	-	153	23	175	175	-	-	-	-	-	-	-	-	-	1,300
1a.1.12	Define major work sequence	-	-	-	-	-	-	880	132	1,012	1,012	-	-	-	-	-	-	-	-	-	7,500
1a.1.13	Perform SER and EA	-	-	-	-	-	-	364	55	418	418	-	-	-	-	-	-	-	-	-	3,100
1a.1.14	Prepare/submit Defueled Technical Specifications	-	-	-	-	-	-	880	132	1,012	1,012	-	-	-	-	-	-	-	-	-	7,500
1a.1.15	Perform Site-Specific Cost Study	-	-	-	-	-	-	587	88	675	675	-	-	-	-	-	-	-	-	-	5,000
1a.1.16	Prepare/submit Irradiated Fuel Management Plan	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
Activity Specifications																					
1a.1.17.1	Plant & temporary facilities	-	-	-	-	-	-	578	87	664	598	-	66	-	-	-	-	-	-	-	4,920
1a.1.17.2	Plant systems	-	-	-	-	-	-	489	73	562	506	-	56	-	-	-	-	-	-	-	4,167
1a.1.17.3	NSSS Decontamination Flush	-	-	-	-	-	-	59	9	67	67	-	-	-	-	-	-	-	-	-	500
1a.1.17.4	Reactor internals	-	-	-	-	-	-	833	125	958	958	-	-	-	-	-	-	-	-	-	7,100
1a.1.17.5	Reactor vessel	-	-	-	-	-	-	763	114	877	877	-	-	-	-	-	-	-	-	-	6,500
1a.1.17.6	Sacrificial shield	-	-	-	-	-	-	59	9	67	67	-	-	-	-	-	-	-	-	-	500
1a.1.17.7	Moisture separators/reheaters	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1a.1.17.8	Reinforced concrete	-	-	-	-	-	-	188	28	216	108	-	108	-	-	-	-	-	-	-	1,600
1a.1.17.9	Main Turbine	-	-	-	-	-	-	245	37	282	282	-	-	-	-	-	-	-	-	-	2,088
1a.1.17.10	Main Condensers	-	-	-	-	-	-	245	37	282	282	-	-	-	-	-	-	-	-	-	2,088
1a.1.17.11	Pressure suppression structure	-	-	-	-	-	-	235	35	270	270	-	-	-	-	-	-	-	-	-	2,000
1a.1.17.12	Drywell	-	-	-	-	-	-	188	28	216	216	-	-	-	-	-	-	-	-	-	1,600
1a.1.17.13	Plant structures & buildings	-	-	-	-	-	-	366	55	421	211	-	211	-	-	-	-	-	-	-	3,120
1a.1.17.14	Waste management	-	-	-	-	-	-	540	81	621	621	-	-	-	-	-	-	-	-	-	4,600
1a.1.17.15	Facility & site closeout	-	-	-	-	-	-	106	16	121	61	-	61	-	-	-	-	-	-	-	900
1a.1.17	Total	-	-	-	-	-	-	5,010	752	5,762	5,260	-	502	-	-	-	-	-	-	-	42,683
Planning & Site Preparations																					
1a.1.18	Prepare dismantling sequence	-	-	-	-	-	-	282	42	324	324	-	-	-	-	-	-	-	-	-	2,400
1a.1.19	Plant prep. & temp. svces	-	-	-	-	-	-	3,300	495	3,795	3,795	-	-	-	-	-	-	-	-	-	-
1a.1.20	Design water clean-up system	-	-	-	-	-	-	164	25	189	189	-	-	-	-	-	-	-	-	-	1,400
1a.1.21	Rigging/Cont. Cntrl Envlps/tooling/etc.	-	-	-	-	-	-	2,300	345	2,645	2,645	-	-	-	-	-	-	-	-	-	-
1a.1.22	Procure casks/liners & containers	-	-	-	-	-	-	144	22	166	166	-	-	-	-	-	-	-	-	-	1,230
1a.1	Subtotal Period 1a Activity Costs	-	-	-	-	-	-	15,344	2,302	17,646	17,144	-	502	-	-	-	-	-	-	-	83,013
Period 1a Collateral Costs																					
1a.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	7,181	1,077	8,258	-	8,258	-	-	-	-	-	-	-	-	-
1a.3.2	Retention and Severance	-	-	-	-	-	-	9,892	1,484	11,376	11,376	-	-	-	-	-	-	-	-	-	-
1a.3	Subtotal Period 1a Collateral Costs	-	-	-	-	-	-	17,073	2,561	19,634	11,376	8,258	-	-	-	-	-	-	-	-	-
Period 1a Period-Dependent Costs																					
1a.4.1	Insurance	-	-	-	-	-	-	2,408	241	2,649	2,649	-	-	-	-	-	-	-	-	-	-
1a.4.2	Property taxes	-	-	-	-	-	-	2,242	224	2,466	2,466	-	-	-	-	-	-	-	-	-	-
1a.4.3	Health physics supplies	-	515	-	-	-	-	-	129	644	644	-	-	-	-	-	-	-	-	-	-
1a.4.4	Heavy equipment rental	-	567	-	-	-	-	-	85	652	652	-	-	-	-	-	-	-	-	-	-
1a.4.5	Disposal of DAW generated	-	-	13	4	-	50	-	14	81	81	-	-	-	610	-	-	-	12,190	20	-
1a.4.6	Plant energy budget	-	-	-	-	-	-	1,730	259	1,989	1,989	-	-	-	-	-	-	-	-	-	-
1a.4.7	NRC Fees	-	-	-	-	-	-	1,110	111	1,221	1,221	-	-	-	-	-	-	-	-	-	-
1a.4.8	Emergency Planning Fees	-	-	-	-	-	-	3,166	317	3,482	-	3,482	-	-	-	-	-	-	-	-	-
1a.4.9	Fixed Overhead	-	-	-	-	-	-	2,833	425	3,258	3,258	-	-	-	-	-	-	-	-	-	-
1a.4.10	Spent Fuel Pool O&M	-	-	-	-	-	-	803	120	923	-	923	-	-	-	-	-	-	-	-	-
1a.4.11	ISFSI Operating Costs	-	-	-	-	-	-	103	15	119	-	119	-	-	-	-	-	-	-	-	-
1a.4.12	Railroad Track Maintenance	-	-	-	-	-	-	115	17	133	133	-	-	-	-	-	-	-	-	-	-
1a.4.13	Security Staff Cost	-	-	-	-	-	-	14,260	2,139	16,399	16,399	-	-	-	-	-	-	-	-	-	245,440
1a.4.14	Utility Staff Cost	-	-	-	-	-	-	25,791	3,869	29,660	29,660	-	-	-	-	-	-	-	-	-	422,240
1a.4	Subtotal Period 1a Period-Dependent Costs	-	1,083	13	4	-	50	54,561	7,966	63,676	59,153	4,524	-	-	610	-	-	-	12,190	20	667,680

Table C
Monticello Nuclear Generating Plant
Scenario 1: DECON with 32 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
1a.0	TOTAL PERIOD 1a COST	-	1,083	13	4	-	50	86,978	12,829	100,956	87,672	12,782	502	-	610	-	-	-	12,190	20	750,693
PERIOD 1b - Decommissioning Preparations																					
Period 1b Direct Decommissioning Activities																					
Detailed Work Procedures																					
1b.1.1.1	Plant systems	-	-	-	-	-	-	556	83	639	575	-	64	-	-	-	-	-	-	-	4,733
1b.1.1.2	NSSS Decontamination Flush	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1b.1.1.3	Reactor internals	-	-	-	-	-	-	470	70	540	540	-	-	-	-	-	-	-	-	-	4,000
1b.1.1.4	Remaining buildings	-	-	-	-	-	-	158	24	182	46	-	137	-	-	-	-	-	-	-	1,350
1b.1.1.5	CRD housings & NIs	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1b.1.1.6	Incore instrumentation	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1b.1.1.7	Removal primary containment	-	-	-	-	-	-	235	35	270	270	-	-	-	-	-	-	-	-	-	2,000
1b.1.1.8	Reactor vessel	-	-	-	-	-	-	426	64	490	490	-	-	-	-	-	-	-	-	-	3,630
1b.1.1.9	Facility closeout	-	-	-	-	-	-	141	21	162	81	-	81	-	-	-	-	-	-	-	1,200
1b.1.1.10	Sacrificial shield	-	-	-	-	-	-	141	21	162	162	-	-	-	-	-	-	-	-	-	1,200
1b.1.1.11	Reinforced concrete	-	-	-	-	-	-	117	18	135	67	-	67	-	-	-	-	-	-	-	1,000
1b.1.1.12	Main Turbine	-	-	-	-	-	-	244	37	281	281	-	-	-	-	-	-	-	-	-	2,080
1b.1.1.13	Main Condensers	-	-	-	-	-	-	245	37	282	282	-	-	-	-	-	-	-	-	-	2,088
1b.1.1.14	Moisture separators & reheaters	-	-	-	-	-	-	235	35	270	270	-	-	-	-	-	-	-	-	-	2,000
1b.1.1.15	Radwaste building	-	-	-	-	-	-	320	48	369	332	-	37	-	-	-	-	-	-	-	2,730
1b.1.1.16	Reactor building	-	-	-	-	-	-	320	48	369	332	-	37	-	-	-	-	-	-	-	2,730
1b.1.1	Total	-	-	-	-	-	-	3,961	594	4,555	4,132	-	423	-	-	-	-	-	-	-	33,741
1b.1.2	Decon NSSS	286	-	-	-	-	-	-	143	429	429	-	-	-	-	-	-	-	-	1,067	-
1b.1	Subtotal Period 1b Activity Costs	286	-	-	-	-	-	3,961	737	4,984	4,561	-	423	-	-	-	-	-	-	1,067	33,741
Period 1b Additional Costs																					
1b.2.1	Spent fuel pool isolation	-	-	-	-	-	-	11,691	1,754	13,445	13,445	-	-	-	-	-	-	-	-	-	-
1b.2.2	Site Characterization	-	-	-	-	-	-	6,446	1,934	8,380	8,380	-	-	-	-	-	-	-	-	30,500	10,852
1b.2.3	Mixed & RCRA Waste	-	-	29	19	13	-	-	8	69	69	-	-	43	-	-	-	-	5,253	163	-
1b.2	Subtotal Period 1b Additional Costs	-	-	29	19	13	-	18,137	3,695	21,894	21,894	-	-	43	-	-	-	-	5,253	30,663	10,852
Period 1b Collateral Costs																					
1b.3.1	Decon equipment	973	-	-	-	-	-	-	146	1,119	1,119	-	-	-	-	-	-	-	-	-	-
1b.3.2	DOC staff relocation expenses	-	-	-	-	-	-	1,189	178	1,367	1,367	-	-	-	-	-	-	-	-	-	-
1b.3.3	Process decommissioning water waste	37	-	24	61	-	98	-	54	275	275	-	-	-	233	-	-	-	13,986	45	-
1b.3.4	Process decommissioning chemical flush waste	1	-	23	85	-	969	-	258	1,336	1,336	-	-	-	-	231	-	-	24,599	43	-
1b.3.5	Small tool allowance	-	2	-	-	-	-	-	0	2	2	-	-	-	-	-	-	-	-	-	-
1b.3.6	Pipe cutting equipment	-	1,200	-	-	-	-	-	180	1,380	1,380	-	-	-	-	-	-	-	-	-	-
1b.3.7	Decon rig	1,987	-	-	-	-	-	-	298	2,285	2,285	-	-	-	-	-	-	-	-	-	-
1b.3.8	Spent Fuel Capital and Transfer	-	-	-	-	-	-	334	50	384	-	384	-	-	-	-	-	-	-	-	-
1b.3.9	Retention and Severance	-	-	-	-	-	-	6,362	954	7,316	7,316	-	-	-	-	-	-	-	-	-	-
1b.3	Subtotal Period 1b Collateral Costs	2,997	1,202	47	147	-	1,067	7,884	2,119	15,464	15,080	384	-	-	233	231	-	-	38,585	89	-
Period 1b Period-Dependent Costs																					
1b.4.1	Decon supplies	35	-	-	-	-	-	-	9	44	44	-	-	-	-	-	-	-	-	-	-
1b.4.2	Insurance	-	-	-	-	-	-	1,207	121	1,328	1,328	-	-	-	-	-	-	-	-	-	-
1b.4.3	Property taxes	-	-	-	-	-	-	1,104	110	1,214	1,214	-	-	-	-	-	-	-	-	-	-
1b.4.4	Health physics supplies	-	290	-	-	-	-	-	73	363	363	-	-	-	-	-	-	-	-	-	-
1b.4.5	Heavy equipment rental	-	284	-	-	-	-	-	43	327	327	-	-	-	-	-	-	-	-	-	-
1b.4.6	Disposal of DAW generated	-	-	8	2	-	29	-	8	48	48	-	-	-	358	-	-	-	7,159	12	-
1b.4.7	Plant energy budget	-	-	-	-	-	-	1,735	260	1,995	1,995	-	-	-	-	-	-	-	-	-	-
1b.4.8	NRC Fees	-	-	-	-	-	-	321	32	353	353	-	-	-	-	-	-	-	-	-	-
1b.4.9	Emergency Planning Fees	-	-	-	-	-	-	1,587	159	1,746	-	1,746	-	-	-	-	-	-	-	-	-
1b.4.10	Fixed Overhead	-	-	-	-	-	-	1,420	213	1,633	1,633	-	-	-	-	-	-	-	-	-	-
1b.4.11	Spent Fuel Pool O&M	-	-	-	-	-	-	402	60	463	-	463	-	-	-	-	-	-	-	-	-
1b.4.12	ISFSI Operating Costs	-	-	-	-	-	-	52	8	60	-	60	-	-	-	-	-	-	-	-	-
1b.4.13	Railroad Track Maintenance	-	-	-	-	-	-	58	9	67	67	-	-	-	-	-	-	-	-	-	-
1b.4.14	Security Staff Cost	-	-	-	-	-	-	7,150	1,072	8,222	8,222	-	-	-	-	-	-	-	-	-	123,056
1b.4.15	DOC Staff Cost	-	-	-	-	-	-	5,625	844	6,469	6,469	-	-	-	-	-	-	-	-	-	63,614
1b.4.16	Utility Staff Cost	-	-	-	-	-	-	13,003	1,950	14,953	14,953	-	-	-	-	-	-	-	-	-	212,741
1b.4	Subtotal Period 1b Period-Dependent Costs	35	575	8	2	-	29	33,663	4,971	39,283	37,015	2,268	-	-	358	-	-	-	7,159	12	399,411
1b.0	TOTAL PERIOD 1b COST	3,318	1,777	84	169	13	1,096	63,646	11,522	81,625	78,550	2,652	423	43	591	231	-	-	50,997	31,830	444,004
PERIOD 1 TOTALS		3,318	2,859	97	173	13	1,146	150,623	24,351	182,581	166,222	15,434	925	43	1,201	231	-	-	63,188	31,850	1,194,697

Table C
Monticello Nuclear Generating Plant
Scenario 1: DECON with 32 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
PERIOD 2a - Large Component Removal																					
Period 2a Direct Decommissioning Activities																					
Nuclear Steam Supply System Removal																					
2a.1.1.1	Recirculation System Piping & Valves	107	92	30	39	-	429	-	192	888	888	-	-	-	1,430	-	-	-	99,742	2,905	-
2a.1.1.2	Recirculation Pumps & Motors	38	59	16	40	22	438	-	154	767	767	-	-	96	945	-	-	-	112,200	1,563	-
2a.1.1.3	CRDMs & NIs Removal	187	1,022	402	105	-	919	-	635	3,269	3,269	-	-	-	3,741	-	-	-	213,700	17,768	-
2a.1.1.4	Reactor Vessel Internals	222	6,378	12,908	2,835	-	20,148	356	18,958	61,806	61,806	-	-	-	1,252	1,481	1,010	-	312,338	30,765	1,389
2a.1.1.5	Reactor Vessel	109	8,595	2,644	1,170	-	5,294	356	10,155	28,323	28,323	-	-	-	16,169	-	-	-	1,105,210	30,765	1,389
2a.1.1	Totals	663	16,147	15,999	4,189	22	27,228	711	30,094	95,053	95,053	-	-	96	23,536	1,481	1,010	-	1,843,190	83,767	2,778
Removal of Major Equipment																					
2a.1.2	Main Turbine/Generator	-	362	1,496	349	3,174	357	-	858	6,596	6,596	-	-	24,835	1,383	-	-	-	1,577,959	5,438	-
2a.1.3	Main Condensers	-	1,245	397	128	1,667	198	-	670	4,306	4,306	-	-	17,396	727	-	-	-	828,955	18,831	-
Cascading Costs from Clean Building Demolition																					
2a.1.4.1	Reactor Building	-	317	-	-	-	-	-	48	364	364	-	-	-	-	-	-	-	-	2,217	-
2a.1.4.2	Radwaste	-	24	-	-	-	-	-	4	27	27	-	-	-	-	-	-	-	-	127	-
2a.1.4.3	Turbine	-	118	-	-	-	-	-	18	136	136	-	-	-	-	-	-	-	-	1,254	-
2a.1.4	Totals	-	459	-	-	-	-	-	69	528	528	-	-	-	-	-	-	-	-	3,598	-
Disposal of Plant Systems																					
2a.1.5.1	Automatic Press Relief	-	115	7	8	69	57	-	55	311	311	-	-	803	206	-	-	-	45,852	1,656	-
2a.1.5.2	Chemistry Sampling	-	27	1	1	13	10	-	12	65	65	-	-	156	37	-	-	-	8,681	400	-
2a.1.5.3	Chemistry Sampling - Insulated	-	2	0	0	-	0	-	1	3	3	-	-	-	1	-	-	-	72	28	-
2a.1.5.4	Circulating Water - RCA	-	202	12	41	576	-	-	144	974	974	-	-	6,656	-	-	-	-	270,307	2,860	-
2a.1.5.5	Combustible Gas Control - Insul - RCA	-	29	0	1	18	-	-	10	59	59	-	-	212	-	-	-	-	8,617	378	-
2a.1.5.6	Combustible Gas Control - RCA	-	18	0	2	25	-	-	8	53	53	-	-	285	-	-	-	-	11,577	245	-
2a.1.5.7	Condensate & Feedwater	-	946	189	226	1,725	2,003	-	1,049	6,138	6,138	-	-	19,947	7,319	-	-	-	1,275,810	14,196	-
2a.1.5.8	Condensate & Feedwater - Insulated	-	480	34	43	361	332	-	267	1,517	1,517	-	-	4,176	1,207	-	-	-	246,693	6,964	-
2a.1.5.9	Condensate Demin	-	533	29	35	289	276	-	254	1,416	1,416	-	-	3,346	1,000	-	-	-	199,936	7,618	-
2a.1.5.10	Condensate Storage	-	706	31	55	617	219	-	335	1,963	1,963	-	-	7,131	795	-	-	-	340,568	10,345	-
2a.1.5.11	Control Rod Drive	-	3	0	0	2	1	-	1	7	7	-	-	19	4	-	-	-	1,009	41	-
2a.1.5.12	Control Rod Drive Hydraulic	-	405	16	18	143	155	-	166	902	902	-	-	1,658	562	-	-	-	103,306	5,898	-
2a.1.5.13	Core Spray	-	75	19	34	379	143	-	119	770	770	-	-	4,384	521	-	-	-	211,329	1,163	-
2a.1.5.14	Core Spray - Insulated	-	141	8	9	71	73	-	66	368	368	-	-	818	264	-	-	-	50,149	2,033	-
2a.1.5.15	Demin Water - Insulated - RCA	-	15	0	1	7	-	-	5	27	27	-	-	85	-	-	-	-	3,445	181	-
2a.1.5.16	Demin Water - RCA	-	40	0	2	22	-	-	14	78	78	-	-	253	-	-	-	-	10,278	508	-
2a.1.5.17	Diesel Oil - RCA	-	2	0	0	2	-	-	1	5	5	-	-	23	-	-	-	-	931	25	-
2a.1.5.18	Drywell Atmosphere Cooling - RCA	-	37	1	3	47	-	-	17	105	105	-	-	548	-	-	-	-	22,244	550	-
2a.1.5.19	EDG Emerg Service Water - Insul - RCA	-	0	0	0	0	-	-	0	1	1	-	-	2	-	-	-	-	84	4	-
2a.1.5.20	Electrical - Clean	-	12	-	-	-	-	-	2	13	-	-	13	-	-	-	-	-	-	182	-
2a.1.5.21	Emergency Service Water - Insul - RCA	-	21	0	1	12	-	-	7	41	41	-	-	137	-	-	-	-	5,544	281	-
2a.1.5.22	Emergency Service Water - RCA	-	2	0	0	1	-	-	1	4	4	-	-	13	-	-	-	-	512	22	-
2a.1.5.23	GEZIP - RCA	-	3	0	1	9	-	-	2	15	15	-	-	103	-	-	-	-	4,184	48	-
2a.1.5.24	Generator Physical Design - RCA	-	5	0	0	3	-	-	2	9	9	-	-	31	-	-	-	-	1,250	67	-
2a.1.5.25	H2-O2 Control Analyzing	-	6	0	0	0	4	-	3	13	13	-	-	6	13	-	-	-	1,080	81	-
2a.1.5.26	H2-O2 Control Analyzing - Insulated	-	6	0	0	0	4	-	3	13	13	-	-	6	13	-	-	-	1,080	81	-
2a.1.5.27	High Pressure Coolant Injection	-	64	6	9	84	57	-	45	266	266	-	-	972	209	-	-	-	52,792	966	-
2a.1.5.28	High Pressure Coolant Injection - Insula	-	214	14	17	138	133	-	111	627	627	-	-	1,598	481	-	-	-	95,733	3,079	-
2a.1.5.29	Hydrogen Cooling	-	7	-	-	-	-	-	1	9	-	-	9	-	-	-	-	-	-	118	-
2a.1.5.30	Hydrogen Cooling - RCA	-	7	0	0	3	-	-	2	13	13	-	-	39	-	-	-	-	1,600	79	-
2a.1.5.31	Hydrogen Seal Oil - RCA	-	17	0	1	16	-	-	7	42	42	-	-	189	-	-	-	-	7,669	212	-
2a.1.5.32	Hydrogen Water Chemistry - RCA	-	24	0	1	12	-	-	8	45	45	-	-	140	-	-	-	-	5,672	304	-
2a.1.5.33	Instrument & Service Air - RCA	-	220	3	11	153	-	-	80	466	466	-	-	1,768	-	-	-	-	71,810	2,733	-
2a.1.5.34	Main Condenser	-	191	12	14	115	113	-	97	542	542	-	-	1,333	411	-	-	-	80,439	2,746	-
2a.1.5.35	Main Steam	-	243	17	22	186	163	-	134	764	764	-	-	2,148	594	-	-	-	125,135	3,512	-
2a.1.5.36	Main Turbine	-	972	214	244	1,709	2,375	-	1,151	6,665	6,665	-	-	19,760	8,687	-	-	-	1,354,661	14,733	-
2a.1.5.37	Main Turbine - Insulated	-	209	19	25	219	183	-	136	790	790	-	-	2,530	667	-	-	-	145,208	3,069	-
2a.1.5.38	Miscellaneous	-	42	1	2	26	-	-	15	85	85	-	-	302	-	-	-	-	12,283	622	-
2a.1.5.39	Off Gas Recombiner	-	182	19	22	155	209	-	126	714	714	-	-	1,795	764	-	-	-	121,554	2,708	-
2a.1.5.40	Off Gas Recombiner - Insulated	-	379	19	19	118	195	-	166	897	897	-	-	1,366	709	-	-	-	100,933	5,385	-
2a.1.5.41	Post Accident Sampling	-	24	1	1	5	9	-	9	50	50	-	-	53	33	-	-	-	4,318	345	-
2a.1.5.42	Post Accident Sampling - Insulated	-	16	1	1	1	11	-	7	37	37	-	-	17	37	-	-	-	3,116	212	-
2a.1.5.43	RHR Service Water - Insulated - RCA	-	81	3	9	128	-	-	41	262	262	-	-	1,485	-	-	-	-	60,293	1,125	-
2a.1.5.44	RHR Service Water - RCA	-	4	0	0	3	-	-	1	9	9	-	-	35	-	-	-	-	1,410	57	-
2a.1.5.45	Reactor Feedwater Pump Seal	-	55	3	3	17	26	-	23	126	126	-	-	193	96	-	-	-	14,009	773	-

Table C
Monticello Nuclear Generating Plant
Scenario 1: DECON with 32 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Disposal of Plant Systems (continued)																					
2a.1.5.46	Residual Heat Removal	349	240	168	126	554	1,667	-	770	3,875	3,875	-	-	6,406	6,012	-	-	-	647,941	4,135	-
2a.1.5.47	Residual Heat Removal - Insulated	602	540	64	58	291	715	-	674	2,944	2,944	-	-	3,367	2,607	-	-	-	303,087	10,340	-
2a.1.5.48	Rx Core Isolation Cooling	-	47	2	3	22	21	-	21	116	116	-	-	259	76	-	-	-	15,396	691	-
2a.1.5.49	Rx Core Isolation Cooling - Insulated	-	105	5	5	25	55	-	45	240	240	-	-	288	198	-	-	-	24,419	1,479	-
2a.1.5.50	Rx Recirculation	56	57	6	3	4	53	-	57	235	235	-	-	43	190	-	-	-	14,095	1,580	-
2a.1.5.51	Snubbers	-	168	2	4	33	25	-	54	285	285	-	-	377	90	-	-	-	21,009	2,548	-
2a.1.5.52	Standby Liquid Control - Insul - RCA	-	4	0	0	2	-	-	1	7	7	-	-	22	-	-	-	-	904	48	-
2a.1.5.53	Standby Liquid Control - RCA	-	26	0	1	21	-	-	10	59	59	-	-	245	-	-	-	-	9,969	341	-
2a.1.5.54	Stator Cooling - RCA	-	7	0	1	11	-	-	4	23	23	-	-	126	-	-	-	-	5,135	98	-
2a.1.5.55	Traversing Incore Probe	0	4	0	0	0	2	-	1	7	7	-	-	1	5	-	-	-	386	51	-
2a.1.5	Totals	1,007	7,978	931	1,079	8,447	9,287	-	6,340	35,068	35,046	-	22	97,654	33,808	-	-	-	6,125,515	119,943	-
2a.1.6	Scaffolding in support of decommissioning	-	2,188	25	8	99	25	-	572	2,916	2,916	-	-	1,030	91	-	-	-	52,111	22,564	-
2a.1	Subtotal Period 2a Activity Costs	1,669	28,379	18,848	5,754	13,409	37,095	711	38,602	144,467	144,445	-	22	141,010	59,545	1,481	1,010	-	10,427,730	254,140	2,778
Period 2a Additional Costs																					
2a.2.1	Remedial Action Surveys	-	-	-	-	-	-	2,326	698	3,024	3,024	-	-	-	-	-	-	-	-	30,411	-
2a.2	Subtotal Period 2a Additional Costs	-	-	-	-	-	-	2,326	698	3,024	3,024	-	-	-	-	-	-	-	-	30,411	-
Period 2a Collateral Costs																					
2a.3.1	Process decommissioning water waste	83	-	55	140	-	222	-	123	623	623	-	-	-	531	-	-	-	31,838	103	-
2a.3.2	Process decommissioning chemical flush waste	6	-	208	774	-	1,557	-	529	3,075	3,075	-	-	-	2,093	-	-	-	223,008	392	-
2a.3.3	Small tool allowance	-	315	-	-	-	-	-	47	363	326	-	36	-	-	-	-	-	-	-	-
2a.3.4	Spent Fuel Capital and Transfer	-	-	-	-	-	-	12,181	1,827	14,008	-	14,008	-	-	-	-	-	-	-	-	-
2a.3.5	Retention and Severance	-	-	-	-	-	-	13,235	1,985	15,221	15,221	-	-	-	-	-	-	-	-	-	-
2a.3	Subtotal Period 2a Collateral Costs	89	315	263	914	-	1,779	25,417	4,512	33,290	19,245	14,008	36	-	2,623	-	-	-	254,846	495	-
Period 2a Period-Dependent Costs																					
2a.4.1	Decon supplies	102	-	-	-	-	-	-	25	127	127	-	-	-	-	-	-	-	-	-	-
2a.4.2	Insurance	-	-	-	-	-	-	1,055	106	1,161	1,161	-	-	-	-	-	-	-	-	-	-
2a.4.3	Property taxes	-	-	-	-	-	-	3,061	306	3,367	3,367	-	-	-	-	-	-	-	-	-	-
2a.4.4	Health physics supplies	-	2,133	-	-	-	-	-	533	2,666	2,666	-	-	-	-	-	-	-	-	-	-
2a.4.5	Heavy equipment rental	-	3,212	-	-	-	-	-	482	3,694	3,694	-	-	-	-	-	-	-	-	-	-
2a.4.6	Disposal of DAW generated	-	-	122	37	-	453	-	131	743	743	-	-	-	5,567	-	-	-	111,335	182	-
2a.4.7	Plant energy budget	-	-	-	-	-	-	2,404	361	2,765	2,765	-	-	-	-	-	-	-	-	-	-
2a.4.8	NRC Fees	-	-	-	-	-	-	847	85	932	932	-	-	-	-	-	-	-	-	-	-
2a.4.9	Emergency Planning Fees	-	-	-	-	-	-	3,757	376	4,133	-	4,133	-	-	-	-	-	-	-	-	-
2a.4.10	Fixed Overhead	-	-	-	-	-	-	3,392	509	3,900	3,900	-	-	-	-	-	-	-	-	-	-
2a.4.11	Spent Fuel Pool O&M	-	-	-	-	-	-	1,174	176	1,350	-	1,350	-	-	-	-	-	-	-	-	-
2a.4.12	ISFSI Operating Costs	-	-	-	-	-	-	151	23	174	-	174	-	-	-	-	-	-	-	-	-
2a.4.13	Railroad Track Maintenance	-	-	-	-	-	-	466	70	536	536	-	-	-	-	-	-	-	-	-	-
2a.4.14	Security Staff Cost	-	-	-	-	-	-	19,265	2,890	22,154	22,154	-	-	-	-	-	-	-	-	-	328,651
2a.4.15	DOC Staff Cost	-	-	-	-	-	-	20,125	3,019	23,144	23,144	-	-	-	-	-	-	-	-	-	231,273
2a.4.16	Utility Staff Cost	-	-	-	-	-	-	26,670	4,000	30,670	30,670	-	-	-	-	-	-	-	-	-	430,594
2a.4	Subtotal Period 2a Period-Dependent Costs	102	5,345	122	37	-	453	82,366	13,090	101,515	95,858	5,657	-	-	5,567	-	-	-	111,335	182	990,519
2a.0	TOTAL PERIOD 2a COST	1,860	34,039	19,233	6,705	13,409	39,327	110,821	56,903	282,296	262,573	19,665	58	141,010	67,735	1,481	1,010	-	10,793,910	285,228	993,297
PERIOD 2b - Site Decontamination																					
Period 2b Direct Decommissioning Activities																					
Disposal of Plant Systems																					
2b.1.1.1	ALARA/Radiological	-	18	0	0	3	3	-	6	30	30	-	-	35	10	-	-	-	2,060	277	-
2b.1.1.2	Alternate N2 - RCA	-	16	0	1	8	-	-	5	30	30	-	-	93	-	-	-	-	3,765	185	-
2b.1.1.3	Decontamination Projects	-	1	0	0	0	0	-	0	2	2	-	-	2	0	-	-	-	129	17	-
2b.1.1.4	Electrical - Contaminated	-	439	6	16	207	25	-	150	841	841	-	-	2,389	90	-	-	-	102,726	6,325	-
2b.1.1.5	Electrical - Decontaminated	-	2,657	41	142	2,019	-	-	993	5,852	5,852	-	-	23,344	-	-	-	-	948,013	37,107	-
2b.1.1.6	Fire - RCA	-	99	1	4	53	-	-	33	191	191	-	-	614	-	-	-	-	24,917	1,324	-
2b.1.1.7	HVAC Ductwork	-	309	7	18	231	27	-	122	713	713	-	-	2,665	100	-	-	-	114,598	4,111	-
2b.1.1.8	HVAC/Chilled Water - RCA	-	317	5	17	238	-	-	118	694	694	-	-	2,752	-	-	-	-	111,779	3,985	-
2b.1.1.9	Heating & Ventilation	-	473	15	40	521	62	-	219	1,329	1,329	-	-	6,018	227	-	-	-	258,789	7,101	-
2b.1.1.10	Heating Boiler - Insulated - RCA	-	3	0	0	2	-	-	1	6	6	-	-	26	-	-	-	-	1,058	35	-
2b.1.1.11	Liquid Radwaste	572	669	46	44	266	476	-	623	2,697	2,697	-	-	3,073	1,728	-	-	-	235,484	17,194	-
2b.1.1.12	Makeup Demin - RCA	-	101	3	9	127	-	-	46	286	286	-	-	1,471	-	-	-	-	59,747	1,412	-
2b.1.1.13	Non-Essential Diesel Generator - RCA	-	26	2	9	123	-	-	27	187	187	-	-	1,424	-	-	-	-	57,832	395	-

Table C
Monticello Nuclear Generating Plant
Scenario 1: DECON with 32 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Disposal of Plant Systems (continued)																					
2b.1.1.14	Off Gas Holdup	-	333	20	26	238	174	-	168	960	960	-	-	2,755	630	-	-	-	152,277	4,769	-
2b.1.1.15	Primary Containment	-	443	43	59	536	412	-	308	1,801	1,801	-	-	6,201	1,506	-	-	-	347,704	6,454	-
2b.1.1.16	Process Radiation Monitors	-	45	2	2	12	14	-	17	92	92	-	-	142	52	-	-	-	9,115	649	-
2b.1.1.17	Rx Bldg Closed Clng Water - Insul - RCA	-	111	2	6	85	-	-	42	245	245	-	-	977	-	-	-	-	39,675	1,484	-
2b.1.1.18	Rx Bldg Closed Clng Water - RCA	-	178	12	43	614	-	-	144	991	991	-	-	7,093	-	-	-	-	288,031	2,489	-
2b.1.1.19	Rx Component Handling Equip	26	138	19	19	100	227	-	124	653	653	-	-	1,158	829	-	-	-	99,730	2,462	-
2b.1.1.20	Rx Pressure Vessel	28	46	6	4	7	63	-	43	196	196	-	-	75	230	-	-	-	17,816	1,051	-
2b.1.1.21	Rx Water Cleanup	169	258	19	11	11	204	-	205	877	877	-	-	130	737	-	-	-	52,670	5,736	-
2b.1.1.22	Secondary Containment	-	121	7	10	88	70	-	63	360	360	-	-	1,017	255	-	-	-	57,567	1,763	-
2b.1.1.23	Service & Seal Water - Insulated - RCA	-	117	2	7	102	-	-	46	274	274	-	-	1,180	-	-	-	-	47,917	1,565	-
2b.1.1.24	Service & Seal Water - RCA	-	155	3	11	156	-	-	64	390	390	-	-	1,809	-	-	-	-	73,453	2,016	-
2b.1.1.25	Service Air Blower - RCA	-	15	0	1	18	-	-	7	41	41	-	-	206	-	-	-	-	8,364	206	-
2b.1.1.26	Solid Radwaste	327	483	36	34	206	380	-	419	1,885	1,885	-	-	2,387	1,380	-	-	-	185,221	10,820	-
2b.1.1.27	Structures & Buildings	-	76	2	3	31	23	-	30	166	166	-	-	357	85	-	-	-	19,933	1,128	-
2b.1.1.28	Wells & Domestic Water	-	9	-	-	-	-	-	1	10	-	-	10	-	-	-	-	-	-	144	-
2b.1.1.29	Wells & Domestic Water - RCA	-	51	1	2	30	-	-	18	101	101	-	-	342	-	-	-	-	13,874	633	-
2b.1.1	Totals	1,122	7,707	299	537	6,032	2,160	-	4,042	21,900	21,890	-	10	69,735	7,859	-	-	-	3,334,244	122,835	-
2b.1.2	Scaffolding in support of decommissioning	-	2,735	31	10	123	31	-	715	3,645	3,645	-	-	1,287	114	-	-	-	65,139	28,205	-
Decontamination of Site Buildings																					
2b.1.3.1	Reactor Building	5,006	2,817	155	347	4,159	1,007	-	4,150	17,641	17,641	-	-	48,077	7,014	-	-	-	2,317,670	112,518	-
2b.1.3.2	Admin	103	6	0	2	-	14	-	57	182	182	-	-	-	145	-	-	-	6,840	1,600	-
2b.1.3.3	HPCI Room	28	27	1	2	10	13	-	26	107	107	-	-	118	125	-	-	-	10,759	789	-
2b.1.3.4	Hot Shop	16	4	0	1	-	10	-	12	43	43	-	-	-	103	-	-	-	4,860	286	-
2b.1.3.5	LLRW Storage & Shipping	56	23	1	6	3	41	-	46	176	176	-	-	31	433	-	-	-	21,708	1,127	-
2b.1.3.6	Offgas Stack	360	256	6	16	116	73	-	283	1,109	1,109	-	-	1,343	669	-	-	-	87,045	8,860	-
2b.1.3.7	Offgas Storage & Compressor	39	17	1	4	2	30	-	32	125	125	-	-	25	316	-	-	-	15,948	785	-
2b.1.3.8	Radwaste	117	59	3	13	15	86	-	100	393	393	-	-	172	910	-	-	-	49,943	2,503	-
2b.1.3.9	Radwaste Material Storage Warehouse	62	23	1	6	-	47	-	49	189	189	-	-	-	495	-	-	-	23,400	1,197	-
2b.1.3.10	Recombiner	26	24	1	4	17	22	-	28	122	122	-	-	199	216	-	-	-	18,405	695	-
2b.1.3.11	Turbine	684	341	18	76	111	507	-	583	2,319	2,319	-	-	1,283	5,299	-	-	-	303,150	14,443	-
2b.1.3.12	Turbine Building Addition	56	20	1	6	-	41	-	44	169	169	-	-	-	434	-	-	-	20,478	1,087	-
2b.1.3	Totals	6,554	3,618	188	483	4,433	1,889	-	5,410	22,574	22,574	-	-	51,247	16,159	-	-	-	2,880,206	145,889	-
2b.1.4	Prepare/submit License Termination Plan	-	-	-	-	-	-	481	72	553	553	-	-	-	-	-	-	-	-	-	4,096
2b.1.5	Receive NRC approval of termination plan									a											
2b.1	Subtotal Period 2b Activity Costs	7,676	14,060	518	1,031	10,588	4,079	481	10,239	48,672	48,662	-	10	122,269	24,132	-	-	-	6,279,589	296,929	4,096
Period 2b Additional Costs																					
2b.2.1	Remedial Action Surveys	-	-	-	-	-	-	3,241	972	4,213	4,213	-	-	-	-	-	-	-	-	42,370	-
2b.2.2	Operational Equipment	-	-	19	60	624	-	-	104	807	807	-	-	11,710	-	-	-	-	292,750	32	-
2b.2.3	Security Modifications	-	-	-	-	-	-	8,696	1,304	10,000	10,000	-	-	-	-	-	-	-	-	-	-
2b.2	Subtotal Period 2b Additional Costs	-	-	19	60	624	-	11,937	2,381	15,020	15,020	-	-	11,710	-	-	-	-	292,750	42,402	-
Period 2b Collateral Costs																					
2b.3.1	Process decommissioning water waste	173	-	117	299	-	474	-	261	1,325	1,325	-	-	-	1,133	-	-	-	67,962	221	-
2b.3.2	Process decommissioning chemical flush waste	1	-	41	153	-	307	-	104	606	606	-	-	-	413	-	-	-	43,978	77	-
2b.3.3	Small tool allowance	-	341	-	-	-	-	-	51	392	392	-	-	-	-	-	-	-	-	-	-
2b.3.4	Spent Fuel Capital and Transfer	-	-	-	-	-	-	65,095	9,764	74,859	-	74,859	-	-	-	-	-	-	-	-	-
2b.3.5	Retention and Severance	-	-	-	-	-	-	8,665	1,300	9,964	9,964	-	-	-	-	-	-	-	-	-	-
2b.3	Subtotal Period 2b Collateral Costs	174	341	159	452	-	781	73,759	11,481	87,146	12,287	74,859	-	-	1,545	-	-	-	111,940	298	-
Period 2b Period-Dependent Costs																					
2b.4.1	Decon supplies	1,361	-	-	-	-	-	-	340	1,701	1,701	-	-	-	-	-	-	-	-	-	-
2b.4.2	Insurance	-	-	-	-	-	-	1,470	147	1,617	1,617	-	-	-	-	-	-	-	-	-	-
2b.4.3	Property taxes	-	-	-	-	-	-	3,915	391	4,306	4,306	-	-	-	-	-	-	-	-	-	-
2b.4.4	Health physics supplies	-	2,681	-	-	-	-	-	670	3,352	3,352	-	-	-	-	-	-	-	-	-	-
2b.4.5	Heavy equipment rental	-	4,602	-	-	-	-	-	690	5,292	5,292	-	-	-	-	-	-	-	-	-	-
2b.4.6	Disposal of DAW generated	-	-	124	38	-	463	-	134	759	759	-	-	-	5,690	-	-	-	113,799	186	-
2b.4.7	Plant energy budget	-	-	-	-	-	-	2,645	397	3,041	3,041	-	-	-	-	-	-	-	-	-	-
2b.4.8	NRC Fees	-	-	-	-	-	-	1,180	118	1,298	1,298	-	-	-	-	-	-	-	-	-	-
2b.4.9	Emergency Planning Fees	-	-	-	-	-	-	5,234	523	5,758	-	5,758	-	-	-	-	-	-	-	-	-
2b.4.10	Fixed Overhead	-	-	-	-	-	-	4,725	709	5,434	5,434	-	-	-	-	-	-	-	-	-	-
2b.4.11	Spent Fuel Pool O&M	-	-	-	-	-	-	1,636	245	1,881	-	1,881	-	-	-	-	-	-	-	-	-
2b.4.12	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	412	62	474	474	-	-	-	-	-	-	-	-	-	-

Table C
Monticello Nuclear Generating Plant
Scenario 1: DECON with 32 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 2b Period-Dependent Costs (continued)																					
2b.4.13	ISFSI Operating Costs	-	-	-	-	-	-	210	32	242	-	242	-	-	-	-	-	-	-	-	-
2b.4.14	Railroad Track Maintenance	-	-	-	-	-	-	235	35	270	270	-	-	-	-	-	-	-	-	-	-
2b.4.15	Security Staff Cost	-	-	-	-	-	-	26,840	4,026	30,867	30,867	-	-	-	-	-	-	-	-	-	457,896
2b.4.16	DOC Staff Cost	-	-	-	-	-	-	27,122	4,068	31,191	31,191	-	-	-	-	-	-	-	-	-	309,504
2b.4.17	Utility Staff Cost	-	-	-	-	-	-	35,641	5,346	40,988	40,988	-	-	-	-	-	-	-	-	-	574,490
2b.4	Subtotal Period 2b Period-Dependent Costs	1,361	7,283	124	38	-	463	111,268	17,935	138,473	130,592	7,881	-	-	5,690	-	-	-	113,799	186	1,341,891
2b.0	TOTAL PERIOD 2b COST	9,211	21,684	820	1,580	11,212	5,324	197,445	42,036	289,312	206,561	82,740	10	133,979	31,367	-	-	-	6,798,079	339,814	1,345,987
PERIOD 2d - Decontamination Following Wet Fuel Storage																					
Period 2d Direct Decommissioning Activities																					
2d.1.1	Remove spent fuel racks	634	56	114	109	-	2,091	-	881	3,884	3,884	-	-	-	7,653	-	-	-	486,170	906	-
Disposal of Plant Systems																					
2d.1.2.1	Cranes/Heavy Loads/Rigging - RCA	-	3	0	1	9	-	-	2	15	15	-	-	103	-	-	-	-	4,184	48	-
2d.1.2.2	Electrical - Contaminated Fuel Pool	-	46	1	2	21	2	-	16	87	87	-	-	240	9	-	-	-	10,334	665	-
2d.1.2.3	Electrical - Decontam. Fuel Pool Area	-	293	4	15	213	-	-	108	633	633	-	-	2,457	-	-	-	-	99,783	4,090	-
2d.1.2.4	Fire - RCA - Fuel Pool Area	-	11	0	0	5	-	-	4	20	20	-	-	62	-	-	-	-	2,499	143	-
2d.1.2.5	Fuel Pool Cooling & Cleanup	240	419	34	26	102	370	-	340	1,531	1,531	-	-	1,179	1,341	-	-	-	133,939	8,380	-
2d.1.2.6	Fuel Pool Cooling & Cleanup - Insulated	26	40	3	2	6	32	-	33	143	143	-	-	67	117	-	-	-	10,220	848	-
2d.1.2.7	HVAC Ductwork - Fuel Pool Area	-	34	1	2	26	3	-	14	79	79	-	-	296	11	-	-	-	12,733	457	-
2d.1.2.8	HVAC/Chilled Water - RCA Fuel Pool Area	-	32	0	1	19	-	-	11	64	64	-	-	223	-	-	-	-	9,072	397	-
2d.1.2.9	Instrument & Service Air-RCA-Fuel Pool	-	28	0	2	23	-	-	11	64	64	-	-	267	-	-	-	-	10,841	357	-
2d.1.2	Totals	266	907	44	51	423	408	-	537	2,637	2,637	-	-	4,894	1,479	-	-	-	293,606	15,385	-
Decontamination of Site Buildings																					
2d.1.3.1	Reactor (Post Fuel)	911	2,485	145	669	170	8,544	-	3,353	16,277	16,277	-	-	1,969	62,698	-	-	-	2,732,406	45,703	-
2d.1.3	Totals	911	2,485	145	669	170	8,544	-	3,353	16,277	16,277	-	-	1,969	62,698	-	-	-	2,732,406	45,703	-
2d.1.4	Scaffolding in support of decommissioning	-	547	6	2	25	6	-	143	729	729	-	-	257	23	-	-	-	13,028	5,641	-
2d.1	Subtotal Period 2d Activity Costs	1,811	3,994	309	831	618	11,049	-	4,915	23,527	23,527	-	-	7,120	71,852	-	-	-	3,525,210	67,635	-
Period 2d Additional Costs																					
2d.2.1	License Termination Survey Planning	-	-	-	-	-	-	1,291	387	1,678	1,678	-	-	-	-	-	-	-	-	-	12,480
2d.2.2	Remedial Action Surveys	-	-	-	-	-	-	1,198	359	1,557	1,557	-	-	-	-	-	-	-	-	15,661	-
2d.2	Subtotal Period 2d Additional Costs	-	-	-	-	-	-	2,489	747	3,235	3,235	-	-	-	-	-	-	-	-	15,661	12,480
Period 2d Collateral Costs																					
2d.3.1	Process decommissioning water waste	69	-	47	120	-	191	-	105	533	533	-	-	-	457	-	-	-	27,391	89	-
2d.3.2	Process decommissioning chemical flush waste	1	-	25	92	-	185	-	63	366	366	-	-	-	249	-	-	-	26,553	47	-
2d.3.3	Small tool allowance	-	88	-	-	-	-	-	13	101	101	-	-	-	-	-	-	-	-	-	-
2d.3.4	Decommissioning Equipment Disposition	-	-	143	55	575	145	-	145	1,062	1,062	-	-	6,000	529	-	-	-	303,608	147	-
2d.3.5	Spent Fuel Capital and Transfer	-	-	-	-	-	-	27,017	4,053	31,070	-	31,070	-	-	-	-	-	-	-	-	-
2d.3	Subtotal Period 2d Collateral Costs	70	88	216	267	575	521	27,017	4,379	33,132	2,062	31,070	-	6,000	1,235	-	-	-	357,552	283	-
Period 2d Period-Dependent Costs																					
2d.4.1	Decon supplies	219	-	-	-	-	-	-	55	274	274	-	-	-	-	-	-	-	-	-	-
2d.4.2	Insurance	-	-	-	-	-	-	543	54	598	598	-	-	-	-	-	-	-	-	-	-
2d.4.3	Property taxes	-	-	-	-	-	-	1,336	134	1,470	1,470	-	-	-	-	-	-	-	-	-	-
2d.4.4	Health physics supplies	-	752	-	-	-	-	-	188	940	940	-	-	-	-	-	-	-	-	-	-
2d.4.5	Heavy equipment rental	-	1,701	-	-	-	-	-	255	1,956	1,956	-	-	-	-	-	-	-	-	-	-
2d.4.6	Disposal of DAW generated	-	-	44	14	-	165	-	48	271	271	-	-	-	2,030	-	-	-	40,600	66	-
2d.4.7	Plant energy budget	-	-	-	-	-	-	521	78	600	600	-	-	-	-	-	-	-	-	-	-
2d.4.8	NRC Fees	-	-	-	-	-	-	369	37	405	405	-	-	-	-	-	-	-	-	-	-
2d.4.9	Emergency Planning Fees	-	-	-	-	-	-	1,935	193	2,128	-	2,128	-	-	-	-	-	-	-	-	-
2d.4.10	Fixed Overhead	-	-	-	-	-	-	1,747	262	2,009	2,009	-	-	-	-	-	-	-	-	-	-
2d.4.11	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	305	46	351	351	-	-	-	-	-	-	-	-	-	-
2d.4.12	ISFSI Operating Costs	-	-	-	-	-	-	78	12	89	-	89	-	-	-	-	-	-	-	-	-
2d.4.13	Railroad Track Maintenance	-	-	-	-	-	-	87	13	100	100	-	-	-	-	-	-	-	-	-	-
2d.4.14	Security Staff Cost	-	-	-	-	-	-	9,608	1,441	11,049	7,668	3,381	-	-	-	-	-	-	-	-	162,981
2d.4.15	DOC Staff Cost	-	-	-	-	-	-	6,941	1,041	7,982	7,982	-	-	-	-	-	-	-	-	-	78,356
2d.4.16	Utility Staff Cost	-	-	-	-	-	-	9,556	1,433	10,989	10,132	857	-	-	-	-	-	-	-	-	149,660
2d.4	Subtotal Period 2d Period-Dependent Costs	219	2,453	44	14	-	165	33,025	5,290	41,210	34,754	6,456	-	-	2,030	-	-	-	40,600	66	390,997
2d.0	TOTAL PERIOD 2d COST	2,099	6,535	569	1,112	1,193	11,735	62,531	15,330	101,104	63,579	37,525	-	13,120	75,117	-	-	-	3,923,362	83,645	403,477

Table C
Monticello Nuclear Generating Plant
Scenario 1: DECON with 32 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
PERIOD 2f - License Termination																					
Period 2f Direct Decommissioning Activities																					
2f.1.1	ORISE confirmatory survey	-	-	-	-	-	-	176	53	229	229	-	-	-	-	-	-	-	-	-	-
2f.1.2	Terminate license									a											
2f.1	Subtotal Period 2f Activity Costs	-	-	-	-	-	-	176	53	229	229	-	-	-	-	-	-	-	-	-	-
Period 2f Additional Costs																					
2f.2.1	License Termination Survey	-	-	-	-	-	-	7,341	2,202	9,544	9,544	-	-	-	-	-	-	-	-	96,197	6,240
2f.2	Subtotal Period 2f Additional Costs	-	-	-	-	-	-	7,341	2,202	9,544	9,544	-	-	-	-	-	-	-	-	96,197	6,240
Period 2f Collateral Costs																					
2f.3.1	DOC staff relocation expenses	-	-	-	-	-	-	1,189	178	1,367	1,367	-	-	-	-	-	-	-	-	-	-
2f.3	Subtotal Period 2f Collateral Costs	-	-	-	-	-	-	1,189	178	1,367	1,367	-	-	-	-	-	-	-	-	-	-
Period 2f Period-Dependent Costs																					
2f.4.1	Insurance	-	-	-	-	-	-	543	54	598	598	-	-	-	-	-	-	-	-	-	-
2f.4.2	Property taxes	-	-	-	-	-	-	1,285	128	1,413	1,413	-	-	-	-	-	-	-	-	-	-
2f.4.3	Health physics supplies	-	597	-	-	-	-	-	149	747	747	-	-	-	-	-	-	-	-	-	-
2f.4.4	Disposal of DAW generated	-	-	8	2	-	29	-	8	47	47	-	-	-	355	-	-	-	7,097	12	-
2f.4.5	Plant energy budget	-	-	-	-	-	-	261	39	300	300	-	-	-	-	-	-	-	-	-	-
2f.4.6	NRC Fees	-	-	-	-	-	-	420	42	463	463	-	-	-	-	-	-	-	-	-	-
2f.4.7	Emergency Planning Fees	-	-	-	-	-	-	103	10	113	-	113	-	-	-	-	-	-	-	-	-
2f.4.8	Fixed Overhead	-	-	-	-	-	-	1,747	262	2,009	2,009	-	-	-	-	-	-	-	-	-	-
2f.4.9	ISFSI Operating Costs	-	-	-	-	-	-	78	12	89	-	89	-	-	-	-	-	-	-	-	-
2f.4.10	Railroad Track Maintenance	-	-	-	-	-	-	87	13	100	100	-	-	-	-	-	-	-	-	-	-
2f.4.11	Security Staff Cost	-	-	-	-	-	-	9,608	1,441	11,049	7,668	3,381	-	-	-	-	-	-	-	-	162,981
2f.4.12	DOC Staff Cost	-	-	-	-	-	-	5,174	776	5,950	5,950	-	-	-	-	-	-	-	-	-	57,200
2f.4.13	Utility Staff Cost	-	-	-	-	-	-	5,456	818	6,274	5,415	860	-	-	-	-	-	-	-	-	80,707
2f.4	Subtotal Period 2f Period-Dependent Costs	-	597	8	2	-	29	24,761	3,754	29,152	24,708	4,443	-	-	355	-	-	-	7,097	12	300,888
2f.0	TOTAL PERIOD 2f COST	-	597	8	2	-	29	33,467	6,188	40,291	35,848	4,443	-	-	355	-	-	-	7,097	96,208	307,128
PERIOD 2 TOTALS		13,170	62,856	20,629	9,399	25,814	56,415	404,263	120,456	713,004	568,562	144,374	68	288,110	174,575	1,481	1,010	-	21,522,450	804,895	3,049,889
PERIOD 3b - Site Restoration																					
Period 3b Direct Decommissioning Activities																					
Demolition of Remaining Site Buildings																					
3b.1.1.1	Reactor Building	-	1,881	-	-	-	-	-	282	2,163	-	-	2,163	-	-	-	-	-	-	13,966	-
3b.1.1.2	Condensate Tanks Foundation	-	10	-	-	-	-	-	1	11	-	-	11	-	-	-	-	-	-	50	-
3b.1.1.3	Discharge Retention Basin	-	4	-	-	-	-	-	1	4	-	-	4	-	-	-	-	-	-	25	-
3b.1.1.4	HPCI Room	-	18	-	-	-	-	-	3	21	-	-	21	-	-	-	-	-	-	97	-
3b.1.1.5	Hot Shop	-	15	-	-	-	-	-	2	17	-	-	17	-	-	-	-	-	-	177	-
3b.1.1.6	Hydrogen & Oxygen Storage	-	2	-	-	-	-	-	0	2	-	-	2	-	-	-	-	-	-	19	-
3b.1.1.7	LLRW Storage & Shipping	-	78	-	-	-	-	-	12	90	-	-	90	-	-	-	-	-	-	662	-
3b.1.1.8	MSIV	-	3	-	-	-	-	-	0	4	-	-	4	-	-	-	-	-	-	42	-
3b.1.1.9	Misc Structures 2017	-	759	-	-	-	-	-	114	872	-	-	872	-	-	-	-	-	-	7,919	-
3b.1.1.10	Offgas Stack	-	104	-	-	-	-	-	16	120	-	-	120	-	-	-	-	-	-	544	-
3b.1.1.11	Offgas Storage & Compressor	-	38	-	-	-	-	-	6	44	-	-	44	-	-	-	-	-	-	199	-
3b.1.1.12	Radwaste	-	219	-	-	-	-	-	33	252	-	-	252	-	-	-	-	-	-	1,220	-
3b.1.1.13	Recombiner	-	123	-	-	-	-	-	18	141	-	-	141	-	-	-	-	-	-	713	-
3b.1.1.14	Security Barrier	-	179	-	-	-	-	-	27	206	-	-	206	-	-	-	-	-	-	933	-
3b.1.1.15	Structures Greater than 3' Below Grade	-	2,380	-	-	-	-	-	357	2,738	-	-	2,738	-	-	-	-	-	-	12,649	-
3b.1.1.16	Tank Farm	-	4	-	-	-	-	-	1	5	-	-	5	-	-	-	-	-	-	21	-
3b.1.1.17	Turbine	-	1,175	-	-	-	-	-	176	1,351	-	-	1,351	-	-	-	-	-	-	13,091	-
3b.1.1.18	Turbine Building Addition	-	51	-	-	-	-	-	8	58	-	-	58	-	-	-	-	-	-	618	-
3b.1.1.19	Turbine Pedestal	-	175	-	-	-	-	-	26	202	-	-	202	-	-	-	-	-	-	926	-
3b.1.1	Totals	-	7,219	-	-	-	-	-	1,083	8,302	-	-	8,302	-	-	-	-	-	-	53,870	-
Site Closeout Activities																					
3b.1.2	Grade & landscape site	-	864	-	-	-	-	-	130	994	-	-	994	-	-	-	-	-	-	1,841	-
3b.1.3	Final report to NRC	-	-	-	-	-	-	183	27	211	211	-	-	-	-	-	-	-	-	-	1,560
3b.1	Subtotal Period 3b Activity Costs	-	8,083	-	-	-	-	183	1,240	9,506	211	-	9,295	-	-	-	-	-	-	55,711	1,560

Table C
Monticello Nuclear Generating Plant
Scenario 1: DECON with 32 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 3b Additional Costs																					
3b.2.1	Clean Concrete Disposal	-	3,297	-	-	-	-	11	496	3,805	-	-	3,805	-	-	-	-	-	-	12	-
3b.2.2	Excavation of Underground Services	-	1,380	-	-	-	-	947	349	2,677	-	-	2,677	-	-	-	-	-	-	13,475	-
3b.2.3	Intake Structure Cofferdam	-	320	-	-	-	-	-	48	368	-	-	368	-	-	-	-	-	-	2,584	-
3b.2.4	Construction Debris	-	-	-	-	-	-	350	53	403	-	-	403	-	-	-	-	-	-	-	-
3b.2.5	Backfill	-	5,102	-	-	-	-	-	765	5,868	-	-	5,868	-	-	-	-	-	-	5,422	-
3b.2	Subtotal Period 3b Additional Costs	-	10,100	-	-	-	-	1,309	1,711	13,120	-	-	13,120	-	-	-	-	-	-	21,493	-
Period 3b Collateral Costs																					
3b.3.1	Small tool allowance	-	97	-	-	-	-	-	15	111	-	-	111	-	-	-	-	-	-	-	-
3b.3	Subtotal Period 3b Collateral Costs	-	97	-	-	-	-	-	15	111	-	-	111	-	-	-	-	-	-	-	-
Period 3b Period-Dependent Costs																					
3b.4.1	Insurance	-	-	-	-	-	-	1,251	125	1,376	-	1,376	-	-	-	-	-	-	-	-	-
3b.4.2	Property taxes	-	-	-	-	-	-	2,737	274	3,011	-	3,011	-	-	-	-	-	-	-	-	-
3b.4.3	Heavy equipment rental	-	5,455	-	-	-	-	-	818	6,273	-	-	6,273	-	-	-	-	-	-	-	-
3b.4.4	Plant energy budget	-	-	-	-	-	-	300	45	345	-	-	345	-	-	-	-	-	-	-	-
3b.4.5	NRC ISFSI Fees	-	-	-	-	-	-	386	39	424	-	424	-	-	-	-	-	-	-	-	-
3b.4.6	Emergency Planning Fees	-	-	-	-	-	-	237	24	261	-	261	-	-	-	-	-	-	-	-	-
3b.4.7	Fixed Overhead	-	-	-	-	-	-	1,260	189	1,450	-	-	1,450	-	-	-	-	-	-	-	-
3b.4.8	ISFSI Operating Costs	-	-	-	-	-	-	179	27	206	-	206	-	-	-	-	-	-	-	-	-
3b.4.9	Railroad Track Maintenance	-	-	-	-	-	-	497	75	572	-	-	572	-	-	-	-	-	-	-	-
3b.4.10	Security Staff Cost	-	-	-	-	-	-	22,115	3,317	25,432	(0)	7,782	17,650	-	-	-	-	-	-	-	375,152
3b.4.11	DOC Staff Cost	-	-	-	-	-	-	11,290	1,693	12,983	-	-	12,983	-	-	-	-	-	-	-	122,646
3b.4.12	Utility Staff Cost	-	-	-	-	-	-	6,583	987	7,571	-	1,976	5,595	-	-	-	-	-	-	-	98,297
3b.4	Subtotal Period 3b Period-Dependent Costs	-	5,455	-	-	-	-	46,836	7,613	59,904	(0)	15,036	44,868	-	-	-	-	-	-	-	596,095
3b.0	TOTAL PERIOD 3b COST	-	23,734	-	-	-	-	48,328	10,579	82,641	211	15,036	67,394	-	-	-	-	-	-	77,204	597,655
PERIOD 3c - Fuel Storage Operations/Shipping																					
Period 3c Collateral Costs																					
3c.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	23,942	3,591	27,533	-	27,533	-	-	-	-	-	-	-	-	-
3c.3	Subtotal Period 3c Collateral Costs	-	-	-	-	-	-	23,942	3,591	27,533	-	27,533	-	-	-	-	-	-	-	-	-
Period 3c Period-Dependent Costs																					
3c.4.1	Insurance	-	-	-	-	-	-	17,378	1,738	19,116	-	19,116	-	-	-	-	-	-	-	-	-
3c.4.2	Property taxes	-	-	-	-	-	-	17,062	1,706	18,768	-	18,768	-	-	-	-	-	-	-	-	-
3c.4.4	NRC ISFSI Fees	-	-	-	-	-	-	7,885	789	8,674	-	8,674	-	-	-	-	-	-	-	-	-
3c.4.5	Emergency Planning Fees	-	-	-	-	-	-	3,295	329	3,624	-	3,624	-	-	-	-	-	-	-	-	-
3c.4.6	Fixed Overhead	-	-	-	-	-	-	5,989	898	6,888	-	6,888	-	-	-	-	-	-	-	-	-
3c.4.7	ISFSI Operating Costs	-	-	-	-	-	-	2,487	373	2,861	-	2,861	-	-	-	-	-	-	-	-	-
3c.4.8	Railroad Track Maintenance	-	-	-	-	-	-	2,779	417	3,196	-	3,196	-	-	-	-	-	-	-	-	-
3c.4.9	Security Staff Cost	-	-	-	-	-	-	93,967	14,095	108,062	-	108,062	-	-	-	-	-	-	-	-	1,302,958
3c.4.10	Utility Staff Cost	-	-	-	-	-	-	23,828	3,574	27,402	-	27,402	-	-	-	-	-	-	-	-	338,268
3c.4	Subtotal Period 3c Period-Dependent Costs	-	-	-	-	-	-	174,671	23,920	198,591	-	198,591	-	-	-	-	-	-	-	-	1,641,226
3c.0	TOTAL PERIOD 3c COST	-	-	-	-	-	-	198,613	27,511	226,124	-	226,124	-	-	-	-	-	-	-	-	1,641,226
PERIOD 3d - GTCC shipping																					
Period 3d Direct Decommissioning Activities																					
Nuclear Steam Supply System Removal																					
3d.1.1.1	Vessel & Internals GTCC Disposal	-	-	1,331	-	-	6,552	-	1,316	9,199	9,199	-	-	-	-	-	-	-	1,547	311,184	-	-
3d.1.1	Totals	-	-	1,331	-	-	6,552	-	1,316	9,199	9,199	-	-	-	-	-	-	-	1,547	311,184	-	-
3d.1	Subtotal Period 3d Activity Costs	-	-	1,331	-	-	6,552	-	1,316	9,199	9,199	-	-	-	-	-	-	-	1,547	311,184	-	-
Period 3d Period-Dependent Costs																					
3d.4.1	Insurance	-	-	-	-	-	-	28	3	30	30	-	-	-	-	-	-	-	-	-	-	-
3d.4.2	Property taxes	-	-	-	-	-	-	26	3	29	29	-	-	-	-	-	-	-	-	-	-	-
3d.4.4	Emergency Planning Fees	-	-	-	-	-	-	5	1	6	-	6	-	-	-	-	-	-	-	-	-	-
3d.4.5	Fixed Overhead	-	-	-	-	-	-	10	1	11	11	-	-	-	-	-	-	-	-	-	-	-
3d.4.6	ISFSI Operating Costs	-	-	-	-	-	-	4	1	5	-	5	-	-	-	-	-	-	-	-	-	-
3d.4.7	Railroad Track Maintenance	-	-	-	-	-	-	4	1	5	-	5	-	-	-	-	-	-	-	-	-	-
3d.4.8	Security Staff Cost	-	-	-	-	-	-	150	22	172	172	-	-	-	-	-	-	-	-	-	-	2,074
3d.4.9	Utility Staff Cost	-	-	-	-	-	-	38	6	44	44	-	-	-	-	-	-	-	-	-	-	539
3d.4	Subtotal Period 3d Period-Dependent Costs	-	-	-	-	-	-	265	37	301	286	15	-	-	-	-	-	-	-	-	-	2,613

Table C
Monticello Nuclear Generating Plant
Scenario 1: DECON with 32 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
3d.0	TOTAL PERIOD 3d COST	-	-	1,331	-	-	6,552	265	1,352	9,500	9,485	15	-	-	-	-	-	1,547	311,184	-	2,613
PERIOD 3e - ISFSI Decontamination																					
Period 3e Additional Costs																					
3e.2.1	Decommissioning of ISFSI	-	131	3	784	-	8,058	1,850	2,707	13,534	13,534	-	-	-	27,284	-	-	-	3,860,412	11,022	1,848
3e.2	Subtotal Period 3e Additional Costs	-	131	3	784	-	8,058	1,850	2,707	13,534	13,534	-	-	-	27,284	-	-	-	3,860,412	11,022	1,848
Period 3e Period-Dependent Costs																					
3e.4.1	Insurance	-	-	-	-	-	-	110	28	138	138	-	-	-	-	-	-	-	-	-	-
3e.4.2	Property taxes	-	-	-	-	-	-	226	57	283	283	-	-	-	-	-	-	-	-	-	-
3e.4.4	Fixed Overhead	-	-	-	-	-	-	82	21	103	103	-	-	-	-	-	-	-	-	-	-
3e.4.5	Railroad Track Maintenance	-	-	-	-	-	-	38	10	48	48	-	-	-	-	-	-	-	-	-	-
3e.4.6	Security Staff Cost	-	-	-	-	-	-	308	77	385	385	-	-	-	-	-	-	-	-	-	4,999
3e.4.7	Utility Staff Cost	-	-	-	-	-	-	260	65	325	325	-	-	-	-	-	-	-	-	-	3,792
3e.4	Subtotal Period 3e Period-Dependent Costs	-	-	-	-	-	-	1,025	256	1,281	1,281	-	-	-	-	-	-	-	-	-	8,792
3e.0	TOTAL PERIOD 3e COST	-	131	3	784	-	8,058	2,875	2,963	14,815	14,815	-	-	-	27,284	-	-	-	3,860,412	11,022	10,640
PERIOD 3f - ISFSI Site Restoration																					
Period 3f Additional Costs																					
3f.2.1	Demolition and Site Restoration of ISFSI	-	1,733	-	-	-	-	185	288	2,205	-	-	2,205	-	-	-	-	-	-	8,390	160
3f.2	Subtotal Period 3f Additional Costs	-	1,733	-	-	-	-	185	288	2,205	-	-	2,205	-	-	-	-	-	-	8,390	160
Period 3f Collateral Costs																					
3f.3.1	Small tool allowance	-	13	-	-	-	-	-	2	15	-	-	15	-	-	-	-	-	-	-	-
3f.3	Subtotal Period 3f Collateral Costs	-	13	-	-	-	-	-	2	15	-	-	15	-	-	-	-	-	-	-	-
Period 3f Period-Dependent Costs																					
3f.4.2	Property taxes	-	-	-	-	-	-	114	11	125	-	-	125	-	-	-	-	-	-	-	-
3f.4.3	Heavy equipment rental	-	123	-	-	-	-	-	19	142	-	-	142	-	-	-	-	-	-	-	-
3f.4.4	Plant energy budget	-	-	-	-	-	-	29	4	33	-	-	33	-	-	-	-	-	-	-	-
3f.4.5	Fixed Overhead	-	-	-	-	-	-	42	6	48	-	-	48	-	-	-	-	-	-	-	-
3f.4.6	Railroad Track Maintenance	-	-	-	-	-	-	19	3	22	-	-	22	-	-	-	-	-	-	-	-
3f.4.7	Security Staff Cost	-	-	-	-	-	-	155	23	179	-	-	179	-	-	-	-	-	-	-	2,520
3f.4.8	Utility Staff Cost	-	-	-	-	-	-	103	16	119	-	-	119	-	-	-	-	-	-	-	1,564
3f.4	Subtotal Period 3f Period-Dependent Costs	-	123	-	-	-	-	462	82	668	-	-	668	-	-	-	-	-	-	-	4,084
3f.0	TOTAL PERIOD 3f COST	-	1,869	-	-	-	-	647	372	2,888	-	-	2,888	-	-	-	-	-	-	8,390	4,244
PERIOD 3 TOTALS		-	25,734	1,335	784	-	14,610	250,728	42,777	335,968	24,510	241,175	70,282	-	27,284	-	-	1,547	4,171,597	96,616	2,256,378
TOTAL COST TO DECOMMISSION		**16,489**	**91,449**	**22,061**	**10,357**	**25,828**	**72,171**	**805,615**	**187,584**	**1,231,552**	**759,294**	**400,983**	**71,275**	**288,153**	**203,059**	**1,711**	**1,010**	**1,547**	**25,757,230**	**933,360**	**6,500,963**

TOTAL COST TO DECOMMISSION WITH 17.97% CONTINGENCY:	**$1,231,552**	**thousands of 2017 dollars**
TOTAL NRC LICENSE TERMINATION COST IS 61.65% OR:	**$759,294**	**thousands of 2017 dollars**
SPENT FUEL MANAGEMENT COST IS 32.56% OR:	**$400,983**	**thousands of 2017 dollars**
NON-NUCLEAR DEMOLITION COST IS 5.79% OR:	**$71,275**	**thousands of 2017 dollars**
TOTAL LOW-LEVEL RADIOACTIVE WASTE VOLUME BURIED (EXCLUDING GTCC):	**205,780**	**cubic feet**
TOTAL GREATER THAN CLASS C RADWASTE VOLUME GENERATED:	**1,547**	**cubic feet**
TOTAL SCRAP METAL REMOVED:	**22,696**	**tons**
TOTAL CRAFT LABOR REQUIREMENTS:	**933,360**	**man-hours**

End Notes:
n/a - indicates that this activity not charged as decommissioning expense
a - indicates that this activity performed by decommissioning staff
0 - indicates that this value is less than 0.5 but is non-zero
A cell containing " - " indicates a zero value

APPENDIX D

DETAILED COST ANALYSIS

SCENARIO 2: DECON with 60 Year DFS

Table D
Monticello Nuclear Generating Plant
Scenario 2: DECON with 60 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
PERIOD 1a - Shutdown through Transition																					
Period 1a Direct Decommissioning Activities																					
1a.1.1	Prepare preliminary decommissioning cost	-	-	-	-	-	-	153	23	175	175	-	-	-	-	-	-	-	-	-	1,300
1a.1.2	Notification of Cessation of Operations									a											
1a.1.3	Remove fuel & source material									n/a											
1a.1.4	Notification of Permanent Defueling									a											
1a.1.5	Deactivate plant systems & process waste									a											
1a.1.6	Prepare and submit PSDAR	-	-	-	-	-	-	235	35	270	270	-	-	-	-	-	-	-	-	-	2,000
1a.1.7	Review plant dwgs & specs.	-	-	-	-	-	-	540	81	621	621	-	-	-	-	-	-	-	-	-	4,600
1a.1.8	Perform detailed rad survey									a											
1a.1.9	Estimate by-product inventory	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1a.1.10	End product description	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1a.1.11	Detailed by-product inventory	-	-	-	-	-	-	153	23	175	175	-	-	-	-	-	-	-	-	-	1,300
1a.1.12	Define major work sequence	-	-	-	-	-	-	880	132	1,012	1,012	-	-	-	-	-	-	-	-	-	7,500
1a.1.13	Perform SER and EA	-	-	-	-	-	-	364	55	418	418	-	-	-	-	-	-	-	-	-	3,100
1a.1.14	Prepare/submit Defueled Technical Specifications	-	-	-	-	-	-	880	132	1,012	1,012	-	-	-	-	-	-	-	-	-	7,500
1a.1.15	Perform Site-Specific Cost Study	-	-	-	-	-	-	587	88	675	675	-	-	-	-	-	-	-	-	-	5,000
1a.1.16	Prepare/submit Irradiated Fuel Management Plan	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
Activity Specifications																					
1a.1.17.1	Plant & temporary facilities	-	-	-	-	-	-	578	87	664	598	-	66	-	-	-	-	-	-	-	4,920
1a.1.17.2	Plant systems	-	-	-	-	-	-	489	73	562	506	-	56	-	-	-	-	-	-	-	4,167
1a.1.17.3	NSSS Decontamination Flush	-	-	-	-	-	-	59	9	67	67	-	-	-	-	-	-	-	-	-	500
1a.1.17.4	Reactor internals	-	-	-	-	-	-	833	125	958	958	-	-	-	-	-	-	-	-	-	7,100
1a.1.17.5	Reactor vessel	-	-	-	-	-	-	763	114	877	877	-	-	-	-	-	-	-	-	-	6,500
1a.1.17.6	Sacrificial shield	-	-	-	-	-	-	59	9	67	67	-	-	-	-	-	-	-	-	-	500
1a.1.17.7	Moisture separators/reheaters	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1a.1.17.8	Reinforced concrete	-	-	-	-	-	-	188	28	216	108	-	108	-	-	-	-	-	-	-	1,600
1a.1.17.9	Main Turbine	-	-	-	-	-	-	245	37	282	282	-	-	-	-	-	-	-	-	-	2,088
1a.1.17.10	Main Condensers	-	-	-	-	-	-	245	37	282	282	-	-	-	-	-	-	-	-	-	2,088
1a.1.17.11	Pressure suppression structure	-	-	-	-	-	-	235	35	270	270	-	-	-	-	-	-	-	-	-	2,000
1a.1.17.12	Drywell	-	-	-	-	-	-	188	28	216	216	-	-	-	-	-	-	-	-	-	1,600
1a.1.17.13	Plant structures & buildings	-	-	-	-	-	-	366	55	421	211	-	211	-	-	-	-	-	-	-	3,120
1a.1.17.14	Waste management	-	-	-	-	-	-	540	81	621	621	-	-	-	-	-	-	-	-	-	4,600
1a.1.17.15	Facility & site closeout	-	-	-	-	-	-	106	16	121	61	-	61	-	-	-	-	-	-	-	900
1a.1.17	Total	-	-	-	-	-	-	5,010	752	5,762	5,260	-	502	-	-	-	-	-	-	-	42,683
Planning & Site Preparations																					
1a.1.18	Prepare dismantling sequence	-	-	-	-	-	-	282	42	324	324	-	-	-	-	-	-	-	-	-	2,400
1a.1.19	Plant prep. & temp. svces	-	-	-	-	-	-	3,300	495	3,795	3,795	-	-	-	-	-	-	-	-	-	-
1a.1.20	Design water clean-up system	-	-	-	-	-	-	164	25	189	189	-	-	-	-	-	-	-	-	-	1,400
1a.1.21	Rigging/Cont. Cntrl Envlps/tooling/etc.	-	-	-	-	-	-	2,300	345	2,645	2,645	-	-	-	-	-	-	-	-	-	-
1a.1.22	Procure casks/liners & containers	-	-	-	-	-	-	144	22	166	166	-	-	-	-	-	-	-	-	-	1,230
1a.1	Subtotal Period 1a Activity Costs	-	-	-	-	-	-	15,344	2,302	17,646	17,144	-	502	-	-	-	-	-	-	-	83,013
Period 1a Collateral Costs																					
1a.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	1,221	183	1,404	-	1,404	-	-	-	-	-	-	-	-	-
1a.3.2	Retention and Severance	-	-	-	-	-	-	9,892	1,484	11,376	11,376	-	-	-	-	-	-	-	-	-	-
1a.3	Subtotal Period 1a Collateral Costs	-	-	-	-	-	-	11,113	1,667	12,779	11,376	1,404	-	-	-	-	-	-	-	-	-
Period 1a Period-Dependent Costs																					
1a.4.1	Insurance	-	-	-	-	-	-	2,408	241	2,649	2,649	-	-	-	-	-	-	-	-	-	-
1a.4.2	Property taxes	-	-	-	-	-	-	2,242	224	2,466	2,466	-	-	-	-	-	-	-	-	-	-
1a.4.3	Health physics supplies	-	515	-	-	-	-	-	129	644	644	-	-	-	-	-	-	-	-	-	-
1a.4.4	Heavy equipment rental	-	567	-	-	-	-	-	85	652	652	-	-	-	-	-	-	-	-	-	-
1a.4.5	Disposal of DAW generated	-	-	13	4	-	50	-	14	81	81	-	-	-	610	-	-	-	12,190	20	-
1a.4.6	Plant energy budget	-	-	-	-	-	-	1,730	259	1,989	1,989	-	-	-	-	-	-	-	-	-	-
1a.4.7	NRC Fees	-	-	-	-	-	-	1,110	111	1,221	1,221	-	-	-	-	-	-	-	-	-	-
1a.4.8	Emergency Planning Fees	-	-	-	-	-	-	3,166	317	3,482	-	3,482	-	-	-	-	-	-	-	-	-
1a.4.9	Fixed Overhead	-	-	-	-	-	-	2,833	425	3,258	3,258	-	-	-	-	-	-	-	-	-	-
1a.4.10	Spent Fuel Pool O&M	-	-	-	-	-	-	803	120	923	-	923	-	-	-	-	-	-	-	-	-
1a.4.11	ISFSI Operating Costs	-	-	-	-	-	-	103	15	119	-	119	-	-	-	-	-	-	-	-	-
1a.4.12	Railroad Track Maintenance	-	-	-	-	-	-	115	17	133	133	-	-	-	-	-	-	-	-	-	-
1a.4.13	Security Staff Cost	-	-	-	-	-	-	14,260	2,139	16,399	16,399	-	-	-	-	-	-	-	-	-	245,440
1a.4.14	Utility Staff Cost	-	-	-	-	-	-	25,791	3,869	29,660	29,660	-	-	-	-	-	-	-	-	-	422,240
1a.4	Subtotal Period 1a Period-Dependent Costs	-	1,083	13	4	-	50	54,561	7,966	63,676	59,153	4,524	-	-	610	-	-	-	12,190	20	667,680

Table D
Monticello Nuclear Generating Plant
Scenario 2: DECON with 60 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
1a.0	TOTAL PERIOD 1a COST	-	1,083	13	4	-	50	81,017	11,935	94,101	87,672	5,927	502	-	610	-	-	-	12,190	20	750,693
PERIOD 1b - Decommissioning Preparations																					
Period 1b Direct Decommissioning Activities																					
Detailed Work Procedures																					
1b.1.1.1	Plant systems	-	-	-	-	-	-	556	83	639	575	-	64	-	-	-	-	-	-	-	4,733
1b.1.1.2	NSSS Decontamination Flush	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1b.1.1.3	Reactor internals	-	-	-	-	-	-	470	70	540	540	-	-	-	-	-	-	-	-	-	4,000
1b.1.1.4	Remaining buildings	-	-	-	-	-	-	158	24	182	46	-	137	-	-	-	-	-	-	-	1,350
1b.1.1.5	CRD housings & NIs	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1b.1.1.6	Incore instrumentation	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1b.1.1.7	Removal primary containment	-	-	-	-	-	-	235	35	270	270	-	-	-	-	-	-	-	-	-	2,000
1b.1.1.8	Reactor vessel	-	-	-	-	-	-	426	64	490	490	-	-	-	-	-	-	-	-	-	3,630
1b.1.1.9	Facility closeout	-	-	-	-	-	-	141	21	162	81	-	81	-	-	-	-	-	-	-	1,200
1b.1.1.10	Sacrificial shield	-	-	-	-	-	-	141	21	162	162	-	-	-	-	-	-	-	-	-	1,200
1b.1.1.11	Reinforced concrete	-	-	-	-	-	-	117	18	135	67	-	67	-	-	-	-	-	-	-	1,000
1b.1.1.12	Main Turbine	-	-	-	-	-	-	244	37	281	281	-	-	-	-	-	-	-	-	-	2,080
1b.1.1.13	Main Condensers	-	-	-	-	-	-	245	37	282	282	-	-	-	-	-	-	-	-	-	2,088
1b.1.1.14	Moisture separators & reheaters	-	-	-	-	-	-	235	35	270	270	-	-	-	-	-	-	-	-	-	2,000
1b.1.1.15	Radwaste building	-	-	-	-	-	-	320	48	369	332	-	37	-	-	-	-	-	-	-	2,730
1b.1.1.16	Reactor building	-	-	-	-	-	-	320	48	369	332	-	37	-	-	-	-	-	-	-	2,730
1b.1.1	Total	-	-	-	-	-	-	3,961	594	4,555	4,132	-	423	-	-	-	-	-	-	-	33,741
1b.1.2	Decon NSSS	286	-	-	-	-	-	-	143	429	429	-	-	-	-	-	-	-	-	1,067	-
1b.1	Subtotal Period 1b Activity Costs	286	-	-	-	-	-	3,961	737	4,984	4,561	-	423	-	-	-	-	-	-	1,067	33,741
Period 1b Additional Costs																					
1b.2.1	Spent fuel pool isolation	-	-	-	-	-	-	11,691	1,754	13,445	13,445	-	-	-	-	-	-	-	-	-	-
1b.2.2	Site Characterization	-	-	-	-	-	-	6,446	1,934	8,380	8,380	-	-	-	-	-	-	-	-	30,500	10,852
1b.2.3	Mixed & RCRA Waste	-	-	29	19	13	-	-	8	69	69	-	-	43	-	-	-	-	5,253	163	-
1b.2	Subtotal Period 1b Additional Costs	-	-	29	19	13	-	18,137	3,695	21,894	21,894	-	-	43	-	-	-	-	5,253	30,663	10,852
Period 1b Collateral Costs																					
1b.3.1	Decon equipment	973	-	-	-	-	-	-	146	1,119	1,119	-	-	-	-	-	-	-	-	-	-
1b.3.2	DOC staff relocation expenses	-	-	-	-	-	-	1,189	178	1,367	1,367	-	-	-	-	-	-	-	-	-	-
1b.3.3	Process decommissioning water waste	37	-	24	61	-	98	-	54	275	275	-	-	-	233	-	-	-	13,986	45	-
1b.3.4	Process decommissioning chemical flush waste	1	-	23	85	-	969	-	258	1,336	1,336	-	-	-	-	231	-	-	24,599	43	-
1b.3.5	Small tool allowance	-	2	-	-	-	-	-	0	2	2	-	-	-	-	-	-	-	-	-	-
1b.3.6	Pipe cutting equipment	-	1,200	-	-	-	-	-	180	1,380	1,380	-	-	-	-	-	-	-	-	-	-
1b.3.7	Decon rig	1,987	-	-	-	-	-	-	298	2,285	2,285	-	-	-	-	-	-	-	-	-	-
1b.3.8	Spent Fuel Capital and Transfer	-	-	-	-	-	-	363	54	417	-	417	-	-	-	-	-	-	-	-	-
1b.3.9	Retention and Severance	-	-	-	-	-	-	6,362	954	7,316	7,316	-	-	-	-	-	-	-	-	-	-
1b.3	Subtotal Period 1b Collateral Costs	2,997	1,202	47	147	-	1,067	7,913	2,124	15,497	15,080	417	-	-	233	231	-	-	38,585	89	-
Period 1b Period-Dependent Costs																					
1b.4.1	Decon supplies	35	-	-	-	-	-	-	9	44	44	-	-	-	-	-	-	-	-	-	-
1b.4.2	Insurance	-	-	-	-	-	-	1,207	121	1,328	1,328	-	-	-	-	-	-	-	-	-	-
1b.4.3	Property taxes	-	-	-	-	-	-	1,104	110	1,214	1,214	-	-	-	-	-	-	-	-	-	-
1b.4.4	Health physics supplies	-	290	-	-	-	-	-	73	363	363	-	-	-	-	-	-	-	-	-	-
1b.4.5	Heavy equipment rental	-	284	-	-	-	-	-	43	327	327	-	-	-	-	-	-	-	-	-	-
1b.4.6	Disposal of DAW generated	-	-	8	2	-	29	-	8	48	48	-	-	-	358	-	-	-	7,159	12	-
1b.4.7	Plant energy budget	-	-	-	-	-	-	1,735	260	1,995	1,995	-	-	-	-	-	-	-	-	-	-
1b.4.8	NRC Fees	-	-	-	-	-	-	321	32	353	353	-	-	-	-	-	-	-	-	-	-
1b.4.9	Emergency Planning Fees	-	-	-	-	-	-	1,587	159	1,746	-	1,746	-	-	-	-	-	-	-	-	-
1b.4.10	Fixed Overhead	-	-	-	-	-	-	1,420	213	1,633	1,633	-	-	-	-	-	-	-	-	-	-
1b.4.11	Spent Fuel Pool O&M	-	-	-	-	-	-	402	60	463	-	463	-	-	-	-	-	-	-	-	-
1b.4.12	ISFSI Operating Costs	-	-	-	-	-	-	52	8	60	-	60	-	-	-	-	-	-	-	-	-
1b.4.13	Railroad Track Maintenance	-	-	-	-	-	-	58	9	67	67	-	-	-	-	-	-	-	-	-	-
1b.4.14	Security Staff Cost	-	-	-	-	-	-	7,150	1,072	8,222	8,222	-	-	-	-	-	-	-	-	-	123,056
1b.4.15	DOC Staff Cost	-	-	-	-	-	-	5,625	844	6,469	6,469	-	-	-	-	-	-	-	-	-	63,614
1b.4.16	Utility Staff Cost	-	-	-	-	-	-	13,003	1,950	14,953	14,953	-	-	-	-	-	-	-	-	-	212,741
1b.4	Subtotal Period 1b Period-Dependent Costs	35	575	8	2	-	29	33,663	4,971	39,283	37,015	2,268	-	-	358	-	-	-	7,159	12	399,411
1b.0	TOTAL PERIOD 1b COST	3,318	1,777	84	169	13	1,096	63,675	11,527	81,658	78,550	2,685	423	43	591	231	-	-	50,998	31,830	444,004
PERIOD 1 TOTALS		3,318	2,859	97	173	13	1,146	144,692	23,461	175,759	166,222	8,613	925	43	1,201	231	-	-	63,188	31,850	1,194,697

Table D
Monticello Nuclear Generating Plant
Scenario 2: DECON with 60 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
PERIOD 2a - Large Component Removal																					
Period 2a Direct Decommissioning Activities																					
Nuclear Steam Supply System Removal																					
2a.1.1.1	Recirculation System Piping & Valves	107	92	30	39	-	429	-	192	888	888	-	-	-	1,430	-	-	-	99,742	2,905	-
2a.1.1.2	Recirculation Pumps & Motors	38	59	16	40	22	438	-	154	767	767	-	-	96	945	-	-	-	112,200	1,563	-
2a.1.1.3	CRDMs & NIs Removal	187	1,022	402	105	-	919	-	635	3,269	3,269	-	-	-	3,741	-	-	-	213,700	17,768	-
2a.1.1.4	Reactor Vessel Internals	222	6,378	12,908	2,835	-	20,148	356	18,958	61,806	61,806	-	-	-	1,252	1,481	1,010	-	312,338	30,765	1,389
2a.1.1.5	Reactor Vessel	109	8,595	2,644	1,170	-	5,294	356	10,155	28,323	28,323	-	-	-	16,169	-	-	-	1,105,210	30,765	1,389
2a.1.1	Totals	663	16,147	15,999	4,189	22	27,228	711	30,094	95,053	95,053	-	-	96	23,536	1,481	1,010	-	1,843,190	83,767	2,778
Removal of Major Equipment																					
2a.1.2	Main Turbine/Generator	-	362	1,496	349	3,174	357	-	858	6,596	6,596	-	-	24,835	1,383	-	-	-	1,577,959	5,438	-
2a.1.3	Main Condensers	-	1,245	397	128	1,667	198	-	670	4,306	4,306	-	-	17,396	727	-	-	-	828,955	18,831	-
Cascading Costs from Clean Building Demolition																					
2a.1.4.1	Reactor Building	-	317	-	-	-	-	-	48	364	364	-	-	-	-	-	-	-	-	2,217	-
2a.1.4.2	Radwaste	-	24	-	-	-	-	-	4	27	27	-	-	-	-	-	-	-	-	127	-
2a.1.4.3	Turbine	-	118	-	-	-	-	-	18	136	136	-	-	-	-	-	-	-	-	1,254	-
2a.1.4	Totals	-	459	-	-	-	-	-	69	528	528	-	-	-	-	-	-	-	-	3,598	-
Disposal of Plant Systems																					
2a.1.5.1	Automatic Press Relief	-	115	7	8	69	57	-	55	311	311	-	-	803	206	-	-	-	45,852	1,656	-
2a.1.5.2	Chemistry Sampling	-	27	1	1	13	10	-	12	65	65	-	-	156	37	-	-	-	8,681	400	-
2a.1.5.3	Chemistry Sampling - Insulated	-	2	0	0	-	0	-	1	3	3	-	-	-	1	-	-	-	72	28	-
2a.1.5.4	Circulating Water - RCA	-	202	12	41	576	-	-	144	974	974	-	-	6,656	-	-	-	-	270,307	2,860	-
2a.1.5.5	Combustible Gas Control - Insul - RCA	-	29	0	1	18	-	-	10	59	59	-	-	212	-	-	-	-	8,617	378	-
2a.1.5.6	Combustible Gas Control - RCA	-	18	0	2	25	-	-	8	53	53	-	-	285	-	-	-	-	11,577	245	-
2a.1.5.7	Condensate & Feedwater	-	946	189	226	1,725	2,003	-	1,049	6,138	6,138	-	-	19,947	7,319	-	-	-	1,275,810	14,196	-
2a.1.5.8	Condensate & Feedwater - Insulated	-	480	34	43	361	332	-	267	1,517	1,517	-	-	4,176	1,207	-	-	-	246,693	6,964	-
2a.1.5.9	Condensate Demin	-	533	29	35	289	276	-	254	1,416	1,416	-	-	3,346	1,000	-	-	-	199,936	7,618	-
2a.1.5.10	Condensate Storage	-	706	31	55	617	219	-	335	1,963	1,963	-	-	7,131	795	-	-	-	340,568	10,345	-
2a.1.5.11	Control Rod Drive	-	3	0	0	2	1	-	1	7	7	-	-	19	4	-	-	-	1,009	41	-
2a.1.5.12	Control Rod Drive Hydraulic	-	405	16	18	143	155	-	166	902	902	-	-	1,658	562	-	-	-	103,306	5,898	-
2a.1.5.13	Core Spray	-	75	19	34	379	143	-	119	770	770	-	-	4,384	521	-	-	-	211,329	1,163	-
2a.1.5.14	Core Spray - Insulated	-	141	8	9	71	73	-	66	368	368	-	-	818	264	-	-	-	50,149	2,033	-
2a.1.5.15	Demin Water - Insulated - RCA	-	15	0	1	7	-	-	5	27	27	-	-	85	-	-	-	-	3,445	181	-
2a.1.5.16	Demin Water - RCA	-	40	0	2	22	-	-	14	78	78	-	-	253	-	-	-	-	10,278	508	-
2a.1.5.17	Diesel Oil - RCA	-	2	0	0	2	-	-	1	5	5	-	-	23	-	-	-	-	931	25	-
2a.1.5.18	Drywell Atmosphere Cooling - RCA	-	37	1	3	47	-	-	17	105	105	-	-	548	-	-	-	-	22,244	550	-
2a.1.5.19	EDG Emerg Service Water - Insul - RCA	-	0	0	0	0	-	-	0	1	1	-	-	2	-	-	-	-	84	4	-
2a.1.5.20	Electrical - Clean	-	12	-	-	-	-	-	2	13	-	-	13	-	-	-	-	-	-	182	-
2a.1.5.21	Emergency Service Water - Insul - RCA	-	21	0	1	12	-	-	7	41	41	-	-	137	-	-	-	-	5,544	281	-
2a.1.5.22	Emergency Service Water - RCA	-	2	0	0	1	-	-	1	4	4	-	-	13	-	-	-	-	512	22	-
2a.1.5.23	GEZIP - RCA	-	3	0	1	9	-	-	2	15	15	-	-	103	-	-	-	-	4,184	48	-
2a.1.5.24	Generator Physical Design - RCA	-	5	0	0	3	-	-	2	9	9	-	-	31	-	-	-	-	1,250	67	-
2a.1.5.25	H2-O2 Control Analyzing	-	6	0	0	0	4	-	3	13	13	-	-	6	13	-	-	-	1,080	81	-
2a.1.5.26	H2-O2 Control Analyzing - Insulated	-	6	0	0	0	4	-	3	13	13	-	-	6	13	-	-	-	1,080	81	-
2a.1.5.27	High Pressure Coolant Injection	-	64	6	9	84	57	-	45	266	266	-	-	972	209	-	-	-	52,792	966	-
2a.1.5.28	High Pressure Coolant Injection - Insula	-	214	14	17	138	133	-	111	627	627	-	-	1,598	481	-	-	-	95,733	3,079	-
2a.1.5.29	Hydrogen Cooling	-	7	-	-	-	-	-	1	9	-	-	9	-	-	-	-	-	-	118	-
2a.1.5.30	Hydrogen Cooling - RCA	-	7	0	0	3	-	-	2	13	13	-	-	39	-	-	-	-	1,600	79	-
2a.1.5.31	Hydrogen Seal Oil - RCA	-	17	0	1	16	-	-	7	42	42	-	-	189	-	-	-	-	7,669	212	-
2a.1.5.32	Hydrogen Water Chemistry - RCA	-	24	0	1	12	-	-	8	45	45	-	-	140	-	-	-	-	5,672	304	-
2a.1.5.33	Instrument & Service Air - RCA	-	220	3	11	153	-	-	80	466	466	-	-	1,768	-	-	-	-	71,810	2,733	-
2a.1.5.34	Main Condenser	-	191	12	14	115	113	-	97	542	542	-	-	1,333	411	-	-	-	80,439	2,746	-
2a.1.5.35	Main Steam	-	243	17	22	186	163	-	134	764	764	-	-	2,148	594	-	-	-	125,135	3,512	-
2a.1.5.36	Main Turbine	-	972	214	244	1,709	2,375	-	1,151	6,665	6,665	-	-	19,760	8,687	-	-	-	1,354,661	14,733	-
2a.1.5.37	Main Turbine - Insulated	-	209	19	25	219	183	-	136	790	790	-	-	2,530	667	-	-	-	145,208	3,069	-
2a.1.5.38	Miscellaneous	-	42	1	2	26	-	-	15	85	85	-	-	302	-	-	-	-	12,283	622	-
2a.1.5.39	Off Gas Recombiner	-	182	19	22	155	209	-	126	714	714	-	-	1,795	764	-	-	-	121,554	2,708	-
2a.1.5.40	Off Gas Recombiner - Insulated	-	379	19	19	118	195	-	166	897	897	-	-	1,366	709	-	-	-	100,933	5,385	-
2a.1.5.41	Post Accident Sampling	-	24	1	1	5	9	-	9	50	50	-	-	53	33	-	-	-	4,318	345	-
2a.1.5.42	Post Accident Sampling - Insulated	-	16	1	1	1	11	-	7	37	37	-	-	17	37	-	-	-	3,116	212	-
2a.1.5.43	RHR Service Water - Insulated - RCA	-	81	3	9	128	-	-	41	262	262	-	-	1,485	-	-	-	-	60,293	1,125	-
2a.1.5.44	RHR Service Water - RCA	-	4	0	0	3	-	-	1	9	9	-	-	35	-	-	-	-	1,410	57	-
2a.1.5.45	Reactor Feedwater Pump Seal	-	55	3	3	17	26	-	23	126	126	-	-	193	96	-	-	-	14,009	773	-

Table D
Monticello Nuclear Generating Plant
Scenario 2: DECON with 60 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Disposal of Plant Systems (continued)																					
2a.1.5.46	Residual Heat Removal	349	240	168	126	554	1,667	-	770	3,875	3,875	-	-	6,406	6,012	-	-	-	647,941	4,135	-
2a.1.5.47	Residual Heat Removal - Insulated	602	540	64	58	291	715	-	674	2,944	2,944	-	-	3,367	2,607	-	-	-	303,087	10,340	-
2a.1.5.48	Rx Core Isolation Cooling	-	47	2	3	22	21	-	21	116	116	-	-	259	76	-	-	-	15,396	691	-
2a.1.5.49	Rx Core Isolation Cooling - Insulated	-	105	5	5	25	55	-	45	240	240	-	-	288	198	-	-	-	24,419	1,479	-
2a.1.5.50	Rx Recirculation	56	57	6	3	4	53	-	57	235	235	-	-	43	190	-	-	-	14,095	1,580	-
2a.1.5.51	Snubbers	-	168	2	4	33	25	-	54	285	285	-	-	377	90	-	-	-	21,009	2,548	-
2a.1.5.52	Standby Liquid Control - Insul - RCA	-	4	0	0	2	-	-	1	7	7	-	-	22	-	-	-	-	904	48	-
2a.1.5.53	Standby Liquid Control - RCA	-	26	0	1	21	-	-	10	59	59	-	-	245	-	-	-	-	9,969	341	-
2a.1.5.54	Stator Cooling - RCA	-	7	0	1	11	-	-	4	23	23	-	-	126	-	-	-	-	5,135	98	-
2a.1.5.55	Traversing Incore Probe	0	4	0	0	0	2	-	1	7	7	-	-	1	5	-	-	-	386	51	-
2a.1.5	Totals	1,007	7,978	931	1,079	8,447	9,287	-	6,340	35,068	35,046	-	22	97,654	33,808	-	-	-	6,125,515	119,943	-
2a.1.6	Scaffolding in support of decommissioning	-	2,188	25	8	99	25	-	572	2,916	2,916	-	-	1,030	91	-	-	-	52,111	22,564	-
2a.1	Subtotal Period 2a Activity Costs	1,669	28,379	18,848	5,754	13,409	37,095	711	38,602	144,467	144,445	-	22	141,010	59,545	1,481	1,010	-	10,427,730	254,140	2,778
Period 2a Additional Costs																					
2a.2.1	Remedial Action Surveys	-	-	-	-	-	-	2,326	698	3,024	3,024	-	-	-	-	-	-	-	-	30,411	-
2a.2	Subtotal Period 2a Additional Costs	-	-	-	-	-	-	2,326	698	3,024	3,024	-	-	-	-	-	-	-	-	30,411	-
Period 2a Collateral Costs																					
2a.3.1	Process decommissioning water waste	83	-	55	140	-	222	-	123	623	623	-	-	-	531	-	-	-	31,838	103	-
2a.3.2	Process decommissioning chemical flush waste	6	-	208	774	-	1,557	-	529	3,075	3,075	-	-	-	2,093	-	-	-	223,008	392	-
2a.3.3	Small tool allowance	-	315	-	-	-	-	-	47	363	326	-	36	-	-	-	-	-	-	-	-
2a.3.4	Spent Fuel Capital and Transfer	-	-	-	-	-	-	13,559	2,034	15,592	-	15,592	-	-	-	-	-	-	-	-	-
2a.3.5	Retention and Severance	-	-	-	-	-	-	13,235	1,985	15,221	15,221	-	-	-	-	-	-	-	-	-	-
2a.3	Subtotal Period 2a Collateral Costs	89	315	263	914	-	1,779	26,794	4,719	34,874	19,245	15,592	36	-	2,623	-	-	-	254,846	495	-
Period 2a Period-Dependent Costs																					
2a.4.1	Decon supplies	102	-	-	-	-	-	-	25	127	127	-	-	-	-	-	-	-	-	-	-
2a.4.2	Insurance	-	-	-	-	-	-	1,055	106	1,161	1,161	-	-	-	-	-	-	-	-	-	-
2a.4.3	Property taxes	-	-	-	-	-	-	3,061	306	3,367	3,367	-	-	-	-	-	-	-	-	-	-
2a.4.4	Health physics supplies	-	2,133	-	-	-	-	-	533	2,666	2,666	-	-	-	-	-	-	-	-	-	-
2a.4.5	Heavy equipment rental	-	3,212	-	-	-	-	-	482	3,694	3,694	-	-	-	-	-	-	-	-	-	-
2a.4.6	Disposal of DAW generated	-	-	122	37	-	453	-	131	743	743	-	-	-	5,567	-	-	-	111,335	182	-
2a.4.7	Plant energy budget	-	-	-	-	-	-	2,404	361	2,765	2,765	-	-	-	-	-	-	-	-	-	-
2a.4.8	NRC Fees	-	-	-	-	-	-	847	85	932	932	-	-	-	-	-	-	-	-	-	-
2a.4.9	Emergency Planning Fees	-	-	-	-	-	-	3,757	376	4,133	-	4,133	-	-	-	-	-	-	-	-	-
2a.4.10	Fixed Overhead	-	-	-	-	-	-	3,392	509	3,900	3,900	-	-	-	-	-	-	-	-	-	-
2a.4.11	Spent Fuel Pool O&M	-	-	-	-	-	-	1,174	176	1,350	-	1,350	-	-	-	-	-	-	-	-	-
2a.4.12	ISFSI Operating Costs	-	-	-	-	-	-	151	23	174	-	174	-	-	-	-	-	-	-	-	-
2a.4.13	Railroad Track Maintenance	-	-	-	-	-	-	466	70	536	536	-	-	-	-	-	-	-	-	-	-
2a.4.14	Security Staff Cost	-	-	-	-	-	-	19,265	2,890	22,154	22,154	-	-	-	-	-	-	-	-	-	328,651
2a.4.15	DOC Staff Cost	-	-	-	-	-	-	20,125	3,019	23,144	23,144	-	-	-	-	-	-	-	-	-	231,273
2a.4.16	Utility Staff Cost	-	-	-	-	-	-	26,670	4,000	30,670	30,670	-	-	-	-	-	-	-	-	-	430,594
2a.4	Subtotal Period 2a Period-Dependent Costs	102	5,345	122	37	-	453	82,366	13,090	101,515	95,858	5,657	-	-	5,567	-	-	-	111,335	182	990,519
2a.0	TOTAL PERIOD 2a COST	1,860	34,039	19,233	6,705	13,409	39,327	112,198	57,109	283,880	262,573	21,249	58	141,010	67,735	1,481	1,010	-	10,793,910	285,228	993,297
PERIOD 2b - Site Decontamination																					
Period 2b Direct Decommissioning Activities																					
Disposal of Plant Systems																					
2b.1.1.1	ALARA/Radiological	-	18	0	0	3	3	-	6	30	30	-	-	35	10	-	-	-	2,060	277	-
2b.1.1.2	Alternate N2 - RCA	-	16	0	1	8	-	-	5	30	30	-	-	93	-	-	-	-	3,765	185	-
2b.1.1.3	Decontamination Projects	-	1	0	0	0	0	-	0	2	2	-	-	2	0	-	-	-	129	17	-
2b.1.1.4	Electrical - Contaminated	-	439	6	16	207	25	-	150	841	841	-	-	2,389	90	-	-	-	102,726	6,325	-
2b.1.1.5	Electrical - Decontaminated	-	2,657	41	142	2,019	-	-	993	5,852	5,852	-	-	23,344	-	-	-	-	948,013	37,107	-
2b.1.1.6	Fire - RCA	-	99	1	4	53	-	-	33	191	191	-	-	614	-	-	-	-	24,917	1,324	-
2b.1.1.7	HVAC Ductwork	-	309	7	18	231	27	-	122	713	713	-	-	2,665	100	-	-	-	114,598	4,111	-
2b.1.1.8	HVAC/Chilled Water - RCA	-	317	5	17	238	-	-	118	694	694	-	-	2,752	-	-	-	-	111,779	3,985	-
2b.1.1.9	Heating & Ventilation	-	473	15	40	521	62	-	219	1,329	1,329	-	-	6,018	227	-	-	-	258,789	7,101	-
2b.1.1.10	Heating Boiler - Insulated - RCA	-	3	0	0	2	-	-	1	6	6	-	-	26	-	-	-	-	1,058	35	-
2b.1.1.11	Liquid Radwaste	572	669	46	44	266	476	-	623	2,697	2,697	-	-	3,073	1,728	-	-	-	235,484	17,194	-
2b.1.1.12	Makeup Demin - RCA	-	101	3	9	127	-	-	46	286	286	-	-	1,471	-	-	-	-	59,747	1,412	-
2b.1.1.13	Non-Essential Diesel Generator - RCA	-	26	2	9	123	-	-	27	187	187	-	-	1,424	-	-	-	-	57,832	395	-

Table D
Monticello Nuclear Generating Plant
Scenario 2: DECON with 60 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Disposal of Plant Systems (continued)																					
2b.1.1.14	Off Gas Holdup	-	333	20	26	238	174	-	168	960	960	-	-	2,755	630	-	-	-	152,277	4,769	-
2b.1.1.15	Primary Containment	-	443	43	59	536	412	-	308	1,801	1,801	-	-	6,201	1,506	-	-	-	347,704	6,454	-
2b.1.1.16	Process Radiation Monitors	-	45	2	2	12	14	-	17	92	92	-	-	142	52	-	-	-	9,115	649	-
2b.1.1.17	Rx Bldg Closed Clng Water - Insul - RCA	-	111	2	6	85	-	-	42	245	245	-	-	977	-	-	-	-	39,675	1,484	-
2b.1.1.18	Rx Bldg Closed Clng Water - RCA	-	178	12	43	614	-	-	144	991	991	-	-	7,093	-	-	-	-	288,031	2,489	-
2b.1.1.19	Rx Component Handling Equip	26	138	19	19	100	227	-	124	653	653	-	-	1,158	829	-	-	-	99,730	2,462	-
2b.1.1.20	Rx Pressure Vessel	28	46	6	4	7	63	-	43	196	196	-	-	75	230	-	-	-	17,816	1,051	-
2b.1.1.21	Rx Water Cleanup	169	258	19	11	11	204	-	205	877	877	-	-	130	737	-	-	-	52,670	5,736	-
2b.1.1.22	Secondary Containment	-	121	7	10	88	70	-	63	360	360	-	-	1,017	255	-	-	-	57,567	1,763	-
2b.1.1.23	Service & Seal Water - Insulated - RCA	-	117	2	7	102	-	-	46	274	274	-	-	1,180	-	-	-	-	47,917	1,565	-
2b.1.1.24	Service & Seal Water - RCA	-	155	3	11	156	-	-	64	390	390	-	-	1,809	-	-	-	-	73,453	2,016	-
2b.1.1.25	Service Air Blower - RCA	-	15	0	1	18	-	-	7	41	41	-	-	206	-	-	-	-	8,364	206	-
2b.1.1.26	Solid Radwaste	327	483	36	34	206	380	-	419	1,885	1,885	-	-	2,387	1,380	-	-	-	185,221	10,820	-
2b.1.1.27	Structures & Buildings	-	76	2	3	31	23	-	30	166	166	-	-	357	85	-	-	-	19,933	1,128	-
2b.1.1.28	Wells & Domestic Water	-	9	-	-	-	-	-	1	10	-	-	10	-	-	-	-	-	-	144	-
2b.1.1.29	Wells & Domestic Water - RCA	-	51	1	2	30	-	-	18	101	101	-	-	342	-	-	-	-	13,874	633	-
2b.1.1	Totals	1,122	7,707	299	537	6,032	2,160	-	4,042	21,900	21,890	-	10	69,735	7,859	-	-	-	3,334,244	122,835	-
2b.1.2	Scaffolding in support of decommissioning	-	2,735	31	10	123	31	-	715	3,645	3,645	-	-	1,287	114	-	-	-	65,139	28,205	-
Decontamination of Site Buildings																					
2b.1.3.1	Reactor Building	5,006	2,817	155	347	4,159	1,007	-	4,150	17,641	17,641	-	-	48,077	7,014	-	-	-	2,317,670	112,518	-
2b.1.3.2	Admin	103	6	0	2	-	14	-	57	182	182	-	-	-	145	-	-	-	6,840	1,600	-
2b.1.3.3	HPCI Room	28	27	1	2	10	13	-	26	107	107	-	-	118	125	-	-	-	10,759	789	-
2b.1.3.4	Hot Shop	16	4	0	1	-	10	-	12	43	43	-	-	-	103	-	-	-	4,860	286	-
2b.1.3.5	LLRW Storage & Shipping	56	23	1	6	3	41	-	46	176	176	-	-	31	433	-	-	-	21,708	1,127	-
2b.1.3.6	Offgas Stack	360	256	6	16	116	73	-	283	1,109	1,109	-	-	1,343	669	-	-	-	87,045	8,860	-
2b.1.3.7	Offgas Storage & Compressor	39	17	1	4	2	30	-	32	125	125	-	-	25	316	-	-	-	15,948	785	-
2b.1.3.8	Radwaste	117	59	3	13	15	86	-	100	393	393	-	-	172	910	-	-	-	49,943	2,503	-
2b.1.3.9	Radwaste Material Storage Warehouse	62	23	1	6	-	47	-	49	189	189	-	-	-	495	-	-	-	23,400	1,197	-
2b.1.3.10	Recombiner	26	24	1	4	17	22	-	28	122	122	-	-	199	216	-	-	-	18,405	695	-
2b.1.3.11	Turbine	684	341	18	76	111	507	-	583	2,319	2,319	-	-	1,283	5,299	-	-	-	303,150	14,443	-
2b.1.3.12	Turbine Building Addition	56	20	1	6	-	41	-	44	169	169	-	-	-	434	-	-	-	20,478	1,087	-
2b.1.3	Totals	6,554	3,618	188	483	4,433	1,889	-	5,410	22,574	22,574	-	-	51,247	16,159	-	-	-	2,880,206	145,889	-
2b.1.4	Prepare/submit License Termination Plan	-	-	-	-	-	-	481	72	553	553	-	-	-	-	-	-	-	-	-	4,096
2b.1.5	Receive NRC approval of termination plan									a											
2b.1	Subtotal Period 2b Activity Costs	7,676	14,060	518	1,031	10,588	4,079	481	10,239	48,672	48,662	-	10	122,269	24,132	-	-	-	6,279,589	296,929	4,096
Period 2b Additional Costs																					
2b.2.1	Remedial Action Surveys	-	-	-	-	-	-	3,241	972	4,213	4,213	-	-	-	-	-	-	-	-	42,370	-
2b.2.2	Operational Equipment	-	-	19	60	624	-	-	104	807	807	-	-	11,710	-	-	-	-	292,750	32	-
2b.2.3	Security Modifications	-	-	-	-	-	-	8,696	1,304	10,000	10,000	-	-	-	-	-	-	-	-	-	-
2b.2	Subtotal Period 2b Additional Costs	-	-	19	60	624	-	11,937	2,381	15,020	15,020	-	-	11,710	-	-	-	-	292,750	42,402	-
Period 2b Collateral Costs																					
2b.3.1	Process decommissioning water waste	173	-	117	299	-	474	-	261	1,325	1,325	-	-	-	1,133	-	-	-	67,962	221	-
2b.3.2	Process decommissioning chemical flush waste	1	-	41	153	-	307	-	104	606	606	-	-	-	413	-	-	-	43,978	77	-
2b.3.3	Small tool allowance	-	341	-	-	-	-	-	51	392	392	-	-	-	-	-	-	-	-	-	-
2b.3.4	Spent Fuel Capital and Transfer	-	-	-	-	-	-	65,919	9,888	75,807	-	75,807	-	-	-	-	-	-	-	-	-
2b.3.5	Retention and Severance	-	-	-	-	-	-	8,665	1,300	9,964	9,964	-	-	-	-	-	-	-	-	-	-
2b.3	Subtotal Period 2b Collateral Costs	174	341	159	452	-	781	74,584	11,604	88,094	12,287	75,807	-	-	1,545	-	-	-	111,940	298	-
Period 2b Period-Dependent Costs																					
2b.4.1	Decon supplies	1,361	-	-	-	-	-	-	340	1,701	1,701	-	-	-	-	-	-	-	-	-	-
2b.4.2	Insurance	-	-	-	-	-	-	1,470	147	1,617	1,617	-	-	-	-	-	-	-	-	-	-
2b.4.3	Property taxes	-	-	-	-	-	-	3,915	391	4,306	4,306	-	-	-	-	-	-	-	-	-	-
2b.4.4	Health physics supplies	-	2,681	-	-	-	-	-	670	3,352	3,352	-	-	-	-	-	-	-	-	-	-
2b.4.5	Heavy equipment rental	-	4,602	-	-	-	-	-	690	5,292	5,292	-	-	-	-	-	-	-	-	-	-
2b.4.6	Disposal of DAW generated	-	-	124	38	-	463	-	134	759	759	-	-	-	5,690	-	-	-	113,799	186	-
2b.4.7	Plant energy budget	-	-	-	-	-	-	2,645	397	3,041	3,041	-	-	-	-	-	-	-	-	-	-
2b.4.8	NRC Fees	-	-	-	-	-	-	1,180	118	1,298	1,298	-	-	-	-	-	-	-	-	-	-
2b.4.9	Emergency Planning Fees	-	-	-	-	-	-	5,234	523	5,758	-	5,758	-	-	-	-	-	-	-	-	-
2b.4.10	Fixed Overhead	-	-	-	-	-	-	4,725	709	5,434	5,434	-	-	-	-	-	-	-	-	-	-
2b.4.11	Spent Fuel Pool O&M	-	-	-	-	-	-	1,636	245	1,881	-	1,881	-	-	-	-	-	-	-	-	-
2b.4.12	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	412	62	474	474	-	-	-	-	-	-	-	-	-	-

Table D
Monticello Nuclear Generating Plant
Scenario 2: DECON with 60 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 2b Period-Dependent Costs (continued)																					
2b.4.13	ISFSI Operating Costs	-	-	-	-	-	-	210	32	242	-	242	-	-	-	-	-	-	-	-	-
2b.4.14	Railroad Track Maintenance	-	-	-	-	-	-	235	35	270	270	-	-	-	-	-	-	-	-	-	-
2b.4.15	Security Staff Cost	-	-	-	-	-	-	26,840	4,026	30,867	30,867	-	-	-	-	-	-	-	-	-	457,896
2b.4.16	DOC Staff Cost	-	-	-	-	-	-	27,122	4,068	31,191	31,191	-	-	-	-	-	-	-	-	-	309,504
2b.4.17	Utility Staff Cost	-	-	-	-	-	-	35,641	5,346	40,988	40,988	-	-	-	-	-	-	-	-	-	574,490
2b.4	Subtotal Period 2b Period-Dependent Costs	1,361	7,283	124	38	-	463	111,268	17,935	138,473	130,592	7,881	-	-	5,690	-	-	-	113,799	186	1,341,891
2b.0	TOTAL PERIOD 2b COST	9,211	21,684	820	1,580	11,212	5,324	198,269	42,159	290,260	206,561	83,688	10	133,979	31,367	-	-	-	6,798,079	339,814	1,345,987
PERIOD 2d - Decontamination Following Wet Fuel Storage																					
Period 2d Direct Decommissioning Activities																					
2d.1.1	Remove spent fuel racks	634	56	114	109	-	2,091	-	881	3,884	3,884	-	-	-	7,653	-	-	-	486,170	906	-
Disposal of Plant Systems																					
2d.1.2.1	Cranes/Heavy Loads/Rigging - RCA	-	3	0	1	9	-	-	2	15	15	-	-	103	-	-	-	-	4,184	48	-
2d.1.2.2	Electrical - Contaminated Fuel Pool	-	46	1	2	21	2	-	16	87	87	-	-	240	9	-	-	-	10,334	665	-
2d.1.2.3	Electrical - Decontam. Fuel Pool Area	-	293	4	15	213	-	-	108	633	633	-	-	2,457	-	-	-	-	99,783	4,090	-
2d.1.2.4	Fire - RCA - Fuel Pool Area	-	11	0	0	5	-	-	4	20	20	-	-	62	-	-	-	-	2,499	143	-
2d.1.2.5	Fuel Pool Cooling & Cleanup	240	419	34	26	102	370	-	340	1,531	1,531	-	-	1,179	1,341	-	-	-	133,939	8,380	-
2d.1.2.6	Fuel Pool Cooling & Cleanup - Insulated	26	40	3	2	6	32	-	33	143	143	-	-	67	117	-	-	-	10,220	848	-
2d.1.2.7	HVAC Ductwork - Fuel Pool Area	-	34	1	2	26	3	-	14	79	79	-	-	296	11	-	-	-	12,733	457	-
2d.1.2.8	HVAC/Chilled Water - RCA Fuel Pool Area	-	32	0	1	19	-	-	11	64	64	-	-	223	-	-	-	-	9,072	397	-
2d.1.2.9	Instrument & Service Air-RCA-Fuel Pool	-	28	0	2	23	-	-	11	64	64	-	-	267	-	-	-	-	10,841	357	-
2d.1.2	Totals	266	907	44	51	423	408	-	537	2,637	2,637	-	-	4,894	1,479	-	-	-	293,606	15,385	-
Decontamination of Site Buildings																					
2d.1.3.1	Reactor (Post Fuel)	911	2,485	145	669	170	8,544	-	3,353	16,277	16,277	-	-	1,969	62,698	-	-	-	2,732,406	45,703	-
2d.1.3	Totals	911	2,485	145	669	170	8,544	-	3,353	16,277	16,277	-	-	1,969	62,698	-	-	-	2,732,406	45,703	-
2d.1.4	Scaffolding in support of decommissioning	-	547	6	2	25	6	-	143	729	729	-	-	257	23	-	-	-	13,028	5,641	-
2d.1	Subtotal Period 2d Activity Costs	1,811	3,994	309	831	618	11,049	-	4,915	23,527	23,527	-	-	7,120	71,852	-	-	-	3,525,210	67,635	-
Period 2d Additional Costs																					
2d.2.1	License Termination Survey Planning	-	-	-	-	-	-	1,291	387	1,678	1,678	-	-	-	-	-	-	-	-	-	12,480
2d.2.2	Remedial Action Surveys	-	-	-	-	-	-	1,198	359	1,557	1,557	-	-	-	-	-	-	-	-	15,661	-
2d.2	Subtotal Period 2d Additional Costs	-	-	-	-	-	-	2,489	747	3,235	3,235	-	-	-	-	-	-	-	-	15,661	12,480
Period 2d Collateral Costs																					
2d.3.1	Process decommissioning water waste	69	-	47	120	-	191	-	105	533	533	-	-	-	457	-	-	-	27,391	89	-
2d.3.2	Process decommissioning chemical flush waste	1	-	25	92	-	185	-	63	366	366	-	-	-	249	-	-	-	26,553	47	-
2d.3.3	Small tool allowance	-	88	-	-	-	-	-	13	101	101	-	-	-	-	-	-	-	-	-	-
2d.3.4	Decommissioning Equipment Disposition	-	-	143	55	575	145	-	145	1,062	1,062	-	-	6,000	529	-	-	-	303,608	147	-
2d.3.5	Spent Fuel Capital and Transfer	-	-	-	-	-	-	27,061	4,059	31,120	-	31,120	-	-	-	-	-	-	-	-	-
2d.3	Subtotal Period 2d Collateral Costs	70	88	216	267	575	521	27,061	4,385	33,182	2,062	31,120	-	6,000	1,235	-	-	-	357,552	283	-
Period 2d Period-Dependent Costs																					
2d.4.1	Decon supplies	219	-	-	-	-	-	-	55	274	274	-	-	-	-	-	-	-	-	-	-
2d.4.2	Insurance	-	-	-	-	-	-	543	54	598	598	-	-	-	-	-	-	-	-	-	-
2d.4.3	Property taxes	-	-	-	-	-	-	1,336	134	1,470	1,470	-	-	-	-	-	-	-	-	-	-
2d.4.4	Health physics supplies	-	752	-	-	-	-	-	188	940	940	-	-	-	-	-	-	-	-	-	-
2d.4.5	Heavy equipment rental	-	1,701	-	-	-	-	-	255	1,956	1,956	-	-	-	-	-	-	-	-	-	-
2d.4.6	Disposal of DAW generated	-	-	44	14	-	165	-	48	271	271	-	-	-	2,030	-	-	-	40,600	66	-
2d.4.7	Plant energy budget	-	-	-	-	-	-	521	78	600	600	-	-	-	-	-	-	-	-	-	-
2d.4.8	NRC Fees	-	-	-	-	-	-	369	37	405	405	-	-	-	-	-	-	-	-	-	-
2d.4.9	Emergency Planning Fees	-	-	-	-	-	-	1,935	193	2,128	-	2,128	-	-	-	-	-	-	-	-	-
2d.4.10	Fixed Overhead	-	-	-	-	-	-	1,747	262	2,009	2,009	-	-	-	-	-	-	-	-	-	-
2d.4.11	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	305	46	351	351	-	-	-	-	-	-	-	-	-	-
2d.4.12	ISFSI Operating Costs	-	-	-	-	-	-	78	12	89	-	89	-	-	-	-	-	-	-	-	-
2d.4.13	Railroad Track Maintenance	-	-	-	-	-	-	87	13	100	100	-	-	-	-	-	-	-	-	-	-
2d.4.14	Security Staff Cost	-	-	-	-	-	-	9,608	1,441	11,049	7,668	3,381	-	-	-	-	-	-	-	-	162,981
2d.4.15	DOC Staff Cost	-	-	-	-	-	-	6,941	1,041	7,982	7,982	-	-	-	-	-	-	-	-	-	78,356
2d.4.16	Utility Staff Cost	-	-	-	-	-	-	9,556	1,433	10,989	10,132	857	-	-	-	-	-	-	-	-	149,660
2d.4	Subtotal Period 2d Period-Dependent Costs	219	2,453	44	14	-	165	33,025	5,290	41,210	34,754	6,456	-	-	2,030	-	-	-	40,600	66	390,997
2d.0	TOTAL PERIOD 2d COST	2,099	6,535	569	1,112	1,193	11,735	62,574	15,337	101,154	63,579	37,575	-	13,120	75,117	-	-	-	3,923,362	83,645	403,477

Table D
Monticello Nuclear Generating Plant
Scenario 2: DECON with 60 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
PERIOD 2f - License Termination																					
Period 2f Direct Decommissioning Activities																					
2f.1.1	ORISE confirmatory survey	-	-	-	-	-	-	176	53	229	229	-	-	-	-	-	-	-	-	-	-
2f.1.2	Terminate license									a											
2f.1	Subtotal Period 2f Activity Costs	-	-	-	-	-	-	176	53	229	229	-	-	-	-	-	-	-	-	-	-
Period 2f Additional Costs																					
2f.2.1	License Termination Survey	-	-	-	-	-	-	7,341	2,202	9,544	9,544	-	-	-	-	-	-	-	-	96,197	6,240
2f.2	Subtotal Period 2f Additional Costs	-	-	-	-	-	-	7,341	2,202	9,544	9,544	-	-	-	-	-	-	-	-	96,197	6,240
Period 2f Collateral Costs																					
2f.3.1	DOC staff relocation expenses	-	-	-	-	-	-	1,189	178	1,367	1,367	-	-	-	-	-	-	-	-	-	-
2f.3.2	Spent Fuel Capital and Transfer	-	-	-	-	-	-	43	7	50	-	50	-	-	-	-	-	-	-	-	-
2f.3	Subtotal Period 2f Collateral Costs	-	-	-	-	-	-	1,232	185	1,417	1,367	50	-	-	-	-	-	-	-	-	-
Period 2f Period-Dependent Costs																					
2f.4.1	Insurance	-	-	-	-	-	-	543	54	598	598	-	-	-	-	-	-	-	-	-	-
2f.4.2	Property taxes	-	-	-	-	-	-	1,285	128	1,413	1,413	-	-	-	-	-	-	-	-	-	-
2f.4.3	Health physics supplies	-	597	-	-	-	-	-	149	747	747	-	-	-	-	-	-	-	-	-	-
2f.4.4	Disposal of DAW generated	-	-	8	2	-	29	-	8	47	47	-	-	-	355	-	-	-	7,097	12	-
2f.4.5	Plant energy budget	-	-	-	-	-	-	261	39	300	300	-	-	-	-	-	-	-	-	-	-
2f.4.6	NRC Fees	-	-	-	-	-	-	420	42	463	463	-	-	-	-	-	-	-	-	-	-
2f.4.7	Emergency Planning Fees	-	-	-	-	-	-	103	10	113	-	113	-	-	-	-	-	-	-	-	-
2f.4.8	Fixed Overhead	-	-	-	-	-	-	1,747	262	2,009	2,009	-	-	-	-	-	-	-	-	-	-
2f.4.9	ISFSI Operating Costs	-	-	-	-	-	-	78	12	89	-	89	-	-	-	-	-	-	-	-	-
2f.4.10	Railroad Track Maintenance	-	-	-	-	-	-	87	13	100	100	-	-	-	-	-	-	-	-	-	-
2f.4.11	Security Staff Cost	-	-	-	-	-	-	9,608	1,441	11,049	7,668	3,381	-	-	-	-	-	-	-	-	162,981
2f.4.12	DOC Staff Cost	-	-	-	-	-	-	5,174	776	5,950	5,950	-	-	-	-	-	-	-	-	-	57,200
2f.4.13	Utility Staff Cost	-	-	-	-	-	-	5,456	818	6,274	5,415	860	-	-	-	-	-	-	-	-	80,707
2f.4	Subtotal Period 2f Period-Dependent Costs	-	597	8	2	-	29	24,761	3,754	29,152	24,708	4,443	-	-	355	-	-	-	7,097	12	300,888
2f.0	TOTAL PERIOD 2f COST	-	597	8	2	-	29	33,511	6,194	40,341	35,848	4,493	-	-	355	-	-	-	7,097	96,208	307,128
PERIOD 2 TOTALS		13,170	62,856	20,629	9,399	25,814	56,415	406,552	120,800	715,636	568,562	147,006	68	288,110	174,575	1,481	1,010	-	21,522,450	804,895	3,049,889
PERIOD 3b - Site Restoration																					
Period 3b Direct Decommissioning Activities																					
Demolition of Remaining Site Buildings																					
3b.1.1.1	Reactor Building	-	1,881	-	-	-	-	-	282	2,163	-	-	2,163	-	-	-	-	-	-	13,966	-
3b.1.1.2	Condensate Tanks Foundation	-	10	-	-	-	-	-	1	11	-	-	11	-	-	-	-	-	-	50	-
3b.1.1.3	Discharge Retention Basin	-	4	-	-	-	-	-	1	4	-	-	4	-	-	-	-	-	-	25	-
3b.1.1.4	HPCI Room	-	18	-	-	-	-	-	3	21	-	-	21	-	-	-	-	-	-	97	-
3b.1.1.5	Hot Shop	-	15	-	-	-	-	-	2	17	-	-	17	-	-	-	-	-	-	177	-
3b.1.1.6	Hydrogen & Oxygen Storage	-	2	-	-	-	-	-	0	2	-	-	2	-	-	-	-	-	-	19	-
3b.1.1.7	LLRW Storage & Shipping	-	78	-	-	-	-	-	12	90	-	-	90	-	-	-	-	-	-	662	-
3b.1.1.8	MSIV	-	3	-	-	-	-	-	0	4	-	-	4	-	-	-	-	-	-	42	-
3b.1.1.9	Misc Structures 2017	-	759	-	-	-	-	-	114	872	-	-	872	-	-	-	-	-	-	7,919	-
3b.1.1.10	Offgas Stack	-	104	-	-	-	-	-	16	120	-	-	120	-	-	-	-	-	-	544	-
3b.1.1.11	Offgas Storage & Compressor	-	38	-	-	-	-	-	6	44	-	-	44	-	-	-	-	-	-	199	-
3b.1.1.12	Radwaste	-	219	-	-	-	-	-	33	252	-	-	252	-	-	-	-	-	-	1,220	-
3b.1.1.13	Recombiner	-	123	-	-	-	-	-	18	141	-	-	141	-	-	-	-	-	-	713	-
3b.1.1.14	Security Barrier	-	179	-	-	-	-	-	27	206	-	-	206	-	-	-	-	-	-	933	-
3b.1.1.15	Structures Greater than 3' Below Grade	-	2,380	-	-	-	-	-	357	2,738	-	-	2,738	-	-	-	-	-	-	12,649	-
3b.1.1.16	Tank Farm	-	4	-	-	-	-	-	1	5	-	-	5	-	-	-	-	-	-	21	-
3b.1.1.17	Turbine	-	1,175	-	-	-	-	-	176	1,351	-	-	1,351	-	-	-	-	-	-	13,091	-
3b.1.1.18	Turbine Building Addition	-	51	-	-	-	-	-	8	58	-	-	58	-	-	-	-	-	-	618	-
3b.1.1.19	Turbine Pedestal	-	175	-	-	-	-	-	26	202	-	-	202	-	-	-	-	-	-	926	-
3b.1.1	Totals	-	7,219	-	-	-	-	-	1,083	8,302	-	-	8,302	-	-	-	-	-	-	53,870	-

Table D
Monticello Nuclear Generating Plant
Scenario 2: DECON with 60 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Site Closeout Activities																					
3b.1.2	Grade & landscape site	-	864	-	-	-	-	-	130	994	-	-	994	-	-	-	-	-	-	1,841	-
3b.1.3	Final report to NRC	-	-	-	-	-	-	183	27	211	211	-	-	-	-	-	-	-	-	-	1,560
3b.1	Subtotal Period 3b Activity Costs	-	8,083	-	-	-	-	183	1,240	9,506	211	-	9,295	-	-	-	-	-	-	55,711	1,560
Period 3b Additional Costs																					
3b.2.1	Clean Concrete Disposal	-	3,297	-	-	-	-	11	496	3,805	-	-	3,805	-	-	-	-	-	-	12	-
3b.2.2	Excavation of Underground Services	-	1,380	-	-	-	-	947	349	2,677	-	-	2,677	-	-	-	-	-	-	13,475	-
3b.2.3	Intake Structure Cofferdam	-	320	-	-	-	-	-	48	368	-	-	368	-	-	-	-	-	-	2,584	-
3b.2.4	Construction Debris	-	-	-	-	-	-	350	53	403	-	-	403	-	-	-	-	-	-	-	-
3b.2.5	Backfill	-	5,102	-	-	-	-	-	765	5,868	-	-	5,868	-	-	-	-	-	-	5,422	-
3b.2	Subtotal Period 3b Additional Costs	-	10,100	-	-	-	-	1,309	1,711	13,120	-	-	13,120	-	-	-	-	-	-	21,493	-
Period 3b Collateral Costs																					
3b.3.1	Small tool allowance	-	97	-	-	-	-	-	15	111	-	-	111	-	-	-	-	-	-	-	-
3b.3.2	Spent Fuel Capital and Transfer	-	-	-	-	-	-	100	15	115	-	115	-	-	-	-	-	-	-	-	-
3b.3	Subtotal Period 3b Collateral Costs	-	97	-	-	-	-	100	30	226	-	115	111	-	-	-	-	-	-	-	-
Period 3b Period-Dependent Costs																					
3b.4.1	Insurance	-	-	-	-	-	-	1,251	125	1,376	-	1,376	-	-	-	-	-	-	-	-	-
3b.4.2	Property taxes	-	-	-	-	-	-	2,737	274	3,011	-	3,011	-	-	-	-	-	-	-	-	-
3b.4.3	Heavy equipment rental	-	5,455	-	-	-	-	-	818	6,273	-	-	6,273	-	-	-	-	-	-	-	-
3b.4.4	Plant energy budget	-	-	-	-	-	-	300	45	345	-	-	345	-	-	-	-	-	-	-	-
3b.4.5	NRC ISFSI Fees	-	-	-	-	-	-	386	39	424	-	424	-	-	-	-	-	-	-	-	-
3b.4.6	Emergency Planning Fees	-	-	-	-	-	-	237	24	261	-	261	-	-	-	-	-	-	-	-	-
3b.4.7	Fixed Overhead	-	-	-	-	-	-	1,260	189	1,450	-	-	1,450	-	-	-	-	-	-	-	-
3b.4.8	ISFSI Operating Costs	-	-	-	-	-	-	179	27	206	-	206	-	-	-	-	-	-	-	-	-
3b.4.9	Railroad Track Maintenance	-	-	-	-	-	-	497	75	572	-	-	572	-	-	-	-	-	-	-	-
3b.4.10	Security Staff Cost	-	-	-	-	-	-	22,115	3,317	25,432	(0)	7,782	17,650	-	-	-	-	-	-	-	375,152
3b.4.11	DOC Staff Cost	-	-	-	-	-	-	11,290	1,693	12,983	-	-	12,983	-	-	-	-	-	-	-	122,646
3b.4.12	Utility Staff Cost	-	-	-	-	-	-	6,583	987	7,571	-	1,976	5,595	-	-	-	-	-	-	-	98,297
3b.4	Subtotal Period 3b Period-Dependent Costs	-	5,455	-	-	-	-	46,836	7,613	59,904	(0)	15,036	44,868	-	-	-	-	-	-	-	596,095
3b.0	TOTAL PERIOD 3b COST	-	23,734	-	-	-	-	48,428	10,594	82,756	211	15,152	67,394	-	-	-	-	-	-	77,204	597,655
PERIOD 3c - Fuel Storage Operations/Shipping																					
Period 3c Collateral Costs																					
3c.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	59,208	8,881	68,089	-	68,089	-	-	-	-	-	-	-	-	-
3c.3	Subtotal Period 3c Collateral Costs	-	-	-	-	-	-	59,208	8,881	68,089	-	68,089	-	-	-	-	-	-	-	-	-
Period 3c Period-Dependent Costs																					
3c.4.1	Insurance	-	-	-	-	-	-	28,205	2,821	31,026	-	31,026	-	-	-	-	-	-	-	-	-
3c.4.2	Property taxes	-	-	-	-	-	-	24,796	2,480	27,276	-	27,276	-	-	-	-	-	-	-	-	-
3c.4.3	Plant energy budget	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3c.4.4	NRC ISFSI Fees	-	-	-	-	-	-	8,697	870	9,567	-	9,567	-	-	-	-	-	-	-	-	-
3c.4.5	Emergency Planning Fees	-	-	-	-	-	-	5,348	535	5,883	-	5,883	-	-	-	-	-	-	-	-	-
3c.4.6	Fixed Overhead	-	-	-	-	-	-	9,721	1,458	11,179	-	11,179	-	-	-	-	-	-	-	-	-
3c.4.7	ISFSI Operating Costs	-	-	-	-	-	-	4,037	606	4,643	-	4,643	-	-	-	-	-	-	-	-	-
3c.4.8	Railroad Track Maintenance	-	-	-	-	-	-	4,510	677	5,187	-	5,187	-	-	-	-	-	-	-	-	-
3c.4.9	Security Staff Cost	-	-	-	-	-	-	152,513	22,877	175,389	-	175,389	-	-	-	-	-	-	-	-	2,114,750
3c.4.10	Utility Staff Cost	-	-	-	-	-	-	38,674	5,801	44,475	-	44,475	-	-	-	-	-	-	-	-	549,022
3c.4	Subtotal Period 3c Period-Dependent Costs	-	-	-	-	-	-	276,502	38,123	314,624	-	314,624	-	-	-	-	-	-	-	-	2,663,772
3c.0	TOTAL PERIOD 3c COST	-	-	-	-	-	-	335,709	47,004	382,713	-	382,713	-	-	-	-	-	-	-	-	2,663,772

Table D
Monticello Nuclear Generating Plant
Scenario 2: DECON with 60 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
PERIOD 3d - GTCC shipping																					
Period 3d Direct Decommissioning Activities																					
Nuclear Steam Supply System Removal																					
3d.1.1.1	Vessel & Internals GTCC Disposal	-	-	1,331	-	-	6,552	-	1,316	9,199	9,199	-	-	-	-	-	-	1,547	311,184	-	-
3d.1.1	Totals	-	-	1,331	-	-	6,552	-	1,316	9,199	9,199	-	-	-	-	-	-	1,547	311,184	-	-
3d.1	Subtotal Period 3d Activity Costs	-	-	1,331	-	-	6,552	-	1,316	9,199	9,199	-	-	-	-	-	-	1,547	311,184	-	-
Period 3d Collateral Costs																					
3d.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	23,942	3,591	27,533	-	27,533	-	-	-	-	-	-	-	-	-
3d.3	Subtotal Period 3d Collateral Costs	-	-	-	-	-	-	23,942	3,591	27,533	-	27,533	-	-	-	-	-	-	-	-	-
Period 3d Period-Dependent Costs																					
3d.4.1	Insurance	-	-	-	-	-	-	9,383	938	10,321	-	10,321	-	-	-	-	-	-	-	-	-
3d.4.2	Property taxes	-	-	-	-	-	-	6,703	670	7,374	-	7,374	-	-	-	-	-	-	-	-	-
3d.4.4	NRC ISFSI Fees	-	-	-	-	-	-	4,257	426	4,683	-	4,683	-	-	-	-	-	-	-	-	-
Period 3d Period-Dependent Costs (continued)																					
3d.4.5	Emergency Planning Fees	-	-	-	-	-	-	1,779	178	1,957	-	1,957	-	-	-	-	-	-	-	-	-
3d.4.6	Fixed Overhead	-	-	-	-	-	-	3,234	485	3,719	-	3,719	-	-	-	-	-	-	-	-	-
3d.4.7	ISFSI Operating Costs	-	-	-	-	-	-	1,343	201	1,544	-	1,544	-	-	-	-	-	-	-	-	-
3d.4.8	Railroad Track Maintenance	-	-	-	-	-	-	1,500	225	1,725	-	1,725	-	-	-	-	-	-	-	-	-
3d.4.9	Security Staff Cost	-	-	-	-	-	-	50,734	7,610	58,344	-	58,344	-	-	-	-	-	-	-	-	703,485
3d.4.10	Utility Staff Cost	-	-	-	-	-	-	12,865	1,930	14,795	-	14,795	-	-	-	-	-	-	-	-	182,635
3d.4	Subtotal Period 3d Period-Dependent Costs	-	-	-	-	-	-	91,799	12,664	104,462	-	104,462	-	-	-	-	-	-	-	-	886,120
3d.0	TOTAL PERIOD 3d COST	-	-	1,331	-	-	6,552	115,740	17,571	141,194	9,199	131,995	-	-	-	-	-	1,547	311,184	-	886,120
PERIOD 3e - ISFSI Decontamination																					
Period 3e Additional Costs																					
3e.2.1	Decommissioning of ISFSI	-	131	3	784	-	8,058	1,865	2,710	13,551	13,551	-	-	-	27,284	-	-	-	3,860,412	11,160	1,848
3e.2	Subtotal Period 3e Additional Costs	-	131	3	784	-	8,058	1,865	2,710	13,551	13,551	-	-	-	27,284	-	-	-	3,860,412	11,160	1,848
Period 3e Period-Dependent Costs																					
3e.4.1	Insurance	-	-	-	-	-	-	110	28	138	138	-	-	-	-	-	-	-	-	-	-
3e.4.2	Property taxes	-	-	-	-	-	-	244	61	304	304	-	-	-	-	-	-	-	-	-	-
3e.4.4	Fixed Overhead	-	-	-	-	-	-	82	21	103	103	-	-	-	-	-	-	-	-	-	-
3e.4.5	Railroad Track Maintenance	-	-	-	-	-	-	38	10	48	48	-	-	-	-	-	-	-	-	-	-
3e.4.6	Security Staff Cost	-	-	-	-	-	-	308	77	385	385	-	-	-	-	-	-	-	-	-	4,999
3e.4.7	Utility Staff Cost	-	-	-	-	-	-	260	65	325	325	-	-	-	-	-	-	-	-	-	3,792
3e.4	Subtotal Period 3e Period-Dependent Costs	-	-	-	-	-	-	1,042	261	1,303	1,303	-	-	-	-	-	-	-	-	-	8,792
3e.0	TOTAL PERIOD 3e COST	-	131	3	784	-	8,058	2,907	2,971	14,854	14,854	-	-	-	27,284	-	-	-	3,860,412	11,160	10,640
PERIOD 3f - ISFSI Site Restoration																					
Period 3f Additional Costs																					
3f.2.1	Demolition and Site Restoration of ISFSI	-	1,766	-	-	-	-	185	293	2,244	-	-	2,244	-	-	-	-	-	-	8,537	160
3f.2	Subtotal Period 3f Additional Costs	-	1,766	-	-	-	-	185	293	2,244	-	-	2,244	-	-	-	-	-	-	8,537	160
Period 3f Collateral Costs																					
3f.3.1	Small tool allowance	-	13	-	-	-	-	-	2	15	-	-	15	-	-	-	-	-	-	-	-
3f.3	Subtotal Period 3f Collateral Costs	-	13	-	-	-	-	-	2	15	-	-	15	-	-	-	-	-	-	-	-

Table D
Monticello Nuclear Generating Plant
Scenario 2: DECON with 60 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 3f Period-Dependent Costs																					
3f.4.2	Property taxes	-	-	-	-	-	-	123	12	135	-	-	135	-	-	-	-	-	-	-	-
3f.4.3	Heavy equipment rental	-	123	-	-	-	-	-	19	142	-	-	142	-	-	-	-	-	-	-	-
3f.4.4	Plant energy budget	-	-	-	-	-	-	29	4	33	-	-	33	-	-	-	-	-	-	-	-
3f.4.5	Fixed Overhead	-	-	-	-	-	-	42	6	48	-	-	48	-	-	-	-	-	-	-	-
3f.4.6	Railroad Track Maintenance	-	-	-	-	-	-	19	3	22	-	-	22	-	-	-	-	-	-	-	-
3f.4.7	Security Staff Cost	-	-	-	-	-	-	155	23	179	-	-	179	-	-	-	-	-	-	-	2,520
3f.4.8	Utility Staff Cost	-	-	-	-	-	-	103	16	119	-	-	119	-	-	-	-	-	-	-	1,564
3f.4	Subtotal Period 3f Period-Dependent Costs	-	123	-	-	-	-	471	83	678	-	-	678	-	-	-	-	-	-	-	4,084
3f.0	TOTAL PERIOD 3f COST	-	1,903	-	-	-	-	656	378	2,937	-	-	2,937	-	-	-	-	-	-	8,537	4,244
PERIOD 3 TOTALS		-	25,768	1,335	784	-	14,610	503,441	78,517	624,455	24,264	529,860	70,331	-	27,284	-	-	1,547	4,171,597	96,902	4,162,431
TOTAL COST TO DECOMMISSION		**16,489**	**91,483**	**22,061**	**10,357**	**25,828**	**72,171**	**1,054,685**	**222,778**	**1,515,850**	**759,047**	**685,479**	**71,324**	**288,153**	**203,059**	**1,711**	**1,010**	**1,547**	**25,757,230**	**933,647**	**8,407,016**

TOTAL COST TO DECOMMISSION WITH 17.23% CONTINGENCY:	**$1,515,850**	**thousands of 2017 dollars**
TOTAL NRC LICENSE TERMINATION COST IS 50.07% OR:	**$759,047**	**thousands of 2017 dollars**
SPENT FUEL MANAGEMENT COST IS 45.22% OR:	**$685,479**	**thousands of 2017 dollars**
NON-NUCLEAR DEMOLITION COST IS 4.71% OR:	**$71,324**	**thousands of 2017 dollars**
TOTAL LOW-LEVEL RADIOACTIVE WASTE VOLUME BURIED (EXCLUDING GTCC):	**205,780**	**cubic feet**
TOTAL GREATER THAN CLASS C RADWASTE VOLUME GENERATED:	**1,547**	**cubic feet**
TOTAL SCRAP METAL REMOVED:	**22,696**	**tons**
TOTAL CRAFT LABOR REQUIREMENTS:	**933,647**	**man-hours**

End Notes:
n/a - indicates that this activity not charged as decommissioning expense
a - indicates that this activity performed by decommissioning staff
0 - indicates that this value is less than 0.5 but is non-zero
A cell containing " - " indicates a zero value

APPENDIX E

DETAILED COST ANALYSIS

SCENARIO 3: DECON with 100 Year DFS

Table E
Monticello Nuclear Generating Plant
Scenario 3: DECON with 100 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
PERIOD 1a - Shutdown through Transition																					
Period 1a Direct Decommissioning Activities																					
1a.1.1	Prepare preliminary decommissioning cost	-	-	-	-	-	-	153	23	175	175	-	-	-	-	-	-	-	-	-	1,300
1a.1.2	Notification of Cessation of Operations									a											
1a.1.3	Remove fuel & source material									n/a											
1a.1.4	Notification of Permanent Defueling									a											
1a.1.5	Deactivate plant systems & process waste									a											
1a.1.6	Prepare and submit PSDAR	-	-	-	-	-	-	235	35	270	270	-	-	-	-	-	-	-	-	-	2,000
1a.1.7	Review plant dwgs & specs.	-	-	-	-	-	-	540	81	621	621	-	-	-	-	-	-	-	-	-	4,600
1a.1.8	Perform detailed rad survey									a											
1a.1.9	Estimate by-product inventory	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1a.1.10	End product description	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1a.1.11	Detailed by-product inventory	-	-	-	-	-	-	153	23	175	175	-	-	-	-	-	-	-	-	-	1,300
1a.1.12	Define major work sequence	-	-	-	-	-	-	880	132	1,012	1,012	-	-	-	-	-	-	-	-	-	7,500
1a.1.13	Perform SER and EA	-	-	-	-	-	-	364	55	418	418	-	-	-	-	-	-	-	-	-	3,100
1a.1.14	Prepare/submit Defueled Technical Specifications	-	-	-	-	-	-	880	132	1,012	1,012	-	-	-	-	-	-	-	-	-	7,500
1a.1.15	Perform Site-Specific Cost Study	-	-	-	-	-	-	587	88	675	675	-	-	-	-	-	-	-	-	-	5,000
1a.1.16	Prepare/submit Irradiated Fuel Management Plan	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
Activity Specifications																					
1a.1.17.1	Plant & temporary facilities	-	-	-	-	-	-	578	87	664	598	-	66	-	-	-	-	-	-	-	4,920
1a.1.17.2	Plant systems	-	-	-	-	-	-	489	73	562	506	-	56	-	-	-	-	-	-	-	4,167
1a.1.17.3	NSSS Decontamination Flush	-	-	-	-	-	-	59	9	67	67	-	-	-	-	-	-	-	-	-	500
1a.1.17.4	Reactor internals	-	-	-	-	-	-	833	125	958	958	-	-	-	-	-	-	-	-	-	7,100
1a.1.17.5	Reactor vessel	-	-	-	-	-	-	763	114	877	877	-	-	-	-	-	-	-	-	-	6,500
1a.1.17.6	Sacrificial shield	-	-	-	-	-	-	59	9	67	67	-	-	-	-	-	-	-	-	-	500
1a.1.17.7	Moisture separators/reheaters	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1a.1.17.8	Reinforced concrete	-	-	-	-	-	-	188	28	216	108	-	108	-	-	-	-	-	-	-	1,600
1a.1.17.9	Main Turbine	-	-	-	-	-	-	245	37	282	282	-	-	-	-	-	-	-	-	-	2,088
1a.1.17.10	Main Condensers	-	-	-	-	-	-	245	37	282	282	-	-	-	-	-	-	-	-	-	2,088
1a.1.17.11	Pressure suppression structure	-	-	-	-	-	-	235	35	270	270	-	-	-	-	-	-	-	-	-	2,000
1a.1.17.12	Drywell	-	-	-	-	-	-	188	28	216	216	-	-	-	-	-	-	-	-	-	1,600
1a.1.17.13	Plant structures & buildings	-	-	-	-	-	-	366	55	421	211	-	211	-	-	-	-	-	-	-	3,120
1a.1.17.14	Waste management	-	-	-	-	-	-	540	81	621	621	-	-	-	-	-	-	-	-	-	4,600
1a.1.17.15	Facility & site closeout	-	-	-	-	-	-	106	16	121	61	-	61	-	-	-	-	-	-	-	900
1a.1.17	Total	-	-	-	-	-	-	5,010	752	5,762	5,260	-	502	-	-	-	-	-	-	-	42,683
Planning & Site Preparations																					
1a.1.18	Prepare dismantling sequence	-	-	-	-	-	-	282	42	324	324	-	-	-	-	-	-	-	-	-	2,400
1a.1.19	Plant prep. & temp. svces	-	-	-	-	-	-	3,300	495	3,795	3,795	-	-	-	-	-	-	-	-	-	-
1a.1.20	Design water clean-up system	-	-	-	-	-	-	164	25	189	189	-	-	-	-	-	-	-	-	-	1,400
1a.1.21	Rigging/Cont. Cntrl Envlps/tooling/etc.	-	-	-	-	-	-	2,300	345	2,645	2,645	-	-	-	-	-	-	-	-	-	-
1a.1.22	Procure casks/liners & containers	-	-	-	-	-	-	144	22	166	166	-	-	-	-	-	-	-	-	-	1,230
1a.1	Subtotal Period 1a Activity Costs	-	-	-	-	-	-	15,344	2,302	17,646	17,144	-	502	-	-	-	-	-	-	-	83,013
Period 1a Collateral Costs																					
1a.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	1,221	183	1,404	-	1,404	-	-	-	-	-	-	-	-	-
1a.3.2	Retention and Severance	-	-	-	-	-	-	9,892	1,484	11,376	11,376	-	-	-	-	-	-	-	-	-	-
1a.3	Subtotal Period 1a Collateral Costs	-	-	-	-	-	-	11,113	1,667	12,779	11,376	1,404	-	-	-	-	-	-	-	-	-
Period 1a Period-Dependent Costs																					
1a.4.1	Insurance	-	-	-	-	-	-	2,408	241	2,649	2,649	-	-	-	-	-	-	-	-	-	-
1a.4.2	Property taxes	-	-	-	-	-	-	2,242	224	2,466	2,466	-	-	-	-	-	-	-	-	-	-
1a.4.3	Health physics supplies	-	515	-	-	-	-	-	129	644	644	-	-	-	-	-	-	-	-	-	-
1a.4.4	Heavy equipment rental	-	567	-	-	-	-	-	85	652	652	-	-	-	-	-	-	-	-	-	-
1a.4.5	Disposal of DAW generated	-	-	13	4	-	50	-	14	81	81	-	-	-	610	-	-	-	12,190	20	-
1a.4.6	Plant energy budget	-	-	-	-	-	-	1,730	259	1,989	1,989	-	-	-	-	-	-	-	-	-	-
1a.4.7	NRC Fees	-	-	-	-	-	-	1,110	111	1,221	1,221	-	-	-	-	-	-	-	-	-	-
1a.4.8	Emergency Planning Fees	-	-	-	-	-	-	3,166	317	3,482	-	3,482	-	-	-	-	-	-	-	-	-
1a.4.9	Fixed Overhead	-	-	-	-	-	-	2,833	425	3,258	3,258	-	-	-	-	-	-	-	-	-	-
1a.4.10	Spent Fuel Pool O&M	-	-	-	-	-	-	803	120	923	-	923	-	-	-	-	-	-	-	-	-
1a.4.11	ISFSI Operating Costs	-	-	-	-	-	-	103	15	119	-	119	-	-	-	-	-	-	-	-	-
1a.4.12	Railroad Track Maintenance	-	-	-	-	-	-	115	17	133	133	-	-	-	-	-	-	-	-	-	-
1a.4.13	Security Staff Cost	-	-	-	-	-	-	14,260	2,139	16,399	16,399	-	-	-	-	-	-	-	-	-	245,440
1a.4.14	Utility Staff Cost	-	-	-	-	-	-	25,791	3,869	29,660	29,660	-	-	-	-	-	-	-	-	-	422,240
1a.4	Subtotal Period 1a Period-Dependent Costs	-	1,083	13	4	-	50	54,561	7,966	63,676	59,153	4,524	-	-	610	-	-	-	12,190	20	667,680

Table E
Monticello Nuclear Generating Plant
Scenario 3: DECON with 100 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
1a.0	TOTAL PERIOD 1a COST	-	1,083	13	4	-	50	81,017	11,935	94,101	87,672	5,927	502	-	610	-	-	-	12,190	20	750,693
PERIOD 1b - Decommissioning Preparations																					
Period 1b Direct Decommissioning Activities																					
Detailed Work Procedures																					
1b.1.1.1	Plant systems	-	-	-	-	-	-	556	83	639	575	-	64	-	-	-	-	-	-	-	4,733
1b.1.1.2	NSSS Decontamination Flush	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1b.1.1.3	Reactor internals	-	-	-	-	-	-	470	70	540	540	-	-	-	-	-	-	-	-	-	4,000
1b.1.1.4	Remaining buildings	-	-	-	-	-	-	158	24	182	46	-	137	-	-	-	-	-	-	-	1,350
1b.1.1.5	CRD housings & NIs	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1b.1.1.6	Incore instrumentation	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1b.1.1.7	Removal primary containment	-	-	-	-	-	-	235	35	270	270	-	-	-	-	-	-	-	-	-	2,000
1b.1.1.8	Reactor vessel	-	-	-	-	-	-	426	64	490	490	-	-	-	-	-	-	-	-	-	3,630
1b.1.1.9	Facility closeout	-	-	-	-	-	-	141	21	162	81	-	81	-	-	-	-	-	-	-	1,200
1b.1.1.10	Sacrificial shield	-	-	-	-	-	-	141	21	162	162	-	-	-	-	-	-	-	-	-	1,200
1b.1.1.11	Reinforced concrete	-	-	-	-	-	-	117	18	135	67	-	67	-	-	-	-	-	-	-	1,000
1b.1.1.12	Main Turbine	-	-	-	-	-	-	244	37	281	281	-	-	-	-	-	-	-	-	-	2,080
1b.1.1.13	Main Condensers	-	-	-	-	-	-	245	37	282	282	-	-	-	-	-	-	-	-	-	2,088
1b.1.1.14	Moisture separators & reheaters	-	-	-	-	-	-	235	35	270	270	-	-	-	-	-	-	-	-	-	2,000
1b.1.1.15	Radwaste building	-	-	-	-	-	-	320	48	369	332	-	37	-	-	-	-	-	-	-	2,730
1b.1.1.16	Reactor building	-	-	-	-	-	-	320	48	369	332	-	37	-	-	-	-	-	-	-	2,730
1b.1.1	Total	-	-	-	-	-	-	3,961	594	4,555	4,132	-	423	-	-	-	-	-	-	-	33,741
1b.1.2	Decon NSSS	286	-	-	-	-	-	-	143	429	429	-	-	-	-	-	-	-	-	1,067	-
1b.1	Subtotal Period 1b Activity Costs	286	-	-	-	-	-	3,961	737	4,984	4,561	-	423	-	-	-	-	-	-	1,067	33,741
Period 1b Additional Costs																					
1b.2.1	Spent fuel pool isolation	-	-	-	-	-	-	11,691	1,754	13,445	13,445	-	-	-	-	-	-	-	-	-	-
1b.2.2	Site Characterization	-	-	-	-	-	-	6,446	1,934	8,380	8,380	-	-	-	-	-	-	-	-	30,500	10,852
1b.2.3	Mixed & RCRA Waste	-	-	29	19	13	-	-	8	69	69	-	-	43	-	-	-	-	5,253	163	-
1b.2	Subtotal Period 1b Additional Costs	-	-	29	19	13	-	18,137	3,695	21,894	21,894	-	-	43	-	-	-	-	5,253	30,663	10,852
Period 1b Collateral Costs																					
1b.3.1	Decon equipment	973	-	-	-	-	-	-	146	1,119	1,119	-	-	-	-	-	-	-	-	-	-
1b.3.2	DOC staff relocation expenses	-	-	-	-	-	-	1,189	178	1,367	1,367	-	-	-	-	-	-	-	-	-	-
1b.3.3	Process decommissioning water waste	37	-	24	61	-	98	-	54	275	275	-	-	-	233	-	-	-	13,986	45	-
1b.3.4	Process decommissioning chemical flush waste	1	-	23	85	-	969	-	258	1,336	1,336	-	-	-	-	231	-	-	24,599	43	-
1b.3.5	Small tool allowance	-	2	-	-	-	-	-	0	2	2	-	-	-	-	-	-	-	-	-	-
1b.3.6	Pipe cutting equipment	-	1,200	-	-	-	-	-	180	1,380	1,380	-	-	-	-	-	-	-	-	-	-
1b.3.7	Decon rig	1,987	-	-	-	-	-	-	298	2,285	2,285	-	-	-	-	-	-	-	-	-	-
1b.3.8	Spent Fuel Capital and Transfer	-	-	-	-	-	-	2,557	383	2,940	-	2,940	-	-	-	-	-	-	-	-	-
1b.3.9	Retention and Severance	-	-	-	-	-	-	6,362	954	7,316	7,316	-	-	-	-	-	-	-	-	-	-
1b.3	Subtotal Period 1b Collateral Costs	2,997	1,202	47	147	-	1,067	10,107	2,453	18,020	15,080	2,940	-	-	233	231	-	-	38,585	89	-
Period 1b Period-Dependent Costs																					
1b.4.1	Decon supplies	35	-	-	-	-	-	-	9	44	44	-	-	-	-	-	-	-	-	-	-
1b.4.2	Insurance	-	-	-	-	-	-	1,207	121	1,328	1,328	-	-	-	-	-	-	-	-	-	-
1b.4.3	Property taxes	-	-	-	-	-	-	1,104	110	1,214	1,214	-	-	-	-	-	-	-	-	-	-
1b.4.4	Health physics supplies	-	290	-	-	-	-	-	73	363	363	-	-	-	-	-	-	-	-	-	-
1b.4.5	Heavy equipment rental	-	284	-	-	-	-	-	43	327	327	-	-	-	-	-	-	-	-	-	-
1b.4.6	Disposal of DAW generated	-	-	8	2	-	29	-	8	48	48	-	-	-	358	-	-	-	7,159	12	-
1b.4.7	Plant energy budget	-	-	-	-	-	-	1,735	260	1,995	1,995	-	-	-	-	-	-	-	-	-	-
1b.4.8	NRC Fees	-	-	-	-	-	-	321	32	353	353	-	-	-	-	-	-	-	-	-	-
1b.4.9	Emergency Planning Fees	-	-	-	-	-	-	1,587	159	1,746	-	1,746	-	-	-	-	-	-	-	-	-
1b.4.10	Fixed Overhead	-	-	-	-	-	-	1,420	213	1,633	1,633	-	-	-	-	-	-	-	-	-	-
1b.4.11	Spent Fuel Pool O&M	-	-	-	-	-	-	402	60	463	-	463	-	-	-	-	-	-	-	-	-
1b.4.12	ISFSI Operating Costs	-	-	-	-	-	-	52	8	60	-	60	-	-	-	-	-	-	-	-	-
1b.4.13	Railroad Track Maintenance	-	-	-	-	-	-	58	9	67	67	-	-	-	-	-	-	-	-	-	-
1b.4.14	Security Staff Cost	-	-	-	-	-	-	7,150	1,072	8,222	8,222	-	-	-	-	-	-	-	-	-	123,056
1b.4.15	DOC Staff Cost	-	-	-	-	-	-	5,625	844	6,469	6,469	-	-	-	-	-	-	-	-	-	63,614
1b.4.16	Utility Staff Cost	-	-	-	-	-	-	13,003	1,950	14,953	14,953	-	-	-	-	-	-	-	-	-	212,741
1b.4	Subtotal Period 1b Period-Dependent Costs	35	575	8	2	-	29	33,663	4,971	39,283	37,015	2,268	-	-	358	-	-	-	7,159	12	399,411
1b.0	TOTAL PERIOD 1b COST	3,318	1,777	84	169	13	1,096	65,868	11,856	84,181	78,550	5,208	423	43	591	231	-	-	50,997	31,830	444,004
PERIOD 1 TOTALS		3,318	2,859	97	173	13	1,146	146,886	23,790	178,282	166,222	11,136	925	43	1,201	231	-	-	63,188	31,850	1,194,697

Table E
Monticello Nuclear Generating Plant
Scenario 3: DECON with 100 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
PERIOD 2a - Large Component Removal																					
Period 2a Direct Decommissioning Activities																					
Nuclear Steam Supply System Removal																					
2a.1.1.1	Recirculation System Piping & Valves	107	92	30	39	-	429	-	192	888	888	-	-	-	1,430	-	-	-	99,742	2,905	-
2a.1.1.2	Recirculation Pumps & Motors	38	59	16	40	22	438	-	154	767	767	-	-	96	945	-	-	-	112,200	1,563	-
2a.1.1.3	CRDMs & NIs Removal	187	1,022	402	105	-	919	-	635	3,269	3,269	-	-	-	3,741	-	-	-	213,700	17,768	-
2a.1.1.4	Reactor Vessel Internals	222	6,378	12,908	2,835	-	20,148	356	18,958	61,806	61,806	-	-	-	1,252	1,481	1,010	-	312,338	30,765	1,389
2a.1.1.5	Reactor Vessel	109	8,595	2,644	1,170	-	5,294	356	10,155	28,323	28,323	-	-	-	16,169	-	-	-	1,105,210	30,765	1,389
2a.1.1	Totals	663	16,147	15,999	4,189	22	27,228	711	30,094	95,053	95,053	-	-	96	23,536	1,481	1,010	-	1,843,190	83,767	2,778
Removal of Major Equipment																					
2a.1.2	Main Turbine/Generator	-	362	1,496	349	3,174	357	-	858	6,596	6,596	-	-	24,835	1,383	-	-	-	1,577,959	5,438	-
2a.1.3	Main Condensers	-	1,245	397	128	1,667	198	-	670	4,306	4,306	-	-	17,396	727	-	-	-	828,955	18,831	-
Cascading Costs from Clean Building Demolition																					
2a.1.4.1	Reactor Building	-	317	-	-	-	-	-	48	364	364	-	-	-	-	-	-	-	-	2,217	-
2a.1.4.2	Radwaste	-	24	-	-	-	-	-	4	27	27	-	-	-	-	-	-	-	-	127	-
2a.1.4.3	Turbine	-	118	-	-	-	-	-	18	136	136	-	-	-	-	-	-	-	-	1,254	-
2a.1.4	Totals	-	459	-	-	-	-	-	69	528	528	-	-	-	-	-	-	-	-	3,598	-
Disposal of Plant Systems																					
2a.1.5.1	Automatic Press Relief	-	115	7	8	69	57	-	55	311	311	-	-	803	206	-	-	-	45,852	1,656	-
2a.1.5.2	Chemistry Sampling	-	27	1	1	13	10	-	12	65	65	-	-	156	37	-	-	-	8,681	400	-
2a.1.5.3	Chemistry Sampling - Insulated	-	2	0	0	-	0	-	1	3	3	-	-	-	1	-	-	-	72	28	-
2a.1.5.4	Circulating Water - RCA	-	202	12	41	576	-	-	144	974	974	-	-	6,656	-	-	-	-	270,307	2,860	-
2a.1.5.5	Combustible Gas Control - Insul - RCA	-	29	0	1	18	-	-	10	59	59	-	-	212	-	-	-	-	8,617	378	-
2a.1.5.6	Combustible Gas Control - RCA	-	18	0	2	25	-	-	8	53	53	-	-	285	-	-	-	-	11,577	245	-
2a.1.5.7	Condensate & Feedwater	-	946	189	226	1,725	2,003	-	1,049	6,138	6,138	-	-	19,947	7,319	-	-	-	1,275,810	14,196	-
2a.1.5.8	Condensate & Feedwater - Insulated	-	480	34	43	361	332	-	267	1,517	1,517	-	-	4,176	1,207	-	-	-	246,693	6,964	-
2a.1.5.9	Condensate Demin	-	533	29	35	289	276	-	254	1,416	1,416	-	-	3,346	1,000	-	-	-	199,936	7,618	-
2a.1.5.10	Condensate Storage	-	706	31	55	617	219	-	335	1,963	1,963	-	-	7,131	795	-	-	-	340,568	10,345	-
2a.1.5.11	Control Rod Drive	-	3	0	0	2	1	-	1	7	7	-	-	19	4	-	-	-	1,009	41	-
2a.1.5.12	Control Rod Drive Hydraulic	-	405	16	18	143	155	-	166	902	902	-	-	1,658	562	-	-	-	103,306	5,898	-
2a.1.5.13	Core Spray	-	75	19	34	379	143	-	119	770	770	-	-	4,384	521	-	-	-	211,329	1,163	-
2a.1.5.14	Core Spray - Insulated	-	141	8	9	71	73	-	66	368	368	-	-	818	264	-	-	-	50,149	2,033	-
2a.1.5.15	Demin Water - Insulated - RCA	-	15	0	1	7	-	-	5	27	27	-	-	85	-	-	-	-	3,445	181	-
2a.1.5.16	Demin Water - RCA	-	40	0	2	22	-	-	14	78	78	-	-	253	-	-	-	-	10,278	508	-
2a.1.5.17	Diesel Oil - RCA	-	2	0	0	2	-	-	1	5	5	-	-	23	-	-	-	-	931	25	-
2a.1.5.18	Drywell Atmosphere Cooling - RCA	-	37	1	3	47	-	-	17	105	105	-	-	548	-	-	-	-	22,244	550	-
2a.1.5.19	EDG Emerg Service Water - Insul - RCA	-	0	0	0	0	-	-	0	1	1	-	-	2	-	-	-	-	84	4	-
2a.1.5.20	Electrical - Clean	-	12	-	-	-	-	-	2	13	-	-	13	-	-	-	-	-	-	182	-
2a.1.5.21	Emergency Service Water - Insul - RCA	-	21	0	1	12	-	-	7	41	41	-	-	137	-	-	-	-	5,544	281	-
2a.1.5.22	Emergency Service Water - RCA	-	2	0	0	1	-	-	1	4	4	-	-	13	-	-	-	-	512	22	-
2a.1.5.23	GEZIP - RCA	-	3	0	1	9	-	-	2	15	15	-	-	103	-	-	-	-	4,184	48	-
2a.1.5.24	Generator Physical Design - RCA	-	5	0	0	3	-	-	2	9	9	-	-	31	-	-	-	-	1,250	67	-
2a.1.5.25	H2-O2 Control Analyzing	-	6	0	0	0	4	-	3	13	13	-	-	6	13	-	-	-	1,080	81	-
2a.1.5.26	H2-O2 Control Analyzing - Insulated	-	6	0	0	0	4	-	3	13	13	-	-	6	13	-	-	-	1,080	81	-
2a.1.5.27	High Pressure Coolant Injection	-	64	6	9	84	57	-	45	266	266	-	-	972	209	-	-	-	52,792	966	-
2a.1.5.28	High Pressure Coolant Injection - Insula	-	214	14	17	138	133	-	111	627	627	-	-	1,598	481	-	-	-	95,733	3,079	-
2a.1.5.29	Hydrogen Cooling	-	7	-	-	-	-	-	1	9	-	-	9	-	-	-	-	-	-	118	-
2a.1.5.30	Hydrogen Cooling - RCA	-	7	0	0	3	-	-	2	13	13	-	-	39	-	-	-	-	1,600	79	-
2a.1.5.31	Hydrogen Seal Oil - RCA	-	17	0	1	16	-	-	7	42	42	-	-	189	-	-	-	-	7,669	212	-
2a.1.5.32	Hydrogen Water Chemistry - RCA	-	24	0	1	12	-	-	8	45	45	-	-	140	-	-	-	-	5,672	304	-
2a.1.5.33	Instrument & Service Air - RCA	-	220	3	11	153	-	-	80	466	466	-	-	1,768	-	-	-	-	71,810	2,733	-
2a.1.5.34	Main Condenser	-	191	12	14	115	113	-	97	542	542	-	-	1,333	411	-	-	-	80,439	2,746	-
2a.1.5.35	Main Steam	-	243	17	22	186	163	-	134	764	764	-	-	2,148	594	-	-	-	125,135	3,512	-
2a.1.5.36	Main Turbine	-	972	214	244	1,709	2,375	-	1,151	6,665	6,665	-	-	19,760	8,687	-	-	-	1,354,661	14,733	-
2a.1.5.37	Main Turbine - Insulated	-	209	19	25	219	183	-	136	790	790	-	-	2,530	667	-	-	-	145,208	3,069	-
2a.1.5.38	Miscellaneous	-	42	1	2	26	-	-	15	85	85	-	-	302	-	-	-	-	12,283	622	-
2a.1.5.39	Off Gas Recombiner	-	182	19	22	155	209	-	126	714	714	-	-	1,795	764	-	-	-	121,554	2,708	-
2a.1.5.40	Off Gas Recombiner - Insulated	-	379	19	19	118	195	-	166	897	897	-	-	1,366	709	-	-	-	100,933	5,385	-
2a.1.5.41	Post Accident Sampling	-	24	1	1	5	9	-	9	50	50	-	-	53	33	-	-	-	4,318	345	-
2a.1.5.42	Post Accident Sampling - Insulated	-	16	1	1	1	11	-	7	37	37	-	-	17	37	-	-	-	3,116	212	-
2a.1.5.43	RHR Service Water - Insulated - RCA	-	81	3	9	128	-	-	41	262	262	-	-	1,485	-	-	-	-	60,293	1,125	-
2a.1.5.44	RHR Service Water - RCA	-	4	0	0	3	-	-	1	9	9	-	-	35	-	-	-	-	1,410	57	-
2a.1.5.45	Reactor Feedwater Pump Seal	-	55	3	3	17	26	-	23	126	126	-	-	193	96	-	-	-	14,009	773	-

Table E
Monticello Nuclear Generating Plant
Scenario 3: DECON with 100 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Disposal of Plant Systems (continued)																					
2a.1.5.46	Residual Heat Removal	349	240	168	126	554	1,667	-	770	3,875	3,875	-	-	6,406	6,012	-	-	-	647,941	4,135	-
2a.1.5.47	Residual Heat Removal - Insulated	602	540	64	58	291	715	-	674	2,944	2,944	-	-	3,367	2,607	-	-	-	303,087	10,340	-
2a.1.5.48	Rx Core Isolation Cooling	-	47	2	3	22	21	-	21	116	116	-	-	259	76	-	-	-	15,396	691	-
2a.1.5.49	Rx Core Isolation Cooling - Insulated	-	105	5	5	25	55	-	45	240	240	-	-	288	198	-	-	-	24,419	1,479	-
2a.1.5.50	Rx Recirculation	56	57	6	3	4	53	-	57	235	235	-	-	43	190	-	-	-	14,095	1,580	-
2a.1.5.51	Snubbers	-	168	2	4	33	25	-	54	285	285	-	-	377	90	-	-	-	21,009	2,548	-
2a.1.5.52	Standby Liquid Control - Insul - RCA	-	4	0	0	2	-	-	1	7	7	-	-	22	-	-	-	-	904	48	-
2a.1.5.53	Standby Liquid Control - RCA	-	26	0	1	21	-	-	10	59	59	-	-	245	-	-	-	-	9,969	341	-
2a.1.5.54	Stator Cooling - RCA	-	7	0	1	11	-	-	4	23	23	-	-	126	-	-	-	-	5,135	98	-
2a.1.5.55	Traversing Incore Probe	0	4	0	0	0	2	-	1	7	7	-	-	1	5	-	-	-	386	51	-
2a.1.5	Totals	1,007	7,978	931	1,079	8,447	9,287	-	6,340	35,068	35,046	-	22	97,654	33,808	-	-	-	6,125,515	119,943	-
2a.1.6	Scaffolding in support of decommissioning	-	2,188	25	8	99	25	-	572	2,916	2,916	-	-	1,030	91	-	-	-	52,111	22,564	-
2a.1	Subtotal Period 2a Activity Costs	1,669	28,379	18,848	5,754	13,409	37,095	711	38,602	144,467	144,445	-	22	141,010	59,545	1,481	1,010	-	10,427,730	254,140	2,778
Period 2a Additional Costs																					
2a.2.1	Remedial Action Surveys	-	-	-	-	-	-	2,326	698	3,024	3,024	-	-	-	-	-	-	-	-	30,411	-
2a.2	Subtotal Period 2a Additional Costs	-	-	-	-	-	-	2,326	698	3,024	3,024	-	-	-	-	-	-	-	-	30,411	-
Period 2a Collateral Costs																					
2a.3.1	Process decommissioning water waste	83	-	55	140	-	222	-	123	623	623	-	-	-	531	-	-	-	31,838	103	-
2a.3.2	Process decommissioning chemical flush waste	6	-	208	774	-	1,557	-	529	3,075	3,075	-	-	-	2,093	-	-	-	223,008	392	-
2a.3.3	Small tool allowance	-	315	-	-	-	-	-	47	363	326	-	36	-	-	-	-	-	-	-	-
2a.3.4	Spent Fuel Capital and Transfer	-	-	-	-	-	-	23,173	3,476	26,649	-	26,649	-	-	-	-	-	-	-	-	-
2a.3.5	Retention and Severance	-	-	-	-	-	-	13,235	1,985	15,221	15,221	-	-	-	-	-	-	-	-	-	-
2a.3	Subtotal Period 2a Collateral Costs	89	315	263	914	-	1,779	36,408	6,161	45,930	19,245	26,649	36	-	2,623	-	-	-	254,846	495	-
Period 2a Period-Dependent Costs																					
2a.4.1	Decon supplies	102	-	-	-	-	-	-	25	127	127	-	-	-	-	-	-	-	-	-	-
2a.4.2	Insurance	-	-	-	-	-	-	1,055	106	1,161	1,161	-	-	-	-	-	-	-	-	-	-
2a.4.3	Property taxes	-	-	-	-	-	-	3,061	306	3,367	3,367	-	-	-	-	-	-	-	-	-	-
2a.4.4	Health physics supplies	-	2,133	-	-	-	-	-	533	2,666	2,666	-	-	-	-	-	-	-	-	-	-
2a.4.5	Heavy equipment rental	-	3,212	-	-	-	-	-	482	3,694	3,694	-	-	-	-	-	-	-	-	-	-
2a.4.6	Disposal of DAW generated	-	-	122	37	-	453	-	131	743	743	-	-	-	5,567	-	-	-	111,335	182	-
2a.4.7	Plant energy budget	-	-	-	-	-	-	2,404	361	2,765	2,765	-	-	-	-	-	-	-	-	-	-
2a.4.8	NRC Fees	-	-	-	-	-	-	847	85	932	932	-	-	-	-	-	-	-	-	-	-
2a.4.9	Emergency Planning Fees	-	-	-	-	-	-	3,757	376	4,133	-	4,133	-	-	-	-	-	-	-	-	-
2a.4.10	Fixed Overhead	-	-	-	-	-	-	3,392	509	3,900	3,900	-	-	-	-	-	-	-	-	-	-
2a.4.11	Spent Fuel Pool O&M	-	-	-	-	-	-	1,174	176	1,350	-	1,350	-	-	-	-	-	-	-	-	-
2a.4.12	ISFSI Operating Costs	-	-	-	-	-	-	151	23	174	-	174	-	-	-	-	-	-	-	-	-
2a.4.13	Railroad Track Maintenance	-	-	-	-	-	-	466	70	536	536	-	-	-	-	-	-	-	-	-	-
2a.4.14	Security Staff Cost	-	-	-	-	-	-	19,265	2,890	22,154	22,154	-	-	-	-	-	-	-	-	-	328,651
2a.4.15	DOC Staff Cost	-	-	-	-	-	-	20,125	3,019	23,144	23,144	-	-	-	-	-	-	-	-	-	231,273
2a.4.16	Utility Staff Cost	-	-	-	-	-	-	26,670	4,000	30,670	30,670	-	-	-	-	-	-	-	-	-	430,594
2a.4	Subtotal Period 2a Period-Dependent Costs	102	5,345	122	37	-	453	82,366	13,090	101,515	95,858	5,657	-	-	5,567	-	-	-	111,335	182	990,519
2a.0	TOTAL PERIOD 2a COST	1,860	34,039	19,233	6,705	13,409	39,327	121,812	58,551	294,937	262,573	32,305	58	141,010	67,735	1,481	1,010	-	10,793,910	285,228	993,297
PERIOD 2b - Site Decontamination																					
Period 2b Direct Decommissioning Activities																					
Disposal of Plant Systems																					
2b.1.1.1	ALARA/Radiological	-	18	0	0	3	3	-	6	30	30	-	-	35	10	-	-	-	2,060	277	-
2b.1.1.2	Alternate N2 - RCA	-	16	0	1	8	-	-	5	30	30	-	-	93	-	-	-	-	3,765	185	-
2b.1.1.3	Decontamination Projects	-	1	0	0	0	0	-	0	2	2	-	-	2	0	-	-	-	129	17	-
2b.1.1.4	Electrical - Contaminated	-	439	6	16	207	25	-	150	841	841	-	-	2,389	90	-	-	-	102,726	6,325	-
2b.1.1.5	Electrical - Decontaminated	-	2,657	41	142	2,019	-	-	993	5,852	5,852	-	-	23,344	-	-	-	-	948,013	37,107	-
2b.1.1.6	Fire - RCA	-	99	1	4	53	-	-	33	191	191	-	-	614	-	-	-	-	24,917	1,324	-
2b.1.1.7	HVAC Ductwork	-	309	7	18	231	27	-	122	713	713	-	-	2,665	100	-	-	-	114,598	4,111	-
2b.1.1.8	HVAC/Chilled Water - RCA	-	317	5	17	238	-	-	118	694	694	-	-	2,752	-	-	-	-	111,779	3,985	-
2b.1.1.9	Heating & Ventilation	-	473	15	40	521	62	-	219	1,329	1,329	-	-	6,018	227	-	-	-	258,789	7,101	-
2b.1.1.10	Heating Boiler - Insulated - RCA	-	3	0	0	2	-	-	1	6	6	-	-	26	-	-	-	-	1,058	35	-
2b.1.1.11	Liquid Radwaste	572	669	46	44	266	476	-	623	2,697	2,697	-	-	3,073	1,728	-	-	-	235,484	17,194	-
2b.1.1.12	Makeup Demin - RCA	-	101	3	9	127	-	-	46	286	286	-	-	1,471	-	-	-	-	59,747	1,412	-
2b.1.1.13	Non-Essential Diesel Generator - RCA	-	26	2	9	123	-	-	27	187	187	-	-	1,424	-	-	-	-	57,832	395	-

Table E
Monticello Nuclear Generating Plant
Scenario 3: DECON with 100 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Disposal of Plant Systems (continued)																					
2b.1.1.14	Off Gas Holdup	-	333	20	26	238	174	-	168	960	960	-	-	2,755	630	-	-	-	152,277	4,769	-
2b.1.1.15	Primary Containment	-	443	43	59	536	412	-	308	1,801	1,801	-	-	6,201	1,506	-	-	-	347,704	6,454	-
2b.1.1.16	Process Radiation Monitors	-	45	2	2	12	14	-	17	92	92	-	-	142	52	-	-	-	9,115	649	-
2b.1.1.17	Rx Bldg Closed Clng Water - Insul - RCA	-	111	2	6	85	-	-	42	245	245	-	-	977	-	-	-	-	39,675	1,484	-
2b.1.1.18	Rx Bldg Closed Clng Water - RCA	-	178	12	43	614	-	-	144	991	991	-	-	7,093	-	-	-	-	288,031	2,489	-
2b.1.1.19	Rx Component Handling Equip	26	138	19	19	100	227	-	124	653	653	-	-	1,158	829	-	-	-	99,730	2,462	-
2b.1.1.20	Rx Pressure Vessel	28	46	6	4	7	63	-	43	196	196	-	-	75	230	-	-	-	17,816	1,051	-
2b.1.1.21	Rx Water Cleanup	169	258	19	11	11	204	-	205	877	877	-	-	130	737	-	-	-	52,670	5,736	-
2b.1.1.22	Secondary Containment	-	121	7	10	88	70	-	63	360	360	-	-	1,017	255	-	-	-	57,567	1,763	-
2b.1.1.23	Service & Seal Water - Insulated - RCA	-	117	2	7	102	-	-	46	274	274	-	-	1,180	-	-	-	-	47,917	1,565	-
2b.1.1.24	Service & Seal Water - RCA	-	155	3	11	156	-	-	64	390	390	-	-	1,809	-	-	-	-	73,453	2,016	-
2b.1.1.25	Service Air Blower - RCA	-	15	0	1	18	-	-	7	41	41	-	-	206	-	-	-	-	8,364	206	-
2b.1.1.26	Solid Radwaste	327	483	36	34	206	380	-	419	1,885	1,885	-	-	2,387	1,380	-	-	-	185,221	10,820	-
2b.1.1.27	Structures & Buildings	-	76	2	3	31	23	-	30	166	166	-	-	357	85	-	-	-	19,933	1,128	-
2b.1.1.28	Wells & Domestic Water	-	9	-	-	-	-	-	1	10	-	-	10	-	-	-	-	-	-	144	-
2b.1.1.29	Wells & Domestic Water - RCA	-	51	1	2	30	-	-	18	101	101	-	-	342	-	-	-	-	13,874	633	-
2b.1.1	Totals	1,122	7,707	299	537	6,032	2,160	-	4,042	21,900	21,890	-	10	69,735	7,859	-	-	-	3,334,244	122,835	-
2b.1.2	Scaffolding in support of decommissioning	-	2,735	31	10	123	31	-	715	3,645	3,645	-	-	1,287	114	-	-	-	65,139	28,205	-
Decontamination of Site Buildings																					
2b.1.3.1	Reactor Building	5,006	2,817	155	347	4,159	1,007	-	4,150	17,641	17,641	-	-	48,077	7,014	-	-	-	2,317,670	112,518	-
2b.1.3.2	Admin	103	6	0	2	-	14	-	57	182	182	-	-	-	145	-	-	-	6,840	1,600	-
2b.1.3.3	HPCI Room	28	27	1	2	10	13	-	26	107	107	-	-	118	125	-	-	-	10,759	789	-
2b.1.3.4	Hot Shop	16	4	0	1	-	10	-	12	43	43	-	-	-	103	-	-	-	4,860	286	-
2b.1.3.5	LLRW Storage & Shipping	56	23	1	6	3	41	-	46	176	176	-	-	31	433	-	-	-	21,708	1,127	-
2b.1.3.6	Offgas Stack	360	256	6	16	116	73	-	283	1,109	1,109	-	-	1,343	669	-	-	-	87,045	8,860	-
2b.1.3.7	Offgas Storage & Compressor	39	17	1	4	2	30	-	32	125	125	-	-	25	316	-	-	-	15,948	785	-
2b.1.3.8	Radwaste	117	59	3	13	15	86	-	100	393	393	-	-	172	910	-	-	-	49,943	2,503	-
2b.1.3.9	Radwaste Material Storage Warehouse	62	23	1	6	-	47	-	49	189	189	-	-	-	495	-	-	-	23,400	1,197	-
2b.1.3.10	Recombiner	26	24	1	4	17	22	-	28	122	122	-	-	199	216	-	-	-	18,405	695	-
2b.1.3.11	Turbine	684	341	18	76	111	507	-	583	2,319	2,319	-	-	1,283	5,299	-	-	-	303,150	14,443	-
2b.1.3.12	Turbine Building Addition	56	20	1	6	-	41	-	44	169	169	-	-	-	434	-	-	-	20,478	1,087	-
2b.1.3	Totals	6,554	3,618	188	483	4,433	1,889	-	5,410	22,574	22,574	-	-	51,247	16,159	-	-	-	2,880,206	145,889	-
2b.1.4	Prepare/submit License Termination Plan	-	-	-	-	-	-	481	72	553	553	-	-	-	-	-	-	-	-	-	4,096
2b.1.5	Receive NRC approval of termination plan									a											
2b.1	Subtotal Period 2b Activity Costs	7,676	14,060	518	1,031	10,588	4,079	481	10,239	48,672	48,662	-	10	122,269	24,132	-	-	-	6,279,589	296,929	4,096
Period 2b Additional Costs																					
2b.2.1	Remedial Action Surveys	-	-	-	-	-	-	3,241	972	4,213	4,213	-	-	-	-	-	-	-	-	42,370	-
2b.2.2	Operational Equipment	-	-	19	60	624	-	-	104	807	807	-	-	11,710	-	-	-	-	292,750	32	-
2b.2.3	Security Modifications	-	-	-	-	-	-	8,696	1,304	10,000	10,000	-	-	-	-	-	-	-	-	-	-
2b.2	Subtotal Period 2b Additional Costs	-	-	19	60	624	-	11,937	2,381	15,020	15,020	-	-	11,710	-	-	-	-	292,750	42,402	-
Period 2b Collateral Costs																					
2b.3.1	Process decommissioning water waste	173	-	117	299	-	474	-	261	1,325	1,325	-	-	-	1,133	-	-	-	67,962	221	-
2b.3.2	Process decommissioning chemical flush waste	1	-	41	153	-	307	-	104	606	606	-	-	-	413	-	-	-	43,978	77	-
2b.3.3	Small tool allowance	-	341	-	-	-	-	-	51	392	392	-	-	-	-	-	-	-	-	-	-
2b.3.4	Spent Fuel Capital and Transfer	-	-	-	-	-	-	65,919	9,888	75,807	-	75,807	-	-	-	-	-	-	-	-	-
2b.3.5	Retention and Severance	-	-	-	-	-	-	8,665	1,300	9,964	9,964	-	-	-	-	-	-	-	-	-	-
2b.3	Subtotal Period 2b Collateral Costs	174	341	159	452	-	781	74,584	11,604	88,094	12,287	75,807	-	-	1,545	-	-	-	111,940	298	-
Period 2b Period-Dependent Costs																					
2b.4.1	Decon supplies	1,361	-	-	-	-	-	-	340	1,701	1,701	-	-	-	-	-	-	-	-	-	-
2b.4.2	Insurance	-	-	-	-	-	-	1,470	147	1,617	1,617	-	-	-	-	-	-	-	-	-	-
2b.4.3	Property taxes	-	-	-	-	-	-	3,915	391	4,306	4,306	-	-	-	-	-	-	-	-	-	-
2b.4.4	Health physics supplies	-	2,681	-	-	-	-	-	670	3,352	3,352	-	-	-	-	-	-	-	-	-	-
2b.4.5	Heavy equipment rental	-	4,602	-	-	-	-	-	690	5,292	5,292	-	-	-	-	-	-	-	-	-	-
2b.4.6	Disposal of DAW generated	-	-	124	38	-	463	-	134	759	759	-	-	-	5,690	-	-	-	113,799	186	-
2b.4.7	Plant energy budget	-	-	-	-	-	-	2,645	397	3,041	3,041	-	-	-	-	-	-	-	-	-	-
2b.4.8	NRC Fees	-	-	-	-	-	-	1,180	118	1,298	1,298	-	-	-	-	-	-	-	-	-	-
2b.4.9	Emergency Planning Fees	-	-	-	-	-	-	5,234	523	5,758	-	5,758	-	-	-	-	-	-	-	-	-
2b.4.10	Fixed Overhead	-	-	-	-	-	-	4,725	709	5,434	5,434	-	-	-	-	-	-	-	-	-	-
2b.4.11	Spent Fuel Pool O&M	-	-	-	-	-	-	1,636	245	1,881	-	1,881	-	-	-	-	-	-	-	-	-
2b.4.12	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	412	62	474	474	-	-	-	-	-	-	-	-	-	-

Table E
Monticello Nuclear Generating Plant
Scenario 3: DECON with 100 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 2b Period-Dependent Costs (continued)																					
2b.4.13	ISFSI Operating Costs	-	-	-	-	-	-	210	32	242	-	242	-	-	-	-	-	-	-	-	-
2b.4.14	Railroad Track Maintenance	-	-	-	-	-	-	235	35	270	270	-	-	-	-	-	-	-	-	-	-
2b.4.15	Security Staff Cost	-	-	-	-	-	-	26,840	4,026	30,867	30,867	-	-	-	-	-	-	-	-	-	457,896
2b.4.16	DOC Staff Cost	-	-	-	-	-	-	27,122	4,068	31,191	31,191	-	-	-	-	-	-	-	-	-	309,504
2b.4.17	Utility Staff Cost	-	-	-	-	-	-	35,641	5,346	40,988	40,988	-	-	-	-	-	-	-	-	-	574,490
2b.4	Subtotal Period 2b Period-Dependent Costs	1,361	7,283	124	38	-	463	111,268	17,935	138,473	130,592	7,881	-	-	5,690	-	-	-	113,799	186	1,341,891
2b.0	TOTAL PERIOD 2b COST	9,211	21,684	820	1,580	11,212	5,324	198,269	42,159	290,260	206,561	83,688	10	133,979	31,367	-	-	-	6,798,079	339,814	1,345,987
PERIOD 2d - Decontamination Following Wet Fuel Storage																					
Period 2d Direct Decommissioning Activities																					
2d.1.1	Remove spent fuel racks	634	56	114	109	-	2,091	-	881	3,884	3,884	-	-	-	7,653	-	-	-	486,170	906	-
Disposal of Plant Systems																					
2d.1.2.1	Cranes/Heavy Loads/Rigging - RCA	-	3	0	1	9	-	-	2	15	15	-	-	103	-	-	-	-	4,184	48	-
2d.1.2.2	Electrical - Contaminated Fuel Pool	-	46	1	2	21	2	-	16	87	87	-	-	240	9	-	-	-	10,334	665	-
2d.1.2.3	Electrical - Decontam. Fuel Pool Area	-	293	4	15	213	-	-	108	633	633	-	-	2,457	-	-	-	-	99,783	4,090	-
2d.1.2.4	Fire - RCA - Fuel Pool Area	-	11	0	0	5	-	-	4	20	20	-	-	62	-	-	-	-	2,499	143	-
2d.1.2.5	Fuel Pool Cooling & Cleanup	240	419	34	26	102	370	-	340	1,531	1,531	-	-	1,179	1,341	-	-	-	133,939	8,380	-
2d.1.2.6	Fuel Pool Cooling & Cleanup - Insulated	26	40	3	2	6	32	-	33	143	143	-	-	67	117	-	-	-	10,220	848	-
2d.1.2.7	HVAC Ductwork - Fuel Pool Area	-	34	1	2	26	3	-	14	79	79	-	-	296	11	-	-	-	12,733	457	-
2d.1.2.8	HVAC/Chilled Water - RCA Fuel Pool Area	-	32	0	1	19	-	-	11	64	64	-	-	223	-	-	-	-	9,072	397	-
2d.1.2.9	Instrument & Service Air-RCA-Fuel Pool	-	28	0	2	23	-	-	11	64	64	-	-	267	-	-	-	-	10,841	357	-
2d.1.2	Totals	266	907	44	51	423	408	-	537	2,637	2,637	-	-	4,894	1,479	-	-	-	293,606	15,385	-
Decontamination of Site Buildings																					
2d.1.3.1	Reactor (Post Fuel)	911	2,485	145	669	170	8,544	-	3,353	16,277	16,277	-	-	1,969	62,698	-	-	-	2,732,406	45,703	-
2d.1.3	Totals	911	2,485	145	669	170	8,544	-	3,353	16,277	16,277	-	-	1,969	62,698	-	-	-	2,732,406	45,703	-
2d.1.4	Scaffolding in support of decommissioning	-	547	6	2	25	6	-	143	729	729	-	-	257	23	-	-	-	13,028	5,641	-
2d.1	Subtotal Period 2d Activity Costs	1,811	3,994	309	831	618	11,049	-	4,915	23,527	23,527	-	-	7,120	71,852	-	-	-	3,525,210	67,635	-
Period 2d Additional Costs																					
2d.2.1	License Termination Survey Planning	-	-	-	-	-	-	1,291	387	1,678	1,678	-	-	-	-	-	-	-	-	-	12,480
2d.2.2	Remedial Action Surveys	-	-	-	-	-	-	1,198	359	1,557	1,557	-	-	-	-	-	-	-	-	15,661	-
2d.2	Subtotal Period 2d Additional Costs	-	-	-	-	-	-	2,489	747	3,235	3,235	-	-	-	-	-	-	-	-	15,661	12,480
Period 2d Collateral Costs																					
2d.3.1	Process decommissioning water waste	69	-	47	120	-	191	-	105	533	533	-	-	-	457	-	-	-	27,391	89	-
2d.3.2	Process decommissioning chemical flush waste	1	-	25	92	-	185	-	63	366	366	-	-	-	249	-	-	-	26,553	47	-
2d.3.3	Small tool allowance	-	88	-	-	-	-	-	13	101	101	-	-	-	-	-	-	-	-	-	-
2d.3.4	Decommissioning Equipment Disposition	-	-	143	55	575	145	-	145	1,062	1,062	-	-	6,000	529	-	-	-	303,608	147	-
2d.3.5	Spent Fuel Capital and Transfer	-	-	-	-	-	-	27,061	4,059	31,120	-	31,120	-	-	-	-	-	-	-	-	-
2d.3	Subtotal Period 2d Collateral Costs	70	88	216	267	575	521	27,061	4,385	33,182	2,062	31,120	-	6,000	1,235	-	-	-	357,552	283	-

Table E
Monticello Nuclear Generating Plant
Scenario 3: DECON with 100 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 2d Period-Dependent Costs																					
2d.4.1	Decon supplies	219	-	-	-	-	-	-	55	274	274	-	-	-	-	-	-	-	-	-	-
2d.4.2	Insurance	-	-	-	-	-	-	543	54	598	598	-	-	-	-	-	-	-	-	-	-
2d.4.3	Property taxes	-	-	-	-	-	-	1,336	134	1,470	1,470	-	-	-	-	-	-	-	-	-	-
2d.4.4	Health physics supplies	-	752	-	-	-	-	-	188	940	940	-	-	-	-	-	-	-	-	-	-
2d.4.5	Heavy equipment rental	-	1,701	-	-	-	-	-	255	1,956	1,956	-	-	-	-	-	-	-	-	-	-
2d.4.6	Disposal of DAW generated	-	-	44	14	-	165	-	48	271	271	-	-	-	2,030	-	-	-	40,600	66	-
2d.4.7	Plant energy budget	-	-	-	-	-	-	521	78	600	600	-	-	-	-	-	-	-	-	-	-
2d.4.8	NRC Fees	-	-	-	-	-	-	369	37	405	405	-	-	-	-	-	-	-	-	-	-
2d.4.9	Emergency Planning Fees	-	-	-	-	-	-	1,935	193	2,128	-	2,128	-	-	-	-	-	-	-	-	-
2d.4.10	Fixed Overhead	-	-	-	-	-	-	1,747	262	2,009	2,009	-	-	-	-	-	-	-	-	-	-
2d.4.11	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	305	46	351	351	-	-	-	-	-	-	-	-	-	-
2d.4.12	ISFSI Operating Costs	-	-	-	-	-	-	78	12	89	-	89	-	-	-	-	-	-	-	-	-
2d.4.13	Railroad Track Maintenance	-	-	-	-	-	-	87	13	100	100	-	-	-	-	-	-	-	-	-	-
2d.4.14	Security Staff Cost	-	-	-	-	-	-	9,608	1,441	11,049	7,668	3,381	-	-	-	-	-	-	-	-	162,981
2d.4.15	DOC Staff Cost	-	-	-	-	-	-	6,941	1,041	7,982	7,982	-	-	-	-	-	-	-	-	-	78,356
2d.4.16	Utility Staff Cost	-	-	-	-	-	-	9,556	1,433	10,989	10,132	857	-	-	-	-	-	-	-	-	149,660
2d.4	Subtotal Period 2d Period-Dependent Costs	219	2,453	44	14	-	165	33,025	5,290	41,210	34,754	6,456	-	-	2,030	-	-	-	40,600	66	390,997
2d.0	TOTAL PERIOD 2d COST	2,099	6,535	569	1,112	1,193	11,735	62,574	15,337	101,154	63,579	37,575	-	13,120	75,117	-	-	-	3,923,362	83,645	403,477
PERIOD 2f - License Termination																					
Period 2f Direct Decommissioning Activities																					
2f.1.1	ORISE confirmatory survey	-	-	-	-	-	-	176	53	229	229	-	-	-	-	-	-	-	-	-	-
2f.1.2	Terminate license									a											
2f.1	Subtotal Period 2f Activity Costs	-	-	-	-	-	-	176	53	229	229	-	-	-	-	-	-	-	-	-	-
Period 2f Additional Costs																					
2f.2.1	License Termination Survey	-	-	-	-	-	-	7,341	2,202	9,544	9,544	-	-	-	-	-	-	-	-	96,197	6,240
2f.2	Subtotal Period 2f Additional Costs	-	-	-	-	-	-	7,341	2,202	9,544	9,544	-	-	-	-	-	-	-	-	96,197	6,240
Period 2f Collateral Costs																					
2f.3.1	DOC staff relocation expenses	-	-	-	-	-	-	1,189	178	1,367	1,367	-	-	-	-	-	-	-	-	-	-
2f.3.2	Spent Fuel Capital and Transfer	-	-	-	-	-	-	43	7	50	-	50	-	-	-	-	-	-	-	-	-
2f.3	Subtotal Period 2f Collateral Costs	-	-	-	-	-	-	1,232	185	1,417	1,367	50	-	-	-	-	-	-	-	-	-
Period 2f Period-Dependent Costs																					
2f.4.1	Insurance	-	-	-	-	-	-	543	54	598	598	-	-	-	-	-	-	-	-	-	-
2f.4.2	Property taxes	-	-	-	-	-	-	1,285	128	1,413	1,413	-	-	-	-	-	-	-	-	-	-
2f.4.3	Health physics supplies	-	597	-	-	-	-	-	149	747	747	-	-	-	-	-	-	-	-	-	-
2f.4.4	Disposal of DAW generated	-	-	8	2	-	29	-	8	47	47	-	-	-	355	-	-	-	7,097	12	-
2f.4.5	Plant energy budget	-	-	-	-	-	-	261	39	300	300	-	-	-	-	-	-	-	-	-	-
2f.4.6	NRC Fees	-	-	-	-	-	-	420	42	463	463	-	-	-	-	-	-	-	-	-	-
2f.4.7	Emergency Planning Fees	-	-	-	-	-	-	103	10	113	-	113	-	-	-	-	-	-	-	-	-
2f.4.8	Fixed Overhead	-	-	-	-	-	-	1,747	262	2,009	2,009	-	-	-	-	-	-	-	-	-	-
2f.4.9	ISFSI Operating Costs	-	-	-	-	-	-	78	12	89	-	89	-	-	-	-	-	-	-	-	-
2f.4.10	Railroad Track Maintenance	-	-	-	-	-	-	87	13	100	100	-	-	-	-	-	-	-	-	-	-
2f.4.11	Security Staff Cost	-	-	-	-	-	-	9,608	1,441	11,049	7,668	3,381	-	-	-	-	-	-	-	-	162,981
2f.4.12	DOC Staff Cost	-	-	-	-	-	-	5,174	776	5,950	5,950	-	-	-	-	-	-	-	-	-	57,200
2f.4.13	Utility Staff Cost	-	-	-	-	-	-	5,456	818	6,274	5,415	860	-	-	-	-	-	-	-	-	80,707
2f.4	Subtotal Period 2f Period-Dependent Costs	-	597	8	2	-	29	24,761	3,754	29,152	24,708	4,443	-	-	355	-	-	-	7,097	12	300,888
2f.0	TOTAL PERIOD 2f COST	-	597	8	2	-	29	33,511	6,194	40,341	35,848	4,493	-	-	355	-	-	-	7,097	96,208	307,128
PERIOD 2 TOTALS		13,170	62,856	20,629	9,399	25,814	56,415	416,166	122,242	726,692	568,562	158,062	68	288,110	174,575	1,481	1,010	-	21,522,450	804,895	3,049,889

Table E
Monticello Nuclear Generating Plant
Scenario 3: DECON with 100 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
PERIOD 3b - Site Restoration																					
Period 3b Direct Decommissioning Activities																					
Demolition of Remaining Site Buildings																					
3b.1.1.1	Reactor Building	-	1,881	-	-	-	-	-	282	2,163	-	-	2,163	-	-	-	-	-	-	13,966	-
3b.1.1.2	Condensate Tanks Foundation	-	10	-	-	-	-	-	1	11	-	-	11	-	-	-	-	-	-	50	-
3b.1.1.3	Discharge Retention Basin	-	4	-	-	-	-	-	1	4	-	-	4	-	-	-	-	-	-	25	-
3b.1.1.4	HPCI Room	-	18	-	-	-	-	-	3	21	-	-	21	-	-	-	-	-	-	97	-
3b.1.1.5	Hot Shop	-	15	-	-	-	-	-	2	17	-	-	17	-	-	-	-	-	-	177	-
3b.1.1.6	Hydrogen & Oxygen Storage	-	2	-	-	-	-	-	0	2	-	-	2	-	-	-	-	-	-	19	-
3b.1.1.7	LLRW Storage & Shipping	-	78	-	-	-	-	-	12	90	-	-	90	-	-	-	-	-	-	662	-
3b.1.1.8	MSIV	-	3	-	-	-	-	-	0	4	-	-	4	-	-	-	-	-	-	42	-
3b.1.1.9	Misc Structures 2017	-	759	-	-	-	-	-	114	872	-	-	872	-	-	-	-	-	-	7,919	-
3b.1.1.10	Offgas Stack	-	104	-	-	-	-	-	16	120	-	-	120	-	-	-	-	-	-	544	-
3b.1.1.11	Offgas Storage & Compressor	-	38	-	-	-	-	-	6	44	-	-	44	-	-	-	-	-	-	199	-
3b.1.1.12	Radwaste	-	219	-	-	-	-	-	33	252	-	-	252	-	-	-	-	-	-	1,220	-
3b.1.1.13	Recombiner	-	123	-	-	-	-	-	18	141	-	-	141	-	-	-	-	-	-	713	-
3b.1.1.14	Security Barrier	-	179	-	-	-	-	-	27	206	-	-	206	-	-	-	-	-	-	933	-
3b.1.1.15	Structures Greater than 3' Below Grade	-	2,380	-	-	-	-	-	357	2,738	-	-	2,738	-	-	-	-	-	-	12,649	-
3b.1.1.16	Tank Farm	-	4	-	-	-	-	-	1	5	-	-	5	-	-	-	-	-	-	21	-
3b.1.1.17	Turbine	-	1,175	-	-	-	-	-	176	1,351	-	-	1,351	-	-	-	-	-	-	13,091	-
3b.1.1.18	Turbine Building Addition	-	51	-	-	-	-	-	8	58	-	-	58	-	-	-	-	-	-	618	-
3b.1.1.19	Turbine Pedestal	-	175	-	-	-	-	-	26	202	-	-	202	-	-	-	-	-	-	926	-
3b.1.1	Totals	-	7,219	-	-	-	-	-	1,083	8,302	-	-	8,302	-	-	-	-	-	-	53,870	-
Site Closeout Activities																					
3b.1.2	Grade & landscape site	-	864	-	-	-	-	-	130	994	-	-	994	-	-	-	-	-	-	1,841	-
3b.1.3	Final report to NRC	-	-	-	-	-	-	183	27	211	211	-	-	-	-	-	-	-	-	-	1,560
3b.1	Subtotal Period 3b Activity Costs	-	8,083	-	-	-	-	183	1,240	9,506	211	-	9,295	-	-	-	-	-	-	55,711	1,560
Period 3b Additional Costs																					
3b.2.1	Clean Concrete Disposal	-	3,297	-	-	-	-	11	496	3,805	-	-	3,805	-	-	-	-	-	-	12	-
3b.2.2	Excavation of Underground Services	-	1,380	-	-	-	-	947	349	2,677	-	-	2,677	-	-	-	-	-	-	13,475	-
3b.2.3	Intake Structure Cofferdam	-	320	-	-	-	-	-	48	368	-	-	368	-	-	-	-	-	-	2,584	-
3b.2.4	Constrution Debris	-	-	-	-	-	-	350	53	403	-	-	403	-	-	-	-	-	-	-	-
3b.2.5	Backfill	-	5,102	-	-	-	-	-	765	5,868	-	-	5,868	-	-	-	-	-	-	5,422	-
3b.2	Subtotal Period 3b Additional Costs	-	10,100	-	-	-	-	1,309	1,711	13,120	-	-	13,120	-	-	-	-	-	-	21,493	-
Period 3b Collateral Costs																					
3b.3.1	Small tool allowance	-	97	-	-	-	-	-	15	111	-	-	111	-	-	-	-	-	-	-	-
3b.3.2	Spent Fuel Capital and Transfer	-	-	-	-	-	-	100	15	115	-	115	-	-	-	-	-	-	-	-	-
3b.3	Subtotal Period 3b Collateral Costs	-	97	-	-	-	-	100	30	226	-	115	111	-	-	-	-	-	-	-	-
Period 3b Period-Dependent Costs																					
3b.4.1	Insurance	-	-	-	-	-	-	1,251	125	1,376	-	1,376	-	-	-	-	-	-	-	-	-
3b.4.2	Property taxes	-	-	-	-	-	-	2,737	274	3,011	-	3,011	-	-	-	-	-	-	-	-	-
3b.4.3	Heavy equipment rental	-	5,455	-	-	-	-	-	818	6,273	-	-	6,273	-	-	-	-	-	-	-	-
3b.4.4	Plant energy budget	-	-	-	-	-	-	300	45	345	-	-	345	-	-	-	-	-	-	-	-
3b.4.5	NRC ISFSI Fees	-	-	-	-	-	-	386	39	424	-	424	-	-	-	-	-	-	-	-	-
3b.4.6	Emergency Planning Fees	-	-	-	-	-	-	237	24	261	-	261	-	-	-	-	-	-	-	-	-
3b.4.7	Fixed Overhead	-	-	-	-	-	-	1,260	189	1,450	-	-	1,450	-	-	-	-	-	-	-	-
3b.4.8	ISFSI Operating Costs	-	-	-	-	-	-	179	27	206	-	206	-	-	-	-	-	-	-	-	-
3b.4.9	Railroad Track Maintenance	-	-	-	-	-	-	497	75	572	-	-	572	-	-	-	-	-	-	-	-
3b.4.10	Security Staff Cost	-	-	-	-	-	-	22,115	3,317	25,432	(0)	7,782	17,650	-	-	-	-	-	-	-	375,152
3b.4.11	DOC Staff Cost	-	-	-	-	-	-	11,290	1,693	12,983	-	-	12,983	-	-	-	-	-	-	-	122,646
3b.4.12	Utility Staff Cost	-	-	-	-	-	-	6,830	1,024	7,854	-	2,050	5,804	-	-	-	-	-	-	-	101,904
3b.4	Subtotal Period 3b Period-Dependent Costs	-	5,455	-	-	-	-	47,083	7,650	60,188	(0)	15,110	45,077	-	-	-	-	-	-	-	599,702
3b.0	TOTAL PERIOD 3b COST	-	23,734	-	-	-	-	48,675	10,631	83,040	211	15,226	67,604	-	-	-	-	-	-	77,204	601,262

Table E
Monticello Nuclear Generating Plant
Scenario 3: DECON with 100 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
PERIOD 3c - Fuel Storage Operations																					
Period 3c Additional Costs																					
3c.2.1	ISFSI Disposition of Original MPC Canisters	-	-	-	293	-	7,257	-	1,844	9,395	-	9,395	-	-	23,007	-	-	-	1,317,864	-	-
3c.2	Subtotal Period 3c Additional Costs	-	-	-	293	-	7,257	-	1,844	9,395	-	9,395	-	-	23,007	-	-	-	1,317,864	-	-
Period 3c Collateral Costs																					
3c.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	443,333	66,500	509,833	-	509,833	-	-	-	-	-	-	-	-	-
3c.3	Subtotal Period 3c Collateral Costs	-	-	-	-	-	-	443,333	66,500	509,833	-	509,833	-	-	-	-	-	-	-	-	-
Period 3c Period-Dependent Costs																					
3c.4.1	Insurance	-	-	-	-	-	-	57,075	5,707	62,782	-	62,782	-	-	-	-	-	-	-	-	-
3c.4.2	Property taxes	-	-	-	-	-	-	45,421	4,542	49,963	-	49,963	-	-	-	-	-	-	-	-	-
3c.4.4	NRC ISFSI Fees	-	-	-	-	-	-	17,600	1,760	19,360	-	19,360	-	-	-	-	-	-	-	-	-
3c.4.5	Emergency Planning Fees	-	-	-	-	-	-	10,821	1,082	11,904	-	11,904	-	-	-	-	-	-	-	-	-
3c.4.6	Fixed Overhead	-	-	-	-	-	-	19,671	2,951	22,622	-	22,622	-	-	-	-	-	-	-	-	-
3c.4.7	ISFSI Operating Costs	-	-	-	-	-	-	8,169	1,225	9,395	-	9,395	-	-	-	-	-	-	-	-	-
3c.4.8	Railroad Track Maintenance	-	-	-	-	-	-	9,127	1,369	10,495	-	10,495	-	-	-	-	-	-	-	-	-
3c.4.9	Security Staff Cost	-	-	-	-	-	-	308,615	46,292	354,908	-	354,908	-	-	-	-	-	-	-	-	4,279,284
3c.4.10	DOC Staff Cost	-	-	-	-	-	-	15,257	2,289	17,545	-	17,545	-	-	-	-	-	-	-	-	164,588
3c.4.11	Utility Staff Cost	-	-	-	-	-	-	148,292	22,244	170,536	-	170,536	-	-	-	-	-	-	-	-	2,180,789
3c.4	Subtotal Period 3c Period-Dependent Costs	-	-	-	-	-	-	640,048	89,461	729,509	-	729,509	-	-	-	-	-	-	-	-	6,624,661
3c.0	TOTAL PERIOD 3c COST	-	-	-	293	-	7,257	1,083,381	157,805	1,248,737	-	1,248,737	-	-	23,007	-	-	-	1,317,864	-	6,624,661
PERIOD 3d - Spent Fuel/GTCC shipping																					
Period 3d Direct Decommissioning Activities																					
Nuclear Steam Supply System Removal																					
3d.1.1.1	Vessel & Internals GTCC Disposal	-	-	1,331	-	-	6,552	-	1,316	9,199	9,199	-	-	-	-	-	-	1,547	311,184	-	-
3d.1.1	Totals	-	-	1,331	-	-	6,552	-	1,316	9,199	9,199	-	-	-	-	-	-	1,547	311,184	-	-
3d.1	Subtotal Period 3d Activity Costs	-	-	1,331	-	-	6,552	-	1,316	9,199	9,199	-	-	-	-	-	-	1,547	311,184	-	-
Period 3d Collateral Costs																					
3d.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	53,629	8,044	61,673	-	61,673	-	-	-	-	-	-	-	-	-
3d.3	Subtotal Period 3d Collateral Costs	-	-	-	-	-	-	53,629	8,044	61,673	-	61,673	-	-	-	-	-	-	-	-	-
Period 3d Period-Dependent Costs																					
3d.4.1	Insurance	-	-	-	-	-	-	9,383	938	10,321	-	10,321	-	-	-	-	-	-	-	-	-
3d.4.2	Property taxes	-	-	-	-	-	-	6,703	670	7,374	-	7,374	-	-	-	-	-	-	-	-	-
3d.4.4	NRC ISFSI Fees	-	-	-	-	-	-	4,257	426	4,683	-	4,683	-	-	-	-	-	-	-	-	-
3d.4.5	Emergency Planning Fees	-	-	-	-	-	-	1,779	178	1,957	-	1,957	-	-	-	-	-	-	-	-	-
3d.4.6	Fixed Overhead	-	-	-	-	-	-	3,234	485	3,719	-	3,719	-	-	-	-	-	-	-	-	-
3d.4.7	ISFSI Operating Costs	-	-	-	-	-	-	1,343	201	1,544	-	1,544	-	-	-	-	-	-	-	-	-
3d.4.8	Railroad Track Maintenance	-	-	-	-	-	-	1,500	225	1,725	-	1,725	-	-	-	-	-	-	-	-	-
3d.4.9	Security Staff Cost	-	-	-	-	-	-	50,734	7,610	58,344	-	58,344	-	-	-	-	-	-	-	-	703,485
3d.4.10	Utility Staff Cost	-	-	-	-	-	-	12,865	1,930	14,795	-	14,795	-	-	-	-	-	-	-	-	182,635
3d.4	Subtotal Period 3d Period-Dependent Costs	-	-	-	-	-	-	91,799	12,664	104,462	-	104,462	-	-	-	-	-	-	-	-	886,120
3d.0	TOTAL PERIOD 3d COST	-	-	1,331	-	-	6,552	145,427	22,024	175,334	9,199	166,135	-	-	-	-	-	1,547	311,184	-	886,120

Table E
Monticello Nuclear Generating Plant
Scenario 3: DECON with 100 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
PERIOD 3e - ISFSI Decontamination																					
Period 3e Additional Costs																					
3e.2.1	Decommissioning of ISFSI	30	2	6	14	-	208	1,867	532	2,659	2,659	-	-	-	834	-	-	-	220,333	10,633	1,848
3e.2	Subtotal Period 3e Additional Costs	30	2	6	14	-	208	1,867	532	2,659	2,659	-	-	-	834	-	-	-	220,333	10,633	1,848
Period 3e Period-Dependent Costs																					
3e.4.1	Insurance	-	-	-	-	-	-	110	28	138	138	-	-	-	-	-	-	-	-	-	-
3e.4.2	Property taxes	-	-	-	-	-	-	244	61	304	304	-	-	-	-	-	-	-	-	-	-
3e.4.4	Fixed Overhead	-	-	-	-	-	-	82	21	103	103	-	-	-	-	-	-	-	-	-	-
3e.4.5	Railroad Track Maintenance	-	-	-	-	-	-	38	10	48	48	-	-	-	-	-	-	-	-	-	-
3e.4.6	Security Staff Cost	-	-	-	-	-	-	308	77	385	385	-	-	-	-	-	-	-	-	-	4,999
3e.4.7	Utility Staff Cost	-	-	-	-	-	-	260	65	325	325	-	-	-	-	-	-	-	-	-	3,792
3e.4	Subtotal Period 3e Period-Dependent Costs	-	-	-	-	-	-	1,042	261	1,303	1,303	-	-	-	-	-	-	-	-	-	8,792
3e.0	TOTAL PERIOD 3e COST	30	2	6	14	-	208	2,909	792	3,962	3,962	-	-	-	834	-	-	-	220,333	10,633	10,640
PERIOD 3f - ISFSI Site Restoration																					
Period 3f Additional Costs																					
3f.2.1	Demolition and Site Restoration of ISFSI	-	1,882	-	-	-	-	201	312	2,396	-	-	2,396	-	-	-	-	-	-	9,097	160
3f.2	Subtotal Period 3f Additional Costs	-	1,882	-	-	-	-	201	312	2,396	-	-	2,396	-	-	-	-	-	-	9,097	160
Period 3f Collateral Costs																					
3f.3.1	Small tool allowance	-	13	-	-	-	-	-	2	15	-	-	15	-	-	-	-	-	-	-	-
3f.3	Subtotal Period 3f Collateral Costs	-	13	-	-	-	-	-	2	15	-	-	15	-	-	-	-	-	-	-	-
Period 3f Period-Dependent Costs																					
3f.4.2	Property taxes	-	-	-	-	-	-	123	12	135	-	-	135	-	-	-	-	-	-	-	-
3f.4.3	Heavy equipment rental	-	123	-	-	-	-	-	19	142	-	-	142	-	-	-	-	-	-	-	-
3f.4.4	Plant energy budget	-	-	-	-	-	-	29	4	33	-	-	33	-	-	-	-	-	-	-	-
3f.4.5	Fixed Overhead	-	-	-	-	-	-	42	6	48	-	-	48	-	-	-	-	-	-	-	-
3f.4.6	Railroad Track Maintenance	-	-	-	-	-	-	19	3	22	-	-	22	-	-	-	-	-	-	-	-
3f.4.7	Security Staff Cost	-	-	-	-	-	-	155	23	179	-	-	179	-	-	-	-	-	-	-	2,520
3f.4.8	Utility Staff Cost	-	-	-	-	-	-	103	16	119	-	-	119	-	-	-	-	-	-	-	1,564
3f.4	Subtotal Period 3f Period-Dependent Costs	-	123	-	-	-	-	471	83	678	-	-	678	-	-	-	-	-	-	-	4,084
3f.0	TOTAL PERIOD 3f COST	-	2,018	-	-	-	-	673	398	3,088	-	-	3,088	-	-	-	-	-	-	9,097	4,244
PERIOD 3 TOTALS		30	25,755	1,337	308	-	14,017	1,281,065	191,649	1,514,161	13,372	1,430,098	70,692	-	23,841	-	-	1,547	1,849,382	96,934	8,126,927
TOTAL COST TO DECOMMISSION		**16,519**	**91,470**	**22,063**	**9,880**	**25,828**	**71,578**	**1,844,117**	**337,682**	**2,419,136**	**748,155**	**1,599,295**	**71,685**	**288,153**	**199,616**	**1,711**	**1,010**	**1,547**	**23,435,020**	**933,679**	**12,371,510**

TOTAL COST TO DECOMMISSION WITH 16.22% CONTINGENCY:	**$2,419,136**	**thousands of 2017 dollars**
TOTAL NRC LICENSE TERMINATION COST IS 30.93% OR:	**$748,155**	**thousands of 2017 dollars**
SPENT FUEL MANAGEMENT COST IS 66.11% OR:	**$1,599,295**	**thousands of 2017 dollars**
NON-NUCLEAR DEMOLITION COST IS 2.96% OR:	**$71,685**	**thousands of 2017 dollars**
TOTAL LOW-LEVEL RADIOACTIVE WASTE VOLUME BURIED (EXCLUDING GTCC):	**202,337**	**cubic feet**
TOTAL GREATER THAN CLASS C RADWASTE VOLUME GENERATED:	**1,547**	**cubic feet**
TOTAL SCRAP METAL REMOVED:	**22,696**	**tons**
TOTAL CRAFT LABOR REQUIREMENTS:	**933,679**	**man-hours**

End Notes:
n/a - indicates that this activity not charged as decommissioning expense
a - indicates that this activity performed by decommissioning staff
0 - indicates that this value is less than 0.5 but is non-zero
A cell containing " - " indicates a zero value

APPENDIX F

DETAILED COST ANALYSIS

SCENARIO 4: DECON with 200 Year DFS

Table F
Monticello Nuclear Generating Plant
Scenario 4: DECON with 200 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
PERIOD 1a - Shutdown through Transition																					
Period 1a Direct Decommissioning Activities																					
1a.1.1	Prepare preliminary decommissioning cost	-	-	-	-	-	-	153	23	175	175	-	-	-	-	-	-	-	-	-	1,300
1a.1.2	Notification of Cessation of Operations									a											
1a.1.3	Remove fuel & source material									n/a											
1a.1.4	Notification of Permanent Defueling									a											
1a.1.5	Deactivate plant systems & process waste									a											
1a.1.6	Prepare and submit PSDAR	-	-	-	-	-	-	235	35	270	270	-	-	-	-	-	-	-	-	-	2,000
1a.1.7	Review plant dwgs & specs.	-	-	-	-	-	-	540	81	621	621	-	-	-	-	-	-	-	-	-	4,600
1a.1.8	Perform detailed rad survey									a											
1a.1.9	Estimate by-product inventory	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1a.1.10	End product description	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1a.1.11	Detailed by-product inventory	-	-	-	-	-	-	153	23	175	175	-	-	-	-	-	-	-	-	-	1,300
1a.1.12	Define major work sequence	-	-	-	-	-	-	880	132	1,012	1,012	-	-	-	-	-	-	-	-	-	7,500
1a.1.13	Perform SER and EA	-	-	-	-	-	-	364	55	418	418	-	-	-	-	-	-	-	-	-	3,100
1a.1.14	Prepare/submit Defueled Technical Specifications	-	-	-	-	-	-	880	132	1,012	1,012	-	-	-	-	-	-	-	-	-	7,500
1a.1.15	Perform Site-Specific Cost Study	-	-	-	-	-	-	587	88	675	675	-	-	-	-	-	-	-	-	-	5,000
1a.1.16	Prepare/submit Irradiated Fuel Management Plan	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
Activity Specifications																					
1a.1.17.1	Plant & temporary facilities	-	-	-	-	-	-	578	87	664	598	-	66	-	-	-	-	-	-	-	4,920
1a.1.17.2	Plant systems	-	-	-	-	-	-	489	73	562	506	-	56	-	-	-	-	-	-	-	4,167
1a.1.17.3	NSSS Decontamination Flush	-	-	-	-	-	-	59	9	67	67	-	-	-	-	-	-	-	-	-	500
1a.1.17.4	Reactor internals	-	-	-	-	-	-	833	125	958	958	-	-	-	-	-	-	-	-	-	7,100
1a.1.17.5	Reactor vessel	-	-	-	-	-	-	763	114	877	877	-	-	-	-	-	-	-	-	-	6,500
1a.1.17.6	Sacrificial shield	-	-	-	-	-	-	59	9	67	67	-	-	-	-	-	-	-	-	-	500
1a.1.17.7	Moisture separators/reheaters	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1a.1.17.8	Reinforced concrete	-	-	-	-	-	-	188	28	216	108	-	108	-	-	-	-	-	-	-	1,600
1a.1.17.9	Main Turbine	-	-	-	-	-	-	245	37	282	282	-	-	-	-	-	-	-	-	-	2,088
1a.1.17.10	Main Condensers	-	-	-	-	-	-	245	37	282	282	-	-	-	-	-	-	-	-	-	2,088
1a.1.17.11	Pressure suppression structure	-	-	-	-	-	-	235	35	270	270	-	-	-	-	-	-	-	-	-	2,000
1a.1.17.12	Drywell	-	-	-	-	-	-	188	28	216	216	-	-	-	-	-	-	-	-	-	1,600
1a.1.17.13	Plant structures & buildings	-	-	-	-	-	-	366	55	421	211	-	211	-	-	-	-	-	-	-	3,120
1a.1.17.14	Waste management	-	-	-	-	-	-	540	81	621	621	-	-	-	-	-	-	-	-	-	4,600
1a.1.17.15	Facility & site closeout	-	-	-	-	-	-	106	16	121	61	-	61	-	-	-	-	-	-	-	900
1a.1.17	Total	-	-	-	-	-	-	5,010	752	5,762	5,260	-	502	-	-	-	-	-	-	-	42,683
Planning & Site Preparations																					
1a.1.18	Prepare dismantling sequence	-	-	-	-	-	-	282	42	324	324	-	-	-	-	-	-	-	-	-	2,400
1a.1.19	Plant prep. & temp. svces	-	-	-	-	-	-	3,300	495	3,795	3,795	-	-	-	-	-	-	-	-	-	-
1a.1.20	Design water clean-up system	-	-	-	-	-	-	164	25	189	189	-	-	-	-	-	-	-	-	-	1,400
1a.1.21	Rigging/Cont. Cntrl Envlps/tooling/etc.	-	-	-	-	-	-	2,300	345	2,645	2,645	-	-	-	-	-	-	-	-	-	-
1a.1.22	Procure casks/liners & containers	-	-	-	-	-	-	144	22	166	166	-	-	-	-	-	-	-	-	-	1,230
1a.1	Subtotal Period 1a Activity Costs	-	-	-	-	-	-	15,344	2,302	17,646	17,144	-	502	-	-	-	-	-	-	-	83,013
Period 1a Collateral Costs																					
1a.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	1,221	183	1,404	-	1,404	-	-	-	-	-	-	-	-	-
1a.3.2	Retention and Severance	-	-	-	-	-	-	9,892	1,484	11,376	11,376	-	-	-	-	-	-	-	-	-	-
1a.3	Subtotal Period 1a Collateral Costs	-	-	-	-	-	-	11,113	1,667	12,779	11,376	1,404	-	-	-	-	-	-	-	-	-
Period 1a Period-Dependent Costs																					
1a.4.1	Insurance	-	-	-	-	-	-	2,408	241	2,649	2,649	-	-	-	-	-	-	-	-	-	-
1a.4.2	Property taxes	-	-	-	-	-	-	2,242	224	2,466	2,466	-	-	-	-	-	-	-	-	-	-
1a.4.3	Health physics supplies	-	515	-	-	-	-	-	129	644	644	-	-	-	-	-	-	-	-	-	-
1a.4.4	Heavy equipment rental	-	567	-	-	-	-	-	85	652	652	-	-	-	-	-	-	-	-	-	-
1a.4.5	Disposal of DAW generated	-	-	13	4	-	50	-	14	81	81	-	-	-	610	-	-	-	12,190	20	-
1a.4.6	Plant energy budget	-	-	-	-	-	-	1,730	259	1,989	1,989	-	-	-	-	-	-	-	-	-	-
1a.4.7	NRC Fees	-	-	-	-	-	-	1,110	111	1,221	1,221	-	-	-	-	-	-	-	-	-	-
1a.4.8	Emergency Planning Fees	-	-	-	-	-	-	3,166	317	3,482	-	3,482	-	-	-	-	-	-	-	-	-
1a.4.9	Fixed Overhead	-	-	-	-	-	-	2,833	425	3,258	3,258	-	-	-	-	-	-	-	-	-	-
1a.4.10	Spent Fuel Pool O&M	-	-	-	-	-	-	803	120	923	-	923	-	-	-	-	-	-	-	-	-
1a.4.11	ISFSI Operating Costs	-	-	-	-	-	-	103	15	119	-	119	-	-	-	-	-	-	-	-	-
1a.4.12	Railroad Track Maintenance	-	-	-	-	-	-	115	17	133	133	-	-	-	-	-	-	-	-	-	-
1a.4.13	Security Staff Cost	-	-	-	-	-	-	14,260	2,139	16,399	16,399	-	-	-	-	-	-	-	-	-	245,440
1a.4.14	Utility Staff Cost	-	-	-	-	-	-	25,791	3,869	29,660	29,660	-	-	-	-	-	-	-	-	-	422,240
1a.4	Subtotal Period 1a Period-Dependent Costs	-	1,083	13	4	-	50	54,561	7,966	63,676	59,153	4,524	-	-	610	-	-	-	12,190	20	667,680

Table F
Monticello Nuclear Generating Plant
Scenario 4: DECON with 200 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
1a.0	TOTAL PERIOD 1a COST	-	1,083	13	4	-	50	81,017	11,935	94,101	87,672	5,927	502	-	610	-	-	-	12,190	20	750,693
PERIOD 1b - Decommissioning Preparations																					
Period 1b Direct Decommissioning Activities																					
Detailed Work Procedures																					
1b.1.1.1	Plant systems	-	-	-	-	-	-	556	83	639	575	-	64	-	-	-	-	-	-	-	4,733
1b.1.1.2	NSSS Decontamination Flush	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1b.1.1.3	Reactor internals	-	-	-	-	-	-	470	70	540	540	-	-	-	-	-	-	-	-	-	4,000
1b.1.1.4	Remaining buildings	-	-	-	-	-	-	158	24	182	46	-	137	-	-	-	-	-	-	-	1,350
1b.1.1.5	CRD housings & NIs	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1b.1.1.6	Incore instrumentation	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1b.1.1.7	Removal primary containment	-	-	-	-	-	-	235	35	270	270	-	-	-	-	-	-	-	-	-	2,000
1b.1.1.8	Reactor vessel	-	-	-	-	-	-	426	64	490	490	-	-	-	-	-	-	-	-	-	3,630
1b.1.1.9	Facility closeout	-	-	-	-	-	-	141	21	162	81	-	81	-	-	-	-	-	-	-	1,200
1b.1.1.10	Sacrificial shield	-	-	-	-	-	-	141	21	162	162	-	-	-	-	-	-	-	-	-	1,200
1b.1.1.11	Reinforced concrete	-	-	-	-	-	-	117	18	135	67	-	67	-	-	-	-	-	-	-	1,000
1b.1.1.12	Main Turbine	-	-	-	-	-	-	244	37	281	281	-	-	-	-	-	-	-	-	-	2,080
1b.1.1.13	Main Condensers	-	-	-	-	-	-	245	37	282	282	-	-	-	-	-	-	-	-	-	2,088
1b.1.1.14	Moisture separators & reheaters	-	-	-	-	-	-	235	35	270	270	-	-	-	-	-	-	-	-	-	2,000
1b.1.1.15	Radwaste building	-	-	-	-	-	-	320	48	369	332	-	37	-	-	-	-	-	-	-	2,730
1b.1.1.16	Reactor building	-	-	-	-	-	-	320	48	369	332	-	37	-	-	-	-	-	-	-	2,730
1b.1.1	Total	-	-	-	-	-	-	3,961	594	4,555	4,132	-	423	-	-	-	-	-	-	-	33,741
1b.1.2	Decon NSSS	286	-	-	-	-	-	-	143	429	429	-	-	-	-	-	-	-	-	1,067	-
1b.1	Subtotal Period 1b Activity Costs	286	-	-	-	-	-	3,961	737	4,984	4,561	-	423	-	-	-	-	-	-	1,067	33,741
Period 1b Additional Costs																					
1b.2.1	Spent fuel pool isolation	-	-	-	-	-	-	11,691	1,754	13,445	13,445	-	-	-	-	-	-	-	-	-	-
1b.2.2	Site Characterization	-	-	-	-	-	-	6,446	1,934	8,380	8,380	-	-	-	-	-	-	-	-	30,500	10,852
1b.2.3	Mixed & RCRA Waste	-	-	29	19	13	-	-	8	69	69	-	-	43	-	-	-	-	5,253	163	-
1b.2	Subtotal Period 1b Additional Costs	-	-	29	19	13	-	18,137	3,695	21,894	21,894	-	-	43	-	-	-	-	5,253	30,663	10,852
Period 1b Collateral Costs																					
1b.3.1	Decon equipment	973	-	-	-	-	-	-	146	1,119	1,119	-	-	-	-	-	-	-	-	-	-
1b.3.2	DOC staff relocation expenses	-	-	-	-	-	-	1,189	178	1,367	1,367	-	-	-	-	-	-	-	-	-	-
1b.3.3	Process decommissioning water waste	37	-	24	61	-	98	-	54	275	275	-	-	-	233	-	-	-	13,986	45	-
1b.3.4	Process decommissioning chemical flush waste	1	-	23	85	-	969	-	258	1,336	1,336	-	-	-	-	231	-	-	24,599	43	-
1b.3.5	Small tool allowance	-	2	-	-	-	-	-	0	2	2	-	-	-	-	-	-	-	-	-	-
1b.3.6	Pipe cutting equipment	-	1,200	-	-	-	-	-	180	1,380	1,380	-	-	-	-	-	-	-	-	-	-
1b.3.7	Decon rig	1,987	-	-	-	-	-	-	298	2,285	2,285	-	-	-	-	-	-	-	-	-	-
1b.3.8	Spent Fuel Capital and Transfer	-	-	-	-	-	-	2,557	383	2,940	-	2,940	-	-	-	-	-	-	-	-	-
1b.3.9	Retention and Severance	-	-	-	-	-	-	6,362	954	7,316	7,316	-	-	-	-	-	-	-	-	-	-
1b.3	Subtotal Period 1b Collateral Costs	2,997	1,202	47	147	-	1,067	10,107	2,453	18,020	15,080	2,940	-	-	233	231	-	-	38,585	89	-
Period 1b Period-Dependent Costs																					
1b.4.1	Decon supplies	35	-	-	-	-	-	-	9	44	44	-	-	-	-	-	-	-	-	-	-
1b.4.2	Insurance	-	-	-	-	-	-	1,207	121	1,328	1,328	-	-	-	-	-	-	-	-	-	-
1b.4.3	Property taxes	-	-	-	-	-	-	1,104	110	1,214	1,214	-	-	-	-	-	-	-	-	-	-
1b.4.4	Health physics supplies	-	290	-	-	-	-	-	73	363	363	-	-	-	-	-	-	-	-	-	-
1b.4.5	Heavy equipment rental	-	284	-	-	-	-	-	43	327	327	-	-	-	-	-	-	-	-	-	-
1b.4.6	Disposal of DAW generated	-	-	8	2	-	29	-	8	48	48	-	-	-	358	-	-	-	7,159	12	-
1b.4.7	Plant energy budget	-	-	-	-	-	-	1,735	260	1,995	1,995	-	-	-	-	-	-	-	-	-	-
1b.4.8	NRC Fees	-	-	-	-	-	-	321	32	353	353	-	-	-	-	-	-	-	-	-	-
1b.4.9	Emergency Planning Fees	-	-	-	-	-	-	1,587	159	1,746	-	1,746	-	-	-	-	-	-	-	-	-
1b.4.10	Fixed Overhead	-	-	-	-	-	-	1,420	213	1,633	1,633	-	-	-	-	-	-	-	-	-	-
1b.4.11	Spent Fuel Pool O&M	-	-	-	-	-	-	402	60	463	-	463	-	-	-	-	-	-	-	-	-
1b.4.12	ISFSI Operating Costs	-	-	-	-	-	-	52	8	60	-	60	-	-	-	-	-	-	-	-	-
1b.4.13	Railroad Track Maintenance	-	-	-	-	-	-	58	9	67	67	-	-	-	-	-	-	-	-	-	-
1b.4.14	Security Staff Cost	-	-	-	-	-	-	7,150	1,072	8,222	8,222	-	-	-	-	-	-	-	-	-	123,056
1b.4.15	DOC Staff Cost	-	-	-	-	-	-	5,625	844	6,469	6,469	-	-	-	-	-	-	-	-	-	63,614
1b.4.16	Utility Staff Cost	-	-	-	-	-	-	13,003	1,950	14,953	14,953	-	-	-	-	-	-	-	-	-	212,741
1b.4	Subtotal Period 1b Period-Dependent Costs	35	575	8	2	-	29	33,663	4,971	39,283	37,015	2,268	-	-	358	-	-	-	7,159	12	399,411
1b.0	TOTAL PERIOD 1b COST	3,318	1,777	84	169	13	1,096	65,868	11,856	84,181	78,550	5,208	423	43	591	231	-	-	50,997	31,830	444,004
PERIOD 1 TOTALS		3,318	2,859	97	173	13	1,146	146,886	23,790	178,282	166,222	11,136	925	43	1,201	231	-	-	63,188	31,850	1,194,697

Table F
Monticello Nuclear Generating Plant
Scenario 4: DECON with 200 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
PERIOD 2a - Large Component Removal																					
Period 2a Direct Decommissioning Activities																					
Nuclear Steam Supply System Removal																					
2a.1.1.1	Recirculation System Piping & Valves	107	92	30	39	-	429	-	192	888	888	-	-	-	1,430	-	-	-	99,742	2,905	-
2a.1.1.2	Recirculation Pumps & Motors	38	59	16	40	22	438	-	154	767	767	-	-	96	945	-	-	-	112,200	1,563	-
2a.1.1.3	CRDMs & NIs Removal	187	1,022	402	105	-	919	-	635	3,269	3,269	-	-	-	3,741	-	-	-	213,700	17,768	-
2a.1.1.4	Reactor Vessel Internals	222	6,378	12,908	2,835	-	20,148	356	18,958	61,806	61,806	-	-	-	1,252	1,481	1,010	-	312,338	30,765	1,389
2a.1.1.5	Reactor Vessel	109	8,595	2,644	1,170	-	5,294	356	10,155	28,323	28,323	-	-	-	16,169	-	-	-	1,105,210	30,765	1,389
2a.1.1	Totals	663	16,147	15,999	4,189	22	27,228	711	30,094	95,053	95,053	-	-	96	23,536	1,481	1,010	-	1,843,190	83,767	2,778
Removal of Major Equipment																					
2a.1.2	Main Turbine/Generator	-	362	1,496	349	3,174	357	-	858	6,596	6,596	-	-	24,835	1,383	-	-	-	1,577,959	5,438	-
2a.1.3	Main Condensers	-	1,245	397	128	1,667	198	-	670	4,306	4,306	-	-	17,396	727	-	-	-	828,955	18,831	-
Cascading Costs from Clean Building Demolition																					
2a.1.4.1	Reactor Building	-	317	-	-	-	-	-	48	364	364	-	-	-	-	-	-	-	-	2,217	-
2a.1.4.2	Radwaste	-	24	-	-	-	-	-	4	27	27	-	-	-	-	-	-	-	-	127	-
2a.1.4.3	Turbine	-	118	-	-	-	-	-	18	136	136	-	-	-	-	-	-	-	-	1,254	-
2a.1.4	Totals	-	459	-	-	-	-	-	69	528	528	-	-	-	-	-	-	-	-	3,598	-
Disposal of Plant Systems																					
2a.1.5.1	Automatic Press Relief	-	115	7	8	69	57	-	55	311	311	-	-	803	206	-	-	-	45,852	1,656	-
2a.1.5.2	Chemistry Sampling	-	27	1	1	13	10	-	12	65	65	-	-	156	37	-	-	-	8,681	400	-
2a.1.5.3	Chemistry Sampling - Insulated	-	2	0	0	-	0	-	1	3	3	-	-	-	1	-	-	-	72	28	-
2a.1.5.4	Circulating Water - RCA	-	202	12	41	576	-	-	144	974	974	-	-	6,656	-	-	-	-	270,307	2,860	-
2a.1.5.5	Combustible Gas Control - Insul - RCA	-	29	0	1	18	-	-	10	59	59	-	-	212	-	-	-	-	8,617	378	-
2a.1.5.6	Combustible Gas Control - RCA	-	18	0	2	25	-	-	8	53	53	-	-	285	-	-	-	-	11,577	245	-
2a.1.5.7	Condensate & Feedwater	-	946	189	226	1,725	2,003	-	1,049	6,138	6,138	-	-	19,947	7,319	-	-	-	1,275,810	14,196	-
2a.1.5.8	Condensate & Feedwater - Insulated	-	480	34	43	361	332	-	267	1,517	1,517	-	-	4,176	1,207	-	-	-	246,693	6,964	-
2a.1.5.9	Condensate Demin	-	533	29	35	289	276	-	254	1,416	1,416	-	-	3,346	1,000	-	-	-	199,936	7,618	-
2a.1.5.10	Condensate Storage	-	706	31	55	617	219	-	335	1,963	1,963	-	-	7,131	795	-	-	-	340,568	10,345	-
2a.1.5.11	Control Rod Drive	-	3	0	0	2	1	-	1	7	7	-	-	19	4	-	-	-	1,009	41	-
2a.1.5.12	Control Rod Drive Hydraulic	-	405	16	18	143	155	-	166	902	902	-	-	1,658	562	-	-	-	103,306	5,898	-
2a.1.5.13	Core Spray	-	75	19	34	379	143	-	119	770	770	-	-	4,384	521	-	-	-	211,329	1,163	-
2a.1.5.14	Core Spray - Insulated	-	141	8	9	71	73	-	66	368	368	-	-	818	264	-	-	-	50,149	2,033	-
2a.1.5.15	Demin Water - Insulated - RCA	-	15	0	1	7	-	-	5	27	27	-	-	85	-	-	-	-	3,445	181	-
2a.1.5.16	Demin Water - RCA	-	40	0	2	22	-	-	14	78	78	-	-	253	-	-	-	-	10,278	508	-
2a.1.5.17	Diesel Oil - RCA	-	2	0	0	2	-	-	1	5	5	-	-	23	-	-	-	-	931	25	-
2a.1.5.18	Drywell Atmosphere Cooling - RCA	-	37	1	3	47	-	-	17	105	105	-	-	548	-	-	-	-	22,244	550	-
2a.1.5.19	EDG Emerg Service Water - Insul - RCA	-	0	0	0	0	-	-	0	1	1	-	-	2	-	-	-	-	84	4	-
2a.1.5.20	Electrical - Clean	-	12	-	-	-	-	-	2	13	-	-	13	-	-	-	-	-	-	182	-
2a.1.5.21	Emergency Service Water - Insul - RCA	-	21	0	1	12	-	-	7	41	41	-	-	137	-	-	-	-	5,544	281	-
2a.1.5.22	Emergency Service Water - RCA	-	2	0	0	1	-	-	1	4	4	-	-	13	-	-	-	-	512	22	-
2a.1.5.23	GEZIP - RCA	-	3	0	1	9	-	-	2	15	15	-	-	103	-	-	-	-	4,184	48	-
2a.1.5.24	Generator Physical Design - RCA	-	5	0	0	3	-	-	2	9	9	-	-	31	-	-	-	-	1,250	67	-
2a.1.5.25	H2-O2 Control Analyzing	-	6	0	0	0	4	-	3	13	13	-	-	6	13	-	-	-	1,080	81	-
2a.1.5.26	H2-O2 Control Analyzing - Insulated	-	6	0	0	0	4	-	3	13	13	-	-	6	13	-	-	-	1,080	81	-
2a.1.5.27	High Pressure Coolant Injection	-	64	6	9	84	57	-	45	266	266	-	-	972	209	-	-	-	52,792	966	-
2a.1.5.28	High Pressure Coolant Injection - Insula	-	214	14	17	138	133	-	111	627	627	-	-	1,598	481	-	-	-	95,733	3,079	-
2a.1.5.29	Hydrogen Cooling	-	7	-	-	-	-	-	1	9	-	-	9	-	-	-	-	-	-	118	-
2a.1.5.30	Hydrogen Cooling - RCA	-	7	0	0	3	-	-	2	13	13	-	-	39	-	-	-	-	1,600	79	-
2a.1.5.31	Hydrogen Seal Oil - RCA	-	17	0	1	16	-	-	7	42	42	-	-	189	-	-	-	-	7,669	212	-
2a.1.5.32	Hydrogen Water Chemistry - RCA	-	24	0	1	12	-	-	8	45	45	-	-	140	-	-	-	-	5,672	304	-
2a.1.5.33	Instrument & Service Air - RCA	-	220	3	11	153	-	-	80	466	466	-	-	1,768	-	-	-	-	71,810	2,733	-
2a.1.5.34	Main Condenser	-	191	12	14	115	113	-	97	542	542	-	-	1,333	411	-	-	-	80,439	2,746	-
2a.1.5.35	Main Steam	-	243	17	22	186	163	-	134	764	764	-	-	2,148	594	-	-	-	125,135	3,512	-
2a.1.5.36	Main Turbine	-	972	214	244	1,709	2,375	-	1,151	6,665	6,665	-	-	19,760	8,687	-	-	-	1,354,661	14,733	-
2a.1.5.37	Main Turbine - Insulated	-	209	19	25	219	183	-	136	790	790	-	-	2,530	667	-	-	-	145,208	3,069	-
2a.1.5.38	Miscellaneous	-	42	1	2	26	-	-	15	85	85	-	-	302	-	-	-	-	12,283	622	-
2a.1.5.39	Off Gas Recombiner	-	182	19	22	155	209	-	126	714	714	-	-	1,795	764	-	-	-	121,554	2,708	-
2a.1.5.40	Off Gas Recombiner - Insulated	-	379	19	19	118	195	-	166	897	897	-	-	1,366	709	-	-	-	100,933	5,385	-
2a.1.5.41	Post Accident Sampling	-	24	1	1	5	9	-	9	50	50	-	-	53	33	-	-	-	4,318	345	-
2a.1.5.42	Post Accident Sampling - Insulated	-	16	1	1	1	11	-	7	37	37	-	-	17	37	-	-	-	3,116	212	-
2a.1.5.43	RHR Service Water - Insulated - RCA	-	81	3	9	128	-	-	41	262	262	-	-	1,485	-	-	-	-	60,293	1,125	-
2a.1.5.44	RHR Service Water - RCA	-	4	0	0	3	-	-	1	9	9	-	-	35	-	-	-	-	1,410	57	-
2a.1.5.45	Reactor Feedwater Pump Seal	-	55	3	3	17	26	-	23	126	126	-	-	193	96	-	-	-	14,009	773	-

Table F
Monticello Nuclear Generating Plant
Scenario 4: DECON with 200 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Disposal of Plant Systems (continued)																					
2a.1.5.46	Residual Heat Removal	349	240	168	126	554	1,667	-	770	3,875	3,875	-	-	6,406	6,012	-	-	-	647,941	4,135	-
2a.1.5.47	Residual Heat Removal - Insulated	602	540	64	58	291	715	-	674	2,944	2,944	-	-	3,367	2,607	-	-	-	303,087	10,340	-
2a.1.5.48	Rx Core Isolation Cooling	-	47	2	3	22	21	-	21	116	116	-	-	259	76	-	-	-	15,396	691	-
2a.1.5.49	Rx Core Isolation Cooling - Insulated	-	105	5	5	25	55	-	45	240	240	-	-	288	198	-	-	-	24,419	1,479	-
2a.1.5.50	Rx Recirculation	56	57	6	3	4	53	-	57	235	235	-	-	43	190	-	-	-	14,095	1,580	-
2a.1.5.51	Snubbers	-	168	2	4	33	25	-	54	285	285	-	-	377	90	-	-	-	21,009	2,548	-
2a.1.5.52	Standby Liquid Control - Insul - RCA	-	4	0	0	2	-	-	1	7	7	-	-	22	-	-	-	-	904	48	-
2a.1.5.53	Standby Liquid Control - RCA	-	26	0	1	21	-	-	10	59	59	-	-	245	-	-	-	-	9,969	341	-
2a.1.5.54	Stator Cooling - RCA	-	7	0	1	11	-	-	4	23	23	-	-	126	-	-	-	-	5,135	98	-
2a.1.5.55	Traversing Incore Probe	0	4	0	0	0	2	-	1	7	7	-	-	1	5	-	-	-	386	51	-
2a.1.5	Totals	1,007	7,978	931	1,079	8,447	9,287	-	6,340	35,068	35,046	-	22	97,654	33,808	-	-	-	6,125,515	119,943	-
2a.1.6	Scaffolding in support of decommissioning	-	2,188	25	8	99	25	-	572	2,916	2,916	-	-	1,030	91	-	-	-	52,111	22,564	-
2a.1	Subtotal Period 2a Activity Costs	1,669	28,379	18,848	5,754	13,409	37,095	711	38,602	144,467	144,445	-	22	141,010	59,545	1,481	1,010	-	10,427,730	254,140	2,778
Period 2a Additional Costs																					
2a.2.1	Remedial Action Surveys	-	-	-	-	-	-	2,326	698	3,024	3,024	-	-	-	-	-	-	-	-	30,411	-
2a.2	Subtotal Period 2a Additional Costs	-	-	-	-	-	-	2,326	698	3,024	3,024	-	-	-	-	-	-	-	-	30,411	-
Period 2a Collateral Costs																					
2a.3.1	Process decommissioning water waste	83	-	55	140	-	222	-	123	623	623	-	-	-	531	-	-	-	31,838	103	-
2a.3.2	Process decommissioning chemical flush waste	6	-	208	774	-	1,557	-	529	3,075	3,075	-	-	-	2,093	-	-	-	223,008	392	-
2a.3.3	Small tool allowance	-	315	-	-	-	-	-	47	363	326	-	36	-	-	-	-	-	-	-	-
2a.3.4	Spent Fuel Capital and Transfer	-	-	-	-	-	-	23,173	3,476	26,649	-	26,649	-	-	-	-	-	-	-	-	-
2a.3.5	Retention and Severance	-	-	-	-	-	-	13,235	1,985	15,221	15,221	-	-	-	-	-	-	-	-	-	-
2a.3	Subtotal Period 2a Collateral Costs	89	315	263	914	-	1,779	36,408	6,161	45,930	19,245	26,649	36	-	2,623	-	-	-	254,846	495	-
Period 2a Period-Dependent Costs																					
2a.4.1	Decon supplies	102	-	-	-	-	-	-	25	127	127	-	-	-	-	-	-	-	-	-	-
2a.4.2	Insurance	-	-	-	-	-	-	1,055	106	1,161	1,161	-	-	-	-	-	-	-	-	-	-
2a.4.3	Property taxes	-	-	-	-	-	-	3,061	306	3,367	3,367	-	-	-	-	-	-	-	-	-	-
2a.4.4	Health physics supplies	-	2,133	-	-	-	-	-	533	2,666	2,666	-	-	-	-	-	-	-	-	-	-
2a.4.5	Heavy equipment rental	-	3,212	-	-	-	-	-	482	3,694	3,694	-	-	-	-	-	-	-	-	-	-
2a.4.6	Disposal of DAW generated	-	-	122	37	-	453	-	131	743	743	-	-	-	5,567	-	-	-	111,335	182	-
2a.4.7	Plant energy budget	-	-	-	-	-	-	2,404	361	2,765	2,765	-	-	-	-	-	-	-	-	-	-
2a.4.8	NRC Fees	-	-	-	-	-	-	847	85	932	932	-	-	-	-	-	-	-	-	-	-
2a.4.9	Emergency Planning Fees	-	-	-	-	-	-	3,757	376	4,133	-	4,133	-	-	-	-	-	-	-	-	-
2a.4.10	Fixed Overhead	-	-	-	-	-	-	3,392	509	3,900	3,900	-	-	-	-	-	-	-	-	-	-
2a.4.11	Spent Fuel Pool O&M	-	-	-	-	-	-	1,174	176	1,350	-	1,350	-	-	-	-	-	-	-	-	-
2a.4.12	ISFSI Operating Costs	-	-	-	-	-	-	151	23	174	-	174	-	-	-	-	-	-	-	-	-
2a.4.13	Railroad Track Maintenance	-	-	-	-	-	-	466	70	536	536	-	-	-	-	-	-	-	-	-	-
2a.4.14	Security Staff Cost	-	-	-	-	-	-	19,265	2,890	22,154	22,154	-	-	-	-	-	-	-	-	-	328,651
2a.4.15	DOC Staff Cost	-	-	-	-	-	-	20,125	3,019	23,144	23,144	-	-	-	-	-	-	-	-	-	231,273
2a.4.16	Utility Staff Cost	-	-	-	-	-	-	26,670	4,000	30,670	30,670	-	-	-	-	-	-	-	-	-	430,594
2a.4	Subtotal Period 2a Period-Dependent Costs	102	5,345	122	37	-	453	82,366	13,090	101,515	95,858	5,657	-	-	5,567	-	-	-	111,335	182	990,519
2a.0	TOTAL PERIOD 2a COST	1,860	34,039	19,233	6,705	13,409	39,327	121,812	58,551	294,937	262,573	32,305	58	141,010	67,735	1,481	1,010	-	10,793,910	285,228	993,297
PERIOD 2b - Site Decontamination																					
Period 2b Direct Decommissioning Activities																					
Disposal of Plant Systems																					
2b.1.1.1	ALARA/Radiological	-	18	0	0	3	3	-	6	30	30	-	-	35	10	-	-	-	2,060	277	-
2b.1.1.2	Alternate N2 - RCA	-	16	0	1	8	-	-	5	30	30	-	-	93	-	-	-	-	3,765	185	-
2b.1.1.3	Decontamination Projects	-	1	0	0	0	0	-	0	2	2	-	-	2	0	-	-	-	129	17	-
2b.1.1.4	Electrical - Contaminated	-	439	6	16	207	25	-	150	841	841	-	-	2,389	90	-	-	-	102,726	6,325	-
2b.1.1.5	Electrical - Decontaminated	-	2,657	41	142	2,019	-	-	993	5,852	5,852	-	-	23,344	-	-	-	-	948,013	37,107	-
2b.1.1.6	Fire - RCA	-	99	1	4	53	-	-	33	191	191	-	-	614	-	-	-	-	24,917	1,324	-
2b.1.1.7	HVAC Ductwork	-	309	7	18	231	27	-	122	713	713	-	-	2,665	100	-	-	-	114,598	4,111	-
2b.1.1.8	HVAC/Chilled Water - RCA	-	317	5	17	238	-	-	118	694	694	-	-	2,752	-	-	-	-	111,779	3,985	-
2b.1.1.9	Heating & Ventilation	-	473	15	40	521	62	-	219	1,329	1,329	-	-	6,018	227	-	-	-	258,789	7,101	-
2b.1.1.10	Heating Boiler - Insulated - RCA	-	3	0	0	2	-	-	1	6	6	-	-	26	-	-	-	-	1,058	35	-
2b.1.1.11	Liquid Radwaste	572	669	46	44	266	476	-	623	2,697	2,697	-	-	3,073	1,728	-	-	-	235,484	17,194	-
2b.1.1.12	Makeup Demin - RCA	-	101	3	9	127	-	-	46	286	286	-	-	1,471	-	-	-	-	59,747	1,412	-
2b.1.1.13	Non-Essential Diesel Generator - RCA	-	26	2	9	123	-	-	27	187	187	-	-	1,424	-	-	-	-	57,832	395	-

Table F
Monticello Nuclear Generating Plant
Scenario 4: DECON with 200 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Disposal of Plant Systems (continued)																					
2b.1.1.14	Off Gas Holdup	-	333	20	26	238	174	-	168	960	960	-	-	2,755	630	-	-	-	152,277	4,769	-
2b.1.1.15	Primary Containment	-	443	43	59	536	412	-	308	1,801	1,801	-	-	6,201	1,506	-	-	-	347,704	6,454	-
2b.1.1.16	Process Radiation Monitors	-	45	2	2	12	14	-	17	92	92	-	-	142	52	-	-	-	9,115	649	-
2b.1.1.17	Rx Bldg Closed Clng Water - Insul - RCA	-	111	2	6	85	-	-	42	245	245	-	-	977	-	-	-	-	39,675	1,484	-
2b.1.1.18	Rx Bldg Closed Clng Water - RCA	-	178	12	43	614	-	-	144	991	991	-	-	7,093	-	-	-	-	288,031	2,489	-
2b.1.1.19	Rx Component Handling Equip	26	138	19	19	100	227	-	124	653	653	-	-	1,158	829	-	-	-	99,730	2,462	-
2b.1.1.20	Rx Pressure Vessel	28	46	6	4	7	63	-	43	196	196	-	-	75	230	-	-	-	17,816	1,051	-
2b.1.1.21	Rx Water Cleanup	169	258	19	11	11	204	-	205	877	877	-	-	130	737	-	-	-	52,670	5,736	-
2b.1.1.22	Secondary Containment	-	121	7	10	88	70	-	63	360	360	-	-	1,017	255	-	-	-	57,567	1,763	-
2b.1.1.23	Service & Seal Water - Insulated - RCA	-	117	2	7	102	-	-	46	274	274	-	-	1,180	-	-	-	-	47,917	1,565	-
2b.1.1.24	Service & Seal Water - RCA	-	155	3	11	156	-	-	64	390	390	-	-	1,809	-	-	-	-	73,453	2,016	-
2b.1.1.25	Service Air Blower - RCA	-	15	0	1	18	-	-	7	41	41	-	-	206	-	-	-	-	8,364	206	-
2b.1.1.26	Solid Radwaste	327	483	36	34	206	380	-	419	1,885	1,885	-	-	2,387	1,380	-	-	-	185,221	10,820	-
2b.1.1.27	Structures & Buildings	-	76	2	3	31	23	-	30	166	166	-	-	357	85	-	-	-	19,933	1,128	-
2b.1.1.28	Wells & Domestic Water	-	9	-	-	-	-	-	1	10	-	-	10	-	-	-	-	-	-	144	-
2b.1.1.29	Wells & Domestic Water - RCA	-	51	1	2	30	-	-	18	101	101	-	-	342	-	-	-	-	13,874	633	-
2b.1.1	Totals	1,122	7,707	299	537	6,032	2,160	-	4,042	21,900	21,890	-	10	69,735	7,859	-	-	-	3,334,244	122,835	-
2b.1.2	Scaffolding in support of decommissioning	-	2,735	31	10	123	31	-	715	3,645	3,645	-	-	1,287	114	-	-	-	65,139	28,205	-
Decontamination of Site Buildings																					
2b.1.3.1	Reactor Building	5,006	2,817	155	347	4,159	1,007	-	4,150	17,641	17,641	-	-	48,077	7,014	-	-	-	2,317,670	112,518	-
2b.1.3.2	Admin	103	6	0	2	-	14	-	57	182	182	-	-	-	145	-	-	-	6,840	1,600	-
2b.1.3.3	HPCI Room	28	27	1	2	10	13	-	26	107	107	-	-	118	125	-	-	-	10,759	789	-
2b.1.3.4	Hot Shop	16	4	0	1	-	10	-	12	43	43	-	-	-	103	-	-	-	4,860	286	-
2b.1.3.5	LLRW Storage & Shipping	56	23	1	6	3	41	-	46	176	176	-	-	31	433	-	-	-	21,708	1,127	-
2b.1.3.6	Offgas Stack	360	256	6	16	116	73	-	283	1,109	1,109	-	-	1,343	669	-	-	-	87,045	8,860	-
2b.1.3.7	Offgas Storage & Compressor	39	17	1	4	2	30	-	32	125	125	-	-	25	316	-	-	-	15,948	785	-
2b.1.3.8	Radwaste	117	59	3	13	15	86	-	100	393	393	-	-	172	910	-	-	-	49,943	2,503	-
2b.1.3.9	Radwaste Material Storage Warehouse	62	23	1	6	-	47	-	49	189	189	-	-	-	495	-	-	-	23,400	1,197	-
2b.1.3.10	Recombiner	26	24	1	4	17	22	-	28	122	122	-	-	199	216	-	-	-	18,405	695	-
2b.1.3.11	Turbine	684	341	18	76	111	507	-	583	2,319	2,319	-	-	1,283	5,299	-	-	-	303,150	14,443	-
2b.1.3.12	Turbine Building Addition	56	20	1	6	-	41	-	44	169	169	-	-	-	434	-	-	-	20,478	1,087	-
2b.1.3	Totals	6,554	3,618	188	483	4,433	1,889	-	5,410	22,574	22,574	-	-	51,247	16,159	-	-	-	2,880,206	145,889	-
2b.1.4	Prepare/submit License Termination Plan	-	-	-	-	-	-	481	72	553	553	-	-	-	-	-	-	-	-	-	4,096
2b.1.5	Receive NRC approval of termination plan									a											
2b.1	Subtotal Period 2b Activity Costs	7,676	14,060	518	1,031	10,588	4,079	481	10,239	48,672	48,662	-	10	122,269	24,132	-	-	-	6,279,589	296,929	4,096
Period 2b Additional Costs																					
2b.2.1	Remedial Action Surveys	-	-	-	-	-	-	3,241	972	4,213	4,213	-	-	-	-	-	-	-	-	42,370	-
2b.2.2	Operational Equipment	-	-	19	60	624	-	-	104	807	807	-	-	11,710	-	-	-	-	292,750	32	-
2b.2.3	Security Modifications	-	-	-	-	-	-	8,696	1,304	10,000	10,000	-	-	-	-	-	-	-	-	-	-
2b.2	Subtotal Period 2b Additional Costs	-	-	19	60	624	-	11,937	2,381	15,020	15,020	-	-	11,710	-	-	-	-	292,750	42,402	-
Period 2b Collateral Costs																					
2b.3.1	Process decommissioning water waste	173	-	117	299	-	474	-	261	1,325	1,325	-	-	-	1,133	-	-	-	67,962	221	-
2b.3.2	Process decommissioning chemical flush waste	1	-	41	153	-	307	-	104	606	606	-	-	-	413	-	-	-	43,978	77	-
2b.3.3	Small tool allowance	-	341	-	-	-	-	-	51	392	392	-	-	-	-	-	-	-	-	-	-
2b.3.4	Spent Fuel Capital and Transfer	-	-	-	-	-	-	65,919	9,888	75,807	-	75,807	-	-	-	-	-	-	-	-	-
2b.3.5	Retention and Severance	-	-	-	-	-	-	8,665	1,300	9,964	9,964	-	-	-	-	-	-	-	-	-	-
2b.3	Subtotal Period 2b Collateral Costs	174	341	159	452	-	781	74,584	11,604	88,094	12,287	75,807	-	-	1,545	-	-	-	111,940	298	-

Table F
Monticello Nuclear Generating Plant
Scenario 4: DECON with 200 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 2b Period-Dependent Costs																					
2b.4.1	Decon supplies	1,361	-	-	-	-	-	-	340	1,701	1,701	-	-	-	-	-	-	-	-	-	-
2b.4.2	Insurance	-	-	-	-	-	-	1,470	147	1,617	1,617	-	-	-	-	-	-	-	-	-	-
2b.4.3	Property taxes	-	-	-	-	-	-	3,915	391	4,306	4,306	-	-	-	-	-	-	-	-	-	-
2b.4.4	Health physics supplies	-	2,681	-	-	-	-	-	670	3,352	3,352	-	-	-	-	-	-	-	-	-	-
2b.4.5	Heavy equipment rental	-	4,602	-	-	-	-	-	690	5,292	5,292	-	-	-	-	-	-	-	-	-	-
2b.4.6	Disposal of DAW generated	-	-	124	38	-	463	-	134	759	759	-	-	-	5,690	-	-	-	113,799	186	-
2b.4.7	Plant energy budget	-	-	-	-	-	-	2,645	397	3,041	3,041	-	-	-	-	-	-	-	-	-	-
2b.4.8	NRC Fees	-	-	-	-	-	-	1,180	118	1,298	1,298	-	-	-	-	-	-	-	-	-	-
2b.4.9	Emergency Planning Fees	-	-	-	-	-	-	5,234	523	5,758	-	5,758	-	-	-	-	-	-	-	-	-
2b.4.10	Fixed Overhead	-	-	-	-	-	-	4,725	709	5,434	5,434	-	-	-	-	-	-	-	-	-	-
2b.4.11	Spent Fuel Pool O&M	-	-	-	-	-	-	1,636	245	1,881	-	1,881	-	-	-	-	-	-	-	-	-
2b.4.12	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	412	62	474	474	-	-	-	-	-	-	-	-	-	-
2b.4.13	ISFSI Operating Costs	-	-	-	-	-	-	210	32	242	-	242	-	-	-	-	-	-	-	-	-
2b.4.14	Railroad Track Maintenance	-	-	-	-	-	-	235	35	270	270	-	-	-	-	-	-	-	-	-	-
2b.4.15	Security Staff Cost	-	-	-	-	-	-	26,840	4,026	30,867	30,867	-	-	-	-	-	-	-	-	-	457,896
2b.4.16	DOC Staff Cost	-	-	-	-	-	-	27,122	4,068	31,191	31,191	-	-	-	-	-	-	-	-	-	309,504
2b.4.17	Utility Staff Cost	-	-	-	-	-	-	35,641	5,346	40,988	40,988	-	-	-	-	-	-	-	-	-	574,490
2b.4	Subtotal Period 2b Period-Dependent Costs	1,361	7,283	124	38	-	463	111,268	17,935	138,473	130,592	7,881	-	-	5,690	-	-	-	113,799	186	1,341,891
2b.0	TOTAL PERIOD 2b COST	9,211	21,684	820	1,580	11,212	5,324	198,269	42,159	290,260	206,561	83,688	10	133,979	31,367	-	-	-	6,798,079	339,814	1,345,987
PERIOD 2d - Decontamination Following Wet Fuel Storage																					
Period 2d Direct Decommissioning Activities																					
2d.1.1	Remove spent fuel racks	634	56	114	109	-	2,091	-	881	3,884	3,884	-	-	-	7,653	-	-	-	486,170	906	-
Disposal of Plant Systems																					
2d.1.2.1	Cranes/Heavy Loads/Rigging - RCA	-	3	0	1	9	-	-	2	15	15	-	-	103	-	-	-	-	4,184	48	-
2d.1.2.2	Electrical - Contaminated Fuel Pool	-	46	1	2	21	2	-	16	87	87	-	-	240	9	-	-	-	10,334	665	-
2d.1.2.3	Electrical - Decontam. Fuel Pool Area	-	293	4	15	213	-	-	108	633	633	-	-	2,457	-	-	-	-	99,783	4,090	-
2d.1.2.4	Fire - RCA - Fuel Pool Area	-	11	0	0	5	-	-	4	20	20	-	-	62	-	-	-	-	2,499	143	-
2d.1.2.5	Fuel Pool Cooling & Cleanup	240	419	34	26	102	370	-	340	1,531	1,531	-	-	1,179	1,341	-	-	-	133,939	8,380	-
2d.1.2.6	Fuel Pool Cooling & Cleanup - Insulated	26	40	3	2	6	32	-	33	143	143	-	-	67	117	-	-	-	10,220	848	-
2d.1.2.7	HVAC Ductwork - Fuel Pool Area	-	34	1	2	26	3	-	14	79	79	-	-	296	11	-	-	-	12,733	457	-
2d.1.2.8	HVAC/Chilled Water - RCA Fuel Pool Area	-	32	0	1	19	-	-	11	64	64	-	-	223	-	-	-	-	9,072	397	-
2d.1.2.9	Instrument & Service Air-RCA-Fuel Pool	-	28	0	2	23	-	-	11	64	64	-	-	267	-	-	-	-	10,841	357	-
2d.1.2	Totals	266	907	44	51	423	408	-	537	2,637	2,637	-	-	4,894	1,479	-	-	-	293,606	15,385	-
Decontamination of Site Buildings																					
2d.1.3.1	Reactor (Post Fuel)	911	2,485	145	669	170	8,544	-	3,353	16,277	16,277	-	-	1,969	62,698	-	-	-	2,732,406	45,703	-
2d.1.3	Totals	911	2,485	145	669	170	8,544	-	3,353	16,277	16,277	-	-	1,969	62,698	-	-	-	2,732,406	45,703	-
2d.1.4	Scaffolding in support of decommissioning	-	547	6	2	25	6	-	143	729	729	-	-	257	23	-	-	-	13,028	5,641	-
2d.1	Subtotal Period 2d Activity Costs	1,811	3,994	309	831	618	11,049	-	4,915	23,527	23,527	-	-	7,120	71,852	-	-	-	3,525,210	67,635	-
Period 2d Additional Costs																					
2d.2.1	License Termination Survey Planning	-	-	-	-	-	-	1,291	387	1,678	1,678	-	-	-	-	-	-	-	-	-	12,480
2d.2.2	Remedial Action Surveys	-	-	-	-	-	-	1,198	359	1,557	1,557	-	-	-	-	-	-	-	-	15,661	-
2d.2	Subtotal Period 2d Additional Costs	-	-	-	-	-	-	2,489	747	3,235	3,235	-	-	-	-	-	-	-	-	15,661	12,480
Period 2d Collateral Costs																					
2d.3.1	Process decommissioning water waste	69	-	47	120	-	191	-	105	533	533	-	-	-	457	-	-	-	27,391	89	-
2d.3.2	Process decommissioning chemical flush waste	1	-	25	92	-	185	-	63	366	366	-	-	-	249	-	-	-	26,553	47	-
2d.3.3	Small tool allowance	-	88	-	-	-	-	-	13	101	101	-	-	-	-	-	-	-	-	-	-
2d.3.4	Decommissioning Equipment Disposition	-	-	143	55	575	145	-	145	1,062	1,062	-	-	6,000	529	-	-	-	303,608	147	-
2d.3.5	Spent Fuel Capital and Transfer	-	-	-	-	-	-	27,061	4,059	31,120	-	31,120	-	-	-	-	-	-	-	-	-
2d.3	Subtotal Period 2d Collateral Costs	70	88	216	267	575	521	27,061	4,385	33,182	2,062	31,120	-	6,000	1,235	-	-	-	357,552	283	-

Table F
Monticello Nuclear Generating Plant
Scenario 4: DECON with 200 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 2d Period-Dependent Costs																					
2d.4.1	Decon supplies	219	-	-	-	-	-	-	55	274	274	-	-	-	-	-	-	-	-	-	-
2d.4.2	Insurance	-	-	-	-	-	-	543	54	598	598	-	-	-	-	-	-	-	-	-	-
2d.4.3	Property taxes	-	-	-	-	-	-	1,336	134	1,470	1,470	-	-	-	-	-	-	-	-	-	-
2d.4.4	Health physics supplies	-	752	-	-	-	-	-	188	940	940	-	-	-	-	-	-	-	-	-	-
2d.4.5	Heavy equipment rental	-	1,701	-	-	-	-	-	255	1,956	1,956	-	-	-	-	-	-	-	-	-	-
2d.4.6	Disposal of DAW generated	-	-	44	14	-	165	-	48	271	271	-	-	-	2,030	-	-	-	40,600	66	-
2d.4.7	Plant energy budget	-	-	-	-	-	-	521	78	600	600	-	-	-	-	-	-	-	-	-	-
2d.4.8	NRC Fees	-	-	-	-	-	-	369	37	405	405	-	-	-	-	-	-	-	-	-	-
2d.4.9	Emergency Planning Fees	-	-	-	-	-	-	1,935	193	2,128	-	2,128	-	-	-	-	-	-	-	-	-
2d.4.10	Fixed Overhead	-	-	-	-	-	-	1,747	262	2,009	2,009	-	-	-	-	-	-	-	-	-	-
2d.4.11	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	305	46	351	351	-	-	-	-	-	-	-	-	-	-
2d.4.12	ISFSI Operating Costs	-	-	-	-	-	-	78	12	89	-	89	-	-	-	-	-	-	-	-	-
2d.4.13	Railroad Track Maintenance	-	-	-	-	-	-	87	13	100	100	-	-	-	-	-	-	-	-	-	-
2d.4.14	Security Staff Cost	-	-	-	-	-	-	9,608	1,441	11,049	7,668	3,381	-	-	-	-	-	-	-	-	162,981
2d.4.15	DOC Staff Cost	-	-	-	-	-	-	6,941	1,041	7,982	7,982	-	-	-	-	-	-	-	-	-	78,356
2d.4.16	Utility Staff Cost	-	-	-	-	-	-	9,556	1,433	10,989	10,132	857	-	-	-	-	-	-	-	-	149,660
2d.4	Subtotal Period 2d Period-Dependent Costs	219	2,453	44	14	-	165	33,025	5,290	41,210	34,754	6,456	-	-	2,030	-	-	-	40,600	66	390,997
2d.0	TOTAL PERIOD 2d COST	2,099	6,535	569	1,112	1,193	11,735	62,574	15,337	101,154	63,579	37,575	-	13,120	75,117	-	-	-	3,923,362	83,645	403,477
PERIOD 2f - License Termination																					
Period 2f Direct Decommissioning Activities																					
2f.1.1	ORISE confirmatory survey	-	-	-	-	-	-	176	53	229	229	-	-	-	-	-	-	-	-	-	-
2f.1.2	Terminate license									a											
2f.1	Subtotal Period 2f Activity Costs	-	-	-	-	-	-	176	53	229	229	-	-	-	-	-	-	-	-	-	-
Period 2f Additional Costs																					
2f.2.1	License Termination Survey	-	-	-	-	-	-	7,341	2,202	9,544	9,544	-	-	-	-	-	-	-	-	96,197	6,240
2f.2	Subtotal Period 2f Additional Costs	-	-	-	-	-	-	7,341	2,202	9,544	9,544	-	-	-	-	-	-	-	-	96,197	6,240
Period 2f Collateral Costs																					
2f.3.1	DOC staff relocation expenses	-	-	-	-	-	-	1,189	178	1,367	1,367	-	-	-	-	-	-	-	-	-	-
2f.3.2	Spent Fuel Capital and Transfer	-	-	-	-	-	-	43	7	50	-	50	-	-	-	-	-	-	-	-	-
2f.3	Subtotal Period 2f Collateral Costs	-	-	-	-	-	-	1,232	185	1,417	1,367	50	-	-	-	-	-	-	-	-	-
Period 2f Period-Dependent Costs																					
2f.4.1	Insurance	-	-	-	-	-	-	543	54	598	598	-	-	-	-	-	-	-	-	-	-
2f.4.2	Property taxes	-	-	-	-	-	-	1,285	128	1,413	1,413	-	-	-	-	-	-	-	-	-	-
2f.4.3	Health physics supplies	-	597	-	-	-	-	-	149	747	747	-	-	-	-	-	-	-	-	-	-
2f.4.4	Disposal of DAW generated	-	-	8	2	-	29	-	8	47	47	-	-	-	355	-	-	-	7,097	12	-
2f.4.5	Plant energy budget	-	-	-	-	-	-	261	39	300	300	-	-	-	-	-	-	-	-	-	-
2f.4.6	NRC Fees	-	-	-	-	-	-	420	42	463	463	-	-	-	-	-	-	-	-	-	-
2f.4.7	Emergency Planning Fees	-	-	-	-	-	-	103	10	113	-	113	-	-	-	-	-	-	-	-	-
2f.4.8	Fixed Overhead	-	-	-	-	-	-	1,747	262	2,009	2,009	-	-	-	-	-	-	-	-	-	-
2f.4.9	ISFSI Operating Costs	-	-	-	-	-	-	78	12	89	-	89	-	-	-	-	-	-	-	-	-
2f.4.10	Railroad Track Maintenance	-	-	-	-	-	-	87	13	100	100	-	-	-	-	-	-	-	-	-	-
2f.4.11	Security Staff Cost	-	-	-	-	-	-	9,608	1,441	11,049	7,668	3,381	-	-	-	-	-	-	-	-	162,981
2f.4.12	DOC Staff Cost	-	-	-	-	-	-	5,174	776	5,950	5,950	-	-	-	-	-	-	-	-	-	57,200
2f.4.13	Utility Staff Cost	-	-	-	-	-	-	5,456	818	6,274	5,415	860	-	-	-	-	-	-	-	-	80,707
2f.4	Subtotal Period 2f Period-Dependent Costs	-	597	8	2	-	29	24,761	3,754	29,152	24,708	4,443	-	-	355	-	-	-	7,097	12	300,888
2f.0	TOTAL PERIOD 2f COST	-	597	8	2	-	29	33,511	6,194	40,341	35,848	4,493	-	-	355	-	-	-	7,097	96,208	307,128
PERIOD 2 TOTALS		13,170	62,856	20,629	9,399	25,814	56,415	416,166	122,242	726,692	568,562	158,062	68	288,110	174,575	1,481	1,010	-	21,522,450	804,895	3,049,889

Table F
Monticello Nuclear Generating Plant
Scenario 4: DECON with 200 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
PERIOD 3b - Site Restoration																					
Period 3b Direct Decommissioning Activities																					
Demolition of Remaining Site Buildings																					
3b.1.1.1	Reactor Building	-	1,881	-	-	-	-	-	282	2,163	-	-	2,163	-	-	-	-	-	-	13,966	-
3b.1.1.2	Condensate Tanks Foundation	-	10	-	-	-	-	-	1	11	-	-	11	-	-	-	-	-	-	50	-
3b.1.1.3	Discharge Retention Basin	-	4	-	-	-	-	-	1	4	-	-	4	-	-	-	-	-	-	25	-
3b.1.1.4	HPCI Room	-	18	-	-	-	-	-	3	21	-	-	21	-	-	-	-	-	-	97	-
3b.1.1.5	Hot Shop	-	15	-	-	-	-	-	2	17	-	-	17	-	-	-	-	-	-	177	-
3b.1.1.6	Hydrogen & Oxygen Storage	-	2	-	-	-	-	-	0	2	-	-	2	-	-	-	-	-	-	19	-
3b.1.1.7	LLRW Storage & Shipping	-	78	-	-	-	-	-	12	90	-	-	90	-	-	-	-	-	-	662	-
3b.1.1.8	MSIV	-	3	-	-	-	-	-	0	4	-	-	4	-	-	-	-	-	-	42	-
3b.1.1.9	Misc Structures 2017	-	759	-	-	-	-	-	114	872	-	-	872	-	-	-	-	-	-	7,919	-
3b.1.1.10	Offgas Stack	-	104	-	-	-	-	-	16	120	-	-	120	-	-	-	-	-	-	544	-
3b.1.1.11	Offgas Storage & Compressor	-	38	-	-	-	-	-	6	44	-	-	44	-	-	-	-	-	-	199	-
3b.1.1.12	Radwaste	-	219	-	-	-	-	-	33	252	-	-	252	-	-	-	-	-	-	1,220	-
3b.1.1.13	Recombiner	-	123	-	-	-	-	-	18	141	-	-	141	-	-	-	-	-	-	713	-
3b.1.1.14	Security Barrier	-	179	-	-	-	-	-	27	206	-	-	206	-	-	-	-	-	-	933	-
3b.1.1.15	Structures Greater than 3' Below Grade	-	2,380	-	-	-	-	-	357	2,738	-	-	2,738	-	-	-	-	-	-	12,649	-
3b.1.1.16	Tank Farm	-	4	-	-	-	-	-	1	5	-	-	5	-	-	-	-	-	-	21	-
3b.1.1.17	Turbine	-	1,175	-	-	-	-	-	176	1,351	-	-	1,351	-	-	-	-	-	-	13,091	-
3b.1.1.18	Turbine Building Addition	-	51	-	-	-	-	-	8	58	-	-	58	-	-	-	-	-	-	618	-
3b.1.1.19	Turbine Pedestal	-	175	-	-	-	-	-	26	202	-	-	202	-	-	-	-	-	-	926	-
3b.1.1	Totals	-	7,219	-	-	-	-	-	1,083	8,302	-	-	8,302	-	-	-	-	-	-	53,870	-
Site Closeout Activities																					
3b.1.2	Grade & landscape site	-	864	-	-	-	-	-	130	994	-	-	994	-	-	-	-	-	-	1,841	-
3b.1.3	Final report to NRC	-	-	-	-	-	-	183	27	211	211	-	-	-	-	-	-	-	-	-	1,560
3b.1	Subtotal Period 3b Activity Costs	-	8,083	-	-	-	-	183	1,240	9,506	211	-	9,295	-	-	-	-	-	-	55,711	1,560
Period 3b Additional Costs																					
3b.2.1	Clean Concrete Disposal	-	3,297	-	-	-	-	11	496	3,805	-	-	3,805	-	-	-	-	-	-	12	-
3b.2.2	Excavation of Underground Services	-	1,380	-	-	-	-	947	349	2,677	-	-	2,677	-	-	-	-	-	-	13,475	-
3b.2.3	Intake Structure Cofferdam	-	320	-	-	-	-	-	48	368	-	-	368	-	-	-	-	-	-	2,584	-
3b.2.4	Construction Debris	-	-	-	-	-	-	350	53	403	-	-	403	-	-	-	-	-	-	-	-
3b.2.5	Backfill	-	5,102	-	-	-	-	-	765	5,868	-	-	5,868	-	-	-	-	-	-	5,422	-
3b.2	Subtotal Period 3b Additional Costs	-	10,100	-	-	-	-	1,309	1,711	13,120	-	-	13,120	-	-	-	-	-	-	21,493	-
Period 3b Collateral Costs																					
3b.3.1	Small tool allowance	-	97	-	-	-	-	-	15	111	-	-	111	-	-	-	-	-	-	-	-
3b.3.2	Spent Fuel Capital and Transfer	-	-	-	-	-	-	100	15	115	-	115	-	-	-	-	-	-	-	-	-
3b.3	Subtotal Period 3b Collateral Costs	-	97	-	-	-	-	100	30	226	-	115	111	-	-	-	-	-	-	-	-
Period 3b Period-Dependent Costs																					
3b.4.1	Insurance	-	-	-	-	-	-	1,251	125	1,376	-	1,376	-	-	-	-	-	-	-	-	-
3b.4.2	Property taxes	-	-	-	-	-	-	2,737	274	3,011	-	3,011	-	-	-	-	-	-	-	-	-
3b.4.3	Heavy equipment rental	-	5,455	-	-	-	-	-	818	6,273	-	-	6,273	-	-	-	-	-	-	-	-
3b.4.4	Plant energy budget	-	-	-	-	-	-	300	45	345	-	-	345	-	-	-	-	-	-	-	-
3b.4.5	NRC ISFSI Fees	-	-	-	-	-	-	386	39	424	-	424	-	-	-	-	-	-	-	-	-
3b.4.6	Emergency Planning Fees	-	-	-	-	-	-	237	24	261	-	261	-	-	-	-	-	-	-	-	-
3b.4.7	Fixed Overhead	-	-	-	-	-	-	1,260	189	1,450	-	-	1,450	-	-	-	-	-	-	-	-
3b.4.8	ISFSI Operating Costs	-	-	-	-	-	-	179	27	206	-	206	-	-	-	-	-	-	-	-	-
3b.4.9	Railroad Track Maintenance	-	-	-	-	-	-	497	75	572	-	-	572	-	-	-	-	-	-	-	-
3b.4.10	Security Staff Cost	-	-	-	-	-	-	22,115	3,317	25,432	(0)	7,782	17,650	-	-	-	-	-	-	-	375,152
3b.4.11	DOC Staff Cost	-	-	-	-	-	-	11,290	1,693	12,983	-	-	12,983	-	-	-	-	-	-	-	122,646
3b.4.12	Utility Staff Cost	-	-	-	-	-	-	6,830	1,024	7,854	-	2,050	5,804	-	-	-	-	-	-	-	101,904
3b.4	Subtotal Period 3b Period-Dependent Costs	-	5,455	-	-	-	-	47,083	7,650	60,188	(0)	15,110	45,077	-	-	-	-	-	-	-	599,702
3b.0	TOTAL PERIOD 3b COST	-	23,734	-	-	-	-	48,675	10,631	83,040	211	15,226	67,604	-	-	-	-	-	-	77,204	601,262

Table F
Monticello Nuclear Generating Plant
Scenario 4: DECON with 200 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
PERIOD 3c - Fuel Storage Operations																					
Period 3c Additional Costs																					
3c.2.1	ISFSI Disposition of Retired MPC Canisters	-	-	-	293	-	7,257	-	1,844	9,395	-	9,395	-	-	23,007	-	-	-	1,317,864	-	-
3c.2	Subtotal Period 3c Additional Costs	-	-	-	293	-	7,257	-	1,844	9,395	-	9,395	-	-	23,007	-	-	-	1,317,864	-	-
Period 3c Collateral Costs																					
3c.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	1,251,066	187,660	1,438,726	-	1,438,726	-	-	-	-	-	-	-	-	-
3c.3	Subtotal Period 3c Collateral Costs	-	-	-	-	-	-	1,251,066	187,660	1,438,726	-	1,438,726	-	-	-	-	-	-	-	-	-
Period 3c Period-Dependent Costs																					
3c.4.1	Insurance	-	-	-	-	-	-	129,251	12,925	142,177	-	142,177	-	-	-	-	-	-	-	-	-
3c.4.2	Property taxes	-	-	-	-	-	-	96,984	9,698	106,683	-	106,683	-	-	-	-	-	-	-	-	-
3c.4.4	NRC ISFSI Fees	-	-	-	-	-	-	39,856	3,986	43,841	-	43,841	-	-	-	-	-	-	-	-	-
3c.4.5	Emergency Planning Fees	-	-	-	-	-	-	24,506	2,451	26,957	-	26,957	-	-	-	-	-	-	-	-	-
3c.4.6	Fixed Overhead	-	-	-	-	-	-	44,547	6,682	51,229	-	51,229	-	-	-	-	-	-	-	-	-
3c.4.7	ISFSI Operating Costs	-	-	-	-	-	-	18,500	2,775	21,275	-	21,275	-	-	-	-	-	-	-	-	-
3c.4.8	Railroad Track Maintenance	-	-	-	-	-	-	20,668	3,100	23,768	-	23,768	-	-	-	-	-	-	-	-	-
3c.4.9	Security Staff Cost	-	-	-	-	-	-	698,888	104,833	803,721	-	803,721	-	-	-	-	-	-	-	-	9,690,840
3c.4.10	DOC Staff Cost	-	-	-	-	-	-	34,551	5,183	39,733	-	39,733	-	-	-	-	-	-	-	-	372,725
3c.4.11	Utility Staff Cost	-	-	-	-	-	-	335,821	50,373	386,194	-	386,194	-	-	-	-	-	-	-	-	4,938,601
3c.4	Subtotal Period 3c Period-Dependent Costs	-	-	-	-	-	-	1,443,572	202,006	1,645,578	-	1,645,578	-	-	-	-	-	-	-	-	15,002,170
3c.0	TOTAL PERIOD 3c COST	-	-	-	293	-	7,257	2,694,638	391,510	3,093,699	-	3,093,699	-	-	23,007	-	-	-	1,317,864	-	15,002,170
PERIOD 3d - Spent Fuel/GTCC shipping																					
Period 3d Direct Decommissioning Activities																					
Nuclear Steam Supply System Removal																					
3d.1.1.1	Vessel & Internals GTCC Disposal	-	-	1,331	-	-	6,552	-	1,316	9,199	9,199	-	-	-	-	-	-	1,547	311,184	-	-
3d.1.1	Totals	-	-	1,331	-	-	6,552	-	1,316	9,199	9,199	-	-	-	-	-	-	1,547	311,184	-	-
3d.1	Subtotal Period 3d Activity Costs	-	-	1,331	-	-	6,552	-	1,316	9,199	9,199	-	-	-	-	-	-	1,547	311,184	-	-
Period 3d Collateral Costs																					
3d.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	51,320	7,698	59,018	-	59,018	-	-	-	-	-	-	-	-	-
3d.3	Subtotal Period 3d Collateral Costs	-	-	-	-	-	-	51,320	7,698	59,018	-	59,018	-	-	-	-	-	-	-	-	-
Period 3d Period-Dependent Costs																					
3d.4.1	Insurance	-	-	-	-	-	-	9,383	938	10,321	-	10,321	-	-	-	-	-	-	-	-	-
3d.4.2	Property taxes	-	-	-	-	-	-	6,703	670	7,374	-	7,374	-	-	-	-	-	-	-	-	-
3d.4.4	NRC ISFSI Fees	-	-	-	-	-	-	4,257	426	4,683	-	4,683	-	-	-	-	-	-	-	-	-
3d.4.5	Emergency Planning Fees	-	-	-	-	-	-	1,779	178	1,957	-	1,957	-	-	-	-	-	-	-	-	-
3d.4.6	Fixed Overhead	-	-	-	-	-	-	3,234	485	3,719	-	3,719	-	-	-	-	-	-	-	-	-
3d.4.7	ISFSI Operating Costs	-	-	-	-	-	-	1,343	201	1,544	-	1,544	-	-	-	-	-	-	-	-	-
3d.4.8	Railroad Track Maintenance	-	-	-	-	-	-	1,500	225	1,725	-	1,725	-	-	-	-	-	-	-	-	-
3d.4.9	Security Staff Cost	-	-	-	-	-	-	50,734	7,610	58,344	-	58,344	-	-	-	-	-	-	-	-	703,485
3d.4.10	Utility Staff Cost	-	-	-	-	-	-	12,865	1,930	14,795	-	14,795	-	-	-	-	-	-	-	-	182,635
3d.4	Subtotal Period 3d Period-Dependent Costs	-	-	-	-	-	-	91,799	12,664	104,462	-	104,462	-	-	-	-	-	-	-	-	886,120
3d.0	TOTAL PERIOD 3d COST	-	-	1,331	-	-	6,552	143,119	21,677	172,679	9,199	163,481	-	-	-	-	-	1,547	311,184	-	886,120
PERIOD 3e - ISFSI Decontamination																					
Period 3e Additional Costs																					
3e.2.1	Decommissioning of ISFSI	30	2	6	14	-	208	1,867	532	2,659	2,659	-	-	-	834	-	-	-	220,333	10,633	1,848
3e.2	Subtotal Period 3e Additional Costs	30	2	6	14	-	208	1,867	532	2,659	2,659	-	-	-	834	-	-	-	220,333	10,633	1,848
Period 3e Period-Dependent Costs																					
3e.4.1	Insurance	-	-	-	-	-	-	110	28	138	138	-	-	-	-	-	-	-	-	-	-
3e.4.2	Property taxes	-	-	-	-	-	-	244	61	304	304	-	-	-	-	-	-	-	-	-	-
3e.4.4	Fixed Overhead	-	-	-	-	-	-	82	21	103	103	-	-	-	-	-	-	-	-	-	-
3e.4.5	Railroad Track Maintenance	-	-	-	-	-	-	38	10	48	48	-	-	-	-	-	-	-	-	-	-
3e.4.6	Security Staff Cost	-	-	-	-	-	-	308	77	385	385	-	-	-	-	-	-	-	-	-	4,999
3e.4.7	Utility Staff Cost	-	-	-	-	-	-	260	65	325	325	-	-	-	-	-	-	-	-	-	3,792
3e.4	Subtotal Period 3e Period-Dependent Costs	-	-	-	-	-	-	1,042	261	1,303	1,303	-	-	-	-	-	-	-	-	-	8,792
3e.0	TOTAL PERIOD 3e COST	30	2	6	14	-	208	2,909	792	3,962	3,962	-	-	-	834	-	-	-	220,333	10,633	10,640

Table F
Monticello Nuclear Generating Plant
Scenario 4: DECON with 200 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
PERIOD 3f - ISFSI Site Restoration																					
Period 3f Additional Costs																					
3f.2.1	Demolition and Site Restoration of ISFSI	-	1,882	-	-	-	-	201	312	2,396	-	-	2,396	-	-	-	-	-	-	9,097	160
3f.2	Subtotal Period 3f Additional Costs	-	1,882	-	-	-	-	201	312	2,396	-	-	2,396	-	-	-	-	-	-	9,097	160
Period 3f Collateral Costs																					
3f.3.1	Small tool allowance	-	13	-	-	-	-	-	2	15	-	-	15	-	-	-	-	-	-	-	-
3f.3	Subtotal Period 3f Collateral Costs	-	13	-	-	-	-	-	2	15	-	-	15	-	-	-	-	-	-	-	-
Period 3f Period-Dependent Costs																					
3f.4.2	Property taxes	-	-	-	-	-	-	123	12	135	-	-	135	-	-	-	-	-	-	-	-
3f.4.3	Heavy equipment rental	-	123	-	-	-	-	-	19	142	-	-	142	-	-	-	-	-	-	-	-
3f.4.4	Plant energy budget	-	-	-	-	-	-	29	4	33	-	-	33	-	-	-	-	-	-	-	-
3f.4.5	Fixed Overhead	-	-	-	-	-	-	42	6	48	-	-	48	-	-	-	-	-	-	-	-
3f.4.6	Railroad Track Maintenance	-	-	-	-	-	-	19	3	22	-	-	22	-	-	-	-	-	-	-	-
3f.4.7	Security Staff Cost	-	-	-	-	-	-	155	23	179	-	-	179	-	-	-	-	-	-	-	2,520
3f.4.8	Utility Staff Cost	-	-	-	-	-	-	103	16	119	-	-	119	-	-	-	-	-	-	-	1,564
3f.4	Subtotal Period 3f Period-Dependent Costs	-	123	-	-	-	-	471	83	678	-	-	678	-	-	-	-	-	-	-	4,084
3f.0	TOTAL PERIOD 3f COST	-	2,018	-	-	-	-	673	398	3,088	-	-	3,088	-	-	-	-	-	-	9,097	4,244
PERIOD 3 TOTALS		30	25,755	1,337	308	-	14,017	2,890,014	425,008	3,356,469	13,372	3,272,405	70,692	-	23,841	-	-	1,547	1,849,382	96,934	16,504,430
TOTAL COST TO DECOMMISSION		**16,519**	**91,470**	**22,063**	**9,880**	**25,828**	**71,578**	**3,453,065**	**571,040**	**4,261,443**	**748,155**	**3,441,602**	**71,685**	**288,153**	**199,616**	**1,711**	**1,010**	**1,547**	**23,435,020**	**933,679**	**20,749,020**

TOTAL COST TO DECOMMISSION WITH 15.47% CONTINGENCY:	**$4,261,443**	**thousands of 2017 dollars**
TOTAL NRC LICENSE TERMINATION COST IS 17.56% OR:	**$748,155**	**thousands of 2017 dollars**
SPENT FUEL MANAGEMENT COST IS 80.76% OR:	**$3,441,602**	**thousands of 2017 dollars**
NON-NUCLEAR DEMOLITION COST IS 1.68% OR:	**$71,685**	**thousands of 2017 dollars**
TOTAL LOW-LEVEL RADIOACTIVE WASTE VOLUME BURIED (EXCLUDING GTCC):	**202,337**	**cubic feet**
TOTAL GREATER THAN CLASS C RADWASTE VOLUME GENERATED:	**1,547**	**cubic feet**
TOTAL SCRAP METAL REMOVED:	**22,696**	**tons**
TOTAL CRAFT LABOR REQUIREMENTS:	**933,679**	**man-hours**

End Notes:
n/a - indicates that this activity not charged as decommissioning expense
a - indicates that this activity performed by decommissioning staff
0 - indicates that this value is less than 0.5 but is non-zero
A cell containing " - " indicates a zero value

APPENDIX G

DETAILED COST ANALYSIS

SCENARIO 5: DECON with 60 Year DFS with Recasking

Table G
Monticello Nuclear Generating Plant
Scenario 5: DECON with 60 Year DFS and Recasking Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
PERIOD 1a - Shutdown through Transition																					
Period 1a Direct Decommissioning Activities																					
1a.1.1	Prepare preliminary decommissioning cost	-	-	-	-	-	-	153	23	175	175	-	-	-	-	-	-	-	-	-	1,300
1a.1.2	Notification of Cessation of Operations									a											
1a.1.3	Remove fuel & source material									n/a											
1a.1.4	Notification of Permanent Defueling									a											
1a.1.5	Deactivate plant systems & process waste									a											
1a.1.6	Prepare and submit PSDAR	-	-	-	-	-	-	235	35	270	270	-	-	-	-	-	-	-	-	-	2,000
1a.1.7	Review plant dwgs & specs.	-	-	-	-	-	-	540	81	621	621	-	-	-	-	-	-	-	-	-	4,600
1a.1.8	Perform detailed rad survey									a											
1a.1.9	Estimate by-product inventory	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1a.1.10	End product description	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1a.1.11	Detailed by-product inventory	-	-	-	-	-	-	153	23	175	175	-	-	-	-	-	-	-	-	-	1,300
1a.1.12	Define major work sequence	-	-	-	-	-	-	880	132	1,012	1,012	-	-	-	-	-	-	-	-	-	7,500
1a.1.13	Perform SER and EA	-	-	-	-	-	-	364	55	418	418	-	-	-	-	-	-	-	-	-	3,100
1a.1.14	Prepare/submit Defueled Technical Specifications	-	-	-	-	-	-	880	132	1,012	1,012	-	-	-	-	-	-	-	-	-	7,500
1a.1.15	Perform Site-Specific Cost Study	-	-	-	-	-	-	587	88	675	675	-	-	-	-	-	-	-	-	-	5,000
1a.1.16	Prepare/submit Irradiated Fuel Management Plan	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
Activity Specifications																					
1a.1.17.1	Plant & temporary facilities	-	-	-	-	-	-	578	87	664	598	-	66	-	-	-	-	-	-	-	4,920
1a.1.17.2	Plant systems	-	-	-	-	-	-	489	73	562	506	-	56	-	-	-	-	-	-	-	4,167
1a.1.17.3	NSSS Decontamination Flush	-	-	-	-	-	-	59	9	67	67	-	-	-	-	-	-	-	-	-	500
1a.1.17.4	Reactor internals	-	-	-	-	-	-	833	125	958	958	-	-	-	-	-	-	-	-	-	7,100
1a.1.17.5	Reactor vessel	-	-	-	-	-	-	763	114	877	877	-	-	-	-	-	-	-	-	-	6,500
1a.1.17.6	Sacrificial shield	-	-	-	-	-	-	59	9	67	67	-	-	-	-	-	-	-	-	-	500
1a.1.17.7	Moisture separators/reheaters	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1a.1.17.8	Reinforced concrete	-	-	-	-	-	-	188	28	216	108	-	108	-	-	-	-	-	-	-	1,600
1a.1.17.9	Main Turbine	-	-	-	-	-	-	245	37	282	282	-	-	-	-	-	-	-	-	-	2,088
1a.1.17.10	Main Condensers	-	-	-	-	-	-	245	37	282	282	-	-	-	-	-	-	-	-	-	2,088
1a.1.17.11	Pressure suppression structure	-	-	-	-	-	-	235	35	270	270	-	-	-	-	-	-	-	-	-	2,000
1a.1.17.12	Drywell	-	-	-	-	-	-	188	28	216	216	-	-	-	-	-	-	-	-	-	1,600
1a.1.17.13	Plant structures & buildings	-	-	-	-	-	-	366	55	421	211	-	211	-	-	-	-	-	-	-	3,120
1a.1.17.14	Waste management	-	-	-	-	-	-	540	81	621	621	-	-	-	-	-	-	-	-	-	4,600
1a.1.17.15	Facility & site closeout	-	-	-	-	-	-	106	16	121	61	-	61	-	-	-	-	-	-	-	900
1a.1.17	Total	-	-	-	-	-	-	5,010	752	5,762	5,260	-	502	-	-	-	-	-	-	-	42,683
Planning & Site Preparations																					
1a.1.18	Prepare dismantling sequence	-	-	-	-	-	-	282	42	324	324	-	-	-	-	-	-	-	-	-	2,400
1a.1.19	Plant prep. & temp. svces	-	-	-	-	-	-	3,300	495	3,795	3,795	-	-	-	-	-	-	-	-	-	-
1a.1.20	Design water clean-up system	-	-	-	-	-	-	164	25	189	189	-	-	-	-	-	-	-	-	-	1,400
1a.1.21	Rigging/Cont. Cntrl Envlps/tooling/etc.	-	-	-	-	-	-	2,300	345	2,645	2,645	-	-	-	-	-	-	-	-	-	-
1a.1.22	Procure casks/liners & containers	-	-	-	-	-	-	144	22	166	166	-	-	-	-	-	-	-	-	-	1,230
1a.1	Subtotal Period 1a Activity Costs	-	-	-	-	-	-	15,344	2,302	17,646	17,144	-	502	-	-	-	-	-	-	-	83,013
Period 1a Collateral Costs																					
1a.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	1,221	183	1,404	-	1,404	-	-	-	-	-	-	-	-	-
1a.3.2	Retention and Severance	-	-	-	-	-	-	9,892	1,484	11,376	11,376	-	-	-	-	-	-	-	-	-	-
1a.3	Subtotal Period 1a Collateral Costs	-	-	-	-	-	-	11,113	1,667	12,779	11,376	1,404	-	-	-	-	-	-	-	-	-
Period 1a Period-Dependent Costs																					
1a.4.1	Insurance	-	-	-	-	-	-	2,408	241	2,649	2,649	-	-	-	-	-	-	-	-	-	-
1a.4.2	Property taxes	-	-	-	-	-	-	2,242	224	2,466	2,466	-	-	-	-	-	-	-	-	-	-
1a.4.3	Health physics supplies	-	515	-	-	-	-	-	129	644	644	-	-	-	-	-	-	-	-	-	-
1a.4.4	Heavy equipment rental	-	567	-	-	-	-	-	85	652	652	-	-	-	-	-	-	-	-	-	-
1a.4.5	Disposal of DAW generated	-	-	13	4	-	50	-	14	81	81	-	-	-	610	-	-	-	12,190	20	-
1a.4.6	Plant energy budget	-	-	-	-	-	-	1,730	259	1,989	1,989	-	-	-	-	-	-	-	-	-	-
1a.4.7	NRC Fees	-	-	-	-	-	-	1,110	111	1,221	1,221	-	-	-	-	-	-	-	-	-	-
1a.4.8	Emergency Planning Fees	-	-	-	-	-	-	3,166	317	3,482	-	3,482	-	-	-	-	-	-	-	-	-
1a.4.9	Fixed Overhead	-	-	-	-	-	-	2,833	425	3,258	3,258	-	-	-	-	-	-	-	-	-	-
1a.4.10	Spent Fuel Pool O&M	-	-	-	-	-	-	803	120	923	-	923	-	-	-	-	-	-	-	-	-
1a.4.11	ISFSI Operating Costs	-	-	-	-	-	-	103	15	119	-	119	-	-	-	-	-	-	-	-	-
1a.4.12	Railroad Track Maintenance	-	-	-	-	-	-	115	17	133	133	-	-	-	-	-	-	-	-	-	-
1a.4.13	Security Staff Cost	-	-	-	-	-	-	14,260	2,139	16,399	16,399	-	-	-	-	-	-	-	-	-	245,440
1a.4.14	Utility Staff Cost	-	-	-	-	-	-	25,791	3,869	29,660	29,660	-	-	-	-	-	-	-	-	-	422,240
1a.4	Subtotal Period 1a Period-Dependent Costs	-	1,083	13	4	-	50	54,561	7,966	63,676	59,153	4,524	-	-	610	-	-	-	12,190	20	667,680

Table G
Monticello Nuclear Generating Plant
Scenario 5: DECON with 60 Year DFS and Recasking Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
1a.0	TOTAL PERIOD 1a COST	-	1,083	13	4	-	50	81,017	11,935	94,101	87,672	5,927	502	-	610	-	-	-	12,190	20	750,693
PERIOD 1b - Decommissioning Preparations																					
Detailed Work Procedures																					
1b.1.1.1	Plant systems	-	-	-	-	-	-	556	83	639	575	-	64	-	-	-	-	-	-	-	4,733
1b.1.1.2	NSSS Decontamination Flush	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1b.1.1.3	Reactor internals	-	-	-	-	-	-	470	70	540	540	-	-	-	-	-	-	-	-	-	4,000
1b.1.1.4	Remaining buildings	-	-	-	-	-	-	158	24	182	46	-	137	-	-	-	-	-	-	-	1,350
1b.1.1.5	CRD housings & NIs	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1b.1.1.6	Incore instrumentation	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1b.1.1.7	Removal primary containment	-	-	-	-	-	-	235	35	270	270	-	-	-	-	-	-	-	-	-	2,000
1b.1.1.8	Reactor vessel	-	-	-	-	-	-	426	64	490	490	-	-	-	-	-	-	-	-	-	3,630
1b.1.1.9	Facility closeout	-	-	-	-	-	-	141	21	162	81	-	81	-	-	-	-	-	-	-	1,200
1b.1.1.10	Sacrificial shield	-	-	-	-	-	-	141	21	162	162	-	-	-	-	-	-	-	-	-	1,200
1b.1.1.11	Reinforced concrete	-	-	-	-	-	-	117	18	135	67	-	67	-	-	-	-	-	-	-	1,000
1b.1.1.12	Main Turbine	-	-	-	-	-	-	244	37	281	281	-	-	-	-	-	-	-	-	-	2,080
1b.1.1.13	Main Condensers	-	-	-	-	-	-	245	37	282	282	-	-	-	-	-	-	-	-	-	2,088
1b.1.1.14	Moisture separators & reheaters	-	-	-	-	-	-	235	35	270	270	-	-	-	-	-	-	-	-	-	2,000
1b.1.1.15	Radwaste building	-	-	-	-	-	-	320	48	369	332	-	37	-	-	-	-	-	-	-	2,730
1b.1.1.16	Reactor building	-	-	-	-	-	-	320	48	369	332	-	37	-	-	-	-	-	-	-	2,730
1b.1.1	Total	-	-	-	-	-	-	3,961	594	4,555	4,132	-	423	-	-	-	-	-	-	-	33,741
1b.1.2	Decon NSSS	286	-	-	-	-	-	-	143	429	429	-	-	-	-	-	-	-	-	1,067	-
1b.1	Subtotal Period 1b Activity Costs	286	-	-	-	-	-	3,961	737	4,984	4,561	-	423	-	-	-	-	-	-	1,067	33,741
Period 1b Additional Costs																					
1b.2.1	Spent fuel pool isolation	-	-	-	-	-	-	11,691	1,754	13,445	13,445	-	-	-	-	-	-	-	-	-	-
1b.2.2	Site Characterization	-	-	-	-	-	-	6,446	1,934	8,380	8,380	-	-	-	-	-	-	-	-	30,500	10,852
1b.2.3	Mixed & RCRA Waste	-	-	29	19	13	-	-	8	69	69	-	-	43	-	-	-	-	5,253	163	-
1b.2	Subtotal Period 1b Additional Costs	-	-	29	19	13	-	18,137	3,695	21,894	21,894	-	-	43	-	-	-	-	5,253	30,663	10,852
Period 1b Collateral Costs																					
1b.3.1	Decon equipment	973	-	-	-	-	-	-	146	1,119	1,119	-	-	-	-	-	-	-	-	-	-
1b.3.2	DOC staff relocation expenses	-	-	-	-	-	-	1,189	178	1,367	1,367	-	-	-	-	-	-	-	-	-	-
1b.3.3	Process decommissioning water waste	37	-	24	61	-	98	-	54	275	275	-	-	-	233	-	-	-	13,986	45	-
1b.3.4	Process decommissioning chemical flush waste	1	-	23	85	-	969	-	258	1,336	1,336	-	-	-	-	231	-	-	24,599	43	-
1b.3.5	Small tool allowance	-	2	-	-	-	-	-	0	2	2	-	-	-	-	-	-	-	-	-	-
1b.3.6	Pipe cutting equipment	-	1,200	-	-	-	-	-	180	1,380	1,380	-	-	-	-	-	-	-	-	-	-
1b.3.7	Decon rig	1,987	-	-	-	-	-	-	298	2,285	2,285	-	-	-	-	-	-	-	-	-	-
1b.3.8	Spent Fuel Capital and Transfer	-	-	-	-	-	-	2,557	383	2,940	-	2,940	-	-	-	-	-	-	-	-	-
1b.3.9	Retention and Severance	-	-	-	-	-	-	6,362	954	7,316	7,316	-	-	-	-	-	-	-	-	-	-
1b.3	Subtotal Period 1b Collateral Costs	2,997	1,202	47	147	-	1,067	10,107	2,453	18,020	15,080	2,940	-	-	233	231	-	-	38,585	89	-
Period 1b Period-Dependent Costs																					
1b.4.1	Decon supplies	35	-	-	-	-	-	-	9	44	44	-	-	-	-	-	-	-	-	-	-
1b.4.2	Insurance	-	-	-	-	-	-	1,207	121	1,328	1,328	-	-	-	-	-	-	-	-	-	-
1b.4.3	Property taxes	-	-	-	-	-	-	1,104	110	1,214	1,214	-	-	-	-	-	-	-	-	-	-
1b.4.4	Health physics supplies	-	290	-	-	-	-	-	73	363	363	-	-	-	-	-	-	-	-	-	-
1b.4.5	Heavy equipment rental	-	284	-	-	-	-	-	43	327	327	-	-	-	-	-	-	-	-	-	-
1b.4.6	Disposal of DAW generated	-	-	8	2	-	29	-	8	48	48	-	-	-	358	-	-	-	7,159	12	-
1b.4.7	Plant energy budget	-	-	-	-	-	-	1,735	260	1,995	1,995	-	-	-	-	-	-	-	-	-	-
1b.4.8	NRC Fees	-	-	-	-	-	-	321	32	353	353	-	-	-	-	-	-	-	-	-	-
1b.4.9	Emergency Planning Fees	-	-	-	-	-	-	1,587	159	1,746	-	1,746	-	-	-	-	-	-	-	-	-
1b.4.10	Fixed Overhead	-	-	-	-	-	-	1,420	213	1,633	1,633	-	-	-	-	-	-	-	-	-	-
1b.4.11	Spent Fuel Pool O&M	-	-	-	-	-	-	402	60	463	-	463	-	-	-	-	-	-	-	-	-
1b.4.12	ISFSI Operating Costs	-	-	-	-	-	-	52	8	60	-	60	-	-	-	-	-	-	-	-	-
1b.4.13	Railroad Track Maintenance	-	-	-	-	-	-	58	9	67	67	-	-	-	-	-	-	-	-	-	-
1b.4.14	Security Staff Cost	-	-	-	-	-	-	7,150	1,072	8,222	8,222	-	-	-	-	-	-	-	-	-	123,056
1b.4.15	DOC Staff Cost	-	-	-	-	-	-	5,625	844	6,469	6,469	-	-	-	-	-	-	-	-	-	63,614
1b.4.16	Utility Staff Cost	-	-	-	-	-	-	13,003	1,950	14,953	14,953	-	-	-	-	-	-	-	-	-	212,741
1b.4	Subtotal Period 1b Period-Dependent Costs	35	575	8	2	-	29	33,663	4,971	39,283	37,015	2,268	-	-	358	-	-	-	7,159	12	399,411
1b.0	TOTAL PERIOD 1b COST	3,318	1,777	84	169	13	1,096	65,868	11,856	84,181	78,550	5,208	423	43	591	231	-	-	50,997	31,830	444,004
PERIOD 1 TOTALS		3,318	2,859	97	173	13	1,146	146,886	23,790	178,282	166,222	11,136	925	43	1,201	231	-	-	63,188	31,850	1,194,697

Table G
Monticello Nuclear Generating Plant
Scenario 5: DECON with 60 Year DFS and Recasking Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
PERIOD 2a - Large Component Removal																					
Nuclear Steam Supply System Removal																					
2a.1.1.1	Recirculation System Piping & Valves	107	92	30	39	-	429	-	192	888	888	-	-	-	1,430	-	-	-	99,742	2,905	-
2a.1.1.2	Recirculation Pumps & Motors	38	59	16	40	22	438	-	154	767	767	-	-	96	945	-	-	-	112,200	1,563	-
2a.1.1.3	CRDMs & NIs Removal	187	1,022	402	105	-	919	-	635	3,269	3,269	-	-	-	3,741	-	-	-	213,700	17,768	-
2a.1.1.4	Reactor Vessel Internals	222	6,378	12,908	2,835	-	20,148	356	18,958	61,806	61,806	-	-	-	1,252	1,481	1,010	-	312,338	30,765	1,389
2a.1.1.5	Reactor Vessel	109	8,595	2,644	1,170	-	5,294	356	10,155	28,323	28,323	-	-	-	16,169	-	-	-	1,105,210	30,765	1,389
2a.1.1	Totals	663	16,147	15,999	4,189	22	27,228	711	30,094	95,053	95,053	-	-	96	23,536	1,481	1,010	-	1,843,190	83,767	2,778
Removal of Major Equipment																					
2a.1.2	Main Turbine/Generator	-	362	1,496	349	3,174	357	-	858	6,596	6,596	-	-	24,835	1,383	-	-	-	1,577,959	5,438	-
2a.1.3	Main Condensers	-	1,245	397	128	1,667	198	-	670	4,306	4,306	-	-	17,396	727	-	-	-	828,955	18,831	-
Cascading Costs from Clean Building Demolition																					
2a.1.4.1	Reactor Building	-	317	-	-	-	-	-	48	364	364	-	-	-	-	-	-	-	-	2,217	-
2a.1.4.2	Radwaste	-	24	-	-	-	-	-	4	27	27	-	-	-	-	-	-	-	-	127	-
2a.1.4.3	Turbine	-	118	-	-	-	-	-	18	136	136	-	-	-	-	-	-	-	-	1,254	-
2a.1.4	Totals	-	459	-	-	-	-	-	69	528	528	-	-	-	-	-	-	-	-	3,598	-
Disposal of Plant Systems																					
2a.1.5.1	Automatic Press Relief	-	115	7	8	69	57	-	55	311	311	-	-	803	206	-	-	-	45,852	1,656	-
2a.1.5.2	Chemistry Sampling	-	27	1	1	13	10	-	12	65	65	-	-	156	37	-	-	-	8,681	400	-
2a.1.5.3	Chemistry Sampling - Insulated	-	2	0	0	-	0	-	1	3	3	-	-	-	1	-	-	-	72	28	-
2a.1.5.4	Circulating Water - RCA	-	202	12	41	576	-	-	144	974	974	-	-	6,656	-	-	-	-	270,307	2,860	-
2a.1.5.5	Combustible Gas Control - Insul - RCA	-	29	0	1	18	-	-	10	59	59	-	-	212	-	-	-	-	8,617	378	-
2a.1.5.6	Combustible Gas Control - RCA	-	18	0	2	25	-	-	8	53	53	-	-	285	-	-	-	-	11,577	245	-
2a.1.5.7	Condensate & Feedwater	-	946	189	226	1,725	2,003	-	1,049	6,138	6,138	-	-	19,947	7,319	-	-	-	1,275,810	14,196	-
2a.1.5.8	Condensate & Feedwater - Insulated	-	480	34	43	361	332	-	267	1,517	1,517	-	-	4,176	1,207	-	-	-	246,693	6,964	-
2a.1.5.9	Condensate Demin	-	533	29	35	289	276	-	254	1,416	1,416	-	-	3,346	1,000	-	-	-	199,936	7,618	-
2a.1.5.10	Condensate Storage	-	706	31	55	617	219	-	335	1,963	1,963	-	-	7,131	795	-	-	-	340,568	10,345	-
2a.1.5.11	Control Rod Drive	-	3	0	0	2	1	-	1	7	7	-	-	19	4	-	-	-	1,009	41	-
2a.1.5.12	Control Rod Drive Hydraulic	-	405	16	18	143	155	-	166	902	902	-	-	1,658	562	-	-	-	103,306	5,898	-
2a.1.5.13	Core Spray	-	75	19	34	379	143	-	119	770	770	-	-	4,384	521	-	-	-	211,329	1,163	-
2a.1.5.14	Core Spray - Insulated	-	141	8	9	71	73	-	66	368	368	-	-	818	264	-	-	-	50,149	2,033	-
2a.1.5.15	Demin Water - Insulated - RCA	-	15	0	1	7	-	-	5	27	27	-	-	85	-	-	-	-	3,445	181	-
2a.1.5.16	Demin Water - RCA	-	40	0	2	22	-	-	14	78	78	-	-	253	-	-	-	-	10,278	508	-
2a.1.5.17	Diesel Oil - RCA	-	2	0	0	2	-	-	1	5	5	-	-	23	-	-	-	-	931	25	-
2a.1.5.18	Drywell Atmosphere Cooling - RCA	-	37	1	3	47	-	-	17	105	105	-	-	548	-	-	-	-	22,244	550	-
2a.1.5.19	EDG Emerg Service Water - Insul - RCA	-	0	0	0	0	-	-	0	1	1	-	-	2	-	-	-	-	84	4	-
2a.1.5.20	Electrical - Clean	-	12	-	-	-	-	-	2	13	-	-	13	-	-	-	-	-	-	182	-
2a.1.5.21	Emergency Service Water - Insul - RCA	-	21	0	1	12	-	-	7	41	41	-	-	137	-	-	-	-	5,544	281	-
2a.1.5.22	Emergency Service Water - RCA	-	2	0	0	1	-	-	1	4	4	-	-	13	-	-	-	-	512	22	-
2a.1.5.23	GEZIP - RCA	-	3	0	1	9	-	-	2	15	15	-	-	103	-	-	-	-	4,184	48	-
2a.1.5.24	Generator Physical Design - RCA	-	5	0	0	3	-	-	2	9	9	-	-	31	-	-	-	-	1,250	67	-
2a.1.5.25	H2-O2 Control Analyzing	-	6	0	0	0	4	-	3	13	13	-	-	6	13	-	-	-	1,080	81	-
2a.1.5.26	H2-O2 Control Analyzing - Insulated	-	6	0	0	0	4	-	3	13	13	-	-	6	13	-	-	-	1,080	81	-
2a.1.5.27	High Pressure Coolant Injection	-	64	6	9	84	57	-	45	266	266	-	-	972	209	-	-	-	52,792	966	-
2a.1.5.28	High Pressure Coolant Injection - Insula	-	214	14	17	138	133	-	111	627	627	-	-	1,598	481	-	-	-	95,733	3,079	-
2a.1.5.29	Hydrogen Cooling	-	7	-	-	-	-	-	1	9	-	-	9	-	-	-	-	-	-	118	-
2a.1.5.30	Hydrogen Cooling - RCA	-	7	0	0	3	-	-	2	13	13	-	-	39	-	-	-	-	1,600	79	-
2a.1.5.31	Hydrogen Seal Oil - RCA	-	17	0	1	16	-	-	7	42	42	-	-	189	-	-	-	-	7,669	212	-
2a.1.5.32	Hydrogen Water Chemistry - RCA	-	24	0	1	12	-	-	8	45	45	-	-	140	-	-	-	-	5,672	304	-
2a.1.5.33	Instrument & Service Air - RCA	-	220	3	11	153	-	-	80	466	466	-	-	1,768	-	-	-	-	71,810	2,733	-
2a.1.5.34	Main Condenser	-	191	12	14	115	113	-	97	542	542	-	-	1,333	411	-	-	-	80,439	2,746	-
2a.1.5.35	Main Steam	-	243	17	22	186	163	-	134	764	764	-	-	2,148	594	-	-	-	125,135	3,512	-
2a.1.5.36	Main Turbine	-	972	214	244	1,709	2,375	-	1,151	6,665	6,665	-	-	19,760	8,687	-	-	-	1,354,661	14,733	-
2a.1.5.37	Main Turbine - Insulated	-	209	19	25	219	183	-	136	790	790	-	-	2,530	667	-	-	-	145,208	3,069	-
2a.1.5.38	Miscellaneous	-	42	1	2	26	-	-	15	85	85	-	-	302	-	-	-	-	12,283	622	-
2a.1.5.39	Off Gas Recombiner	-	182	19	22	155	209	-	126	714	714	-	-	1,795	764	-	-	-	121,554	2,708	-
2a.1.5.40	Off Gas Recombiner - Insulated	-	379	19	19	118	195	-	166	897	897	-	-	1,366	709	-	-	-	100,933	5,385	-
2a.1.5.41	Post Accident Sampling	-	24	1	1	5	9	-	9	50	50	-	-	53	33	-	-	-	4,318	345	-
2a.1.5.42	Post Accident Sampling - Insulated	-	16	1	1	1	11	-	7	37	37	-	-	17	37	-	-	-	3,116	212	-
2a.1.5.43	RHR Service Water - Insulated - RCA	-	81	3	9	128	-	-	41	262	262	-	-	1,485	-	-	-	-	60,293	1,125	-
2a.1.5.44	RHR Service Water - RCA	-	4	0	0	3	-	-	1	9	9	-	-	35	-	-	-	-	1,410	57	-
2a.1.5.45	Reactor Feedwater Pump Seal	-	55	3	3	17	26	-	23	126	126	-	-	193	96	-	-	-	14,009	773	-
2a.1.5.46	Residual Heat Removal	349	240	168	126	554	1,667	-	770	3,875	3,875	-	-	6,406	6,012	-	-	-	647,941	4,135	-
2a.1.5.47	Residual Heat Removal - Insulated	602	540	64	58	291	715	-	674	2,944	2,944	-	-	3,367	2,607	-	-	-	303,087	10,340	-

Table G
Monticello Nuclear Generating Plant
Scenario 5: DECON with 60 Year DFS and Recasking Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Disposal of Plant Systems (continued)																					
2a.1.5.48	Rx Core Isolation Cooling	-	47	2	3	22	21	-	21	116	116	-	-	259	76	-	-	-	15,396	691	-
2a.1.5.49	Rx Core Isolation Cooling - Insulated	-	105	5	5	25	55	-	45	240	240	-	-	288	198	-	-	-	24,419	1,479	-
2a.1.5.50	Rx Recirculation	56	57	6	3	4	53	-	57	235	235	-	-	43	190	-	-	-	14,095	1,580	-
2a.1.5.51	Snubbers	-	168	2	4	33	25	-	54	285	285	-	-	377	90	-	-	-	21,009	2,548	-
2a.1.5.52	Standby Liquid Control - Insul - RCA	-	4	0	0	2	-	-	1	7	7	-	-	22	-	-	-	-	904	48	-
2a.1.5.53	Standby Liquid Control - RCA	-	26	0	1	21	-	-	10	59	59	-	-	245	-	-	-	-	9,969	341	-
2a.1.5.54	Stator Cooling - RCA	-	7	0	1	11	-	-	4	23	23	-	-	126	-	-	-	-	5,135	98	-
2a.1.5.55	Traversing Incore Probe	0	4	0	0	0	2	-	1	7	7	-	-	1	5	-	-	-	386	51	-
2a.1.5	Totals	1,007	7,978	931	1,079	8,447	9,287	-	6,340	35,068	35,046	-	22	97,654	33,808	-	-	-	6,125,515	119,943	-
2a.1.6	Scaffolding in support of decommissioning	-	2,188	25	8	99	25	-	572	2,916	2,916	-	-	1,030	91	-	-	-	52,111	22,564	-
2a.1	Subtotal Period 2a Activity Costs	1,669	28,379	18,848	5,754	13,409	37,095	711	38,602	144,467	144,445	-	22	141,010	59,545	1,481	1,010	-	10,427,730	254,140	2,778
Period 2a Additional Costs																					
2a.2.1	Remedial Action Surveys	-	-	-	-	-	-	2,326	698	3,024	3,024	-	-	-	-	-	-	-	-	30,411	-
2a.2	Subtotal Period 2a Additional Costs	-	-	-	-	-	-	2,326	698	3,024	3,024	-	-	-	-	-	-	-	-	30,411	-
Period 2a Collateral Costs																					
2a.3.1	Process decommissioning water waste	83	-	55	140	-	222	-	123	623	623	-	-	-	531	-	-	-	31,838	103	-
2a.3.2	Process decommissioning chemical flush waste	6	-	208	774	-	1,557	-	529	3,075	3,075	-	-	-	2,093	-	-	-	223,008	392	-
2a.3.3	Small tool allowance	-	315	-	-	-	-	-	47	363	326	-	36	-	-	-	-	-	-	-	-
2a.3.4	Spent Fuel Capital and Transfer	-	-	-	-	-	-	23,173	3,476	26,649	-	26,649	-	-	-	-	-	-	-	-	-
2a.3.5	Retention and Severance	-	-	-	-	-	-	13,235	1,985	15,221	15,221	-	-	-	-	-	-	-	-	-	-
2a.3	Subtotal Period 2a Collateral Costs	89	315	263	914	-	1,779	36,408	6,161	45,930	19,245	26,649	36	-	2,623	-	-	-	254,846	495	-
Period 2a Period-Dependent Costs																					
2a.4.1	Decon supplies	102	-	-	-	-	-	-	25	127	127	-	-	-	-	-	-	-	-	-	-
2a.4.2	Insurance	-	-	-	-	-	-	1,055	106	1,161	1,161	-	-	-	-	-	-	-	-	-	-
2a.4.3	Property taxes	-	-	-	-	-	-	3,061	306	3,367	3,367	-	-	-	-	-	-	-	-	-	-
2a.4.4	Health physics supplies	-	2,133	-	-	-	-	-	533	2,666	2,666	-	-	-	-	-	-	-	-	-	-
2a.4.5	Heavy equipment rental	-	3,212	-	-	-	-	-	482	3,694	3,694	-	-	-	-	-	-	-	-	-	-
2a.4.6	Disposal of DAW generated	-	-	122	37	-	453	-	131	743	743	-	-	-	5,567	-	-	-	111,335	182	-
2a.4.7	Plant energy budget	-	-	-	-	-	-	2,404	361	2,765	2,765	-	-	-	-	-	-	-	-	-	-
2a.4.8	NRC Fees	-	-	-	-	-	-	847	85	932	932	-	-	-	-	-	-	-	-	-	-
2a.4.9	Emergency Planning Fees	-	-	-	-	-	-	3,757	376	4,133	-	4,133	-	-	-	-	-	-	-	-	-
2a.4.10	Fixed Overhead	-	-	-	-	-	-	3,392	509	3,900	3,900	-	-	-	-	-	-	-	-	-	-
2a.4.11	Spent Fuel Pool O&M	-	-	-	-	-	-	1,174	176	1,350	-	1,350	-	-	-	-	-	-	-	-	-
2a.4.12	ISFSI Operating Costs	-	-	-	-	-	-	151	23	174	-	174	-	-	-	-	-	-	-	-	-
2a.4.13	Railroad Track Maintenance	-	-	-	-	-	-	466	70	536	536	-	-	-	-	-	-	-	-	-	-
2a.4.14	Security Staff Cost	-	-	-	-	-	-	19,265	2,890	22,154	22,154	-	-	-	-	-	-	-	-	-	328,651
2a.4.15	DOC Staff Cost	-	-	-	-	-	-	20,125	3,019	23,144	23,144	-	-	-	-	-	-	-	-	-	231,273
2a.4.16	Utility Staff Cost	-	-	-	-	-	-	26,670	4,000	30,670	30,670	-	-	-	-	-	-	-	-	-	430,594
2a.4	Subtotal Period 2a Period-Dependent Costs	102	5,345	122	37	-	453	82,366	13,090	101,515	95,858	5,657	-	-	5,567	-	-	-	111,335	182	990,519
2a.0	TOTAL PERIOD 2a COST	1,860	34,039	19,233	6,705	13,409	39,327	121,812	58,551	294,937	262,573	32,305	58	141,010	67,735	1,481	1,010	-	10,793,910	285,228	993,297

Table G
Monticello Nuclear Generating Plant
Scenario 5: DECON with 60 Year DFS and Recasking Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
PERIOD 2b - Site Decontamination																					
Disposal of Plant Systems																					
2b.1.1.1	ALARA/Radiological	-	18	0	0	3	3	-	6	30	30	-	-	35	10	-	-	-	2,060	277	-
2b.1.1.2	Alternate N2 - RCA	-	16	0	1	8	-	-	5	30	30	-	-	93	-	-	-	-	3,765	185	-
2b.1.1.3	Decontamination Projects	-	1	0	0	0	0	-	0	2	2	-	-	2	0	-	-	-	129	17	-
2b.1.1.4	Electrical - Contaminated	-	439	6	16	207	25	-	150	841	841	-	-	2,389	90	-	-	-	102,726	6,325	-
2b.1.1.5	Electrical - Decontaminated	-	2,657	41	142	2,019	-	-	993	5,852	5,852	-	-	23,344	-	-	-	-	948,013	37,107	-
2b.1.1.6	Fire - RCA	-	99	1	4	53	-	-	33	191	191	-	-	614	-	-	-	-	24,917	1,324	-
2b.1.1.7	HVAC Ductwork	-	309	7	18	231	27	-	122	713	713	-	-	2,665	100	-	-	-	114,598	4,111	-
2b.1.1.8	HVAC/Chilled Water - RCA	-	317	5	17	238	-	-	118	694	694	-	-	2,752	-	-	-	-	111,779	3,985	-
2b.1.1.9	Heating & Ventilation	-	473	15	40	521	62	-	219	1,329	1,329	-	-	6,018	227	-	-	-	258,789	7,101	-
2b.1.1.10	Heating Boiler - Insulated - RCA	-	3	0	0	2	-	-	1	6	6	-	-	26	-	-	-	-	1,058	35	-
2b.1.1.11	Liquid Radwaste	572	669	46	44	266	476	-	623	2,697	2,697	-	-	3,073	1,728	-	-	-	235,484	17,194	-
2b.1.1.12	Makeup Demin - RCA	-	101	3	9	127	-	-	46	286	286	-	-	1,471	-	-	-	-	59,747	1,412	-
2b.1.1.13	Non-Essential Diesel Generator - RCA	-	26	2	9	123	-	-	27	187	187	-	-	1,424	-	-	-	-	57,832	395	-
2b.1.1.14	Off Gas Holdup	-	333	20	26	238	174	-	168	960	960	-	-	2,755	630	-	-	-	152,277	4,769	-
2b.1.1.15	Primary Containment	-	443	43	59	536	412	-	308	1,801	1,801	-	-	6,201	1,506	-	-	-	347,704	6,454	-
2b.1.1.16	Process Radiation Monitors	-	45	2	2	12	14	-	17	92	92	-	-	142	52	-	-	-	9,115	649	-
2b.1.1.17	Rx Bldg Closed Clng Water - Insul - RCA	-	111	2	6	85	-	-	42	245	245	-	-	977	-	-	-	-	39,675	1,484	-
2b.1.1.18	Rx Bldg Closed Clng Water - RCA	-	178	12	43	614	-	-	144	991	991	-	-	7,093	-	-	-	-	288,031	2,489	-
2b.1.1.19	Rx Component Handling Equip	26	138	19	19	100	227	-	124	653	653	-	-	1,158	829	-	-	-	99,730	2,462	-
2b.1.1.20	Rx Pressure Vessel	28	46	6	4	7	63	-	43	196	196	-	-	75	230	-	-	-	17,816	1,051	-
2b.1.1.21	Rx Water Cleanup	169	258	19	11	11	204	-	205	877	877	-	-	130	737	-	-	-	52,670	5,736	-
2b.1.1.22	Secondary Containment	-	121	7	10	88	70	-	63	360	360	-	-	1,017	255	-	-	-	57,567	1,763	-
2b.1.1.23	Service & Seal Water - Insulated - RCA	-	117	2	7	102	-	-	46	274	274	-	-	1,180	-	-	-	-	47,917	1,565	-
2b.1.1.24	Service & Seal Water - RCA	-	155	3	11	156	-	-	64	390	390	-	-	1,809	-	-	-	-	73,453	2,016	-
2b.1.1.25	Service Air Blower - RCA	-	15	0	1	18	-	-	7	41	41	-	-	206	-	-	-	-	8,364	206	-
2b.1.1.26	Solid Radwaste	327	483	36	34	206	380	-	419	1,885	1,885	-	-	2,387	1,380	-	-	-	185,221	10,820	-
2b.1.1.27	Structures & Buildings	-	76	2	3	31	23	-	30	166	166	-	-	357	85	-	-	-	19,933	1,128	-
2b.1.1.28	Wells & Domestic Water	-	9	-	-	-	-	-	1	10	-	-	10	-	-	-	-	-	-	144	-
2b.1.1.29	Wells & Domestic Water - RCA	-	51	1	2	30	-	-	18	101	101	-	-	342	-	-	-	-	13,874	633	-
2b.1.1	Totals	1,122	7,707	299	537	6,032	2,160	-	4,042	21,900	21,890	-	10	69,735	7,859	-	-	-	3,334,244	122,835	-
2b.1.2	Scaffolding in support of decommissioning	-	2,735	31	10	123	31	-	715	3,645	3,645	-	-	1,287	114	-	-	-	65,139	28,205	-
Decontamination of Site Buildings																					
2b.1.3.1	Reactor Building	5,006	2,817	155	347	4,159	1,007	-	4,150	17,641	17,641	-	-	48,077	7,014	-	-	-	2,317,670	112,518	-
2b.1.3.2	Admin	103	6	0	2	-	14	-	57	182	182	-	-	-	145	-	-	-	6,840	1,600	-
2b.1.3.3	HPCI Room	28	27	1	2	10	13	-	26	107	107	-	-	118	125	-	-	-	10,759	789	-
2b.1.3.4	Hot Shop	16	4	0	1	-	10	-	12	43	43	-	-	-	103	-	-	-	4,860	286	-
2b.1.3.5	LLRW Storage & Shipping	56	23	1	6	3	41	-	46	176	176	-	-	31	433	-	-	-	21,708	1,127	-
2b.1.3.6	Offgas Stack	360	256	6	16	116	73	-	283	1,109	1,109	-	-	1,343	669	-	-	-	87,045	8,860	-
2b.1.3.7	Offgas Storage & Compressor	39	17	1	4	2	30	-	32	125	125	-	-	25	316	-	-	-	15,948	785	-
2b.1.3.8	Radwaste	117	59	3	13	15	86	-	100	393	393	-	-	172	910	-	-	-	49,943	2,503	-
2b.1.3.9	Radwaste Material Storage Warehouse	62	23	1	6	-	47	-	49	189	189	-	-	-	495	-	-	-	23,400	1,197	-
2b.1.3.10	Recombiner	26	24	1	4	17	22	-	28	122	122	-	-	199	216	-	-	-	18,405	695	-
2b.1.3.11	Turbine	684	341	18	76	111	507	-	583	2,319	2,319	-	-	1,283	5,299	-	-	-	303,150	14,443	-
2b.1.3.12	Turbine Building Addition	56	20	1	6	-	41	-	44	169	169	-	-	-	434	-	-	-	20,478	1,087	-
2b.1.3	Totals	6,554	3,618	188	483	4,433	1,889	-	5,410	22,574	22,574	-	-	51,247	16,159	-	-	-	2,880,206	145,889	-
2b.1.4	Prepare/submit License Termination Plan	-	-	-	-	-	-	481	72	553	553	-	-	-	-	-	-	-	-	-	4,096
2b.1.5	Receive NRC approval of termination plan									a											
2b.1	Subtotal Period 2b Activity Costs	7,676	14,060	518	1,031	10,588	4,079	481	10,239	48,672	48,662	-	10	122,269	24,132	-	-	-	6,279,589	296,929	4,096
Period 2b Additional Costs																					
2b.2.1	Remedial Action Surveys	-	-	-	-	-	-	3,241	972	4,213	4,213	-	-	-	-	-	-	-	-	42,370	-
2b.2.2	Operational Equipment	-	-	19	60	624	-	-	104	807	807	-	-	11,710	-	-	-	-	292,750	32	-
2b.2.3	Security Modifications	-	-	-	-	-	-	8,696	1,304	10,000	10,000	-	-	-	-	-	-	-	-	-	-
2b.2	Subtotal Period 2b Additional Costs	-	-	19	60	624	-	11,937	2,381	15,020	15,020	-	-	11,710	-	-	-	-	292,750	42,402	-

Table G
Monticello Nuclear Generating Plant
Scenario 5: DECON with 60 Year DFS and Recasking Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 2b Collateral Costs																					
2b.3.1	Process decommissioning water waste	173	-	117	299	-	474	-	261	1,325	1,325	-	-	-	1,133	-	-	-	67,962	221	-
2b.3.2	Process decommissioning chemical flush waste	1	-	41	153	-	307	-	104	606	606	-	-	-	413	-	-	-	43,978	77	-
2b.3.3	Small tool allowance	-	341	-	-	-	-	-	51	392	392	-	-	-	-	-	-	-	-	-	-
2b.3.4	Spent Fuel Capital and Transfer	-	-	-	-	-	-	65,919	9,888	75,807	-	75,807	-	-	-	-	-	-	-	-	-
2b.3.5	Retention and Severance	-	-	-	-	-	-	8,665	1,300	9,964	9,964	-	-	-	-	-	-	-	-	-	-
2b.3	Subtotal Period 2b Collateral Costs	174	341	159	452	-	781	74,584	11,604	88,094	12,287	75,807	-	-	1,545	-	-	-	111,940	298	-
Period 2b Period-Dependent Costs																					
2b.4.1	Decon supplies	1,361	-	-	-	-	-	-	340	1,701	1,701	-	-	-	-	-	-	-	-	-	-
2b.4.2	Insurance	-	-	-	-	-	-	1,470	147	1,617	1,617	-	-	-	-	-	-	-	-	-	-
2b.4.3	Property taxes	-	-	-	-	-	-	3,915	391	4,306	4,306	-	-	-	-	-	-	-	-	-	-
2b.4.4	Health physics supplies	-	2,681	-	-	-	-	-	670	3,352	3,352	-	-	-	-	-	-	-	-	-	-
2b.4.5	Heavy equipment rental	-	4,602	-	-	-	-	-	690	5,292	5,292	-	-	-	-	-	-	-	-	-	-
2b.4.6	Disposal of DAW generated	-	-	124	38	-	463	-	134	759	759	-	-	-	5,690	-	-	-	113,799	186	-
2b.4.7	Plant energy budget	-	-	-	-	-	-	2,645	397	3,041	3,041	-	-	-	-	-	-	-	-	-	-
2b.4.8	NRC Fees	-	-	-	-	-	-	1,180	118	1,298	1,298	-	-	-	-	-	-	-	-	-	-
2b.4.9	Emergency Planning Fees	-	-	-	-	-	-	5,234	523	5,758	-	5,758	-	-	-	-	-	-	-	-	-
2b.4.10	Fixed Overhead	-	-	-	-	-	-	4,725	709	5,434	5,434	-	-	-	-	-	-	-	-	-	-
2b.4.11	Spent Fuel Pool O&M	-	-	-	-	-	-	1,636	245	1,881	-	1,881	-	-	-	-	-	-	-	-	-
2b.4.12	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	412	62	474	474	-	-	-	-	-	-	-	-	-	-
2b.4.13	ISFSI Operating Costs	-	-	-	-	-	-	210	32	242	-	242	-	-	-	-	-	-	-	-	-
2b.4.14	Railroad Track Maintenance	-	-	-	-	-	-	235	35	270	270	-	-	-	-	-	-	-	-	-	-
2b.4.15	Security Staff Cost	-	-	-	-	-	-	26,840	4,026	30,867	30,867	-	-	-	-	-	-	-	-	-	457,896
2b.4.16	DOC Staff Cost	-	-	-	-	-	-	27,122	4,068	31,191	31,191	-	-	-	-	-	-	-	-	-	309,504
2b.4.17	Utility Staff Cost	-	-	-	-	-	-	35,641	5,346	40,988	40,988	-	-	-	-	-	-	-	-	-	574,490
2b.4	Subtotal Period 2b Period-Dependent Costs	1,361	7,283	124	38	-	463	111,268	17,935	138,473	130,592	7,881	-	-	5,690	-	-	-	113,799	186	1,341,891
2b.0	TOTAL PERIOD 2b COST	9,211	21,684	820	1,580	11,212	5,324	198,269	42,159	290,260	206,561	83,688	10	133,979	31,367	-	-	-	6,798,079	339,814	1,345,987
PERIOD 2d - Decontamination Following Wet Fuel Storage																					
Period 2d Direct Decommissioning Activities																					
2d.1.1	Remove spent fuel racks	634	56	114	109	-	2,091	-	881	3,884	3,884	-	-	-	7,653	-	-	-	486,170	906	-
Disposal of Plant Systems																					
2d.1.2.1	Cranes/Heavy Loads/Rigging - RCA	-	3	0	1	9	-	-	2	15	15	-	-	103	-	-	-	-	4,184	48	-
2d.1.2.2	Electrical - Contaminated Fuel Pool	-	46	1	2	21	2	-	16	87	87	-	-	240	9	-	-	-	10,334	665	-
2d.1.2.3	Electrical - Decontam. Fuel Pool Area	-	293	4	15	213	-	-	108	633	633	-	-	2,457	-	-	-	-	99,783	4,090	-
2d.1.2.4	Fire - RCA - Fuel Pool Area	-	11	0	0	5	-	-	4	20	20	-	-	62	-	-	-	-	2,499	143	-
2d.1.2.5	Fuel Pool Cooling & Cleanup	240	419	34	26	102	370	-	340	1,531	1,531	-	-	1,179	1,341	-	-	-	133,939	8,380	-
2d.1.2.6	Fuel Pool Cooling & Cleanup - Insulated	26	40	3	2	6	32	-	33	143	143	-	-	67	117	-	-	-	10,220	848	-
2d.1.2.7	HVAC Ductwork - Fuel Pool Area	-	34	1	2	26	3	-	14	79	79	-	-	296	11	-	-	-	12,733	457	-
2d.1.2.8	HVAC/Chilled Water - RCA Fuel Pool Area	-	32	0	1	19	-	-	11	64	64	-	-	223	-	-	-	-	9,072	397	-
2d.1.2.9	Instrument & Service Air-RCA-Fuel Pool	-	28	0	2	23	-	-	11	64	64	-	-	267	-	-	-	-	10,841	357	-
2d.1.2	Totals	266	907	44	51	423	408	-	537	2,637	2,637	-	-	4,894	1,479	-	-	-	293,606	15,385	-
Decontamination of Site Buildings																					
2d.1.3.1	Reactor (Post Fuel)	911	2,485	145	669	170	8,544	-	3,353	16,277	16,277	-	-	1,969	62,698	-	-	-	2,732,406	45,703	-
2d.1.3	Totals	911	2,485	145	669	170	8,544	-	3,353	16,277	16,277	-	-	1,969	62,698	-	-	-	2,732,406	45,703	-
2d.1.4	Scaffolding in support of decommissioning	-	547	6	2	25	6	-	143	729	729	-	-	257	23	-	-	-	13,028	5,641	-
2d.1	Subtotal Period 2d Activity Costs	1,811	3,994	309	831	618	11,049	-	4,915	23,527	23,527	-	-	7,120	71,852	-	-	-	3,525,210	67,635	-

Table G
Monticello Nuclear Generating Plant
Scenario 5: DECON with 60 Year DFS and Recasking Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 2d Additional Costs																					
2d.2.1	License Termination Survey Planning	-	-	-	-	-	-	1,291	387	1,678	1,678	-	-	-	-	-	-	-	-	-	12,480
2d.2.2	Remedial Action Surveys	-	-	-	-	-	-	1,198	359	1,557	1,557	-	-	-	-	-	-	-	-	15,661	-
2d.2	Subtotal Period 2d Additional Costs	-	-	-	-	-	-	2,489	747	3,235	3,235	-	-	-	-	-	-	-	-	15,661	12,480
Period 2d Collateral Costs																					
2d.3.1	Process decommissioning water waste	69	-	47	120	-	191	-	105	533	533	-	-	-	457	-	-	-	27,391	89	-
2d.3.2	Process decommissioning chemical flush waste	1	-	25	92	-	185	-	63	366	366	-	-	-	249	-	-	-	26,553	47	-
2d.3.3	Small tool allowance	-	88	-	-	-	-	-	13	101	101	-	-	-	-	-	-	-	-	-	-
2d.3.4	Decommissioning Equipment Disposition	-	-	143	55	575	145	-	145	1,062	1,062	-	-	6,000	529	-	-	-	303,608	147	-
2d.3.5	Spent Fuel Capital and Transfer	-	-	-	-	-	-	27,061	4,059	31,120	-	31,120	-	-	-	-	-	-	-	-	-
2d.3	Subtotal Period 2d Collateral Costs	70	88	216	267	575	521	27,061	4,385	33,182	2,062	31,120	-	6,000	1,235	-	-	-	357,552	283	-
Period 2d Period-Dependent Costs																					
2d.4.1	Decon supplies	219	-	-	-	-	-	-	55	274	274	-	-	-	-	-	-	-	-	-	-
2d.4.2	Insurance	-	-	-	-	-	-	543	54	598	598	-	-	-	-	-	-	-	-	-	-
2d.4.3	Property taxes	-	-	-	-	-	-	1,336	134	1,470	1,470	-	-	-	-	-	-	-	-	-	-
2d.4.4	Health physics supplies	-	752	-	-	-	-	-	188	940	940	-	-	-	-	-	-	-	-	-	-
2d.4.5	Heavy equipment rental	-	1,701	-	-	-	-	-	255	1,956	1,956	-	-	-	-	-	-	-	-	-	-
2d.4.6	Disposal of DAW generated	-	-	44	14	-	165	-	48	271	271	-	-	-	2,030	-	-	-	40,600	66	-
2d.4.7	Plant energy budget	-	-	-	-	-	-	521	78	600	600	-	-	-	-	-	-	-	-	-	-
2d.4.8	NRC Fees	-	-	-	-	-	-	369	37	405	405	-	-	-	-	-	-	-	-	-	-
2d.4.9	Emergency Planning Fees	-	-	-	-	-	-	1,935	193	2,128	-	2,128	-	-	-	-	-	-	-	-	-
2d.4.10	Fixed Overhead	-	-	-	-	-	-	1,747	262	2,009	2,009	-	-	-	-	-	-	-	-	-	-
2d.4.11	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	305	46	351	351	-	-	-	-	-	-	-	-	-	-
2d.4.12	ISFSI Operating Costs	-	-	-	-	-	-	78	12	89	-	89	-	-	-	-	-	-	-	-	-
2d.4.13	Railroad Track Maintenance	-	-	-	-	-	-	87	13	100	100	-	-	-	-	-	-	-	-	-	-
2d.4.14	Security Staff Cost	-	-	-	-	-	-	9,608	1,441	11,049	7,668	3,381	-	-	-	-	-	-	-	-	162,981
2d.4.15	DOC Staff Cost	-	-	-	-	-	-	6,941	1,041	7,982	7,982	-	-	-	-	-	-	-	-	-	78,356
2d.4.16	Utility Staff Cost	-	-	-	-	-	-	9,556	1,433	10,989	10,132	857	-	-	-	-	-	-	-	-	149,660
2d.4	Subtotal Period 2d Period-Dependent Costs	219	2,453	44	14	-	165	33,025	5,290	41,210	34,754	6,456	-	-	2,030	-	-	-	40,600	66	390,997
2d.0	TOTAL PERIOD 2d COST	2,099	6,535	569	1,112	1,193	11,735	62,574	15,337	101,154	63,579	37,575	-	13,120	75,117	-	-	-	3,923,362	83,645	403,477
PERIOD 2f - License Termination																					
Period 2f Direct Decommissioning Activities																					
2f.1.1	ORISE confirmatory survey	-	-	-	-	-	-	176	53	229	229	-	-	-	-	-	-	-	-	-	-
2f.1.2	Terminate license									a											
2f.1	Subtotal Period 2f Activity Costs	-	-	-	-	-	-	176	53	229	229	-	-	-	-	-	-	-	-	-	-
Period 2f Additional Costs																					
2f.2.1	License Termination Survey	-	-	-	-	-	-	7,341	2,202	9,544	9,544	-	-	-	-	-	-	-	-	96,197	6,240
2f.2	Subtotal Period 2f Additional Costs	-	-	-	-	-	-	7,341	2,202	9,544	9,544	-	-	-	-	-	-	-	-	96,197	6,240
Period 2f Collateral Costs																					
2f.3.1	DOC staff relocation expenses	-	-	-	-	-	-	1,189	178	1,367	1,367	-	-	-	-	-	-	-	-	-	-
2f.3.2	Spent Fuel Capital and Transfer	-	-	-	-	-	-	43	7	50	-	50	-	-	-	-	-	-	-	-	-
2f.3	Subtotal Period 2f Collateral Costs	-	-	-	-	-	-	1,232	185	1,417	1,367	50	-	-	-	-	-	-	-	-	-

Table G
Monticello Nuclear Generating Plant
Scenario 5: DECON with 60 Year DFS and Recasking Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 2f Period-Dependent Costs																					
2f.4.1	Insurance	-	-	-	-	-	-	543	54	598	598	-	-	-	-	-	-	-	-	-	-
2f.4.2	Property taxes	-	-	-	-	-	-	1,285	128	1,413	1,413	-	-	-	-	-	-	-	-	-	-
2f.4.3	Health physics supplies	-	597	-	-	-	-	-	149	747	747	-	-	-	-	-	-	-	-	-	-
2f.4.4	Disposal of DAW generated	-	-	8	2	-	29	-	8	47	47	-	-	-	355	-	-	-	7,097	12	-
2f.4.5	Plant energy budget	-	-	-	-	-	-	261	39	300	300	-	-	-	-	-	-	-	-	-	-
2f.4.6	NRC Fees	-	-	-	-	-	-	420	42	463	463	-	-	-	-	-	-	-	-	-	-
2f.4.7	Emergency Planning Fees	-	-	-	-	-	-	103	10	113	-	113	-	-	-	-	-	-	-	-	-
2f.4.8	Fixed Overhead	-	-	-	-	-	-	1,747	262	2,009	2,009	-	-	-	-	-	-	-	-	-	-
2f.4.9	ISFSI Operating Costs	-	-	-	-	-	-	78	12	89	-	89	-	-	-	-	-	-	-	-	-
2f.4.10	Railroad Track Maintenance	-	-	-	-	-	-	87	13	100	100	-	-	-	-	-	-	-	-	-	-
2f.4.11	Security Staff Cost	-	-	-	-	-	-	9,608	1,441	11,049	7,668	3,381	-	-	-	-	-	-	-	-	162,981
2f.4.12	DOC Staff Cost	-	-	-	-	-	-	5,174	776	5,950	5,950	-	-	-	-	-	-	-	-	-	57,200
2f.4.13	Utility Staff Cost	-	-	-	-	-	-	5,456	818	6,274	5,415	860	-	-	-	-	-	-	-	-	80,707
2f.4	Subtotal Period 2f Period-Dependent Costs	-	597	8	2	-	29	24,761	3,754	29,152	24,708	4,443	-	-	355	-	-	-	7,097	12	300,888
2f.0	TOTAL PERIOD 2f COST	-	597	8	2	-	29	33,511	6,194	40,341	35,848	4,493	-	-	355	-	-	-	7,097	96,208	307,128
PERIOD 2 TOTALS		13,170	62,856	20,629	9,399	25,814	56,415	416,166	122,242	726,692	568,562	158,062	68	288,110	174,575	1,481	1,010	-	21,522,450	804,895	3,049,889
PERIOD 3b - Site Restoration																					
Period 3b Direct Decommissioning Activities																					
Demolition of Remaining Site Buildings																					
3b.1.1.1	Reactor Building	-	1,881	-	-	-	-	-	282	2,163	-	-	2,163	-	-	-	-	-	-	13,966	-
3b.1.1.2	Condensate Tanks Foundation	-	10	-	-	-	-	-	1	11	-	-	11	-	-	-	-	-	-	50	-
3b.1.1.3	Discharge Retention Basin	-	4	-	-	-	-	-	1	4	-	-	4	-	-	-	-	-	-	25	-
3b.1.1.4	HPCI Room	-	18	-	-	-	-	-	3	21	-	-	21	-	-	-	-	-	-	97	-
3b.1.1.5	Hot Shop	-	15	-	-	-	-	-	2	17	-	-	17	-	-	-	-	-	-	177	-
3b.1.1.6	Hydrogen & Oxygen Storage	-	2	-	-	-	-	-	0	2	-	-	2	-	-	-	-	-	-	19	-
3b.1.1.7	LLRW Storage & Shipping	-	78	-	-	-	-	-	12	90	-	-	90	-	-	-	-	-	-	662	-
3b.1.1.8	MSIV	-	3	-	-	-	-	-	0	4	-	-	4	-	-	-	-	-	-	42	-
3b.1.1.9	Misc Structures 2017	-	759	-	-	-	-	-	114	872	-	-	872	-	-	-	-	-	-	7,919	-
3b.1.1.10	Offgas Stack	-	104	-	-	-	-	-	16	120	-	-	120	-	-	-	-	-	-	544	-
3b.1.1.11	Offgas Storage & Compressor	-	38	-	-	-	-	-	6	44	-	-	44	-	-	-	-	-	-	199	-
3b.1.1.12	Radwaste	-	219	-	-	-	-	-	33	252	-	-	252	-	-	-	-	-	-	1,220	-
3b.1.1.13	Recombiner	-	123	-	-	-	-	-	18	141	-	-	141	-	-	-	-	-	-	713	-
3b.1.1.14	Security Barrier	-	179	-	-	-	-	-	27	206	-	-	206	-	-	-	-	-	-	933	-
3b.1.1.15	Structures Greater than 3' Below Grade	-	2,380	-	-	-	-	-	357	2,738	-	-	2,738	-	-	-	-	-	-	12,649	-
3b.1.1.16	Tank Farm	-	4	-	-	-	-	-	1	5	-	-	5	-	-	-	-	-	-	21	-
3b.1.1.17	Turbine	-	1,175	-	-	-	-	-	176	1,351	-	-	1,351	-	-	-	-	-	-	13,091	-
3b.1.1.18	Turbine Building Addition	-	51	-	-	-	-	-	8	58	-	-	58	-	-	-	-	-	-	618	-
3b.1.1.19	Turbine Pedestal	-	175	-	-	-	-	-	26	202	-	-	202	-	-	-	-	-	-	926	-
3b.1.1	Totals	-	7,219	-	-	-	-	-	1,083	8,302	-	-	8,302	-	-	-	-	-	-	53,870	-
Site Closeout Activities																					
3b.1.2	Grade & landscape site	-	864	-	-	-	-	-	130	994	-	-	994	-	-	-	-	-	-	1,841	-
3b.1.3	Final report to NRC	-	-	-	-	-	-	183	27	211	211	-	-	-	-	-	-	-	-	-	1,560
3b.1	Subtotal Period 3b Activity Costs	-	8,083	-	-	-	-	183	1,240	9,506	211	-	9,295	-	-	-	-	-	-	55,711	1,560
Period 3b Additional Costs																					
3b.2.1	Clean Concrete Disposal	-	3,297	-	-	-	-	11	496	3,805	-	-	3,805	-	-	-	-	-	-	12	-
3b.2.2	Excavation of Underground Services	-	1,380	-	-	-	-	947	349	2,677	-	-	2,677	-	-	-	-	-	-	13,475	-
3b.2.3	Intake Structure Cofferdam	-	320	-	-	-	-	-	48	368	-	-	368	-	-	-	-	-	-	2,584	-
3b.2.4	Construction Debris	-	-	-	-	-	-	350	53	403	-	-	403	-	-	-	-	-	-	-	-
3b.2.5	Backfill	-	5,102	-	-	-	-	-	765	5,868	-	-	5,868	-	-	-	-	-	-	5,422	-
3b.2	Subtotal Period 3b Additional Costs	-	10,100	-	-	-	-	1,309	1,711	13,120	-	-	13,120	-	-	-	-	-	-	21,493	-
Period 3b Collateral Costs																					
3b.3.1	Small tool allowance	-	97	-	-	-	-	-	15	111	-	-	111	-	-	-	-	-	-	-	-
3b.3.2	Spent Fuel Capital and Transfer	-	-	-	-	-	-	100	15	115	-	115	-	-	-	-	-	-	-	-	-
3b.3	Subtotal Period 3b Collateral Costs	-	97	-	-	-	-	100	30	226	-	115	111	-	-	-	-	-	-	-	-

Table G
Monticello Nuclear Generating Plant
Scenario 5: DECON with 60 Year DFS and Recasking Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 3b Period-Dependent Costs																					
3b.4.1	Insurance	-	-	-	-	-	-	1,251	125	1,376	-	1,376	-	-	-	-	-	-	-	-	-
3b.4.2	Property taxes	-	-	-	-	-	-	2,737	274	3,011	-	3,011	-	-	-	-	-	-	-	-	-
3b.4.3	Heavy equipment rental	-	5,455	-	-	-	-	-	818	6,273	-	-	6,273	-	-	-	-	-	-	-	-
3b.4.4	Plant energy budget	-	-	-	-	-	-	300	45	345	-	-	345	-	-	-	-	-	-	-	-
3b.4.5	NRC ISFSI Fees	-	-	-	-	-	-	386	39	424	-	424	-	-	-	-	-	-	-	-	-
3b.4.6	Emergency Planning Fees	-	-	-	-	-	-	237	24	261	-	261	-	-	-	-	-	-	-	-	-
3b.4.7	Fixed Overhead	-	-	-	-	-	-	1,260	189	1,450	-	-	1,450	-	-	-	-	-	-	-	-
3b.4.8	ISFSI Operating Costs	-	-	-	-	-	-	179	27	206	-	206	-	-	-	-	-	-	-	-	-
3b.4.9	Railroad Track Maintenance	-	-	-	-	-	-	497	75	572	-	-	572	-	-	-	-	-	-	-	-
3b.4.10	Security Staff Cost	-	-	-	-	-	-	22,115	3,317	25,432	(0)	7,782	17,650	-	-	-	-	-	-	-	375,152
3b.4.11	DOC Staff Cost	-	-	-	-	-	-	11,290	1,693	12,983	-	-	12,983	-	-	-	-	-	-	-	122,646
3b.4.12	Utility Staff Cost	-	-	-	-	-	-	6,583	987	7,571	-	1,976	5,595	-	-	-	-	-	-	-	98,297
3b.4	Subtotal Period 3b Period-Dependent Costs	-	5,455	-	-	-	-	46,836	7,613	59,904	(0)	15,036	44,868	-	-	-	-	-	-	-	596,095
3b.0	TOTAL PERIOD 3b COST	-	23,734	-	-	-	-	48,428	10,594	82,756	211	15,152	67,394	-	-	-	-	-	-	77,204	597,655
PERIOD 3c - Fuel Storage Operations/Shipping																					
Period 3c Direct Decommissioning Activities																					
Period 3c Collateral Costs																					
3c.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	122,822	18,423	141,246	-	141,246	-	-	-	-	-	-	-	-	-
3c.3	Subtotal Period 3c Collateral Costs	-	-	-	-	-	-	122,822	18,423	141,246	-	141,246	-	-	-	-	-	-	-	-	-
Period 3c Period-Dependent Costs																					
3c.4.1	Insurance	-	-	-	-	-	-	28,205	2,821	31,026	-	31,026	-	-	-	-	-	-	-	-	-
3c.4.2	Property taxes	-	-	-	-	-	-	24,796	2,480	27,276	-	27,276	-	-	-	-	-	-	-	-	-
3c.4.4	NRC ISFSI Fees	-	-	-	-	-	-	8,697	870	9,567	-	9,567	-	-	-	-	-	-	-	-	-
3c.4.5	Emergency Planning Fees	-	-	-	-	-	-	5,348	535	5,883	-	5,883	-	-	-	-	-	-	-	-	-
3c.4.6	Fixed Overhead	-	-	-	-	-	-	9,721	1,458	11,179	-	11,179	-	-	-	-	-	-	-	-	-
3c.4.7	ISFSI Operating Costs	-	-	-	-	-	-	4,037	606	4,643	-	4,643	-	-	-	-	-	-	-	-	-
3c.4.8	Railroad Track Maintenance	-	-	-	-	-	-	4,510	677	5,187	-	5,187	-	-	-	-	-	-	-	-	-
3c.4.9	Security Staff Cost	-	-	-	-	-	-	152,513	22,877	175,389	-	175,389	-	-	-	-	-	-	-	-	2,114,750
3c.4.10	Utility Staff Cost	-	-	-	-	-	-	38,674	5,801	44,475	-	44,475	-	-	-	-	-	-	-	-	549,022
3c.4	Subtotal Period 3c Period-Dependent Costs	-	-	-	-	-	-	276,502	38,123	314,624	-	314,624	-	-	-	-	-	-	-	-	2,663,772
3c.0	TOTAL PERIOD 3c COST	-	-	-	-	-	-	399,324	56,546	455,870	-	455,870	-	-	-	-	-	-	-	-	2,663,772
PERIOD 3d - GTCC shipping																					
Period 3d Direct Decommissioning Activities																					
Nuclear Steam Supply System Removal																					
3d.1.1.1	Vessel & Internals GTCC Disposal	-	-	1,331	-	-	6,552	-	1,316	9,199	9,199	-	-	-	-	-	-	-	1,547	311,184	-	-
3d.1.1	Totals	-	-	1,331	-	-	6,552	-	1,316	9,199	9,199	-	-	-	-	-	-	-	1,547	311,184	-	-
3d.1	Subtotal Period 3d Activity Costs	-	-	1,331	-	-	6,552	-	1,316	9,199	9,199	-	-	-	-	-	-	-	1,547	311,184	-	-
Period 3d Collateral Costs																					
3d.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	23,942	3,591	27,533	-	27,533	-	-	-	-	-	-	-	-	-
3d.3	Subtotal Period 3d Collateral Costs	-	-	-	-	-	-	23,942	3,591	27,533	-	27,533	-	-	-	-	-	-	-	-	-
Period 3d Period-Dependent Costs																					
3d.4.1	Insurance	-	-	-	-	-	-	9,383	938	10,321	-	10,321	-	-	-	-	-	-	-	-	-
3d.4.2	Property taxes	-	-	-	-	-	-	6,703	670	7,374	-	7,374	-	-	-	-	-	-	-	-	-
3d.4.4	NRC ISFSI Fees	-	-	-	-	-	-	4,257	426	4,683	-	4,683	-	-	-	-	-	-	-	-	-
3d.4.5	Emergency Planning Fees	-	-	-	-	-	-	1,779	178	1,957	-	1,957	-	-	-	-	-	-	-	-	-
3d.4.6	Fixed Overhead	-	-	-	-	-	-	3,234	485	3,719	-	3,719	-	-	-	-	-	-	-	-	-
3d.4.7	ISFSI Operating Costs	-	-	-	-	-	-	1,343	201	1,544	-	1,544	-	-	-	-	-	-	-	-	-
3d.4.8	Railroad Track Maintenance	-	-	-	-	-	-	1,500	225	1,725	-	1,725	-	-	-	-	-	-	-	-	-
3d.4.9	Security Staff Cost	-	-	-	-	-	-	50,734	7,610	58,344	-	58,344	-	-	-	-	-	-	-	-	703,485
3d.4.10	Utility Staff Cost	-	-	-	-	-	-	12,865	1,930	14,795	-	14,795	-	-	-	-	-	-	-	-	182,635
3d.4	Subtotal Period 3d Period-Dependent Costs	-	-	-	-	-	-	91,799	12,664	104,462	-	104,462	-	-	-	-	-	-	-	-	886,120
3d.0	TOTAL PERIOD 3d COST	-	-	1,331	-	-	6,552	115,740	17,571	141,194	9,199	131,995	-	-	-	-	-	-	1,547	311,184	-	886,120

Table G
Monticello Nuclear Generating Plant
Scenario 5: DECON with 60 Year DFS and Recasking Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
PERIOD 3e - ISFSI Decontamination																					
Period 3e Direct Decommissioning Activities																					
Period 3e Additional Costs																					
3e.2.1	Decommissioning of ISFSI	30	133	8	788	-	8,077	1,865	2,725	13,626	13,626	-	-	-	27,473	-	-	-	3,877,048	11,519	1,848
3e.2	Subtotal Period 3e Additional Costs	30	133	8	788	-	8,077	1,865	2,725	13,626	13,626	-	-	-	27,473	-	-	-	3,877,048	11,519	1,848
Period 3e Period-Dependent Costs																					
3e.4.1	Insurance	-	-	-	-	-	-	110	28	138	138	-	-	-	-	-	-	-	-	-	-
3e.4.2	Property taxes	-	-	-	-	-	-	244	61	304	304	-	-	-	-	-	-	-	-	-	-
3e.4.4	Fixed Overhead	-	-	-	-	-	-	82	21	103	103	-	-	-	-	-	-	-	-	-	-
3e.4.5	Railroad Track Maintenance	-	-	-	-	-	-	38	10	48	48	-	-	-	-	-	-	-	-	-	-
3e.4.6	Security Staff Cost	-	-	-	-	-	-	308	77	385	385	-	-	-	-	-	-	-	-	-	4,999
3e.4.7	Utility Staff Cost	-	-	-	-	-	-	260	65	325	325	-	-	-	-	-	-	-	-	-	3,792
3e.4	Subtotal Period 3e Period-Dependent Costs	-	-	-	-	-	-	1,042	261	1,303	1,303	-	-	-	-	-	-	-	-	-	8,792
3e.0	TOTAL PERIOD 3e COST	30	133	8	788	-	8,077	2,907	2,986	14,929	14,929	-	-	-	27,473	-	-	-	3,877,048	11,519	10,640
PERIOD 3f - ISFSI Site Restoration																					
Period 3f Direct Decommissioning Activities																					
Period 3f Additional Costs																					
3f.2.1	Demolition and Site Restoration of ISFSI	-	1,766	-	-	-	-	185	293	2,244	-	-	2,244	-	-	-	-	-	-	8,537	160
3f.2	Subtotal Period 3f Additional Costs	-	1,766	-	-	-	-	185	293	2,244	-	-	2,244	-	-	-	-	-	-	8,537	160
Period 3f Collateral Costs																					
3f.3.1	Small tool allowance	-	14	-	-	-	-	-	2	16	-	-	16	-	-	-	-	-	-	-	-
3f.3	Subtotal Period 3f Collateral Costs	-	14	-	-	-	-	-	2	16	-	-	16	-	-	-	-	-	-	-	-
Period 3f Period-Dependent Costs																					
3f.4.2	Property taxes	-	-	-	-	-	-	123	12	135	-	-	135	-	-	-	-	-	-	-	-
3f.4.3	Heavy equipment rental	-	123	-	-	-	-	-	19	142	-	-	142	-	-	-	-	-	-	-	-
3f.4.4	Plant energy budget	-	-	-	-	-	-	29	4	33	-	-	33	-	-	-	-	-	-	-	-
3f.4.5	Fixed Overhead	-	-	-	-	-	-	42	6	48	-	-	48	-	-	-	-	-	-	-	-
3f.4.6	Railroad Track Maintenance	-	-	-	-	-	-	19	3	22	-	-	22	-	-	-	-	-	-	-	-
3f.4.7	Security Staff Cost	-	-	-	-	-	-	155	23	179	-	-	179	-	-	-	-	-	-	-	2,520
3f.4.8	Utility Staff Cost	-	-	-	-	-	-	103	16	119	-	-	119	-	-	-	-	-	-	-	1,564
3f.4	Subtotal Period 3f Period-Dependent Costs	-	123	-	-	-	-	471	83	678	-	-	678	-	-	-	-	-	-	-	4,084
3f.0	TOTAL PERIOD 3f COST	-	1,903	-	-	-	-	656	378	2,937	-	-	2,937	-	-	-	-	-	-	8,537	4,244
PERIOD 3 TOTALS		30	25,770	1,339	788	-	14,629	567,055	88,074	697,686	24,338	603,017	70,331	-	27,473	-	-	1,547	4,188,233	97,261	4,162,431
TOTAL COST TO DECOMMISSION		**16,519**	**91,485**	**22,065**	**10,360**	**25,828**	**72,190**	**1,130,107**	**234,106**	**1,602,660**	**759,122**	**772,214**	**71,324**	**288,153**	**203,249**	**1,711**	**1,010**	**1,547**	**25,773,870**	**934,006**	**8,407,016**

TOTAL COST TO DECOMMISSION WITH 17.11% CONTINGENCY:	**$1,602,660**	**thousands of 2017 dollars**	
TOTAL NRC LICENSE TERMINATION COST IS 47.37% OR:	**$759,122**	**thousands of 2017 dollars**	
SPENT FUEL MANAGEMENT COST IS 48.18% OR:	**$772,214**	**thousands of 2017 dollars**	
NON-NUCLEAR DEMOLITION COST IS 4.45% OR:	**$71,324**	**thousands of 2017 dollars**	
TOTAL LOW-LEVEL RADIOACTIVE WASTE VOLUME BURIED (EXCLUDING GTCC):	**205,970**	**cubic feet**	
TOTAL GREATER THAN CLASS C RADWASTE VOLUME GENERATED:	**1,547**	**cubic feet**	
TOTAL SCRAP METAL REMOVED:	**22,696**	**tons**	
TOTAL CRAFT LABOR REQUIREMENTS:	**934,006**	**man-hours**	

End Notes:
n/a - indicates that this activity not charged as decommissioning expense
a - indicates that this activity performed by decommissioning staff
0 - indicates that this value is less than 0.5 but is non-zero
A cell containing " - " indicates a zero value

APPENDIX H

DETAILED COST ANALYSIS

SCENARIO 6: SAFSTOR with 32 Year DFS

Table H
Monticello Nuclear Generating Plant
Scenario 6: SAFSTOR with 32 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
PERIOD 1a - Shutdown through Transition																					
Period 1a Direct Decommissioning Activities																					
1a.1.1	SAFSTOR site characterization survey	-	-	-	-	-	-	380	114	494	494	-	-	-	-	-	-	-	-	-	-
1a.1.2	Prepare preliminary decommissioning cost	-	-	-	-	-	-	153	23	175	175	-	-	-	-	-	-	-	-	-	1,300
1a.1.3	Notification of Cessation of Operations									a											
1a.1.4	Remove fuel & source material									n/a											
1a.1.5	Notification of Permanent Defueling									a											
1a.1.6	Deactivate plant systems & process waste									a											
1a.1.7	Prepare and submit PSDAR	-	-	-	-	-	-	235	35	270	270	-	-	-	-	-	-	-	-	-	2,000
1a.1.8	Review plant dwgs & specs.	-	-	-	-	-	-	153	23	175	175	-	-	-	-	-	-	-	-	-	1,300
1a.1.9	Perform detailed rad survey									a											
1a.1.10	Estimate by-product inventory	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1a.1.11	End product description	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1a.1.12	Detailed by-product inventory	-	-	-	-	-	-	176	26	202	202	-	-	-	-	-	-	-	-	-	1,500
1a.1.13	Define major work sequence	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1a.1.14	Perform SER and EA	-	-	-	-	-	-	364	55	418	418	-	-	-	-	-	-	-	-	-	3,100
1a.1.15	Prepare/submit Defueled Technical Specifications	-	-	-	-	-	-	880	132	1,012	1,012	-	-	-	-	-	-	-	-	-	7,500
1a.1.16	Perform Site-Specific Cost Study	-	-	-	-	-	-	587	88	675	675	-	-	-	-	-	-	-	-	-	5,000
1a.1.17	Prepare/submit Irradiated Fuel Management Plan	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
Activity Specifications																					
1a.1.18.1	Prepare plant and facilities for SAFSTOR	-	-	-	-	-	-	578	87	664	664	-	-	-	-	-	-	-	-	-	4,920
1a.1.18.2	Plant systems	-	-	-	-	-	-	489	73	562	562	-	-	-	-	-	-	-	-	-	4,167
1a.1.18.3	Plant structures and buildings	-	-	-	-	-	-	366	55	421	421	-	-	-	-	-	-	-	-	-	3,120
1a.1.18.4	Waste management	-	-	-	-	-	-	235	35	270	270	-	-	-	-	-	-	-	-	-	2,000
1a.1.18.5	Facility and site dormancy	-	-	-	-	-	-	235	35	270	270	-	-	-	-	-	-	-	-	-	2,000
1a.1.18	Total	-	-	-	-	-	-	1,902	285	2,188	2,188	-	-	-	-	-	-	-	-	-	16,207
Detailed Work Procedures																					
1a.1.19.1	Plant systems	-	-	-	-	-	-	139	21	160	160	-	-	-	-	-	-	-	-	-	1,183
1a.1.19.2	Facility closeout & dormancy	-	-	-	-	-	-	141	21	162	162	-	-	-	-	-	-	-	-	-	1,200
1a.1.19	Total	-	-	-	-	-	-	280	42	322	322	-	-	-	-	-	-	-	-	-	2,383
1a.1.20	Procure vacuum drying system	-	-	-	-	-	-	12	2	13	13	-	-	-	-	-	-	-	-	-	100
1a.1.21	Drain/de-energize non-cont. systems									a											
1a.1.22	Drain & dry NSSS									a											
1a.1.23	Drain/de-energize contaminated systems									a											
1a.1.24	Decon/secure contaminated systems									a											
1a.1	Subtotal Period 1a Activity Costs	-	-	-	-	-	-	5,590	896	6,486	6,486	-	-	-	-	-	-	-	-	-	44,390
Period 1a Collateral Costs																					
1a.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	7,181	1,077	8,258	-	8,258	-	-	-	-	-	-	-	-	-
1a.3.2	Retention and Severance	-	-	-	-	-	-	9,892	1,484	11,376	11,376	-	-	-	-	-	-	-	-	-	-
1a.3	Subtotal Period 1a Collateral Costs	-	-	-	-	-	-	17,073	2,561	19,634	11,376	8,258	-	-	-	-	-	-	-	-	-
Period 1a Period-Dependent Costs																					
1a.4.1	Insurance	-	-	-	-	-	-	2,408	241	2,649	2,649	-	-	-	-	-	-	-	-	-	-
1a.4.2	Property taxes	-	-	-	-	-	-	2,242	224	2,466	2,466	-	-	-	-	-	-	-	-	-	-
1a.4.3	Health physics supplies	-	515	-	-	-	-	-	129	644	644	-	-	-	-	-	-	-	-	-	-
1a.4.4	Heavy equipment rental	-	567	-	-	-	-	-	85	652	652	-	-	-	-	-	-	-	-	-	-
1a.4.5	Disposal of DAW generated	-	-	13	4	-	50	-	14	81	81	-	-	-	610	-	-	-	12,190	20	-
1a.4.6	Plant energy budget	-	-	-	-	-	-	1,730	259	1,989	1,989	-	-	-	-	-	-	-	-	-	-
1a.4.7	NRC Fees	-	-	-	-	-	-	1,110	111	1,221	1,221	-	-	-	-	-	-	-	-	-	-
1a.4.8	Emergency Planning Fees	-	-	-	-	-	-	3,166	317	3,482	-	3,482	-	-	-	-	-	-	-	-	-
1a.4.9	Fixed Overhead	-	-	-	-	-	-	2,833	425	3,258	3,258	-	-	-	-	-	-	-	-	-	-
1a.4.10	Spent Fuel Pool O&M	-	-	-	-	-	-	803	120	923	-	923	-	-	-	-	-	-	-	-	-
1a.4.11	ISFSI Operating Costs	-	-	-	-	-	-	103	15	119	-	119	-	-	-	-	-	-	-	-	-
1a.4.12	Railroad Track Maintenance	-	-	-	-	-	-	115	17	133	133	-	-	-	-	-	-	-	-	-	-
1a.4.13	Security Staff Cost	-	-	-	-	-	-	14,260	2,139	16,399	16,399	-	-	-	-	-	-	-	-	-	245,440
1a.4.14	Utility Staff Cost	-	-	-	-	-	-	25,791	3,869	29,660	29,660	-	-	-	-	-	-	-	-	-	422,240
1a.4	Subtotal Period 1a Period-Dependent Costs	-	1,083	13	4	-	50	54,561	7,966	63,676	59,152	4,524	-	-	610	-	-	-	12,190	20	667,680
1a.0	TOTAL PERIOD 1a COST	-	1,083	13	4	-	50	77,224	11,423	89,796	77,014	12,782	-	-	610	-	-	-	12,190	20	712,070

Table H
Monticello Nuclear Generating Plant
Scenario 6: SAFSTOR with 32 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
PERIOD 1b - SAFSTOR Limited DECON Activities																					
Period 1b Direct Decommissioning Activities																					
Decontamination of Site Buildings																					
1b.1.1.1	Reactor Building	4,303	-	-	-	-	-	-	2,152	6,455	6,455	-	-	-	-	-	-	-	-	70,157	-
1b.1.1.2	Admin	81	-	-	-	-	-	-	41	122	122	-	-	-	-	-	-	-	-	1,357	-
1b.1.1.3	HPCI Room	21	-	-	-	-	-	-	11	32	32	-	-	-	-	-	-	-	-	350	-
1b.1.1.4	Hot Shop	12	-	-	-	-	-	-	6	19	19	-	-	-	-	-	-	-	-	208	-
1b.1.1.5	LLRW Storage & Shipping	42	-	-	-	-	-	-	21	63	63	-	-	-	-	-	-	-	-	705	-
1b.1.1.6	Offgas Stack	276	-	-	-	-	-	-	138	414	414	-	-	-	-	-	-	-	-	4,575	-
1b.1.1.7	Offgas Storage & Compressor	29	-	-	-	-	-	-	15	44	44	-	-	-	-	-	-	-	-	488	-
1b.1.1.8	Radwaste	88	-	-	-	-	-	-	44	132	132	-	-	-	-	-	-	-	-	1,473	-
1b.1.1.9	Radwaste Material Storage Warehouse	46	-	-	-	-	-	-	23	69	69	-	-	-	-	-	-	-	-	768	-
1b.1.1.10	Recombiner	19	-	-	-	-	-	-	10	29	29	-	-	-	-	-	-	-	-	323	-
1b.1.1.11	Turbine	512	-	-	-	-	-	-	256	768	768	-	-	-	-	-	-	-	-	8,583	-
1b.1.1.12	Turbine Building Addition	42	-	-	-	-	-	-	21	63	63	-	-	-	-	-	-	-	-	709	-
1b.1.1.13	Reactor (Post Fuel)	695	-	-	-	-	-	-	347	1,042	1,042	-	-	-	-	-	-	-	-	11,337	-
1b.1.1	Totals	6,167	-	-	-	-	-	-	3,084	9,251	9,251	-	-	-	-	-	-	-	-	101,033	-
1b.1	Subtotal Period 1b Activity Costs	6,167	-	-	-	-	-	-	3,084	9,251	9,251	-	-	-	-	-	-	-	-	101,033	-
Period 1b Additional Costs																					
1b.2.1	Spent fuel pool isolation	-	-	-	-	-	-	11,691	1,754	13,445	13,445	-	-	-	-	-	-	-	-	-	-
1b.2	Subtotal Period 1b Additional Costs	-	-	-	-	-	-	11,691	1,754	13,445	13,445	-	-	-	-	-	-	-	-	-	-
Period 1b Collateral Costs																					
1b.3.1	Decon equipment	973	-	-	-	-	-	-	146	1,119	1,119	-	-	-	-	-	-	-	-	-	-
1b.3.2	Process decommissioning water waste	214	-	138	356	-	566	-	316	1,589	1,589	-	-	-	1,350	-	-	-	81,018	263	-
1b.3.4	Small tool allowance	-	105	-	-	-	-	-	16	121	121	-	-	-	-	-	-	-	-	-	-
1b.3.5	Spent Fuel Capital and Transfer	-	-	-	-	-	-	168	25	193	-	193	-	-	-	-	-	-	-	-	-
1b.3.6	Retention and Severance	-	-	-	-	-	-	3,640	546	4,186	4,186	-	-	-	-	-	-	-	-	-	-
1b.3	Subtotal Period 1b Collateral Costs	1,187	105	138	356	-	566	3,808	1,049	7,209	7,016	193	-	-	1,350	-	-	-	81,018	263	-
Period 1b Period-Dependent Costs																					
1b.4.1	Decon supplies	1,264	-	-	-	-	-	-	316	1,580	1,580	-	-	-	-	-	-	-	-	-	-
1b.4.2	Insurance	-	-	-	-	-	-	607	61	668	668	-	-	-	-	-	-	-	-	-	-
1b.4.3	Property taxes	-	-	-	-	-	-	565	57	622	622	-	-	-	-	-	-	-	-	-	-
1b.4.4	Health physics supplies	-	614	-	-	-	-	-	153	767	767	-	-	-	-	-	-	-	-	-	-
1b.4.5	Heavy equipment rental	-	143	-	-	-	-	-	21	164	164	-	-	-	-	-	-	-	-	-	-
1b.4.6	Disposal of DAW generated	-	-	12	4	-	45	-	13	74	74	-	-	-	556	-	-	-	11,126	18	-
1b.4.7	Plant energy budget	-	-	-	-	-	-	436	65	501	501	-	-	-	-	-	-	-	-	-	-
1b.4.8	NRC Fees	-	-	-	-	-	-	161	16	178	178	-	-	-	-	-	-	-	-	-	-
1b.4.9	Emergency Planning Fees	-	-	-	-	-	-	798	80	878	-	878	-	-	-	-	-	-	-	-	-
1b.4.10	Fixed Overhead	-	-	-	-	-	-	714	107	821	821	-	-	-	-	-	-	-	-	-	-
1b.4.11	Spent Fuel Pool O&M	-	-	-	-	-	-	202	30	233	-	233	-	-	-	-	-	-	-	-	-
1b.4.12	ISFSI Operating Costs	-	-	-	-	-	-	26	4	30	-	30	-	-	-	-	-	-	-	-	-
1b.4.13	Railroad Track Maintenance	-	-	-	-	-	-	29	4	33	33	-	-	-	-	-	-	-	-	-	-
1b.4.14	Security Staff Cost	-	-	-	-	-	-	3,594	539	4,134	4,134	-	-	-	-	-	-	-	-	-	61,864
1b.4.15	Utility Staff Cost	-	-	-	-	-	-	6,501	975	7,476	7,476	-	-	-	-	-	-	-	-	-	106,428
1b.4	Subtotal Period 1b Period-Dependent Costs	1,264	757	12	4	-	45	13,634	2,442	18,157	17,017	1,140	-	-	556	-	-	-	11,126	18	168,292
1b.0	TOTAL PERIOD 1b COST	8,618	862	150	360	-	611	29,134	8,328	48,062	46,729	1,333	-	-	1,907	-	-	-	92,144	101,314	168,292
PERIOD 1c - Preparations for SAFSTOR Dormancy																					
Period 1c Direct Decommissioning Activities																					
1c.1.1	Prepare support equipment for storage	-	470	-	-	-	-	-	71	541	541	-	-	-	-	-	-	-	-	3,000	-
1c.1.2	Install containment pressure equal. lines	-	44	-	-	-	-	-	7	51	51	-	-	-	-	-	-	-	-	700	-
1c.1.3	Interim survey prior to dormancy	-	-	-	-	-	-	733	220	953	953	-	-	-	-	-	-	-	-	14,124	-
1c.1.4	Secure building accesses									a											
1c.1.5	Prepare & submit interim report	-	-	-	-	-	-	68	10	79	79	-	-	-	-	-	-	-	-	-	583
1c.1	Subtotal Period 1c Activity Costs	-	514	-	-	-	-	801	307	1,623	1,623	-	-	-	-	-	-	-	-	17,824	583

Table H
Monticello Nuclear Generating Plant
Scenario 6: SAFSTOR with 32 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 1c Collateral Costs																					
1c.3.1	Process decommissioning water waste	157	-	102	262	-	416	-	232	1,170	1,170	-	-	-	994	-	-	-	59,665	194	-
1c.3.3	Small tool allowance	-	4	-	-	-	-	-	1	5	5	-	-	-	-	-	-	-	-	-	-
1c.3.4	Spent Fuel Capital and Transfer	-	-	-	-	-	-	166	25	191	-	191	-	-	-	-	-	-	-	-	-
1c.3.5	Retention and Severance	-	-	-	-	-	-	2,722	408	3,130	3,130	-	-	-	-	-	-	-	-	-	-
1c.3	Subtotal Period 1c Collateral Costs	157	4	102	262	-	416	2,887	666	4,495	4,304	191	-	-	994	-	-	-	59,665	194	-
Period 1c Period-Dependent Costs																					
1c.4.1	Insurance	-	-	-	-	-	-	600	60	660	660	-	-	-	-	-	-	-	-	-	-
1c.4.2	Property taxes	-	-	-	-	-	-	558	56	614	614	-	-	-	-	-	-	-	-	-	-
1c.4.3	Health physics supplies	-	215	-	-	-	-	-	54	268	268	-	-	-	-	-	-	-	-	-	-
1c.4.4	Heavy equipment rental	-	141	-	-	-	-	-	21	163	163	-	-	-	-	-	-	-	-	-	-
1c.4.5	Disposal of DAW generated	-	-	3	1	-	12	-	4	20	20	-	-	-	152	-	-	-	3,039	5	-
1c.4.6	Plant energy budget	-	-	-	-	-	-	431	65	496	496	-	-	-	-	-	-	-	-	-	-
1c.4.7	NRC Fees	-	-	-	-	-	-	160	16	176	176	-	-	-	-	-	-	-	-	-	-
1c.4.8	Emergency Planning Fees	-	-	-	-	-	-	789	79	868	-	868	-	-	-	-	-	-	-	-	-
1c.4.9	Fixed Overhead	-	-	-	-	-	-	706	106	812	812	-	-	-	-	-	-	-	-	-	-
1c.4.10	Spent Fuel Pool O&M	-	-	-	-	-	-	200	30	230	-	230	-	-	-	-	-	-	-	-	-
1c.4.11	ISFSI Operating Costs	-	-	-	-	-	-	26	4	30	-	30	-	-	-	-	-	-	-	-	-
1c.4.12	Railroad Track Maintenance	-	-	-	-	-	-	29	4	33	33	-	-	-	-	-	-	-	-	-	-
1c.4.13	Security Staff Cost	-	-	-	-	-	-	3,555	533	4,089	4,089	-	-	-	-	-	-	-	-	-	61,192
1c.4.14	Utility Staff Cost	-	-	-	-	-	-	6,430	965	7,395	7,395	-	-	-	-	-	-	-	-	-	105,271
1c.4	Subtotal Period 1c Period-Dependent Costs	-	356	3	1	-	12	13,485	1,996	15,853	14,725	1,128	-	-	152	-	-	-	3,039	5	166,463
1c.0	TOTAL PERIOD 1c COST	157	874	105	263	-	429	17,173	2,969	21,971	20,652	1,319	-	-	1,146	-	-	-	62,705	18,023	167,046
PERIOD 1 TOTALS		8,775	2,819	268	627	-	1,089	123,531	22,720	159,829	144,395	15,434	-	-	3,662	-	-	-	167,039	119,357	1,047,408
PERIOD 2a - SAFSTOR Dormancy with Wet Spent Fuel Storage																					
Period 2a Direct Decommissioning Activities																					
2a.1.1	Quarterly Inspection									a											
2a.1.2	Semi-annual environmental survey									a											
2a.1.3	Prepare reports									a											
2a.1.4	Bituminous roof replacement	-	-	-	-	-	-	216	32	248	248	-	-	-	-	-	-	-	-	-	-
2a.1.5	Maintenance supplies	-	-	-	-	-	-	480	120	599	599	-	-	-	-	-	-	-	-	-	-
2a.1	Subtotal Period 2a Activity Costs	-	-	-	-	-	-	695	152	848	848	-	-	-	-	-	-	-	-	-	-
Period 2a Additional Costs																					
2a.2.1	Security Modifications	-	-	-	-	-	-	8,696	1,304	10,000	10,000	-	-	-	-	-	-	-	-	-	-
2a.2	Subtotal Period 2a Additional Costs	-	-	-	-	-	-	8,696	1,304	10,000	10,000	-	-	-	-	-	-	-	-	-	-
Period 2a Collateral Costs																					
2a.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	77,276	11,591	88,867	-	88,867	-	-	-	-	-	-	-	-	-
2a.3.2	Retention and Severance	-	-	-	-	-	-	21,900	3,285	25,185	25,185	-	-	-	-	-	-	-	-	-	-
2a.3	Subtotal Period 2a Collateral Costs	-	-	-	-	-	-	99,176	14,876	114,052	25,185	88,867	-	-	-	-	-	-	-	-	-
Period 2a Period-Dependent Costs																					
2a.4.1	Insurance	-	-	-	-	-	-	2,526	253	2,778	2,778	-	-	-	-	-	-	-	-	-	-
2a.4.2	Property taxes	-	-	-	-	-	-	7,844	784	8,628	8,628	-	-	-	-	-	-	-	-	-	-
2a.4.3	Health physics supplies	-	724	-	-	-	-	-	181	905	905	-	-	-	-	-	-	-	-	-	-
2a.4.4	Disposal of DAW generated	-	-	17	5	-	66	-	19	107	107	-	-	-	806	-	-	-	16,112	26	-
2a.4.5	Plant energy budget	-	-	-	-	-	-	1,211	182	1,393	1,393	-	-	-	-	-	-	-	-	-	-
2a.4.6	NRC Fees	-	-	-	-	-	-	898	90	988	988	-	-	-	-	-	-	-	-	-	-
2a.4.7	Emergency Planning Fees	-	-	-	-	-	-	8,991	899	9,891	-	9,891	-	-	-	-	-	-	-	-	-
2a.4.8	Fixed Overhead	-	-	-	-	-	-	9,919	1,488	11,407	11,407	-	-	-	-	-	-	-	-	-	-
2a.4.9	Spent Fuel Pool O&M	-	-	-	-	-	-	2,810	422	3,232	-	3,232	-	-	-	-	-	-	-	-	-
2a.4.10	ISFSI Operating Costs	-	-	-	-	-	-	361	54	416	-	416	-	-	-	-	-	-	-	-	-
2a.4.11	Railroad Track Maintenance	-	-	-	-	-	-	701	105	806	806	-	-	-	-	-	-	-	-	-	-
2a.4.12	Security Staff Cost	-	-	-	-	-	-	46,105	6,916	53,021	37,327	15,694	-	-	-	-	-	-	-	-	786,548
2a.4.13	Utility Staff Cost	-	-	-	-	-	-	17,653	2,648	20,301	16,322	3,979	-	-	-	-	-	-	-	-	287,673
2a.4	Subtotal Period 2a Period-Dependent Costs	-	724	17	5	-	66	99,020	14,040	113,872	80,661	33,211	-	-	806	-	-	-	16,112	26	1,074,220
2a.0	TOTAL PERIOD 2a COST	-	724	17	5	-	66	207,587	30,373	238,772	116,694	122,078	-	-	806	-	-	-	16,112	26	1,074,220

Table H
Monticello Nuclear Generating Plant
Scenario 6: SAFSTOR with 32 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
PERIOD 2b - SAFSTOR Dormancy with Dry Spent Fuel Storage																					
Period 2b Direct Decommissioning Activities																					
2b.1.1	Quarterly Inspection									a											
2b.1.2	Semi-annual environmental survey									a											
2b.1.3	Prepare reports									a											
2b.1.4	Bituminous roof replacement	-	-	-	-	-	-	1,685	253	1,937	1,937	-	-	-	-	-	-	-	-	-	-
2b.1.5	Maintenance supplies	-	-	-	-	-	-	3,744	936	4,680	4,680	-	-	-	-	-	-	-	-	-	-
2b.1	Subtotal Period 2b Activity Costs	-	-	-	-	-	-	5,428	1,189	6,617	6,617	-	-	-	-	-	-	-	-	-	-
Period 2b Collateral Costs																					
2b.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	50,959	7,644	58,603	-	58,603	-	-	-	-	-	-	-	-	-
2b.3	Subtotal Period 2b Collateral Costs	-	-	-	-	-	-	50,959	7,644	58,603	-	58,603	-	-	-	-	-	-	-	-	-
Period 2b Period-Dependent Costs																					
2b.4.1	Insurance	-	-	-	-	-	-	19,716	1,972	21,688	21,688	-	-	-	-	-	-	-	-	-	-
2b.4.2	Property taxes	-	-	-	-	-	-	61,232	6,123	67,355	67,355	-	-	-	-	-	-	-	-	-	-
2b.4.3	Health physics supplies	-	2,741	-	-	-	-	-	685	3,427	3,427	-	-	-	-	-	-	-	-	-	-
2b.4.4	Disposal of DAW generated	-	-	63	20	-	246	-	71	400	400	-	-	-	3,021	-	-	-	60,421	99	-
2b.4.5	Plant energy budget	-	-	-	-	-	-	4,728	709	5,438	5,438	-	-	-	-	-	-	-	-	-	-
2b.4.6	NRC Fees	-	-	-	-	-	-	6,663	666	7,329	7,329	-	-	-	-	-	-	-	-	-	-
2b.4.7	Emergency Planning Fees	-	-	-	-	-	-	3,738	374	4,112	-	4,112	-	-	-	-	-	-	-	-	-
2b.4.8	Fixed Overhead	-	-	-	-	-	-	6,795	1,019	7,814	7,814	-	-	-	-	-	-	-	-	-	-
2b.4.9	ISFSI Operating Costs	-	-	-	-	-	-	2,822	423	3,245	-	3,245	-	-	-	-	-	-	-	-	-
2b.4.10	Railroad Track Maintenance	-	-	-	-	-	-	3,153	473	3,626	3,626	-	-	-	-	-	-	-	-	-	-
2b.4.11	Security Staff Cost	-	-	-	-	-	-	135,018	20,253	155,271	32,607	122,664	-	-	-	-	-	-	-	-	2,046,789
2b.4.12	Utility Staff Cost	-	-	-	-	-	-	57,735	8,660	66,395	35,322	31,073	-	-	-	-	-	-	-	-	909,684
2b.4	Subtotal Period 2b Period-Dependent Costs	-	2,741	63	20	-	246	301,600	41,429	346,099	185,005	161,094	-	-	3,021	-	-	-	60,421	99	2,956,472
2b.0	TOTAL PERIOD 2b COST	-	2,741	63	20	-	246	357,987	50,261	411,319	191,622	219,697	-	-	3,021	-	-	-	60,421	99	2,956,472
PERIOD 2c - SAFSTOR Dormancy without Spent Fuel Storage																					
Period 2c Direct Decommissioning Activities																					
2c.1.1	Quarterly Inspection									a											
2c.1.2	Semi-annual environmental survey									a											
2c.1.3	Prepare reports									a											
2c.1.4	Bituminous roof replacement	-	-	-	-	-	-	1,359	204	1,563	1,563	-	-	-	-	-	-	-	-	-	-
2c.1.5	Maintenance supplies	-	-	-	-	-	-	3,021	755	3,776	3,776	-	-	-	-	-	-	-	-	-	-
2c.1	Subtotal Period 2c Activity Costs	-	-	-	-	-	-	4,380	959	5,339	5,339	-	-	-	-	-	-	-	-	-	-
Period 2c Period-Dependent Costs																					
2c.4.1	Insurance	-	-	-	-	-	-	15,623	1,562	17,185	17,185	-	-	-	-	-	-	-	-	-	-
2c.4.2	Property taxes	-	-	-	-	-	-	49,403	4,940	54,343	54,343	-	-	-	-	-	-	-	-	-	-
2c.4.3	Health physics supplies	-	2,080	-	-	-	-	-	520	2,601	2,601	-	-	-	-	-	-	-	-	-	-
2c.4.4	Disposal of DAW generated	-	-	47	15	-	183	-	53	297	297	-	-	-	2,245	-	-	-	44,899	73	-
2c.4.5	Plant energy budget	-	-	-	-	-	-	3,815	572	4,387	4,387	-	-	-	-	-	-	-	-	-	-
2c.4.6	NRC Fees	-	-	-	-	-	-	4,905	491	5,396	5,396	-	-	-	-	-	-	-	-	-	-
2c.4.7	Emergency Planning Fees	-	-	-	-	-	-	3,016	302	3,318	-	3,318	-	-	-	-	-	-	-	-	-
2c.4.8	Fixed Overhead	-	-	-	-	-	-	5,483	822	6,305	6,305	-	-	-	-	-	-	-	-	-	-
2c.4.9	ISFSI Operating Costs	-	-	-	-	-	-	2,277	342	2,619	-	2,619	-	-	-	-	-	-	-	-	-
2c.4.10	Railroad Track Maintenance	-	-	-	-	-	-	2,544	382	2,925	2,925	-	-	-	-	-	-	-	-	-	-
2c.4.11	Utility Staff Cost	-	-	-	-	-	-	24,505	3,676	28,181	28,181	-	-	-	-	-	-	-	-	-	401,397
2c.4	Subtotal Period 2c Period-Dependent Costs	-	2,080	47	15	-	183	111,571	13,661	127,557	121,620	5,936	-	-	2,245	-	-	-	44,899	73	401,397
2c.0	TOTAL PERIOD 2c COST	-	2,080	47	15	-	183	115,951	14,620	132,896	126,959	5,936	-	-	2,245	-	-	-	44,899	73	401,397
PERIOD 2 TOTALS		-	5,546	126	40	-	494	681,525	95,254	782,986	435,275	347,711	-	-	6,072	-	-	-	121,431	198	4,432,090
PERIOD 3a - Reactivate Site Following SAFSTOR Dormancy																					
Period 3a Direct Decommissioning Activities																					
3a.1.1	Prepare preliminary decommissioning cost	-	-	-	-	-	-	153	23	175	175	-	-	-	-	-	-	-	-	-	1,300
3a.1.2	Review plant dwgs & specs.	-	-	-	-	-	-	540	81	621	621	-	-	-	-	-	-	-	-	-	4,600
3a.1.3	Perform detailed rad survey									a											
3a.1.4	End product description	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
3a.1.5	Detailed by-product inventory	-	-	-	-	-	-	153	23	175	175	-	-	-	-	-	-	-	-	-	1,300
3a.1.6	Define major work sequence	-	-	-	-	-	-	880	132	1,012	1,012	-	-	-	-	-	-	-	-	-	7,500

Table H
Monticello Nuclear Generating Plant
Scenario 6: SAFSTOR with 32 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
3a.1.7	Perform SER and EA	-	-	-	-	-	-	364	55	418	418	-	-	-	-	-	-	-	-	-	3,100
3a.1.8	Perform Site-Specific Cost Study	-	-	-	-	-	-	587	88	675	675	-	-	-	-	-	-	-	-	-	5,000
Activity Specifications																					
3a.1.9.1	Re-activate plant & temporary facilities	-	-	-	-	-	-	865	130	995	895	-	99	-	-	-	-	-	-	-	7,370
3a.1.9.2	Plant systems	-	-	-	-	-	-	489	73	562	506	-	56	-	-	-	-	-	-	-	4,167
3a.1.9.3	Reactor internals	-	-	-	-	-	-	833	125	958	958	-	-	-	-	-	-	-	-	-	7,100
3a.1.9.4	Reactor vessel	-	-	-	-	-	-	763	114	877	877	-	-	-	-	-	-	-	-	-	6,500
3a.1.9.5	Sacrificial shield	-	-	-	-	-	-	59	9	67	67	-	-	-	-	-	-	-	-	-	500
3a.1.9.6	Moisture separators/reheaters	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
3a.1.9.7	Reinforced concrete	-	-	-	-	-	-	188	28	216	108	-	108	-	-	-	-	-	-	-	1,600
3a.1.9.8	Main Turbine	-	-	-	-	-	-	245	37	282	282	-	-	-	-	-	-	-	-	-	2,088
3a.1.9.9	Main Condensers	-	-	-	-	-	-	245	37	282	282	-	-	-	-	-	-	-	-	-	2,088
3a.1.9.10	Pressure suppression structure	-	-	-	-	-	-	235	35	270	270	-	-	-	-	-	-	-	-	-	2,000
3a.1.9.11	Drywell	-	-	-	-	-	-	188	28	216	216	-	-	-	-	-	-	-	-	-	1,600
3a.1.9.12	Plant structures & buildings	-	-	-	-	-	-	366	55	421	211	-	211	-	-	-	-	-	-	-	3,120
3a.1.9.13	Waste management	-	-	-	-	-	-	540	81	621	621	-	-	-	-	-	-	-	-	-	4,600
3a.1.9.14	Facility & site closeout	-	-	-	-	-	-	106	16	121	61	-	61	-	-	-	-	-	-	-	900
3a.1.9	Total	-	-	-	-	-	-	5,239	786	6,025	5,490	-	535	-	-	-	-	-	-	-	44,633
Planning & Site Preparations																					
3a.1.10	Prepare dismantling sequence	-	-	-	-	-	-	282	42	324	324	-	-	-	-	-	-	-	-	-	2,400
3a.1.11	Plant prep. & temp. svces	-	-	-	-	-	-	3,300	495	3,795	3,795	-	-	-	-	-	-	-	-	-	-
3a.1.12	Design water clean-up system	-	-	-	-	-	-	164	25	189	189	-	-	-	-	-	-	-	-	-	1,400
3a.1.13	Rigging/Cont. Cntrl Envlps/tooling/etc.	-	-	-	-	-	-	2,300	345	2,645	2,645	-	-	-	-	-	-	-	-	-	-
3a.1.14	Procure casks/liners & containers	-	-	-	-	-	-	144	22	166	166	-	-	-	-	-	-	-	-	-	1,230
3a.1	Subtotal Period 3a Activity Costs	-	-	-	-	-	-	14,223	2,133	16,357	15,821	-	535	-	-	-	-	-	-	-	73,463
Period 3a Additional Costs																					
3a.2.1	Site Characterization	-	-	-	-	-	-	6,446	1,934	8,380	8,380	-	-	-	-	-	-	-	-	30,500	10,852
3a.2.2	Mixed & RCRA Waste	-	-	29	19	13	-	-	8	69	69	-	-	43	-	-	-	-	5,253	163	-
3a.2	Subtotal Period 3a Additional Costs	-	-	29	19	13	-	6,446	1,942	8,449	8,449	-	-	43	-	-	-	-	5,253	30,663	10,852
Period 3a Period-Dependent Costs																					
3a.4.1	Insurance	-	-	-	-	-	-	708	71	779	779	-	-	-	-	-	-	-	-	-	-
3a.4.2	Property taxes	-	-	-	-	-	-	2,232	223	2,455	2,455	-	-	-	-	-	-	-	-	-	-
3a.4.3	Health physics supplies	-	451	-	-	-	-	-	113	564	564	-	-	-	-	-	-	-	-	-	-
3a.4.4	Heavy equipment rental	-	567	-	-	-	-	-	85	652	652	-	-	-	-	-	-	-	-	-	-
3a.4.5	Disposal of DAW generated	-	-	11	3	-	42	-	12	68	68	-	-	-	514	-	-	-	10,287	17	-
3a.4.6	Plant energy budget	-	-	-	-	-	-	1,730	259	1,989	1,989	-	-	-	-	-	-	-	-	-	-
3a.4.7	NRC Fees	-	-	-	-	-	-	341	34	376	376	-	-	-	-	-	-	-	-	-	-
3a.4.8	Emergency Planning Fees	-	-	-	-	-	-	137	14	150	-	150	-	-	-	-	-	-	-	-	-
3a.4.9	Fixed Overhead	-	-	-	-	-	-	2,833	425	3,258	3,258	-	-	-	-	-	-	-	-	-	-
3a.4.10	ISFSI Operating Costs	-	-	-	-	-	-	103	15	119	-	119	-	-	-	-	-	-	-	-	-
3a.4.11	Railroad Track Maintenance	-	-	-	-	-	-	115	17	133	133	-	-	-	-	-	-	-	-	-	-
3a.4.12	Utility Staff Cost	-	-	-	-	-	-	15,819	2,373	18,191	18,191	-	-	-	-	-	-	-	-	-	257,920
3a.4	Subtotal Period 3a Period-Dependent Costs	-	1,018	11	3	-	42	24,019	3,642	28,735	28,466	269	-	-	514	-	-	-	10,287	17	257,920
3a.0	TOTAL PERIOD 3a COST	-	1,018	39	23	13	42	44,688	7,717	53,540	52,736	269	535	43	514	-	-	-	15,540	30,680	342,235
PERIOD 3b - Decommissioning Preparations																					
Period 3b Direct Decommissioning Activities																					
Detailed Work Procedures																					
3b.1.1.1	Plant systems	-	-	-	-	-	-	556	83	639	575	-	64	-	-	-	-	-	-	-	4,733
3b.1.1.2	Reactor internals	-	-	-	-	-	-	470	70	540	540	-	-	-	-	-	-	-	-	-	4,000
3b.1.1.3	Remaining buildings	-	-	-	-	-	-	158	24	182	46	-	137	-	-	-	-	-	-	-	1,350
3b.1.1.4	CRD housings & NIs	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
3b.1.1.5	Incore instrumentation	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
3b.1.1.6	Removal primary containment	-	-	-	-	-	-	235	35	270	270	-	-	-	-	-	-	-	-	-	2,000
3b.1.1.7	Reactor vessel	-	-	-	-	-	-	426	64	490	490	-	-	-	-	-	-	-	-	-	3,630
3b.1.1.8	Facility closeout	-	-	-	-	-	-	141	21	162	81	-	81	-	-	-	-	-	-	-	1,200
3b.1.1.9	Sacrificial shield	-	-	-	-	-	-	141	21	162	162	-	-	-	-	-	-	-	-	-	1,200
3b.1.1.10	Reinforced concrete	-	-	-	-	-	-	117	18	135	67	-	67	-	-	-	-	-	-	-	1,000
3b.1.1.11	Main Turbine	-	-	-	-	-	-	244	37	281	281	-	-	-	-	-	-	-	-	-	2,080
3b.1.1.12	Main Condensers	-	-	-	-	-	-	245	37	282	282	-	-	-	-	-	-	-	-	-	2,088
3b.1.1.13	Moisture separators & reheaters	-	-	-	-	-	-	235	35	270	270	-	-	-	-	-	-	-	-	-	2,000

Table H
Monticello Nuclear Generating Plant
Scenario 6: SAFSTOR with 32 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Detailed Work Procedures (continued)																					
3b.1.1.14	Radwaste building	-	-	-	-	-	-	320	48	369	332	-	37	-	-	-	-	-	-	-	2,730
3b.1.1.15	Reactor building	-	-	-	-	-	-	320	48	369	332	-	37	-	-	-	-	-	-	-	2,730
3b.1.1	Total	-	-	-	-	-	-	3,843	576	4,420	3,997	-	423	-	-	-	-	-	-	-	32,741
3b.1	Subtotal Period 3b Activity Costs	-	-	-	-	-	-	3,843	576	4,420	3,997	-	423	-	-	-	-	-	-	-	32,741
Period 3b Collateral Costs																					
3b.3.1	Decon equipment	973	-	-	-	-	-	-	146	1,119	1,119	-	-	-	-	-	-	-	-	-	-
3b.3.2	DOC staff relocation expenses	-	-	-	-	-	-	1,189	178	1,367	1,367	-	-	-	-	-	-	-	-	-	-
3b.3.3	Pipe cutting equipment	-	1,200	-	-	-	-	-	180	1,380	1,380	-	-	-	-	-	-	-	-	-	-
3b.3	Subtotal Period 3b Collateral Costs	973	1,200	-	-	-	-	1,189	504	3,866	3,866	-	-	-	-	-	-	-	-	-	-
Period 3b Period-Dependent Costs																					
3b.4.1	Decon supplies	35	-	-	-	-	-	-	9	43	43	-	-	-	-	-	-	-	-	-	-
3b.4.2	Insurance	-	-	-	-	-	-	360	36	396	396	-	-	-	-	-	-	-	-	-	-
3b.4.3	Property taxes	-	-	-	-	-	-	995	99	1,094	1,094	-	-	-	-	-	-	-	-	-	-
3b.4.4	Health physics supplies	-	248	-	-	-	-	-	62	309	309	-	-	-	-	-	-	-	-	-	-
3b.4.5	Heavy equipment rental	-	283	-	-	-	-	-	42	325	325	-	-	-	-	-	-	-	-	-	-
3b.4.6	Disposal of DAW generated	-	-	6	2	-	24	-	7	38	38	-	-	-	290	-	-	-	5,802	9	-
3b.4.7	Plant energy budget	-	-	-	-	-	-	863	129	992	992	-	-	-	-	-	-	-	-	-	-
3b.4.8	NRC Fees	-	-	-	-	-	-	170	17	187	187	-	-	-	-	-	-	-	-	-	-
3b.4.9	Emergency Planning Fees	-	-	-	-	-	-	68	7	75	-	75	-	-	-	-	-	-	-	-	-
3b.4.10	Fixed Overhead	-	-	-	-	-	-	1,413	212	1,625	1,625	-	-	-	-	-	-	-	-	-	-
3b.4.11	ISFSI Operating Costs	-	-	-	-	-	-	51	8	59	-	59	-	-	-	-	-	-	-	-	-
3b.4.12	Railroad Track Maintenance	-	-	-	-	-	-	58	9	66	66	-	-	-	-	-	-	-	-	-	-
3b.4.13	DOC Staff Cost	-	-	-	-	-	-	5,123	769	5,892	5,892	-	-	-	-	-	-	-	-	-	58,080
3b.4.14	Utility Staff Cost	-	-	-	-	-	-	7,888	1,183	9,071	9,071	-	-	-	-	-	-	-	-	-	128,607
3b.4	Subtotal Period 3b Period-Dependent Costs	35	530	6	2	-	24	16,988	2,588	20,173	20,039	134	-	-	290	-	-	-	5,802	9	186,687
3b.0	TOTAL PERIOD 3b COST	1,008	1,730	6	2	-	24	22,020	3,669	28,459	27,902	134	423	-	290	-	-	-	5,802	9	219,428
PERIOD 3 TOTALS		1,008	2,749	45	25	13	65	66,708	11,386	81,999	80,638	403	958	43	804	-	-	-	21,343	30,690	561,663
PERIOD 4a - Large Component Removal																					
Period 4a Direct Decommissioning Activities																					
Nuclear Steam Supply System Removal																					
4a.1.1.1	Recirculation System Piping & Valves	20	71	28	22	96	214	-	102	553	553	-	-	676	715	-	-	-	94,867	1,594	-
4a.1.1.2	Recirculation Pumps & Motors	7	47	15	26	130	219	-	95	539	539	-	-	568	473	-	-	-	112,200	1,049	-
4a.1.1.3	CRDMs & NIs Removal	35	674	400	72	-	919	-	466	2,565	2,565	-	-	-	3,741	-	-	-	213,700	12,506	-
4a.1.1.4	Reactor Vessel Internals	102	5,782	8,903	1,187	-	14,647	275	14,274	45,170	45,170	-	-	-	2,943	1,127	643	-	306,123	22,915	1,075
4a.1.1.5	Vessel & Internals GTCC Disposal	-	-	-	-	-	6,552	-	983	7,535	7,535	-	-	-	-	-	-	1,547	311,184	-	-
4a.1.1.6	Reactor Vessel	-	7,999	1,877	606	-	5,622	275	9,472	25,852	25,852	-	-	-	17,823	-	-	-	1,110,260	22,915	1,075
4a.1.1	Totals	163	14,571	11,223	1,914	226	28,174	551	25,392	82,215	82,215	-	-	1,244	25,695	1,127	643	1,547	2,148,335	60,979	2,150
Removal of Major Equipment																					
4a.1.2	Main Turbine/Generator	-	282	1,424	349	3,174	357	-	831	6,417	6,417	-	-	24,835	1,383	-	-	-	1,577,959	4,796	-
4a.1.3	Main Condensers	-	994	378	128	1,667	198	-	605	3,970	3,970	-	-	17,396	727	-	-	-	828,955	16,823	-
Cascading Costs from Clean Building Demolition																					
4a.1.4.1	Reactor Building	-	611	-	-	-	-	-	92	703	703	-	-	-	-	-	-	-	-	6,238	-
4a.1.4.2	Radwaste	-	53	-	-	-	-	-	8	61	61	-	-	-	-	-	-	-	-	569	-
4a.1.4.3	Turbine	-	157	-	-	-	-	-	24	180	180	-	-	-	-	-	-	-	-	1,884	-
4a.1.4	Totals	-	821	-	-	-	-	-	123	944	944	-	-	-	-	-	-	-	-	8,691	-
Disposal of Plant Systems																					
4a.1.5.1	Automatic Press Relief	-	88	2	7	94	-	-	37	228	228	-	-	1,088	-	-	-	-	44,184	1,468	-
4a.1.5.2	Chemistry Sampling	-	20	0	1	18	-	-	8	48	48	-	-	207	-	-	-	-	8,422	356	-
4a.1.5.3	Chemistry Sampling - Insulated	-	1	0	0	0	-	-	0	2	2	-	-	1	-	-	-	-	61	25	-
4a.1.5.4	Circulating Water - RCA	-	172	10	41	576	-	-	136	935	935	-	-	6,656	-	-	-	-	270,307	2,860	-
4a.1.5.5	Combustible Gas Control - Insul - RCA	-	24	0	1	18	-	-	9	53	53	-	-	212	-	-	-	-	8,617	378	-
4a.1.5.6	Combustible Gas Control - RCA	-	15	0	2	25	-	-	8	50	50	-	-	285	-	-	-	-	11,577	245	-
4a.1.5.7	Condensate & Feedwater	-	736	45	184	2,609	-	-	607	4,181	4,181	-	-	30,157	-	-	-	-	1,224,704	12,501	-
4a.1.5.8	Condensate & Feedwater - Insulated	-	368	9	36	506	-	-	174	1,093	1,093	-	-	5,855	-	-	-	-	237,764	6,185	-
4a.1.5.9	Condensate Demin	-	408	7	29	410	-	-	168	1,022	1,022	-	-	4,735	-	-	-	-	192,293	6,784	-
4a.1.5.10	Condensate Storage	-	546	12	50	712	-	-	252	1,573	1,573	-	-	8,237	-	-	-	-	334,489	9,265	-
4a.1.5.11	Control Rod Drive	-	2	0	0	2	-	-	1	5	5	-	-	24	-	-	-	-	976	36	-

Table H
Monticello Nuclear Generating Plant
Scenario 6: SAFSTOR with 32 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Disposal of Plant Systems (continued)																					
4a.1.5.12	Control Rod Drive Hydraulic	-	309	4	15	211	-	-	112	651	651	-	-	2,440	-	-	-	-	99,094	5,255	-
4a.1.5.13	Core Spray	-	59	8	31	442	-	-	86	626	626	-	-	5,109	-	-	-	-	207,487	1,026	-
4a.1.5.14	Core Spray - Insulated	-	108	2	7	102	-	-	44	263	263	-	-	1,184	-	-	-	-	48,081	1,806	-
4a.1.5.15	Demin Water - Insulated - RCA	-	12	0	1	7	-	-	4	25	25	-	-	85	-	-	-	-	3,445	181	-
4a.1.5.16	Demin Water - RCA	-	34	0	2	22	-	-	12	70	70	-	-	253	-	-	-	-	10,278	508	-
4a.1.5.17	Diesel Oil - RCA	-	2	0	0	2	-	-	1	4	4	-	-	23	-	-	-	-	931	25	-
4a.1.5.18	Drywell Atmosphere Cooling - RCA	-	31	1	3	47	-	-	15	98	98	-	-	548	-	-	-	-	22,244	550	-
4a.1.5.19	EDG Emerg Service Water - Insul - RCA	-	0	0	0	0	-	-	0	1	1	-	-	2	-	-	-	-	84	4	-
4a.1.5.20	Electrical - Clean	-	11	-	-	-	-	-	2	12	-	-	12	-	-	-	-	-	-	182	-
4a.1.5.21	Emergency Service Water - Insul - RCA	-	18	0	1	12	-	-	6	37	37	-	-	137	-	-	-	-	5,544	281	-
4a.1.5.22	Emergency Service Water - RCA	-	1	0	0	1	-	-	1	3	3	-	-	13	-	-	-	-	512	22	-
4a.1.5.23	GEZIP - RCA	-	3	0	1	9	-	-	2	15	15	-	-	103	-	-	-	-	4,184	48	-
4a.1.5.24	Generator Physical Design - RCA	-	4	0	0	3	-	-	1	8	8	-	-	31	-	-	-	-	1,250	67	-
4a.1.5.25	H2-O2 Control Analyzing	-	5	0	0	2	-	-	1	8	8	-	-	23	-	-	-	-	948	72	-
4a.1.5.26	H2-O2 Control Analyzing - Insulated	-	5	0	0	2	-	-	1	8	8	-	-	23	-	-	-	-	948	72	-
4a.1.5.27	High Pressure Coolant Injection	-	50	2	8	109	-	-	30	199	199	-	-	1,262	-	-	-	-	51,257	850	-
4a.1.5.28	High Pressure Coolant Injection - Insula	-	164	3	14	196	-	-	73	450	450	-	-	2,266	-	-	-	-	92,018	2,734	-
4a.1.5.29	Hydrogen Cooling	-	7	-	-	-	-	-	1	8	-	-	8	-	-	-	-	-	-	118	-
4a.1.5.30	Hydrogen Cooling - RCA	-	6	0	0	3	-	-	2	11	11	-	-	39	-	-	-	-	1,600	79	-
4a.1.5.31	Hydrogen Seal Oil - RCA	-	14	0	1	16	-	-	6	38	38	-	-	189	-	-	-	-	7,669	212	-
4a.1.5.32	Hydrogen Water Chemistry - RCA	-	20	0	1	12	-	-	7	40	40	-	-	140	-	-	-	-	5,672	304	-
4a.1.5.33	Instrument & Service Air - RCA	-	185	3	11	153	-	-	71	423	423	-	-	1,768	-	-	-	-	71,810	2,733	-
4a.1.5.34	Main Condenser	-	147	3	12	165	-	-	63	389	389	-	-	1,903	-	-	-	-	77,301	2,443	-
4a.1.5.35	Main Steam	-	186	4	18	257	-	-	88	554	554	-	-	2,975	-	-	-	-	120,806	3,122	-
4a.1.5.36	Main Turbine	-	754	48	194	2,758	-	-	636	4,391	4,391	-	-	31,885	-	-	-	-	1,294,866	12,952	-
4a.1.5.37	Main Turbine - Insulated	-	160	5	21	299	-	-	89	574	574	-	-	3,460	-	-	-	-	140,506	2,725	-
4a.1.5.38	Miscellaneous	-	32	0	2	26	-	-	12	72	72	-	-	302	-	-	-	-	12,283	556	-
4a.1.5.39	Off Gas Recombiner	-	140	4	17	247	-	-	75	485	485	-	-	2,861	-	-	-	-	116,194	2,387	-
4a.1.5.40	Off Gas Recombiner - Insulated	-	289	4	14	203	-	-	105	616	616	-	-	2,350	-	-	-	-	95,441	4,785	-
4a.1.5.41	Post Accident Sampling	-	19	0	1	9	-	-	6	34	34	-	-	99	-	-	-	-	4,004	306	-
4a.1.5.42	Post Accident Sampling - Insulated	-	13	0	0	6	-	-	4	23	23	-	-	67	-	-	-	-	2,737	190	-
4a.1.5.43	RHR Service Water - Insulated - RCA	-	69	2	9	128	-	-	38	246	246	-	-	1,485	-	-	-	-	60,293	1,125	-
4a.1.5.44	RHR Service Water - RCA	-	3	0	0	3	-	-	1	8	8	-	-	35	-	-	-	-	1,410	57	-
4a.1.5.45	Reactor Feedwater Pump Seal	-	42	0	2	28	-	-	15	87	87	-	-	327	-	-	-	-	13,295	687	-
4a.1.5.46	Residual Heat Removal	-	187	52	99	1,091	418	-	335	2,181	2,181	-	-	12,609	1,519	-	-	-	609,174	3,282	-
4a.1.5.47	Residual Heat Removal - Insulated	-	415	37	51	440	377	-	275	1,595	1,595	-	-	5,084	1,374	-	-	-	294,206	7,027	-
4a.1.5.48	Rx Core Isolation Cooling	-	36	1	2	31	-	-	14	84	84	-	-	364	-	-	-	-	14,781	609	-
4a.1.5.49	Rx Core Isolation Cooling - Insulated	-	80	1	3	49	-	-	28	161	161	-	-	563	-	-	-	-	22,843	1,315	-
4a.1.5.50	Rx Recirculation	-	44	5	3	8	43	-	24	126	126	-	-	96	152	-	-	-	13,794	691	-
4a.1.5.51	Snubbers	-	126	1	3	43	-	-	39	212	212	-	-	502	-	-	-	-	20,395	2,272	-
4a.1.5.52	Standby Liquid Control - Insul - RCA	-	3	0	0	2	-	-	1	6	6	-	-	22	-	-	-	-	904	48	-
4a.1.5.53	Standby Liquid Control - RCA	-	22	0	1	21	-	-	9	54	54	-	-	245	-	-	-	-	9,969	341	-
4a.1.5.54	Stator Cooling - RCA	-	6	0	1	11	-	-	3	21	21	-	-	126	-	-	-	-	5,135	98	-
4a.1.5.55	Traversing Incore Probe	-	3	0	0	0	1	-	1	5	5	-	-	2	5	-	-	-	379	46	-
4a.1.5	Totals	-	6,203	280	899	12,150	839	-	3,744	24,114	24,094	-	20	140,459	3,050	-	-	-	5,899,167	104,297	-
4a.1.6	Scaffolding in support of decommissioning	-	1,778	23	8	99	25	-	469	2,402	2,402	-	-	1,030	91	-	-	-	52,111	19,968	-
4a.1	Subtotal Period 4a Activity Costs	163	24,648	13,329	3,299	17,316	29,592	551	31,164	120,062	120,042	-	20	184,963	30,945	1,127	643	1,547	10,506,530	215,555	2,150
Period 4a Additional Costs																					
4a.2.1	Remedial Action Surveys	-	-	-	-	-	-	2,161	648	2,809	2,809	-	-	-	-	-	-	-	-	28,247	-
4a.2	Subtotal Period 4a Additional Costs	-	-	-	-	-	-	2,161	648	2,809	2,809	-	-	-	-	-	-	-	-	28,247	-
Period 4a Collateral Costs																					
4a.3.1	Process decommissioning water waste	4	-	7	17	-	27	-	12	66	66	-	-	-	64	-	-	-	3,860	13	-
4a.3.3	Small tool allowance	-	240	-	-	-	-	-	36	276	248	-	28	-	-	-	-	-	-	-	-
4a.3	Subtotal Period 4a Collateral Costs	4	240	7	17	-	27	-	48	342	314	-	28	-	64	-	-	-	3,860	13	-
Period 4a Period-Dependent Costs																					
4a.4.1	Decon supplies	94	-	-	-	-	-	-	24	118	118	-	-	-	-	-	-	-	-	-	-
4a.4.2	Insurance	-	-	-	-	-	-	980	98	1,078	1,078	-	-	-	-	-	-	-	-	-	-
4a.4.3	Property taxes	-	-	-	-	-	-	2,674	267	2,942	2,942	-	-	-	-	-	-	-	-	-	-
4a.4.4	Health physics supplies	-	1,855	-	-	-	-	-	464	2,318	2,318	-	-	-	-	-	-	-	-	-	-
4a.4.5	Heavy equipment rental	-	2,984	-	-	-	-	-	448	3,431	3,431	-	-	-	-	-	-	-	-	-	-
4a.4.6	Disposal of DAW generated	-	-	97	31	-	378	-	109	614	614	-	-	-	4,639	-	-	-	92,777	151	-
4a.4.7	Plant energy budget	-	-	-	-	-	-	2,233	335	2,568	2,568	-	-	-	-	-	-	-	-	-	-

Table H
Monticello Nuclear Generating Plant
Scenario 6: SAFSTOR with 32 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 4a Period-Dependent Costs (continued)																					
4a.4.8	NRC Fees	-	-	-	-	-	-	757	76	833	833	-	-	-	-	-	-	-	-	-	-
4a.4.9	Emergency Planning Fees	-	-	-	-	-	-	186	19	204	-	204	-	-	-	-	-	-	-	-	-
4a.4.10	Fixed Overhead	-	-	-	-	-	-	3,150	473	3,623	3,623	-	-	-	-	-	-	-	-	-	-
4a.4.11	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	550	82	632	632	-	-	-	-	-	-	-	-	-	-
4a.4.12	ISFSI Operating Costs	-	-	-	-	-	-	140	21	161	-	161	-	-	-	-	-	-	-	-	-
4a.4.13	Railroad Track Maintenance	-	-	-	-	-	-	157	24	180	180	-	-	-	-	-	-	-	-	-	-
4a.4.14	DOC Staff Cost	-	-	-	-	-	-	16,810	2,522	19,332	19,332	-	-	-	-	-	-	-	-	-	195,030
4a.4.15	Utility Staff Cost	-	-	-	-	-	-	21,650	3,247	24,897	24,897	-	-	-	-	-	-	-	-	-	353,315
4a.4	Subtotal Period 4a Period-Dependent Costs	94	4,838	97	31	-	378	49,288	8,207	62,932	62,567	366	-	-	4,639	-	-	-	92,777	151	548,345
4a.0	TOTAL PERIOD 4a COST	262	29,726	13,432	3,346	17,316	29,997	51,999	40,067	186,146	185,732	366	48	184,963	35,648	1,127	643	1,547	10,603,160	243,966	550,495
PERIOD 4b - Site Decontamination																					
Period 4b Direct Decommissioning Activities																					
4b.1.1	Remove spent fuel racks	504	49	108	109	-	2,091	-	814	3,675	3,675	-	-	-	7,653	-	-	-	486,170	906	-
Disposal of Plant Systems																					
4b.1.2.1	ALARA/Radiological	-	14	0	0	4	-	-	4	22	22	-	-	49	-	-	-	-	1,987	247	-
4b.1.2.2	Alternate N2 - RCA	-	13	0	1	8	-	-	5	27	27	-	-	93	-	-	-	-	3,765	185	-
4b.1.2.3	Cranes/Heavy Loads/Rigging - RCA	-	3	0	1	9	-	-	2	15	15	-	-	103	-	-	-	-	4,184	48	-
4b.1.2.4	Decontamination Projects	-	1	0	0	0	-	-	0	1	1	-	-	3	-	-	-	-	125	15	-
4b.1.2.5	Electrical - Contaminated	-	328	4	15	217	-	-	117	682	682	-	-	2,514	-	-	-	-	102,112	5,633	-
4b.1.2.6	Electrical - Contaminated Fuel Pool	-	34	0	2	22	-	-	12	70	70	-	-	253	-	-	-	-	10,272	592	-
4b.1.2.7	Electrical - Decontam. Fuel Pool Area	-	242	4	15	213	-	-	95	568	568	-	-	2,457	-	-	-	-	99,783	4,090	-
4b.1.2.8	Electrical - Decontaminated	-	2,195	36	142	2,019	-	-	877	5,269	5,269	-	-	23,344	-	-	-	-	948,013	37,107	-
4b.1.2.9	Fire - RCA	-	84	1	4	53	-	-	30	171	171	-	-	614	-	-	-	-	24,917	1,324	-
4b.1.2.10	Fire - RCA - Fuel Pool Area	-	9	0	0	5	-	-	3	18	18	-	-	62	-	-	-	-	2,499	143	-
4b.1.2.11	Fuel Pool Cooling & Cleanup	-	319	19	23	177	196	-	161	895	895	-	-	2,051	712	-	-	-	128,918	5,363	-
4b.1.2.12	Fuel Pool Cooling & Cleanup - Insulated	-	31	2	2	11	20	-	15	80	80	-	-	130	71	-	-	-	9,830	514	-
4b.1.2.13	HVAC Ductwork	-	238	4	17	243	-	-	99	601	601	-	-	2,805	-	-	-	-	113,913	3,539	-
4b.1.2.14	HVAC Ductwork - Fuel Pool Area	-	26	0	2	27	-	-	11	67	67	-	-	312	-	-	-	-	12,657	393	-
4b.1.2.15	HVAC/Chilled Water - RCA	-	267	4	17	238	-	-	105	631	631	-	-	2,752	-	-	-	-	111,779	3,985	-
4b.1.2.16	HVAC/Chilled Water - RCA Fuel Pool Area	-	27	0	1	19	-	-	10	58	58	-	-	223	-	-	-	-	9,072	397	-
4b.1.2.17	Heating & Ventilation	-	359	10	39	548	-	-	179	1,134	1,134	-	-	6,334	-	-	-	-	257,243	6,340	-
4b.1.2.18	Heating Boiler - Insulated - RCA	-	2	0	0	2	-	-	1	6	6	-	-	26	-	-	-	-	1,058	35	-
4b.1.2.19	Instrument & Service Air-RCA-Fuel Pool	-	24	0	2	23	-	-	10	58	58	-	-	267	-	-	-	-	10,841	357	-
4b.1.2.20	Liquid Radwaste	-	515	28	39	364	253	-	255	1,453	1,453	-	-	4,203	915	-	-	-	229,422	8,550	-
4b.1.2.21	Makeup Demin - RCA	-	86	2	9	127	-	-	42	266	266	-	-	1,471	-	-	-	-	59,747	1,412	-
4b.1.2.22	Non-Essential Diesel Generator - RCA	-	23	2	9	123	-	-	26	183	183	-	-	1,424	-	-	-	-	57,832	395	-
4b.1.2.23	Off Gas Holdup	-	257	5	22	314	-	-	115	713	713	-	-	3,629	-	-	-	-	147,355	4,256	-
4b.1.2.24	Primary Containment	-	341	13	51	718	-	-	202	1,324	1,324	-	-	8,302	-	-	-	-	337,148	5,729	-
4b.1.2.25	Process Radiation Monitors	-	34	0	1	18	-	-	12	66	66	-	-	213	-	-	-	-	8,667	577	-
4b.1.2.26	Rx Bldg Closed Clng Water - Insul - RCA	-	93	2	6	85	-	-	37	222	222	-	-	977	-	-	-	-	39,675	1,484	-
4b.1.2.27	Rx Bldg Closed Clng Water - RCA	-	152	11	43	614	-	-	138	957	957	-	-	7,093	-	-	-	-	288,031	2,489	-
4b.1.2.28	Rx Component Handling Equip	-	105	11	16	150	113	-	81	477	477	-	-	1,737	415	-	-	-	96,901	1,839	-
4b.1.2.29	Rx Pressure Vessel	-	35	4	3	14	47	-	24	127	127	-	-	161	169	-	-	-	17,375	578	-
4b.1.2.30	Rx Water Cleanup	-	198	16	11	24	174	-	100	523	523	-	-	278	630	-	-	-	51,819	3,264	-
4b.1.2.31	Secondary Containment	-	93	2	8	119	-	-	42	264	264	-	-	1,372	-	-	-	-	55,702	1,569	-
4b.1.2.32	Service & Seal Water - Insulated - RCA	-	99	2	7	102	-	-	41	252	252	-	-	1,180	-	-	-	-	47,917	1,565	-
4b.1.2.33	Service & Seal Water - RCA	-	131	3	11	156	-	-	58	360	360	-	-	1,809	-	-	-	-	73,453	2,016	-
4b.1.2.34	Service Air Blower - RCA	-	13	0	1	18	-	-	6	38	38	-	-	206	-	-	-	-	8,364	206	-
4b.1.2.35	Solid Radwaste	-	369	20	30	293	181	-	188	1,081	1,081	-	-	3,390	659	-	-	-	179,772	6,270	-
4b.1.2.36	Structures & Buildings	-	58	1	3	41	-	-	21	124	124	-	-	477	-	-	-	-	19,351	1,005	-
4b.1.2.37	Wells & Domestic Water	-	8	-	-	-	-	-	1	9	-	-	9	-	-	-	-	-	-	144	-
4b.1.2.38	Wells & Domestic Water - RCA	-	43	1	2	30	-	-	16	91	91	-	-	342	-	-	-	-	13,874	633	-
4b.1.2	Totals	-	6,869	208	555	7,150	984	-	3,139	18,904	18,894	-	9	82,654	3,571	-	-	-	3,585,374	114,290	-
4b.1.3	Scaffolding in support of decommissioning	-	2,667	35	12	148	37	-	704	3,603	3,603	-	-	1,545	136	-	-	-	78,166	29,953	-
Decontamination of Site Buildings																					
4b.1.4.1	Reactor Building	3,881	2,049	138	314	4,159	765	-	3,329	14,634	14,634	-	-	48,077	4,434	-	-	-	2,195,768	98,722	-
4b.1.4.2	Admin	82	2	0	1	-	7	-	43	135	135	-	-	-	72	-	-	-	3,420	1,389	-
4b.1.4.3	HPCI Room	22	19	0	1	10	7	-	19	78	78	-	-	118	65	-	-	-	7,927	664	-
4b.1.4.4	Hot Shop	13	2	0	1	-	5	-	8	28	28	-	-	-	51	-	-	-	2,430	231	-
4b.1.4.5	LLRW Storage & Shipping	43	11	1	3	3	21	-	30	111	111	-	-	31	217	-	-	-	11,532	875	-
4b.1.4.6	Offgas Stack	280	127	4	12	116	44	-	202	786	786	-	-	1,343	361	-	-	-	72,483	6,692	-

Table H
Monticello Nuclear Generating Plant
Scenario 6: SAFSTOR with 32 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Decontamination of Site Buildings (continued)																					
4b.1.4.7	Offgas Storage & Compressor	30	7	0	2	2	15	-	21	79	79	-	-	25	159	-	-	-	8,502	603	-
4b.1.4.8	Radwaste	91	30	2	7	15	44	-	67	255	255	-	-	172	460	-	-	-	28,679	1,960	-
4b.1.4.9	Radwaste Material Storage Warehouse	48	9	1	3	-	23	-	32	116	116	-	-	-	248	-	-	-	11,700	915	-
4b.1.4.10	Recombiner	20	15	1	3	17	12	-	20	87	87	-	-	199	112	-	-	-	13,491	554	-
4b.1.4.11	Turbine	528	172	9	42	111	260	-	396	1,517	1,517	-	-	1,283	2,675	-	-	-	179,172	11,286	-
4b.1.4.12	Turbine Building Addition	44	8	1	3	-	20	-	29	105	105	-	-	-	217	-	-	-	10,248	838	-
4b.1.4.13	Reactor (Post Fuel)	703	1,924	129	656	170	4,681	-	2,140	10,403	10,403	-	-	1,969	49,647	-	-	-	2,426,544	39,766	-
4b.1.4	Totals	5,783	4,375	286	1,047	4,603	5,903	-	6,337	28,334	28,334	-	-	53,216	58,718	-	-	-	4,971,896	164,495	-
4b.1.5	Prepare/submit License Termination Plan	-	-	-	-	-	-	481	72	553	553	-	-	-	-	-	-	-	-	-	4,096
4b.1.6	Receive NRC approval of termination plan									a											
4b.1	Subtotal Period 4b Activity Costs	6,287	13,960	637	1,723	11,901	9,015	481	11,066	55,069	55,060	-	9	137,414	70,078	-	-	-	9,121,606	309,644	4,096
Period 4b Additional Costs																					
4b.2.1	License Termination Survey Planning	-	-	-	-	-	-	1,291	387	1,678	1,678	-	-	-	-	-	-	-	-	-	12,480
4b.2.2	Remedial Action Surveys	-	-	-	-	-	-	3,241	972	4,213	4,213	-	-	-	-	-	-	-	-	42,370	-
4b.2.3	Operational Equipment	-	-	19	60	624	-	-	104	807	807	-	-	11,710	-	-	-	-	292,750	32	-
4b.2	Subtotal Period 4b Additional Costs	-	-	19	60	624	-	4,532	1,464	6,698	6,698	-	-	11,710	-	-	-	-	292,750	42,402	12,480
Period 4b Collateral Costs																					
4b.3.1	Process decommissioning water waste	12	-	21	53	-	84	-	37	207	207	-	-	-	201	-	-	-	12,055	39	-
4b.3.3	Small tool allowance	-	314	-	-	-	-	-	47	361	361	-	-	-	-	-	-	-	-	-	-
4b.3.4	Decommissioning Equipment Disposition	-	-	137	55	575	145	-	144	1,055	1,055	-	-	6,000	529	-	-	-	303,608	147	-
4b.3	Subtotal Period 4b Collateral Costs	12	314	157	108	575	229	-	228	1,622	1,622	-	-	6,000	730	-	-	-	315,663	186	-
Period 4b Period-Dependent Costs																					
4b.4.1	Decon supplies	1,388	-	-	-	-	-	-	347	1,735	1,735	-	-	-	-	-	-	-	-	-	-
4b.4.2	Insurance	-	-	-	-	-	-	1,470	147	1,617	1,617	-	-	-	-	-	-	-	-	-	-
4b.4.3	Property taxes	-	-	-	-	-	-	3,786	379	4,165	4,165	-	-	-	-	-	-	-	-	-	-
4b.4.4	Health physics supplies	-	2,702	-	-	-	-	-	676	3,378	3,378	-	-	-	-	-	-	-	-	-	-
4b.4.5	Heavy equipment rental	-	4,602	-	-	-	-	-	690	5,292	5,292	-	-	-	-	-	-	-	-	-	-
4b.4.6	Disposal of DAW generated	-	-	121	39	-	472	-	136	767	767	-	-	-	5,798	-	-	-	115,951	189	-
4b.4.7	Plant energy budget	-	-	-	-	-	-	2,645	397	3,041	3,041	-	-	-	-	-	-	-	-	-	-
4b.4.8	NRC Fees	-	-	-	-	-	-	1,136	114	1,250	1,250	-	-	-	-	-	-	-	-	-	-
4b.4.9	Emergency Planning Fees	-	-	-	-	-	-	279	28	307	-	307	-	-	-	-	-	-	-	-	-
4b.4.10	Fixed Overhead	-	-	-	-	-	-	4,725	709	5,434	5,434	-	-	-	-	-	-	-	-	-	-
4b.4.11	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	825	124	949	949	-	-	-	-	-	-	-	-	-	-
4b.4.12	ISFSI Operating Costs	-	-	-	-	-	-	210	32	242	-	242	-	-	-	-	-	-	-	-	-
4b.4.13	Railroad Track Maintenance	-	-	-	-	-	-	235	35	270	270	-	-	-	-	-	-	-	-	-	-
4b.4.14	DOC Staff Cost	-	-	-	-	-	-	24,690	3,704	28,394	28,394	-	-	-	-	-	-	-	-	-	284,065
4b.4.15	Utility Staff Cost	-	-	-	-	-	-	30,782	4,617	35,399	35,399	-	-	-	-	-	-	-	-	-	500,294
4b.4	Subtotal Period 4b Period-Dependent Costs	1,388	7,304	121	39	-	472	70,783	12,133	92,240	91,691	549	-	-	5,798	-	-	-	115,951	189	784,360
4b.0	TOTAL PERIOD 4b COST	7,687	21,578	934	1,929	13,100	9,715	75,796	24,891	155,630	155,072	549	9	155,124	76,605	-	-	-	9,845,969	352,420	800,936
PERIOD 4f - License Termination																					
Period 4f Direct Decommissioning Activities																					
4f.1.1	ORISE confirmatory survey	-	-	-	-	-	-	159	48	207	207	-	-	-	-	-	-	-	-	-	-
4f.1.2	Terminate license									a											
4f.1	Subtotal Period 4f Activity Costs	-	-	-	-	-	-	159	48	207	207	-	-	-	-	-	-	-	-	-	-
Period 4f Additional Costs																					
4f.2.1	License Termination Survey	-	-	-	-	-	-	7,341	2,202	9,544	9,544	-	-	-	-	-	-	-	-	96,197	6,240
4f.2.2	License Termination ISFSI	-	131	3	784	-	8,058	2,875	2,963	14,815	14,815	-	-	-	27,284	-	-	-	3,860,412	11,022	10,640
4f.2	Subtotal Period 4f Additional Costs	-	131	3	784	-	8,058	10,217	5,165	24,358	24,358	-	-	-	27,284	-	-	-	3,860,412	107,218	16,880
Period 4f Collateral Costs																					
4f.3.1	DOC staff relocation expenses	-	-	-	-	-	-	1,189	178	1,367	1,367	-	-	-	-	-	-	-	-	-	-
4f.3.2	Small tool allowance	-	1	-	-	-	-	-	0	1	1	-	-	-	-	-	-	-	-	-	-
4f.3	Subtotal Period 4f Collateral Costs	-	1	-	-	-	-	1,189	178	1,368	1,368	-	-	-	-	-	-	-	-	-	-
Period 4f Period-Dependent Costs																					
4f.4.1	Insurance	-	-	-	-	-	-	543	54	598	598	-	-	-	-	-	-	-	-	-	-
4f.4.2	Property taxes	-	-	-	-	-	-	1,265	127	1,392	1,392	-	-	-	-	-	-	-	-	-	-
4f.4.3	Health physics supplies	-	648	-	-	-	-	-	162	809	809	-	-	-	-	-	-	-	-	-	-

Table H
Monticello Nuclear Generating Plant
Scenario 6: SAFSTOR with 32 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 4f Period-Dependent Costs (continued)																					
4f.4.4	Disposal of DAW generated	-	-	7	2	-	29	-	8	46	46	-	-	-	351	-	-	-	7,025	11	-
4f.4.5	Plant energy budget	-	-	-	-	-	-	261	39	300	300	-	-	-	-	-	-	-	-	-	-
4f.4.6	NRC Fees	-	-	-	-	-	-	420	42	463	463	-	-	-	-	-	-	-	-	-	-
4f.4.7	Emergency Planning Fees	-	-	-	-	-	-	103	10	113	-	113	-	-	-	-	-	-	-	-	-
4f.4.8	Fixed Overhead	-	-	-	-	-	-	1,747	262	2,009	2,009	-	-	-	-	-	-	-	-	-	-
4f.4.9	ISFSI Operating Costs	-	-	-	-	-	-	78	12	89	-	89	-	-	-	-	-	-	-	-	-
4f.4.10	Railroad Track Maintenance	-	-	-	-	-	-	87	13	100	100	-	-	-	-	-	-	-	-	-	-
4f.4.11	DOC Staff Cost	-	-	-	-	-	-	5,174	776	5,950	5,950	-	-	-	-	-	-	-	-	-	57,200
4f.4.12	Utility Staff Cost	-	-	-	-	-	-	5,003	750	5,754	5,754	-	-	-	-	-	-	-	-	-	74,438
4f.4	Subtotal Period 4f Period-Dependent Costs	-	648	7	2	-	29	14,681	2,256	17,623	17,420	203	-	-	351	-	-	-	7,025	11	131,638
4f.0	TOTAL PERIOD 4f COST	-	779	11	787	-	8,087	26,246	7,647	43,556	43,354	203	-	-	27,635	-	-	-	3,867,437	107,230	148,518
PERIOD 4 TOTALS		7,949	52,083	14,377	6,063	30,416	47,799	154,041	72,605	385,332	384,157	1,117	57	340,088	139,889	1,127	643	1,547	24,316,570	703,616	1,499,949
PERIOD 5b - Site Restoration																					
Period 5b Direct Decommissioning Activities																					
Demolition of Remaining Site Buildings																					
5b.1.1.1	Reactor Building	-	3,541	-	-	-	-	-	531	4,073	-	-	4,073	-	-	-	-	-	-	36,752	-
5b.1.1.2	Condensate Tanks Foundation	-	19	-	-	-	-	-	3	22	-	-	22	-	-	-	-	-	-	219	-
5b.1.1.3	Discharge Retention Basin	-	9	-	-	-	-	-	1	10	-	-	10	-	-	-	-	-	-	110	-
5b.1.1.4	HPCI Room	-	44	-	-	-	-	-	7	50	-	-	50	-	-	-	-	-	-	401	-
5b.1.1.5	Hot Shop	-	21	-	-	-	-	-	3	24	-	-	24	-	-	-	-	-	-	298	-
5b.1.1.6	Hydrogen & Oxygen Storage	-	2	-	-	-	-	-	0	2	-	-	2	-	-	-	-	-	-	21	-
5b.1.1.7	LLRW Storage & Shipping	-	140	-	-	-	-	-	21	161	-	-	161	-	-	-	-	-	-	1,794	-
5b.1.1.8	MSIV	-	4	-	-	-	-	-	1	5	-	-	5	-	-	-	-	-	-	59	-
5b.1.1.9	Misc Structures 2017	-	1,075	-	-	-	-	-	161	1,236	-	-	1,236	-	-	-	-	-	-	13,787	-
5b.1.1.10	Offgas Stack	-	232	-	-	-	-	-	35	267	-	-	267	-	-	-	-	-	-	2,668	-
5b.1.1.11	Offgas Storage & Compressor	-	88	-	-	-	-	-	13	101	-	-	101	-	-	-	-	-	-	963	-
5b.1.1.12	Radwaste	-	482	-	-	-	-	-	72	554	-	-	554	-	-	-	-	-	-	5,196	-
5b.1.1.13	Recombiner	-	258	-	-	-	-	-	39	297	-	-	297	-	-	-	-	-	-	2,490	-
5b.1.1.14	Security Barrier	-	362	-	-	-	-	-	54	416	-	-	416	-	-	-	-	-	-	4,083	-
5b.1.1.15	Structures Greater than 3' Below Grade	-	4,946	-	-	-	-	-	742	5,688	-	-	5,688	-	-	-	-	-	-	46,737	-
5b.1.1.16	Tank Farm	-	10	-	-	-	-	-	1	11	-	-	11	-	-	-	-	-	-	121	-
5b.1.1.17	Turbine	-	1,514	-	-	-	-	-	227	1,741	-	-	1,741	-	-	-	-	-	-	18,764	-
5b.1.1.18	Turbine Building Addition	-	67	-	-	-	-	-	10	77	-	-	77	-	-	-	-	-	-	971	-
5b.1.1.19	Turbine Pedestal	-	415	-	-	-	-	-	62	478	-	-	478	-	-	-	-	-	-	3,762	-
5b.1.1	Totals	-	13,228	-	-	-	-	-	1,984	15,212	-	-	15,212	-	-	-	-	-	-	139,199	-
Site Closeout Activities																					
5b.1.2	Grade & landscape site	-	864	-	-	-	-	-	130	994	-	-	994	-	-	-	-	-	-	1,841	-
5b.1.3	Final report to NRC	-	-	-	-	-	-	183	27	211	211	-	-	-	-	-	-	-	-	-	1,560
5b.1	Subtotal Period 5b Activity Costs	-	14,092	-	-	-	-	183	2,141	16,417	211	-	16,206	-	-	-	-	-	-	141,040	1,560
Period 5b Additional Costs																					
5b.2.1	Clean Concrete Disposal	-	3,297	-	-	-	-	11	496	3,805	-	-	3,805	-	-	-	-	-	-	12	-
5b.2.2	Cofferdam	-	320	-	-	-	-	-	48	368	368	-	-	-	-	-	-	-	-	2,584	-
5b.2.3	Excavation of Underground Services	-	1,380	-	-	-	-	947	349	2,677	-	-	2,677	-	-	-	-	-	-	13,475	-
5b.2.4	Constrution Debris	-	-	-	-	-	-	350	53	403	-	-	403	-	-	-	-	-	-	-	-
5b.2.5	Backfill	-	5,102	-	-	-	-	-	765	5,868	-	-	5,868	-	-	-	-	-	-	5,422	-
5b.2.6	Demolition and Site Restoration ISFSI	-	1,733	-	-	-	-	185	288	2,205	-	-	2,205	-	-	-	-	-	-	8,390	160
5b.2	Subtotal Period 5b Additional Costs	-	11,833	-	-	-	-	1,493	1,999	15,325	368	-	14,957	-	-	-	-	-	-	29,883	160
Period 5b Collateral Costs																					
5b.3.1	Small tool allowance	-	192	-	-	-	-	-	29	221	-	-	221	-	-	-	-	-	-	-	-
5b.3	Subtotal Period 5b Collateral Costs	-	192	-	-	-	-	-	29	221	-	-	221	-	-	-	-	-	-	-	-

Table H
Monticello Nuclear Generating Plant
Scenario 6: SAFSTOR with 32 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 5b Period-Dependent Costs																					
5b.4.1	Insurance	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5b.4.2	Property taxes	-	-	-	-	-	-	2,419	242	2,661	-	-	2,661	-	-	-	-	-	-	-	-
5b.4.3	Heavy equipment rental	-	5,455	-	-	-	-	-	818	6,273	-	-	6,273	-	-	-	-	-	-	-	-
5b.4.4	Plant energy budget	-	-	-	-	-	-	300	45	345	-	-	345	-	-	-	-	-	-	-	-
5b.4.5	Fixed Overhead	-	-	-	-	-	-	1,260	189	1,450	-	-	1,450	-	-	-	-	-	-	-	-
5b.4.6	Railroad Track Maintenance	-	-	-	-	-	-	200	30	230	-	-	230	-	-	-	-	-	-	-	-
5b.4.7	Security Staff Cost	-	-	-	-	-	-	2,739	411	3,150	-	-	3,150	-	-	-	-	-	-	-	43,287
Period 5b Period-Dependent Costs (continued)																					
5b.4.8	DOC Staff Cost	-	-	-	-	-	-	11,290	1,693	12,983	-	-	12,983	-	-	-	-	-	-	-	122,646
5b.4.9	Utility Staff Cost	-	-	-	-	-	-	4,718	708	5,426	-	-	5,426	-	-	-	-	-	-	-	70,341
5b.4	Subtotal Period 5b Period-Dependent Costs	-	5,455	-	-	-	-	22,927	4,136	32,517	-	-	32,517	-	-	-	-	-	-	-	236,274
5b.0	TOTAL PERIOD 5b COST	-	31,572	-	-	-	-	24,603	8,305	64,481	578	-	63,902	-	-	-	-	-	-	170,923	237,994
PERIOD 5 TOTALS		-	31,572	-	-	-	-	24,603	8,305	64,481	578	-	63,902	-	-	-	-	-	-	170,923	237,994
TOTAL COST TO DECOMMISSION		**17,731**	**94,769**	**14,816**	**6,755**	**30,429**	**49,448**	**1,050,409**	**210,270**	**1,474,626**	**1,045,043**	**364,666**	**64,917**	**340,130**	**150,427**	**1,127**	**643**	**1,547**	**24,626,380**	**1,024,783**	**7,779,103**

TOTAL COST TO DECOMMISSION WITH 16.63% CONTINGENCY:	**$1,474,626**	**thousands of 2017 dollars**
TOTAL NRC LICENSE TERMINATION COST IS 70.87% OR:	**$1,045,043**	**thousands of 2017 dollars**
SPENT FUEL MANAGEMENT COST IS 24.73% OR:	**$364,666**	**thousands of 2017 dollars**
NON-NUCLEAR DEMOLITION COST IS 4.4% OR:	**$64,917**	**thousands of 2017 dollars**
TOTAL LOW-LEVEL RADIOACTIVE WASTE VOLUME BURIED (EXCLUDING GTCC):	**152,197**	**cubic feet**
TOTAL GREATER THAN CLASS C RADWASTE VOLUME GENERATED:	**1,547**	**cubic feet**
TOTAL SCRAP METAL REMOVED:	**22,696**	**tons**
TOTAL CRAFT LABOR REQUIREMENTS:	**1,024,783**	**man-hours**

End Notes:
n/a - indicates that this activity not charged as decommissioning expense
a - indicates that this activity performed by decommissioning staff
0 - indicates that this value is less than 0.5 but is non-zero
A cell containing " - " indicates a zero value

APPENDIX I

DETAILED COST ANALYSIS

SCENARIO 7: SAFSTOR with 60 Year DFS

Table I
Monticello Nuclear Generating Plant
Scenario 7: SAFSTOR with 60 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
PERIOD 1a - Shutdown through Transition																					
Period 1a Direct Decommissioning Activities																					
1a.1.1	SAFSTOR site characterization survey	-	-	-	-	-	-	380	114	494	494	-	-	-	-	-	-	-	-	-	-
1a.1.2	Prepare preliminary decommissioning cost	-	-	-	-	-	-	153	23	175	175	-	-	-	-	-	-	-	-	-	1,300
1a.1.3	Notification of Cessation of Operations									a											
1a.1.4	Remove fuel & source material									n/a											
1a.1.5	Notification of Permanent Defueling									a											
1a.1.6	Deactivate plant systems & process waste									a											
1a.1.7	Prepare and submit PSDAR	-	-	-	-	-	-	235	35	270	270	-	-	-	-	-	-	-	-	-	2,000
1a.1.8	Review plant dwgs & specs.	-	-	-	-	-	-	153	23	175	175	-	-	-	-	-	-	-	-	-	1,300
1a.1.9	Perform detailed rad survey									a											
1a.1.10	Estimate by-product inventory	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1a.1.11	End product description	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1a.1.12	Detailed by-product inventory	-	-	-	-	-	-	176	26	202	202	-	-	-	-	-	-	-	-	-	1,500
1a.1.13	Define major work sequence	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1a.1.14	Perform SER and EA	-	-	-	-	-	-	364	55	418	418	-	-	-	-	-	-	-	-	-	3,100
1a.1.15	Prepare/submit Defueled Technical Specifications	-	-	-	-	-	-	880	132	1,012	1,012	-	-	-	-	-	-	-	-	-	7,500
1a.1.16	Perform Site-Specific Cost Study	-	-	-	-	-	-	587	88	675	675	-	-	-	-	-	-	-	-	-	5,000
1a.1.17	Prepare/submit Irradiated Fuel Management Plan	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
Activity Specifications																					
1a.1.18.1	Prepare plant and facilities for SAFSTOR	-	-	-	-	-	-	578	87	664	664	-	-	-	-	-	-	-	-	-	4,920
1a.1.18.2	Plant systems	-	-	-	-	-	-	489	73	562	562	-	-	-	-	-	-	-	-	-	4,167
1a.1.18.3	Plant structures and buildings	-	-	-	-	-	-	366	55	421	421	-	-	-	-	-	-	-	-	-	3,120
1a.1.18.4	Waste management	-	-	-	-	-	-	235	35	270	270	-	-	-	-	-	-	-	-	-	2,000
1a.1.18.5	Facility and site dormancy	-	-	-	-	-	-	235	35	270	270	-	-	-	-	-	-	-	-	-	2,000
1a.1.18	Total	-	-	-	-	-	-	1,902	285	2,188	2,188	-	-	-	-	-	-	-	-	-	16,207
Detailed Work Procedures																					
1a.1.19.1	Plant systems	-	-	-	-	-	-	139	21	160	160	-	-	-	-	-	-	-	-	-	1,183
1a.1.19.2	Facility closeout & dormancy	-	-	-	-	-	-	141	21	162	162	-	-	-	-	-	-	-	-	-	1,200
1a.1.19	Total	-	-	-	-	-	-	280	42	322	322	-	-	-	-	-	-	-	-	-	2,383
1a.1.20	Procure vacuum drying system	-	-	-	-	-	-	12	2	13	13	-	-	-	-	-	-	-	-	-	100
1a.1.21	Drain/de-energize non-cont. systems									a											
1a.1.22	Drain & dry NSSS									a											
1a.1.23	Drain/de-energize contaminated systems									a											
1a.1.24	Decon/secure contaminated systems									a											
1a.1	Subtotal Period 1a Activity Costs	-	-	-	-	-	-	5,590	896	6,486	6,486	-	-	-	-	-	-	-	-	-	44,390
Period 1a Collateral Costs																					
1a.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	1,221	183	1,404	-	1,404	-	-	-	-	-	-	-	-	-
1a.3.2	Retention and Severance	-	-	-	-	-	-	9,892	1,484	11,376	11,376	-	-	-	-	-	-	-	-	-	-
1a.3	Subtotal Period 1a Collateral Costs	-	-	-	-	-	-	11,113	1,667	12,779	11,376	1,404	-	-	-	-	-	-	-	-	-
Period 1a Period-Dependent Costs																					
1a.4.1	Insurance	-	-	-	-	-	-	2,408	241	2,649	2,649	-	-	-	-	-	-	-	-	-	-
1a.4.2	Property taxes	-	-	-	-	-	-	2,242	224	2,466	2,466	-	-	-	-	-	-	-	-	-	-
1a.4.3	Health physics supplies	-	515	-	-	-	-	-	129	644	644	-	-	-	-	-	-	-	-	-	-
1a.4.4	Heavy equipment rental	-	567	-	-	-	-	-	85	652	652	-	-	-	-	-	-	-	-	-	-
1a.4.5	Disposal of DAW generated	-	-	13	4	-	50	-	14	81	81	-	-	-	610	-	-	-	12,190	20	-
1a.4.6	Plant energy budget	-	-	-	-	-	-	1,730	259	1,989	1,989	-	-	-	-	-	-	-	-	-	-
1a.4.7	NRC Fees	-	-	-	-	-	-	1,110	111	1,221	1,221	-	-	-	-	-	-	-	-	-	-
1a.4.8	Emergency Planning Fees	-	-	-	-	-	-	3,166	317	3,482	-	3,482	-	-	-	-	-	-	-	-	-
1a.4.9	Fixed Overhead	-	-	-	-	-	-	2,833	425	3,258	3,258	-	-	-	-	-	-	-	-	-	-
1a.4.10	Spent Fuel Pool O&M	-	-	-	-	-	-	803	120	923	-	923	-	-	-	-	-	-	-	-	-
1a.4.11	ISFSI Operating Costs	-	-	-	-	-	-	103	15	119	-	119	-	-	-	-	-	-	-	-	-
1a.4.12	Railroad Track Maintenance	-	-	-	-	-	-	115	17	133	133	-	-	-	-	-	-	-	-	-	-
1a.4.13	Security Staff Cost	-	-	-	-	-	-	14,260	2,139	16,399	16,399	-	-	-	-	-	-	-	-	-	245,440
1a.4.14	Utility Staff Cost	-	-	-	-	-	-	25,791	3,869	29,660	29,660	-	-	-	-	-	-	-	-	-	422,240
1a.4	Subtotal Period 1a Period-Dependent Costs	-	1,083	13	4	-	50	54,561	7,966	63,676	59,152	4,524	-	-	610	-	-	-	12,190	20	667,680
1a.0	TOTAL PERIOD 1a COST	-	1,083	13	4	-	50	71,264	10,528	82,941	77,014	5,927	-	-	610	-	-	-	12,190	20	712,070

Table I
Monticello Nuclear Generating Plant
Scenario 7: SAFSTOR with 60 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
PERIOD 1b - SAFSTOR Limited DECON Activities																					
Period 1b Direct Decommissioning Activities																					
Decontamination of Site Buildings																					
1b.1.1.1	Reactor Building	4,303	-	-	-	-	-	-	2,152	6,455	6,455	-	-	-	-	-	-	-	-	70,157	-
1b.1.1.2	Admin	81	-	-	-	-	-	-	41	122	122	-	-	-	-	-	-	-	-	1,357	-
1b.1.1.3	HPCI Room	21	-	-	-	-	-	-	11	32	32	-	-	-	-	-	-	-	-	350	-
1b.1.1.4	Hot Shop	12	-	-	-	-	-	-	6	19	19	-	-	-	-	-	-	-	-	208	-
1b.1.1.5	LLRW Storage & Shipping	42	-	-	-	-	-	-	21	63	63	-	-	-	-	-	-	-	-	705	-
1b.1.1.6	Offgas Stack	276	-	-	-	-	-	-	138	414	414	-	-	-	-	-	-	-	-	4,575	-
1b.1.1.7	Offgas Storage & Compressor	29	-	-	-	-	-	-	15	44	44	-	-	-	-	-	-	-	-	488	-
1b.1.1.8	Radwaste	88	-	-	-	-	-	-	44	132	132	-	-	-	-	-	-	-	-	1,473	-
1b.1.1.9	Radwaste Material Storage Warehouse	46	-	-	-	-	-	-	23	69	69	-	-	-	-	-	-	-	-	768	-
1b.1.1.10	Recombiner	19	-	-	-	-	-	-	10	29	29	-	-	-	-	-	-	-	-	323	-
1b.1.1.11	Turbine	512	-	-	-	-	-	-	256	768	768	-	-	-	-	-	-	-	-	8,583	-
1b.1.1.12	Turbine Building Addition	42	-	-	-	-	-	-	21	63	63	-	-	-	-	-	-	-	-	709	-
1b.1.1.13	Reactor (Post Fuel)	695	-	-	-	-	-	-	347	1,042	1,042	-	-	-	-	-	-	-	-	11,337	-
1b.1.1	Totals	6,167	-	-	-	-	-	-	3,084	9,251	9,251	-	-	-	-	-	-	-	-	101,033	-
1b.1	Subtotal Period 1b Activity Costs	6,167	-	-	-	-	-	-	3,084	9,251	9,251	-	-	-	-	-	-	-	-	101,033	-
Period 1b Additional Costs																					
1b.2.1	Spent fuel pool isolation	-	-	-	-	-	-	11,691	1,754	13,445	13,445	-	-	-	-	-	-	-	-	-	-
1b.2	Subtotal Period 1b Additional Costs	-	-	-	-	-	-	11,691	1,754	13,445	13,445	-	-	-	-	-	-	-	-	-	-
Period 1b Collateral Costs																					
1b.3.1	Decon equipment	973	-	-	-	-	-	-	146	1,119	1,119	-	-	-	-	-	-	-	-	-	-
1b.3.2	Process decommissioning water waste	214	-	138	356	-	566	-	316	1,589	1,589	-	-	-	1,350	-	-	-	81,018	263	-
1b.3.4	Small tool allowance	-	105	-	-	-	-	-	16	121	121	-	-	-	-	-	-	-	-	-	-
1b.3.5	Spent Fuel Capital and Transfer	-	-	-	-	-	-	183	27	210	-	210	-	-	-	-	-	-	-	-	-
1b.3.6	Retention and Severance	-	-	-	-	-	-	3,640	546	4,186	4,186	-	-	-	-	-	-	-	-	-	-
1b.3	Subtotal Period 1b Collateral Costs	1,187	105	138	356	-	566	3,823	1,051	7,226	7,016	210	-	-	1,350	-	-	-	81,018	263	-
Period 1b Period-Dependent Costs																					
1b.4.1	Decon supplies	1,264	-	-	-	-	-	-	316	1,580	1,580	-	-	-	-	-	-	-	-	-	-
1b.4.2	Insurance	-	-	-	-	-	-	607	61	668	668	-	-	-	-	-	-	-	-	-	-
1b.4.3	Property taxes	-	-	-	-	-	-	565	57	622	622	-	-	-	-	-	-	-	-	-	-
1b.4.4	Health physics supplies	-	614	-	-	-	-	-	153	767	767	-	-	-	-	-	-	-	-	-	-
1b.4.5	Heavy equipment rental	-	143	-	-	-	-	-	21	164	164	-	-	-	-	-	-	-	-	-	-
1b.4.6	Disposal of DAW generated	-	-	12	4	-	45	-	13	74	74	-	-	-	556	-	-	-	11,126	18	-
1b.4.7	Plant energy budget	-	-	-	-	-	-	436	65	501	501	-	-	-	-	-	-	-	-	-	-
1b.4.8	NRC Fees	-	-	-	-	-	-	161	16	178	178	-	-	-	-	-	-	-	-	-	-
1b.4.9	Emergency Planning Fees	-	-	-	-	-	-	798	80	878	-	878	-	-	-	-	-	-	-	-	-
1b.4.10	Fixed Overhead	-	-	-	-	-	-	714	107	821	821	-	-	-	-	-	-	-	-	-	-
1b.4.11	Spent Fuel Pool O&M	-	-	-	-	-	-	202	30	233	-	233	-	-	-	-	-	-	-	-	-
1b.4.12	ISFSI Operating Costs	-	-	-	-	-	-	26	4	30	-	30	-	-	-	-	-	-	-	-	-
1b.4.13	Railroad Track Maintenance	-	-	-	-	-	-	29	4	33	33	-	-	-	-	-	-	-	-	-	-
1b.4.14	Security Staff Cost	-	-	-	-	-	-	3,594	539	4,134	4,134	-	-	-	-	-	-	-	-	-	61,864
1b.4.15	Utility Staff Cost	-	-	-	-	-	-	6,501	975	7,476	7,476	-	-	-	-	-	-	-	-	-	106,428
1b.4	Subtotal Period 1b Period-Dependent Costs	1,264	757	12	4	-	45	13,634	2,442	18,157	17,017	1,140	-	-	556	-	-	-	11,126	18	168,292
1b.0	TOTAL PERIOD 1b COST	8,618	862	150	360	-	611	29,148	8,330	48,079	46,729	1,350	-	-	1,907	-	-	-	92,144	101,314	168,292
PERIOD 1c - Preparations for SAFSTOR Dormancy																					
Period 1c Direct Decommissioning Activities																					
1c.1.1	Prepare support equipment for storage	-	470	-	-	-	-	-	71	541	541	-	-	-	-	-	-	-	-	3,000	-
1c.1.2	Install containment pressure equal. lines	-	44	-	-	-	-	-	7	51	51	-	-	-	-	-	-	-	-	700	-
1c.1.3	Interim survey prior to dormancy	-	-	-	-	-	-	733	220	953	953	-	-	-	-	-	-	-	-	14,124	-
1c.1.4	Secure building accesses									a											
1c.1.5	Prepare & submit interim report	-	-	-	-	-	-	68	10	79	79	-	-	-	-	-	-	-	-	-	583
1c.1	Subtotal Period 1c Activity Costs	-	514	-	-	-	-	801	307	1,623	1,623	-	-	-	-	-	-	-	-	17,824	583

Table I
Monticello Nuclear Generating Plant
Scenario 7: SAFSTOR with 60 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 1c Collateral Costs																					
1c.3.1	Process decommissioning water waste	157	-	102	262	-	416	-	232	1,170	1,170	-	-	-	994	-	-	-	59,665	194	-
1c.3.3	Small tool allowance	-	4	-	-	-	-	-	1	5	5	-	-	-	-	-	-	-	-	-	-
1c.3.4	Spent Fuel Capital and Transfer	-	-	-	-	-	-	180	27	207	-	207	-	-	-	-	-	-	-	-	-
1c.3.5	Retention and Severance	-	-	-	-	-	-	2,722	408	3,130	3,130	-	-	-	-	-	-	-	-	-	-
1c.3	Subtotal Period 1c Collateral Costs	157	4	102	262	-	416	2,902	668	4,512	4,304	207	-	-	994	-	-	-	59,665	194	-
Period 1c Period-Dependent Costs																					
1c.4.1	Insurance	-	-	-	-	-	-	600	60	660	660	-	-	-	-	-	-	-	-	-	-
1c.4.2	Property taxes	-	-	-	-	-	-	558	56	614	614	-	-	-	-	-	-	-	-	-	-
1c.4.3	Health physics supplies	-	215	-	-	-	-	-	54	268	268	-	-	-	-	-	-	-	-	-	-
1c.4.4	Heavy equipment rental	-	141	-	-	-	-	-	21	163	163	-	-	-	-	-	-	-	-	-	-
1c.4.5	Disposal of DAW generated	-	-	3	1	-	12	-	4	20	20	-	-	-	152	-	-	-	3,039	5	-
1c.4.6	Plant energy budget	-	-	-	-	-	-	431	65	496	496	-	-	-	-	-	-	-	-	-	-
1c.4.7	NRC Fees	-	-	-	-	-	-	160	16	176	176	-	-	-	-	-	-	-	-	-	-
1c.4.8	Emergency Planning Fees	-	-	-	-	-	-	789	79	868	-	868	-	-	-	-	-	-	-	-	-
1c.4.9	Fixed Overhead	-	-	-	-	-	-	706	106	812	812	-	-	-	-	-	-	-	-	-	-
1c.4.10	Spent Fuel Pool O&M	-	-	-	-	-	-	200	30	230	-	230	-	-	-	-	-	-	-	-	-
1c.4.11	ISFSI Operating Costs	-	-	-	-	-	-	26	4	30	-	30	-	-	-	-	-	-	-	-	-
1c.4.12	Railroad Track Maintenance	-	-	-	-	-	-	29	4	33	33	-	-	-	-	-	-	-	-	-	-
1c.4.13	Security Staff Cost	-	-	-	-	-	-	3,555	533	4,089	4,089	-	-	-	-	-	-	-	-	-	61,192
1c.4.14	Utility Staff Cost	-	-	-	-	-	-	6,430	965	7,395	7,395	-	-	-	-	-	-	-	-	-	105,271
1c.4	Subtotal Period 1c Period-Dependent Costs	-	356	3	1	-	12	13,485	1,996	15,853	14,725	1,128	-	-	152	-	-	-	3,039	5	166,463
1c.0	TOTAL PERIOD 1c COST	157	874	105	263	-	429	17,188	2,971	21,987	20,652	1,335	-	-	1,146	-	-	-	62,705	18,023	167,046
PERIOD 1 TOTALS		8,775	2,819	268	627	-	1,089	117,600	21,830	153,007	144,395	8,613	-	-	3,662	-	-	-	167,039	119,357	1,047,408
PERIOD 2a - SAFSTOR Dormancy with Wet Spent Fuel Storage																					
Period 2a Direct Decommissioning Activities																					
2a.1.1	Quarterly Inspection									a											
2a.1.2	Semi-annual environmental survey									a											
2a.1.3	Prepare reports									a											
2a.1.4	Bituminous roof replacement	-	-	-	-	-	-	216	32	248	248	-	-	-	-	-	-	-	-	-	-
2a.1.5	Maintenance supplies	-	-	-	-	-	-	480	120	599	599	-	-	-	-	-	-	-	-	-	-
2a.1	Subtotal Period 2a Activity Costs	-	-	-	-	-	-	695	152	848	848	-	-	-	-	-	-	-	-	-	-
Period 2a Additional Costs																					
2a.2.1	Security Modifications	-	-	-	-	-	-	8,696	1,304	10,000	10,000	-	-	-	-	-	-	-	-	-	-
2a.2	Subtotal Period 2a Additional Costs	-	-	-	-	-	-	8,696	1,304	10,000	10,000	-	-	-	-	-	-	-	-	-	-
Period 2a Collateral Costs																					
2a.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	79,478	11,922	91,399	-	91,399	-	-	-	-	-	-	-	-	-
2a.3.2	Retention and Severance	-	-	-	-	-	-	21,900	3,285	25,185	25,185	-	-	-	-	-	-	-	-	-	-
2a.3	Subtotal Period 2a Collateral Costs	-	-	-	-	-	-	101,378	15,207	116,584	25,185	91,399	-	-	-	-	-	-	-	-	-
Period 2a Period-Dependent Costs																					
2a.4.1	Insurance	-	-	-	-	-	-	2,526	253	2,778	2,778	-	-	-	-	-	-	-	-	-	-
2a.4.2	Property taxes	-	-	-	-	-	-	7,844	784	8,628	8,628	-	-	-	-	-	-	-	-	-	-
2a.4.3	Health physics supplies	-	724	-	-	-	-	-	181	905	905	-	-	-	-	-	-	-	-	-	-
2a.4.4	Disposal of DAW generated	-	-	17	5	-	66	-	19	107	107	-	-	-	806	-	-	-	16,112	26	-
2a.4.5	Plant energy budget	-	-	-	-	-	-	1,211	182	1,393	1,393	-	-	-	-	-	-	-	-	-	-
2a.4.6	NRC Fees	-	-	-	-	-	-	898	90	988	988	-	-	-	-	-	-	-	-	-	-
2a.4.7	Emergency Planning Fees	-	-	-	-	-	-	8,991	899	9,891	-	9,891	-	-	-	-	-	-	-	-	-
2a.4.8	Fixed Overhead	-	-	-	-	-	-	9,919	1,488	11,407	11,407	-	-	-	-	-	-	-	-	-	-
2a.4.9	Spent Fuel Pool O&M	-	-	-	-	-	-	2,810	422	3,232	-	3,232	-	-	-	-	-	-	-	-	-
2a.4.10	ISFSI Operating Costs	-	-	-	-	-	-	361	54	416	-	416	-	-	-	-	-	-	-	-	-
2a.4.11	Railroad Track Maintenance	-	-	-	-	-	-	701	105	806	806	-	-	-	-	-	-	-	-	-	-
2a.4.12	Security Staff Cost	-	-	-	-	-	-	46,105	6,916	53,021	37,327	15,694	-	-	-	-	-	-	-	-	786,548
2a.4.13	Utility Staff Cost	-	-	-	-	-	-	17,653	2,648	20,301	16,322	3,979	-	-	-	-	-	-	-	-	287,673
2a.4	Subtotal Period 2a Period-Dependent Costs	-	724	17	5	-	66	99,020	14,040	113,872	80,661	33,211	-	-	806	-	-	-	16,112	26	1,074,220
2a.0	TOTAL PERIOD 2a COST	-	724	17	5	-	66	209,789	30,703	241,304	116,694	124,610	-	-	806	-	-	-	16,112	26	1,074,220

Table I
Monticello Nuclear Generating Plant
Scenario 7: SAFSTOR with 60 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
PERIOD 2b - SAFSTOR Dormancy with Dry Spent Fuel Storage																					
Period 2b Direct Decommissioning Activities																					
2b.1.1	Quarterly Inspection									a											
2b.1.2	Semi-annual environmental survey									a											
2b.1.3	Prepare reports									a											
2b.1.4	Bituminous roof replacement	-	-	-	-	-	-	3,044	457	3,500	3,500	-	-	-	-	-	-	-	-	-	-
2b.1.5	Maintenance supplies	-	-	-	-	-	-	6,765	1,691	8,456	8,456	-	-	-	-	-	-	-	-	-	-
2b.1	Subtotal Period 2b Activity Costs	-	-	-	-	-	-	9,808	2,148	11,956	11,956	-	-	-	-	-	-	-	-	-	-
Period 2b Collateral Costs																					
2b.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	98,790	14,819	113,609	-	113,609	-	-	-	-	-	-	-	-	-
2b.3	Subtotal Period 2b Collateral Costs	-	-	-	-	-	-	98,790	14,819	113,609	-	113,609	-	-	-	-	-	-	-	-	-
Period 2b Period-Dependent Costs																					
2b.4.1	Insurance	-	-	-	-	-	-	35,624	3,562	39,186	39,186	-	-	-	-	-	-	-	-	-	-
2b.4.2	Property taxes	-	-	-	-	-	-	110,635	11,064	121,699	121,699	-	-	-	-	-	-	-	-	-	-
2b.4.3	Health physics supplies	-	4,953	-	-	-	-	-	1,238	6,192	6,192	-	-	-	-	-	-	-	-	-	-
2b.4.4	Disposal of DAW generated	-	-	114	36	-	444	-	128	722	722	-	-	-	5,459	-	-	-	109,172	178	-
2b.4.5	Plant energy budget	-	-	-	-	-	-	8,544	1,282	9,825	9,825	-	-	-	-	-	-	-	-	-	-
2b.4.6	NRC Fees	-	-	-	-	-	-	12,039	1,204	13,243	13,243	-	-	-	-	-	-	-	-	-	-
2b.4.7	Emergency Planning Fees	-	-	-	-	-	-	6,754	675	7,430	-	7,430	-	-	-	-	-	-	-	-	-
2b.4.8	Fixed Overhead	-	-	-	-	-	-	12,278	1,842	14,120	14,120	-	-	-	-	-	-	-	-	-	-
2b.4.9	ISFSI Operating Costs	-	-	-	-	-	-	5,099	765	5,864	-	5,864	-	-	-	-	-	-	-	-	-
2b.4.10	Railroad Track Maintenance	-	-	-	-	-	-	5,696	854	6,551	6,551	-	-	-	-	-	-	-	-	-	-
2b.4.11	Security Staff Cost	-	-	-	-	-	-	243,958	36,594	280,552	58,916	221,636	-	-	-	-	-	-	-	-	3,698,252
2b.4.12	Utility Staff Cost	-	-	-	-	-	-	104,318	15,648	119,966	63,822	56,144	-	-	-	-	-	-	-	-	1,643,667
2b.4	Subtotal Period 2b Period-Dependent Costs	-	4,953	114	36	-	444	544,946	74,855	625,348	334,275	291,074	-	-	5,459	-	-	-	109,172	178	5,341,919
2b.0	TOTAL PERIOD 2b COST	-	4,953	114	36	-	444	653,544	91,822	750,913	346,231	404,682	-	-	5,459	-	-	-	109,172	178	5,341,919
PERIOD 2 TOTALS		-	5,677	130	42	-	510	863,333	122,525	992,217	462,925	529,292	-	-	6,264	-	-	-	125,283	204	6,416,139
PERIOD 3a - Reactivate Site Following SAFSTOR Dormancy																					
Period 3a Direct Decommissioning Activities																					
3a.1.1	Prepare preliminary decommissioning cost	-	-	-	-	-	-	153	23	175	175	-	-	-	-	-	-	-	-	-	1,300
3a.1.2	Review plant dwgs & specs.	-	-	-	-	-	-	540	81	621	621	-	-	-	-	-	-	-	-	-	4,600
3a.1.3	Perform detailed rad survey									a											
3a.1.4	End product description	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
3a.1.5	Detailed by-product inventory	-	-	-	-	-	-	153	23	175	175	-	-	-	-	-	-	-	-	-	1,300
3a.1.6	Define major work sequence	-	-	-	-	-	-	880	132	1,012	1,012	-	-	-	-	-	-	-	-	-	7,500
3a.1.7	Perform SER and EA	-	-	-	-	-	-	364	55	418	418	-	-	-	-	-	-	-	-	-	3,100
3a.1.8	Perform Site-Specific Cost Study	-	-	-	-	-	-	587	88	675	675	-	-	-	-	-	-	-	-	-	5,000
Activity Specifications																					
3a.1.9.1	Re-activate plant & temporary facilities	-	-	-	-	-	-	865	130	995	895	-	99	-	-	-	-	-	-	-	7,370
3a.1.9.2	Plant systems	-	-	-	-	-	-	489	73	562	506	-	56	-	-	-	-	-	-	-	4,167
3a.1.9.3	Reactor internals	-	-	-	-	-	-	833	125	958	958	-	-	-	-	-	-	-	-	-	7,100
3a.1.9.4	Reactor vessel	-	-	-	-	-	-	763	114	877	877	-	-	-	-	-	-	-	-	-	6,500
3a.1.9.5	Sacrificial shield	-	-	-	-	-	-	59	9	67	67	-	-	-	-	-	-	-	-	-	500
3a.1.9.6	Moisture separators/reheaters	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
3a.1.9.7	Reinforced concrete	-	-	-	-	-	-	188	28	216	108	-	108	-	-	-	-	-	-	-	1,600
3a.1.9.8	Main Turbine	-	-	-	-	-	-	245	37	282	282	-	-	-	-	-	-	-	-	-	2,088
3a.1.9.9	Main Condensers	-	-	-	-	-	-	245	37	282	282	-	-	-	-	-	-	-	-	-	2,088
3a.1.9.10	Pressure suppression structure	-	-	-	-	-	-	235	35	270	270	-	-	-	-	-	-	-	-	-	2,000
3a.1.9.11	Drywell	-	-	-	-	-	-	188	28	216	216	-	-	-	-	-	-	-	-	-	1,600
3a.1.9.12	Plant structures & buildings	-	-	-	-	-	-	366	55	421	211	-	211	-	-	-	-	-	-	-	3,120
3a.1.9.13	Waste management	-	-	-	-	-	-	540	81	621	621	-	-	-	-	-	-	-	-	-	4,600
3a.1.9.14	Facility & site closeout	-	-	-	-	-	-	106	16	121	61	-	61	-	-	-	-	-	-	-	900
3a.1.9	Total	-	-	-	-	-	-	5,239	786	6,025	5,490	-	535	-	-	-	-	-	-	-	44,633
Planning & Site Preparations																					
3a.1.10	Prepare dismantling sequence	-	-	-	-	-	-	282	42	324	324	-	-	-	-	-	-	-	-	-	2,400
3a.1.11	Plant prep. & temp. svces	-	-	-	-	-	-	3,300	495	3,795	3,795	-	-	-	-	-	-	-	-	-	-
3a.1.12	Design water clean-up system	-	-	-	-	-	-	164	25	189	189	-	-	-	-	-	-	-	-	-	1,400
3a.1.13	Rigging/Cont. Cntrl Envlps/tooling/etc.	-	-	-	-	-	-	2,300	345	2,645	2,645	-	-	-	-	-	-	-	-	-	-
3a.1.14	Procure casks/liners & containers	-	-	-	-	-	-	144	22	166	166	-	-	-	-	-	-	-	-	-	1,230

Table I
Monticello Nuclear Generating Plant
Scenario 7: SAFSTOR with 60 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
3a.1	Subtotal Period 3a Activity Costs	-	-	-	-	-	-	14,223	2,133	16,357	15,821	-	535	-	-	-	-	-	-	-	73,463
Period 3a Additional Costs																					
3a.2.1	Site Characterization	-	-	-	-	-	-	6,446	1,934	8,380	8,380	-	-	-	-	-	-	-	-	30,500	10,852
3a.2.2	Mixed & RCRA Waste	-	-	29	19	13	-	-	8	69	69	-	-	43	-	-	-	-	5,253	163	-
3a.2	Subtotal Period 3a Additional Costs	-	-	29	19	13	-	6,446	1,942	8,449	8,449	-	-	43	-	-	-	-	5,253	30,663	10,852
Period 3a Collateral Costs																					
3a.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	1,664	250	1,914	-	1,914	-	-	-	-	-	-	-	-	-
3a.3	Subtotal Period 3a Collateral Costs	-	-	-	-	-	-	1,664	250	1,914	-	1,914	-	-	-	-	-	-	-	-	-
Period 3a Period-Dependent Costs																					
3a.4.1	Insurance	-	-	-	-	-	-	708	71	779	779	-	-	-	-	-	-	-	-	-	-
3a.4.2	Property taxes	-	-	-	-	-	-	2,232	223	2,455	2,455	-	-	-	-	-	-	-	-	-	-
3a.4.3	Health physics supplies	-	452	-	-	-	-	-	113	565	565	-	-	-	-	-	-	-	-	-	-
3a.4.4	Heavy equipment rental	-	567	-	-	-	-	-	85	652	652	-	-	-	-	-	-	-	-	-	-
3a.4.5	Disposal of DAW generated	-	-	11	3	-	42	-	12	68	68	-	-	-	516	-	-	-	10,311	17	-
3a.4.6	Plant energy budget	-	-	-	-	-	-	1,730	259	1,989	1,989	-	-	-	-	-	-	-	-	-	-
3a.4.7	NRC Fees	-	-	-	-	-	-	341	34	376	376	-	-	-	-	-	-	-	-	-	-
3a.4.8	Emergency Planning Fees	-	-	-	-	-	-	137	14	150	-	150	-	-	-	-	-	-	-	-	-
3a.4.9	Fixed Overhead	-	-	-	-	-	-	2,833	425	3,258	3,258	-	-	-	-	-	-	-	-	-	-
3a.4.10	ISFSI Operating Costs	-	-	-	-	-	-	103	15	119	-	119	-	-	-	-	-	-	-	-	-
3a.4.11	Railroad Track Maintenance	-	-	-	-	-	-	115	17	133	133	-	-	-	-	-	-	-	-	-	-
3a.4.12	Security Staff Cost	-	-	-	-	-	-	3,900	585	4,485	4,485	-	-	-	-	-	-	-	-	-	54,080
3a.4.13	Utility Staff Cost	-	-	-	-	-	-	16,027	2,404	18,431	18,431	-	-	-	-	-	-	-	-	-	260,000
3a.4	Subtotal Period 3a Period-Dependent Costs	-	1,019	11	3	-	42	28,127	4,258	33,461	33,192	269	-	-	516	-	-	-	10,311	17	314,080
3a.0	TOTAL PERIOD 3a COST	-	1,019	39	23	13	42	50,461	8,583	60,180	57,462	2,183	535	43	516	-	-	-	15,565	30,680	398,395
PERIOD 3b - Decommissioning Preparations																					
Period 3b Direct Decommissioning Activities																					
Detailed Work Procedures																					
3b.1.1.1	Plant systems	-	-	-	-	-	-	556	83	639	575	-	64	-	-	-	-	-	-	-	4,733
3b.1.1.2	Reactor internals	-	-	-	-	-	-	470	70	540	540	-	-	-	-	-	-	-	-	-	4,000
3b.1.1.3	Remaining buildings	-	-	-	-	-	-	158	24	182	46	-	137	-	-	-	-	-	-	-	1,350
3b.1.1.4	CRD housings & NIs	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
3b.1.1.5	Incore instrumentation	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
3b.1.1.6	Removal primary containment	-	-	-	-	-	-	235	35	270	270	-	-	-	-	-	-	-	-	-	2,000
3b.1.1.7	Reactor vessel	-	-	-	-	-	-	426	64	490	490	-	-	-	-	-	-	-	-	-	3,630
3b.1.1.8	Facility closeout	-	-	-	-	-	-	141	21	162	81	-	81	-	-	-	-	-	-	-	1,200
3b.1.1.9	Sacrificial shield	-	-	-	-	-	-	141	21	162	162	-	-	-	-	-	-	-	-	-	1,200
3b.1.1.10	Reinforced concrete	-	-	-	-	-	-	117	18	135	67	-	67	-	-	-	-	-	-	-	1,000
3b.1.1.11	Main Turbine	-	-	-	-	-	-	244	37	281	281	-	-	-	-	-	-	-	-	-	2,080
3b.1.1.12	Main Condensers	-	-	-	-	-	-	245	37	282	282	-	-	-	-	-	-	-	-	-	2,088
3b.1.1.13	Moisture separators & reheaters	-	-	-	-	-	-	235	35	270	270	-	-	-	-	-	-	-	-	-	2,000
3b.1.1.14	Radwaste building	-	-	-	-	-	-	320	48	369	332	-	37	-	-	-	-	-	-	-	2,730
3b.1.1.15	Reactor building	-	-	-	-	-	-	320	48	369	332	-	37	-	-	-	-	-	-	-	2,730
3b.1.1	Total	-	-	-	-	-	-	3,843	576	4,420	3,997	-	423	-	-	-	-	-	-	-	32,741
3b.1	Subtotal Period 3b Activity Costs	-	-	-	-	-	-	3,843	576	4,420	3,997	-	423	-	-	-	-	-	-	-	32,741
Period 3b Collateral Costs																					
3b.3.1	Decon equipment	973	-	-	-	-	-	-	146	1,119	1,119	-	-	-	-	-	-	-	-	-	-
3b.3.2	DOC staff relocation expenses	-	-	-	-	-	-	1,189	178	1,367	1,367	-	-	-	-	-	-	-	-	-	-
3b.3.3	Pipe cutting equipment	-	1,200	-	-	-	-	-	180	1,380	1,380	-	-	-	-	-	-	-	-	-	-
3b.3.4	Spent Fuel Capital and Transfer	-	-	-	-	-	-	830	124	954	-	954	-	-	-	-	-	-	-	-	-
3b.3	Subtotal Period 3b Collateral Costs	973	1,200	-	-	-	-	2,018	629	4,820	3,866	954	-	-	-	-	-	-	-	-	-

Table I
Monticello Nuclear Generating Plant
Scenario 7: SAFSTOR with 60 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 3b Period-Dependent Costs																					
3b.4.1	Decon supplies	35	-	-	-	-	-	-	9	43	43	-	-	-	-	-	-	-	-	-	-
3b.4.2	Insurance	-	-	-	-	-	-	360	36	396	396	-	-	-	-	-	-	-	-	-	-
3b.4.3	Property taxes	-	-	-	-	-	-	995	99	1,094	1,094	-	-	-	-	-	-	-	-	-	-
3b.4.4	Health physics supplies	-	248	-	-	-	-	-	62	310	310	-	-	-	-	-	-	-	-	-	-
3b.4.5	Heavy equipment rental	-	283	-	-	-	-	-	42	325	325	-	-	-	-	-	-	-	-	-	-
3b.4.6	Disposal of DAW generated	-	-	6	2	-	24	-	7	38	38	-	-	-	291	-	-	-	5,814	9	-
3b.4.7	Plant energy budget	-	-	-	-	-	-	863	129	992	992	-	-	-	-	-	-	-	-	-	-
3b.4.8	NRC Fees	-	-	-	-	-	-	170	17	187	187	-	-	-	-	-	-	-	-	-	-
3b.4.9	Emergency Planning Fees	-	-	-	-	-	-	68	7	75	-	75	-	-	-	-	-	-	-	-	-
3b.4.10	Fixed Overhead	-	-	-	-	-	-	1,413	212	1,625	1,625	-	-	-	-	-	-	-	-	-	-
3b.4.11	ISFSI Operating Costs	-	-	-	-	-	-	51	8	59	-	59	-	-	-	-	-	-	-	-	-
3b.4.12	Railroad Track Maintenance	-	-	-	-	-	-	58	9	66	66	-	-	-	-	-	-	-	-	-	-
3b.4.13	Security Staff Cost	-	-	-	-	-	-	1,945	292	2,236	2,236	-	-	-	-	-	-	-	-	-	26,966
3b.4.14	DOC Staff Cost	-	-	-	-	-	-	5,123	769	5,892	5,892	-	-	-	-	-	-	-	-	-	58,080
3b.4.15	Utility Staff Cost	-	-	-	-	-	-	7,992	1,199	9,190	9,190	-	-	-	-	-	-	-	-	-	129,644
3b.4	Subtotal Period 3b Period-Dependent Costs	35	531	6	2	-	24	19,037	2,896	22,530	22,396	134	-	-	291	-	-	-	5,814	9	214,690
3b.0	TOTAL PERIOD 3b COST	1,008	1,731	6	2	-	24	24,898	4,101	31,769	30,258	1,088	423	-	291	-	-	-	5,814	9	247,431
PERIOD 3 TOTALS		1,008	2,750	45	25	13	66	75,359	12,684	91,949	87,720	3,271	958	43	806	-	-	-	21,379	30,690	645,826
PERIOD 4a - Large Component Removal																					
Period 4a Direct Decommissioning Activities																					
Nuclear Steam Supply System Removal																					
4a.1.1.1	Recirculation System Piping & Valves	20	71	28	22	96	214	-	102	553	553	-	-	676	715	-	-	-	94,867	1,594	-
4a.1.1.2	Recirculation Pumps & Motors	7	47	15	26	130	219	-	95	539	539	-	-	568	473	-	-	-	112,200	1,049	-
4a.1.1.3	CRDMs & NIs Removal	35	674	400	72	-	919	-	466	2,565	2,565	-	-	-	3,741	-	-	-	213,700	12,506	-
4a.1.1.4	Reactor Vessel Internals	102	5,782	8,903	1,187	-	14,647	275	14,274	45,170	45,170	-	-	-	2,943	1,127	643	-	306,123	22,915	1,075
4a.1.1.5	Vessel & Internals GTCC Disposal	-	-	-	-	-	6,552	-	983	7,535	7,535	-	-	-	-	-	-	1,547	311,184	-	-
4a.1.1.6	Reactor Vessel	-	7,999	1,877	606	-	5,622	275	9,472	25,852	25,852	-	-	-	17,823	-	-	-	1,110,260	22,915	1,075
4a.1.1	Totals	163	14,571	11,223	1,914	226	28,174	551	25,392	82,215	82,215	-	-	1,244	25,695	1,127	643	1,547	2,148,335	60,979	2,150
Removal of Major Equipment																					
4a.1.2	Main Turbine/Generator	-	282	1,424	349	3,174	357	-	831	6,417	6,417	-	-	24,835	1,383	-	-	-	1,577,959	4,796	-
4a.1.3	Main Condensers	-	994	378	128	1,667	198	-	605	3,970	3,970	-	-	17,396	727	-	-	-	828,955	16,823	-
Cascading Costs from Clean Building Demolition																					
4a.1.4.1	Reactor Building	-	611	-	-	-	-	-	92	703	703	-	-	-	-	-	-	-	-	6,238	-
4a.1.4.2	Radwaste	-	53	-	-	-	-	-	8	61	61	-	-	-	-	-	-	-	-	569	-
4a.1.4.3	Turbine	-	157	-	-	-	-	-	24	180	180	-	-	-	-	-	-	-	-	1,884	-
4a.1.4	Totals	-	821	-	-	-	-	-	123	944	944	-	-	-	-	-	-	-	-	8,691	-
Disposal of Plant Systems																					
4a.1.5.1	Automatic Press Relief	-	88	2	7	94	-	-	37	228	228	-	-	1,088	-	-	-	-	44,184	1,468	-
4a.1.5.2	Chemistry Sampling	-	20	0	1	18	-	-	8	48	48	-	-	207	-	-	-	-	8,422	356	-
4a.1.5.3	Chemistry Sampling - Insulated	-	1	0	0	0	-	-	0	2	2	-	-	1	-	-	-	-	61	25	-
4a.1.5.4	Circulating Water - RCA	-	172	10	41	576	-	-	136	935	935	-	-	6,656	-	-	-	-	270,307	2,860	-
4a.1.5.5	Combustible Gas Control - Insul - RCA	-	24	0	1	18	-	-	9	53	53	-	-	212	-	-	-	-	8,617	378	-
4a.1.5.6	Combustible Gas Control - RCA	-	15	0	2	25	-	-	8	50	50	-	-	285	-	-	-	-	11,577	245	-
4a.1.5.7	Condensate & Feedwater	-	736	45	184	2,609	-	-	607	4,181	4,181	-	-	30,157	-	-	-	-	1,224,704	12,501	-
4a.1.5.8	Condensate & Feedwater - Insulated	-	368	9	36	506	-	-	174	1,093	1,093	-	-	5,855	-	-	-	-	237,764	6,185	-
4a.1.5.9	Condensate Demin	-	408	7	29	410	-	-	168	1,022	1,022	-	-	4,735	-	-	-	-	192,293	6,784	-
4a.1.5.10	Condensate Storage	-	546	12	50	712	-	-	252	1,573	1,573	-	-	8,237	-	-	-	-	334,489	9,265	-
4a.1.5.11	Control Rod Drive	-	2	0	0	2	-	-	1	5	5	-	-	24	-	-	-	-	976	36	-
4a.1.5.12	Control Rod Drive Hydraulic	-	309	4	15	211	-	-	112	651	651	-	-	2,440	-	-	-	-	99,094	5,255	-

Table I
Monticello Nuclear Generating Plant
Scenario 7: SAFSTOR with 60 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Disposal of Plant Systems (continued)																					
4a.1.5.13	Core Spray	-	59	8	31	442	-	-	86	626	626	-	-	5,109	-	-	-	-	207,487	1,026	-
4a.1.5.14	Core Spray - Insulated	-	108	2	7	102	-	-	44	263	263	-	-	1,184	-	-	-	-	48,081	1,806	-
4a.1.5.15	Demin Water - Insulated - RCA	-	12	0	1	7	-	-	4	25	25	-	-	85	-	-	-	-	3,445	181	-
4a.1.5.16	Demin Water - RCA	-	34	0	2	22	-	-	12	70	70	-	-	253	-	-	-	-	10,278	508	-
4a.1.5.17	Diesel Oil - RCA	-	2	0	0	2	-	-	1	4	4	-	-	23	-	-	-	-	931	25	-
4a.1.5.18	Drywell Atmosphere Cooling - RCA	-	31	1	3	47	-	-	15	98	98	-	-	548	-	-	-	-	22,244	550	-
4a.1.5.19	EDG Emerg Service Water - Insul - RCA	-	0	0	0	0	-	-	0	1	1	-	-	2	-	-	-	-	84	4	-
4a.1.5.20	Electrical - Clean	-	11	-	-	-	-	-	2	12	-	-	12	-	-	-	-	-	-	182	-
4a.1.5.21	Emergency Service Water - Insul - RCA	-	18	0	1	12	-	-	6	37	37	-	-	137	-	-	-	-	5,544	281	-
4a.1.5.22	Emergency Service Water - RCA	-	1	0	0	1	-	-	1	3	3	-	-	13	-	-	-	-	512	22	-
4a.1.5.23	GEZIP - RCA	-	3	0	1	9	-	-	2	15	15	-	-	103	-	-	-	-	4,184	48	-
4a.1.5.24	Generator Physical Design - RCA	-	4	0	0	3	-	-	1	8	8	-	-	31	-	-	-	-	1,250	67	-
4a.1.5.25	H2-O2 Control Analyzing	-	5	0	0	2	-	-	1	8	8	-	-	23	-	-	-	-	948	72	-
4a.1.5.26	H2-O2 Control Analyzing - Insulated	-	5	0	0	2	-	-	1	8	8	-	-	23	-	-	-	-	948	72	-
4a.1.5.27	High Pressure Coolant Injection	-	50	2	8	109	-	-	30	199	199	-	-	1,262	-	-	-	-	51,257	850	-
4a.1.5.28	High Pressure Coolant Injection - Insula	-	164	3	14	196	-	-	73	450	450	-	-	2,266	-	-	-	-	92,018	2,734	-
4a.1.5.29	Hydrogen Cooling	-	7	-	-	-	-	-	1	8	-	-	8	-	-	-	-	-	-	118	-
4a.1.5.30	Hydrogen Cooling - RCA	-	6	0	0	3	-	-	2	11	11	-	-	39	-	-	-	-	1,600	79	-
4a.1.5.31	Hydrogen Seal Oil - RCA	-	14	0	1	16	-	-	6	38	38	-	-	189	-	-	-	-	7,669	212	-
4a.1.5.32	Hydrogen Water Chemistry - RCA	-	20	0	1	12	-	-	7	40	40	-	-	140	-	-	-	-	5,672	304	-
4a.1.5.33	Instrument & Service Air - RCA	-	185	3	11	153	-	-	71	423	423	-	-	1,768	-	-	-	-	71,810	2,733	-
4a.1.5.34	Main Condenser	-	147	3	12	165	-	-	63	389	389	-	-	1,903	-	-	-	-	77,301	2,443	-
4a.1.5.35	Main Steam	-	186	4	18	257	-	-	88	554	554	-	-	2,975	-	-	-	-	120,806	3,122	-
4a.1.5.36	Main Turbine	-	754	48	194	2,758	-	-	636	4,391	4,391	-	-	31,885	-	-	-	-	1,294,866	12,952	-
4a.1.5.37	Main Turbine - Insulated	-	160	5	21	299	-	-	89	574	574	-	-	3,460	-	-	-	-	140,506	2,725	-
4a.1.5.38	Miscellaneous	-	32	0	2	26	-	-	12	72	72	-	-	302	-	-	-	-	12,283	556	-
4a.1.5.39	Off Gas Recombiner	-	140	4	17	247	-	-	75	485	485	-	-	2,861	-	-	-	-	116,194	2,387	-
4a.1.5.40	Off Gas Recombiner - Insulated	-	289	4	14	203	-	-	105	616	616	-	-	2,350	-	-	-	-	95,441	4,785	-
4a.1.5.41	Post Accident Sampling	-	19	0	1	9	-	-	6	34	34	-	-	99	-	-	-	-	4,004	306	-
4a.1.5.42	Post Accident Sampling - Insulated	-	13	0	0	6	-	-	4	23	23	-	-	67	-	-	-	-	2,737	190	-
4a.1.5.43	RHR Service Water - Insulated - RCA	-	69	2	9	128	-	-	38	246	246	-	-	1,485	-	-	-	-	60,293	1,125	-
4a.1.5.44	RHR Service Water - RCA	-	3	0	0	3	-	-	1	8	8	-	-	35	-	-	-	-	1,410	57	-
4a.1.5.45	Reactor Feedwater Pump Seal	-	42	0	2	28	-	-	15	87	87	-	-	327	-	-	-	-	13,295	687	-
4a.1.5.46	Residual Heat Removal	-	187	52	99	1,091	418	-	335	2,181	2,181	-	-	12,609	1,519	-	-	-	609,174	3,282	-
4a.1.5.47	Residual Heat Removal - Insulated	-	415	37	51	440	377	-	275	1,595	1,595	-	-	5,084	1,374	-	-	-	294,206	7,027	-
4a.1.5.48	Rx Core Isolation Cooling	-	36	1	2	31	-	-	14	84	84	-	-	364	-	-	-	-	14,781	609	-
4a.1.5.49	Rx Core Isolation Cooling - Insulated	-	80	1	3	49	-	-	28	161	161	-	-	563	-	-	-	-	22,843	1,315	-
4a.1.5.50	Rx Recirculation	-	44	5	3	8	43	-	24	126	126	-	-	96	152	-	-	-	13,794	691	-
4a.1.5.51	Snubbers	-	126	1	3	43	-	-	39	212	212	-	-	502	-	-	-	-	20,395	2,272	-
4a.1.5.52	Standby Liquid Control - Insul - RCA	-	3	0	0	2	-	-	1	6	6	-	-	22	-	-	-	-	904	48	-
4a.1.5.53	Standby Liquid Control - RCA	-	22	0	1	21	-	-	9	54	54	-	-	245	-	-	-	-	9,969	341	-
4a.1.5.54	Stator Cooling - RCA	-	6	0	1	11	-	-	3	21	21	-	-	126	-	-	-	-	5,135	98	-
4a.1.5.55	Traversing Incore Probe	-	3	0	0	0	1	-	1	5	5	-	-	2	5	-	-	-	379	46	-
4a.1.5	Totals	-	6,203	280	899	12,150	839	-	3,744	24,114	24,094	-	20	140,459	3,050	-	-	-	5,899,167	104,297	-
4a.1.6	Scaffolding in support of decommissioning	-	1,778	23	8	99	25	-	469	2,402	2,402	-	-	1,030	91	-	-	-	52,111	19,968	-
4a.1	Subtotal Period 4a Activity Costs	163	24,648	13,329	3,299	17,316	29,592	551	31,164	120,062	120,042	-	20	184,963	30,945	1,127	643	1,547	10,506,530	215,555	2,150
Period 4a Additional Costs																					
4a.2.1	Remedial Action Surveys	-	-	-	-	-	-	2,161	648	2,809	2,809	-	-	-	-	-	-	-	-	28,247	-
4a.2	Subtotal Period 4a Additional Costs	-	-	-	-	-	-	2,161	648	2,809	2,809	-	-	-	-	-	-	-	-	28,247	-
Period 4a Collateral Costs																					
4a.3.1	Process decommissioning water waste	4	-	7	17	-	27	-	12	66	66	-	-	-	64	-	-	-	3,860	13	-
4a.3.3	Small tool allowance	-	240	-	-	-	-	-	36	276	248	-	28	-	-	-	-	-	-	-	-
4a.3.4	Spent Fuel Capital and Transfer	-	-	-	-	-	-	2,560	384	2,943	-	2,943	-	-	-	-	-	-	-	-	-
4a.3	Subtotal Period 4a Collateral Costs	4	240	7	17	-	27	2,560	432	3,285	314	2,943	28	-	64	-	-	-	3,860	13	-

Table I
Monticello Nuclear Generating Plant
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(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 4a Period-Dependent Costs																					
4a.4.1	Decon supplies	94	-	-	-	-	-	-	24	118	118	-	-	-	-	-	-	-	-	-	-
4a.4.2	Insurance	-	-	-	-	-	-	980	98	1,078	1,078	-	-	-	-	-	-	-	-	-	-
4a.4.3	Property taxes	-	-	-	-	-	-	2,674	267	2,942	2,942	-	-	-	-	-	-	-	-	-	-
4a.4.4	Health physics supplies	-	1,856	-	-	-	-	-	464	2,320	2,320	-	-	-	-	-	-	-	-	-	-
4a.4.5	Heavy equipment rental	-	2,984	-	-	-	-	-	448	3,431	3,431	-	-	-	-	-	-	-	-	-	-
4a.4.6	Disposal of DAW generated	-	-	97	31	-	378	-	109	614	614	-	-	-	4,640	-	-	-	92,810	151	-
4a.4.7	Plant energy budget	-	-	-	-	-	-	2,233	335	2,568	2,568	-	-	-	-	-	-	-	-	-	-
4a.4.8	NRC Fees	-	-	-	-	-	-	757	76	833	833	-	-	-	-	-	-	-	-	-	-
4a.4.9	Emergency Planning Fees	-	-	-	-	-	-	186	19	204	-	204	-	-	-	-	-	-	-	-	-
4a.4.10	Fixed Overhead	-	-	-	-	-	-	3,150	473	3,623	3,623	-	-	-	-	-	-	-	-	-	-
4a.4.11	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	550	82	632	632	-	-	-	-	-	-	-	-	-	-
4a.4.12	ISFSI Operating Costs	-	-	-	-	-	-	140	21	161	-	161	-	-	-	-	-	-	-	-	-
4a.4.13	Railroad Track Maintenance	-	-	-	-	-	-	157	24	180	180	-	-	-	-	-	-	-	-	-	-
4a.4.14	Security Staff Cost	-	-	-	-	-	-	5,300	795	6,095	6,095	-	-	-	-	-	-	-	-	-	73,490
4a.4.15	DOC Staff Cost	-	-	-	-	-	-	16,810	2,522	19,332	19,332	-	-	-	-	-	-	-	-	-	195,030
4a.4.16	Utility Staff Cost	-	-	-	-	-	-	21,933	3,290	25,223	25,223	-	-	-	-	-	-	-	-	-	356,142
4a.4	Subtotal Period 4a Period-Dependent Costs	94	4,839	97	31	-	378	54,871	9,045	69,355	68,989	366	-	-	4,640	-	-	-	92,810	151	624,661
4a.0	TOTAL PERIOD 4a COST	262	29,727	13,432	3,346	17,316	29,997	60,142	41,289	195,511	192,155	3,309	48	184,963	35,649	1,127	643	1,547	10,603,200	243,966	626,811
PERIOD 4b - Site Decontamination																					
Period 4b Direct Decommissioning Activities																					
4b.1.1	Remove spent fuel racks	504	49	108	109	-	2,091	-	814	3,675	3,675	-	-	-	7,653	-	-	-	486,170	906	-
Disposal of Plant Systems																					
4b.1.2.1	ALARA/Radiological	-	14	0	0	4	-	-	4	22	22	-	-	49	-	-	-	-	1,987	247	-
4b.1.2.2	Alternate N2 - RCA	-	13	0	1	8	-	-	5	27	27	-	-	93	-	-	-	-	3,765	185	-
4b.1.2.3	Cranes/Heavy Loads/Rigging - RCA	-	3	0	1	9	-	-	2	15	15	-	-	103	-	-	-	-	4,184	48	-
4b.1.2.4	Decontamination Projects	-	1	0	0	0	-	-	0	1	1	-	-	3	-	-	-	-	125	15	-
4b.1.2.5	Electrical - Contaminated	-	328	4	15	217	-	-	117	682	682	-	-	2,514	-	-	-	-	102,112	5,633	-
4b.1.2.6	Electrical - Contaminated Fuel Pool	-	34	0	2	22	-	-	12	70	70	-	-	253	-	-	-	-	10,272	592	-
4b.1.2.7	Electrical - Decontam. Fuel Pool Area	-	242	4	15	213	-	-	95	568	568	-	-	2,457	-	-	-	-	99,783	4,090	-
4b.1.2.8	Electrical - Decontaminated	-	2,195	36	142	2,019	-	-	877	5,269	5,269	-	-	23,344	-	-	-	-	948,013	37,107	-
4b.1.2.9	Fire - RCA	-	84	1	4	53	-	-	30	171	171	-	-	614	-	-	-	-	24,917	1,324	-
4b.1.2.10	Fire - RCA - Fuel Pool Area	-	9	0	0	5	-	-	3	18	18	-	-	62	-	-	-	-	2,499	143	-
4b.1.2.11	Fuel Pool Cooling & Cleanup	-	319	19	23	177	196	-	161	895	895	-	-	2,051	712	-	-	-	128,918	5,363	-
4b.1.2.12	Fuel Pool Cooling & Cleanup - Insulated	-	31	2	2	11	20	-	15	80	80	-	-	130	71	-	-	-	9,830	514	-
4b.1.2.13	HVAC Ductwork	-	238	4	17	243	-	-	99	601	601	-	-	2,805	-	-	-	-	113,913	3,539	-
4b.1.2.14	HVAC Ductwork - Fuel Pool Area	-	26	0	2	27	-	-	11	67	67	-	-	312	-	-	-	-	12,657	393	-
4b.1.2.15	HVAC/Chilled Water - RCA	-	267	4	17	238	-	-	105	631	631	-	-	2,752	-	-	-	-	111,779	3,985	-
4b.1.2.16	HVAC/Chilled Water - RCA Fuel Pool Area	-	27	0	1	19	-	-	10	58	58	-	-	223	-	-	-	-	9,072	397	-
4b.1.2.17	Heating & Ventilation	-	359	10	39	548	-	-	179	1,134	1,134	-	-	6,334	-	-	-	-	257,243	6,340	-
4b.1.2.18	Heating Boiler - Insulated - RCA	-	2	0	0	2	-	-	1	6	6	-	-	26	-	-	-	-	1,058	35	-
4b.1.2.19	Instrument & Service Air-RCA-Fuel Pool	-	24	0	2	23	-	-	10	58	58	-	-	267	-	-	-	-	10,841	357	-
4b.1.2.20	Liquid Radwaste	-	515	28	39	364	253	-	255	1,453	1,453	-	-	4,203	915	-	-	-	229,422	8,550	-
4b.1.2.21	Makeup Demin - RCA	-	86	2	9	127	-	-	42	266	266	-	-	1,471	-	-	-	-	59,747	1,412	-
4b.1.2.22	Non-Essential Diesel Generator - RCA	-	23	2	9	123	-	-	26	183	183	-	-	1,424	-	-	-	-	57,832	395	-
4b.1.2.23	Off Gas Holdup	-	257	5	22	314	-	-	115	713	713	-	-	3,629	-	-	-	-	147,355	4,256	-
4b.1.2.24	Primary Containment	-	341	13	51	718	-	-	202	1,324	1,324	-	-	8,302	-	-	-	-	337,148	5,729	-
4b.1.2.25	Process Radiation Monitors	-	34	0	1	18	-	-	12	66	66	-	-	213	-	-	-	-	8,667	577	-
4b.1.2.26	Rx Bldg Closed Clng Water - Insul - RCA	-	93	2	6	85	-	-	37	222	222	-	-	977	-	-	-	-	39,675	1,484	-
4b.1.2.27	Rx Bldg Closed Clng Water - RCA	-	152	11	43	614	-	-	138	957	957	-	-	7,093	-	-	-	-	288,031	2,489	-
4b.1.2.28	Rx Component Handling Equip	-	105	11	16	150	113	-	81	477	477	-	-	1,737	415	-	-	-	96,901	1,839	-
4b.1.2.29	Rx Pressure Vessel	-	35	4	3	14	47	-	24	127	127	-	-	161	169	-	-	-	17,375	578	-
4b.1.2.30	Rx Water Cleanup	-	198	16	11	24	174	-	100	523	523	-	-	278	630	-	-	-	51,819	3,264	-
4b.1.2.31	Secondary Containment	-	93	2	8	119	-	-	42	264	264	-	-	1,372	-	-	-	-	55,702	1,569	-
4b.1.2.32	Service & Seal Water - Insulated - RCA	-	99	2	7	102	-	-	41	252	252	-	-	1,180	-	-	-	-	47,917	1,565	-
4b.1.2.33	Service & Seal Water - RCA	-	131	3	11	156	-	-	58	360	360	-	-	1,809	-	-	-	-	73,453	2,016	-
4b.1.2.34	Service Air Blower - RCA	-	13	0	1	18	-	-	6	38	38	-	-	206	-	-	-	-	8,364	206	-
4b.1.2.35	Solid Radwaste	-	369	20	30	293	181	-	188	1,081	1,081	-	-	3,390	659	-	-	-	179,772	6,270	-
4b.1.2.36	Structures & Buildings	-	58	1	3	41	-	-	21	124	124	-	-	477	-	-	-	-	19,351	1,005	-
4b.1.2.37	Wells & Domestic Water	-	8	-	-	-	-	-	1	9	-	-	9	-	-	-	-	-	-	144	-
4b.1.2.38	Wells & Domestic Water - RCA	-	43	1	2	30	-	-	16	91	91	-	-	342	-	-	-	-	13,874	633	-
4b.1.2	Totals	-	6,869	208	555	7,150	984	-	3,139	18,904	18,894	-	9	82,654	3,571	-	-	-	3,585,374	114,290	-
4b.1.3	Scaffolding in support of decommissioning	-	2,667	35	12	148	37	-	704	3,603	3,603	-	-	1,545	136	-	-	-	78,166	29,953	-

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Decontamination of Site Buildings																					
4b.1.4.1	Reactor Building	3,881	2,049	138	314	4,159	765	-	3,329	14,634	14,634	-	-	48,077	4,434	-	-	-	2,195,768	98,722	-
4b.1.4.2	Admin	82	2	0	1	-	7	-	43	135	135	-	-	-	72	-	-	-	3,420	1,389	-
4b.1.4.3	HPCI Room	22	19	0	1	10	7	-	19	78	78	-	-	118	65	-	-	-	7,927	664	-
4b.1.4.4	Hot Shop	13	2	0	1	-	5	-	8	28	28	-	-	-	51	-	-	-	2,430	231	-
4b.1.4.5	LLRW Storage & Shipping	43	11	1	3	3	21	-	30	111	111	-	-	31	217	-	-	-	11,532	875	-
4b.1.4.6	Offgas Stack	280	127	4	12	116	44	-	202	786	786	-	-	1,343	361	-	-	-	72,483	6,692	-
4b.1.4.7	Offgas Storage & Compressor	30	7	0	2	2	15	-	21	79	79	-	-	25	159	-	-	-	8,502	603	-
4b.1.4.8	Radwaste	91	30	2	7	15	44	-	67	255	255	-	-	172	460	-	-	-	28,679	1,960	-
4b.1.4.9	Radwaste Material Storage Warehouse	48	9	1	3	-	23	-	32	116	116	-	-	-	248	-	-	-	11,700	915	-
4b.1.4.10	Recombiner	20	15	1	3	17	12	-	20	87	87	-	-	199	112	-	-	-	13,491	554	-
4b.1.4.11	Turbine	528	172	9	42	111	260	-	396	1,517	1,517	-	-	1,283	2,675	-	-	-	179,172	11,286	-
4b.1.4.12	Turbine Building Addition	44	8	1	3	-	20	-	29	105	105	-	-	-	217	-	-	-	10,248	838	-
4b.1.4.13	Reactor (Post Fuel)	703	1,924	129	656	170	4,681	-	2,140	10,403	10,403	-	-	1,969	49,647	-	-	-	2,426,544	39,766	-
4b.1.4	Totals	5,783	4,375	286	1,047	4,603	5,903	-	6,337	28,334	28,334	-	-	53,216	58,718	-	-	-	4,971,896	164,495	-
4b.1.5	Prepare/submit License Termination Plan	-	-	-	-	-	-	481	72	553	553	-	-	-	-	-	-	-	-	-	4,096
4b.1.6	Receive NRC approval of termination plan									a											
4b.1	Subtotal Period 4b Activity Costs	6,287	13,960	637	1,723	11,901	9,015	481	11,066	55,069	55,060	-	9	137,414	70,078	-	-	-	9,121,606	309,644	4,096
Period 4b Additional Costs																					
4b.2.1	License Termination Survey Planning	-	-	-	-	-	-	1,291	387	1,678	1,678	-	-	-	-	-	-	-	-	-	12,480
4b.2.2	Remedial Action Surveys	-	-	-	-	-	-	3,241	972	4,213	4,213	-	-	-	-	-	-	-	-	42,370	-
4b.2.3	Operational Equipment	-	-	19	60	624	-	-	104	807	807	-	-	11,710	-	-	-	-	292,750	32	-
4b.2	Subtotal Period 4b Additional Costs	-	-	19	60	624	-	4,532	1,464	6,698	6,698	-	-	11,710	-	-	-	-	292,750	42,402	12,480
Period 4b Collateral Costs																					
4b.3.1	Process decommissioning water waste	12	-	21	53	-	84	-	37	207	207	-	-	-	201	-	-	-	12,055	39	-
4b.3.3	Small tool allowance	-	314	-	-	-	-	-	47	361	361	-	-	-	-	-	-	-	-	-	-
4b.3.4	Decommissioning Equipment Disposition	-	-	137	55	575	145	-	144	1,055	1,055	-	-	6,000	529	-	-	-	303,608	147	-
4b.3.5	Spent Fuel Capital and Transfer	-	-	-	-	-	-	5,730	860	6,590	-	6,590	-	-	-	-	-	-	-	-	-
4b.3	Subtotal Period 4b Collateral Costs	12	314	157	108	575	229	5,730	1,088	8,212	1,622	6,590	-	6,000	730	-	-	-	315,663	186	-
Period 4b Period-Dependent Costs																					
4b.4.1	Decon supplies	1,388	-	-	-	-	-	-	347	1,735	1,735	-	-	-	-	-	-	-	-	-	-
4b.4.2	Insurance	-	-	-	-	-	-	1,470	147	1,617	1,617	-	-	-	-	-	-	-	-	-	-
4b.4.3	Property taxes	-	-	-	-	-	-	3,786	379	4,165	4,165	-	-	-	-	-	-	-	-	-	-
4b.4.4	Health physics supplies	-	2,704	-	-	-	-	-	676	3,380	3,380	-	-	-	-	-	-	-	-	-	-
4b.4.5	Heavy equipment rental	-	4,602	-	-	-	-	-	690	5,292	5,292	-	-	-	-	-	-	-	-	-	-
4b.4.6	Disposal of DAW generated	-	-	121	39	-	472	-	136	767	767	-	-	-	5,800	-	-	-	116,000	189	-
4b.4.7	Plant energy budget	-	-	-	-	-	-	2,645	397	3,041	3,041	-	-	-	-	-	-	-	-	-	-
4b.4.8	NRC Fees	-	-	-	-	-	-	1,136	114	1,250	1,250	-	-	-	-	-	-	-	-	-	-
4b.4.9	Emergency Planning Fees	-	-	-	-	-	-	279	28	307	-	307	-	-	-	-	-	-	-	-	-
4b.4.10	Fixed Overhead	-	-	-	-	-	-	4,725	709	5,434	5,434	-	-	-	-	-	-	-	-	-	-
4b.4.11	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	825	124	949	949	-	-	-	-	-	-	-	-	-	-
4b.4.12	ISFSI Operating Costs	-	-	-	-	-	-	210	32	242	-	242	-	-	-	-	-	-	-	-	-
4b.4.13	Railroad Track Maintenance	-	-	-	-	-	-	235	35	270	270	-	-	-	-	-	-	-	-	-	-
4b.4.14	Security Staff Cost	-	-	-	-	-	-	7,950	1,192	9,142	9,142	-	-	-	-	-	-	-	-	-	110,234
4b.4.15	DOC Staff Cost	-	-	-	-	-	-	24,690	3,704	28,394	28,394	-	-	-	-	-	-	-	-	-	284,065
4b.4.16	Utility Staff Cost	-	-	-	-	-	-	31,207	4,681	35,888	35,888	-	-	-	-	-	-	-	-	-	504,534
4b.4	Subtotal Period 4b Period-Dependent Costs	1,388	7,306	121	39	-	472	79,158	13,389	101,873	101,325	549	-	-	5,800	-	-	-	116,000	189	898,834
4b.0	TOTAL PERIOD 4b COST	7,687	21,579	934	1,929	13,100	9,716	89,901	27,007	171,853	164,705	7,139	9	155,124	76,608	-	-	-	9,846,018	352,420	915,410
PERIOD 4f - License Termination																					
Period 4f Direct Decommissioning Activities																					
4f.1.1	ORISE confirmatory survey	-	-	-	-	-	-	159	48	207	207	-	-	-	-	-	-	-	-	-	-
4f.1.2	Terminate license									a											
4f.1	Subtotal Period 4f Activity Costs	-	-	-	-	-	-	159	48	207	207	-	-	-	-	-	-	-	-	-	-

Table I
Monticello Nuclear Generating Plant
Scenario 7: SAFSTOR with 60 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 4f Additional Costs																					
4f.2.1	License Termination Survey	-	-	-	-	-	-	7,341	2,202	9,544	9,544	-	-	-	-	-	-	-	-	96,197	6,240
4f.2.2	License Termination ISFSI	-	131	3	784	-	8,058	2,907	2,971	14,854	14,854	-	-	-	27,284	-	-	-	3,860,412	11,160	10,640
4f.2	Subtotal Period 4f Additional Costs	-	131	3	784	-	8,058	10,248	5,173	24,398	24,398	-	-	-	27,284	-	-	-	3,860,412	107,357	16,880
Period 4f Collateral Costs																					
4f.3.1	DOC staff relocation expenses	-	-	-	-	-	-	1,189	178	1,367	1,367	-	-	-	-	-	-	-	-	-	-
4f.3.2	Small tool allowance	-	1	-	-	-	-	-	0	1	1	-	-	-	-	-	-	-	-	-	-
4f.3.3	Spent Fuel Capital and Transfer	-	-	-	-	-	-	570	85	655	-	655	-	-	-	-	-	-	-	-	-
4f.3	Subtotal Period 4f Collateral Costs	-	1	-	-	-	-	1,758	264	2,024	1,368	655	-	-	-	-	-	-	-	-	-
Period 4f Period-Dependent Costs																					
4f.4.1	Insurance	-	-	-	-	-	-	543	54	598	598	-	-	-	-	-	-	-	-	-	-
4f.4.2	Property taxes	-	-	-	-	-	-	1,265	127	1,392	1,392	-	-	-	-	-	-	-	-	-	-
4f.4.3	Health physics supplies	-	651	-	-	-	-	-	163	813	813	-	-	-	-	-	-	-	-	-	-
4f.4.4	Disposal of DAW generated	-	-	7	2	-	29	-	8	47	47	-	-	-	355	-	-	-	7,097	12	-
4f.4.5	Plant energy budget	-	-	-	-	-	-	261	39	300	300	-	-	-	-	-	-	-	-	-	-
4f.4.6	NRC Fees	-	-	-	-	-	-	420	42	463	463	-	-	-	-	-	-	-	-	-	-
4f.4.7	Emergency Planning Fees	-	-	-	-	-	-	103	10	113	-	113	-	-	-	-	-	-	-	-	-
4f.4.8	Fixed Overhead	-	-	-	-	-	-	1,747	262	2,009	2,009	-	-	-	-	-	-	-	-	-	-
4f.4.9	ISFSI Operating Costs	-	-	-	-	-	-	78	12	89	-	89	-	-	-	-	-	-	-	-	-
4f.4.10	Railroad Track Maintenance	-	-	-	-	-	-	87	13	100	100	-	-	-	-	-	-	-	-	-	-
4f.4.11	Security Staff Cost	-	-	-	-	-	-	2,938	441	3,379	3,379	-	-	-	-	-	-	-	-	-	40,745
4f.4.12	DOC Staff Cost	-	-	-	-	-	-	5,174	776	5,950	5,950	-	-	-	-	-	-	-	-	-	57,200
4f.4.13	Utility Staff Cost	-	-	-	-	-	-	5,456	818	6,274	6,274	-	-	-	-	-	-	-	-	-	80,707
4f.4	Subtotal Period 4f Period-Dependent Costs	-	651	7	2	-	29	18,072	2,765	21,527	21,324	203	-	-	355	-	-	-	7,097	12	178,652
4f.0	TOTAL PERIOD 4f COST	-	782	11	787	-	8,087	30,238	8,250	48,155	47,297	858	-	-	27,639	-	-	-	3,867,510	107,369	195,532
PERIOD 4 TOTALS		7,949	52,089	14,377	6,063	30,416	47,800	180,282	76,546	415,520	404,157	11,306	57	340,088	139,896	1,127	643	1,547	24,316,720	703,755	1,737,752
PERIOD 5b - Site Restoration																					
Period 5b Direct Decommissioning Activities																					
Demolition of Remaining Site Buildings																					
5b.1.1.1	Reactor Building	-	3,541	-	-	-	-	-	531	4,073	-	-	4,073	-	-	-	-	-	-	36,752	-
5b.1.1.2	Condensate Tanks Foundation	-	19	-	-	-	-	-	3	22	-	-	22	-	-	-	-	-	-	219	-
5b.1.1.3	Discharge Retention Basin	-	9	-	-	-	-	-	1	10	-	-	10	-	-	-	-	-	-	110	-
5b.1.1.4	HPCI Room	-	44	-	-	-	-	-	7	50	-	-	50	-	-	-	-	-	-	401	-
5b.1.1.5	Hot Shop	-	21	-	-	-	-	-	3	24	-	-	24	-	-	-	-	-	-	298	-
5b.1.1.6	Hydrogen & Oxygen Storage	-	2	-	-	-	-	-	0	2	-	-	2	-	-	-	-	-	-	21	-
5b.1.1.7	LLRW Storage & Shipping	-	140	-	-	-	-	-	21	161	-	-	161	-	-	-	-	-	-	1,794	-
5b.1.1.8	MSIV	-	4	-	-	-	-	-	1	5	-	-	5	-	-	-	-	-	-	59	-
5b.1.1.9	Misc Structures 2017	-	1,075	-	-	-	-	-	161	1,236	-	-	1,236	-	-	-	-	-	-	13,787	-
5b.1.1.10	Offgas Stack	-	232	-	-	-	-	-	35	267	-	-	267	-	-	-	-	-	-	2,668	-
5b.1.1.11	Offgas Storage & Compressor	-	88	-	-	-	-	-	13	101	-	-	101	-	-	-	-	-	-	963	-
5b.1.1.12	Radwaste	-	482	-	-	-	-	-	72	554	-	-	554	-	-	-	-	-	-	5,196	-
5b.1.1.13	Recombiner	-	258	-	-	-	-	-	39	297	-	-	297	-	-	-	-	-	-	2,490	-
5b.1.1.14	Security Barrier	-	362	-	-	-	-	-	54	416	-	-	416	-	-	-	-	-	-	4,083	-
5b.1.1.15	Structures Greater than 3' Below Grade	-	4,946	-	-	-	-	-	742	5,688	-	-	5,688	-	-	-	-	-	-	46,737	-
5b.1.1.16	Tank Farm	-	10	-	-	-	-	-	1	11	-	-	11	-	-	-	-	-	-	121	-
5b.1.1.17	Turbine	-	1,514	-	-	-	-	-	227	1,741	-	-	1,741	-	-	-	-	-	-	18,764	-
5b.1.1.18	Turbine Building Addition	-	67	-	-	-	-	-	10	77	-	-	77	-	-	-	-	-	-	971	-
5b.1.1.19	Turbine Pedestal	-	415	-	-	-	-	-	62	478	-	-	478	-	-	-	-	-	-	3,762	-
5b.1.1	Totals	-	13,228	-	-	-	-	-	1,984	15,212	-	-	15,212	-	-	-	-	-	-	139,199	-
Site Closeout Activities																					
5b.1.2	Grade & landscape site	-	864	-	-	-	-	-	130	994	-	-	994	-	-	-	-	-	-	1,841	-
5b.1.3	Final report to NRC	-	-	-	-	-	-	183	27	211	211	-	-	-	-	-	-	-	-	-	1,560
5b.1	Subtotal Period 5b Activity Costs	-	14,092	-	-	-	-	183	2,141	16,417	211	-	16,206	-	-	-	-	-	-	141,040	1,560

Table I
Monticello Nuclear Generating Plant
Scenario 7: SAFSTOR with 60 Year DFS Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 5b Additional Costs																					
5b.2.1	Clean Concrete Disposal	-	3,297	-	-	-	-	11	496	3,805	-	-	3,805	-	-	-	-	-	-	12	-
5b.2.2	Cofferdam	-	320	-	-	-	-	-	48	368	368	-	-	-	-	-	-	-	-	2,584	-
5b.2.3	Excavation of Underground Services	-	1,380	-	-	-	-	947	349	2,677	-	-	2,677	-	-	-	-	-	-	13,475	-
5b.2.4	Constrution Debris	-	-	-	-	-	-	350	53	403	-	-	403	-	-	-	-	-	-	-	-
5b.2.5	Backfill	-	5,102	-	-	-	-	-	765	5,868	-	-	5,868	-	-	-	-	-	-	5,422	-
5b.2.6	Demolition and Site Restoration ISFSI	-	1,766	-	-	-	-	185	293	2,244	-	-	2,244	-	-	-	-	-	-	8,537	160
5b.2	Subtotal Period 5b Additional Costs	-	11,866	-	-	-	-	1,493	2,004	15,364	368	-	14,996	-	-	-	-	-	-	30,030	160
Period 5b Collateral Costs																					
5b.3.1	Small tool allowance	-	193	-	-	-	-	-	29	222	-	-	222	-	-	-	-	-	-	-	-
5b.3.2	Spent Fuel Capital and Transfer	-	-	-	-	-	-	210	31	241	-	241	-	-	-	-	-	-	-	-	-
5b.3	Subtotal Period 5b Collateral Costs	-	193	-	-	-	-	210	60	463	-	241	222	-	-	-	-	-	-	-	-
Period 5b Period-Dependent Costs																					
5b.4.2	Property taxes	-	-	-	-	-	-	2,419	242	2,661	-	-	2,661	-	-	-	-	-	-	-	-
5b.4.3	Heavy equipment rental	-	5,455	-	-	-	-	-	818	6,273	-	-	6,273	-	-	-	-	-	-	-	-
5b.4.4	Plant energy budget	-	-	-	-	-	-	300	45	345	-	-	345	-	-	-	-	-	-	-	-
5b.4.5	Fixed Overhead	-	-	-	-	-	-	1,260	189	1,450	-	-	1,450	-	-	-	-	-	-	-	-
5b.4.6	Railroad Track Maintenance	-	-	-	-	-	-	200	30	230	-	-	230	-	-	-	-	-	-	-	-
5b.4.7	Security Staff Cost	-	-	-	-	-	-	2,739	411	3,150	-	-	3,150	-	-	-	-	-	-	-	43,287
5b.4.8	DOC Staff Cost	-	-	-	-	-	-	11,290	1,693	12,983	-	-	12,983	-	-	-	-	-	-	-	122,646
5b.4.9	Utility Staff Cost	-	-	-	-	-	-	4,718	708	5,426	-	-	5,426	-	-	-	-	-	-	-	70,341
5b.4	Subtotal Period 5b Period-Dependent Costs	-	5,455	-	-	-	-	22,927	4,136	32,517	-	-	32,517	-	-	-	-	-	-	-	236,274
5b.0	TOTAL PERIOD 5b COST	-	31,606	-	-	-	-	24,813	8,342	64,761	578	241	63,941	-	-	-	-	-	-	171,070	237,994
PERIOD 5 TOTALS		-	31,606	-	-	-	-	24,813	8,342	64,761	578	241	63,941	-	-	-	-	-	-	171,070	237,994
TOTAL COST TO DECOMMISSION		**17,731**	**94,941**	**14,820**	**6,756**	**30,429**	**49,464**	**1,261,386**	**241,927**	**1,717,454**	**1,099,775**	**552,724**	**64,956**	**340,130**	**150,629**	**1,127**	**643**	**1,547**	**24,630,430**	**1,025,076**	**10,085,120**

TOTAL COST TO DECOMMISSION WITH 16.4% CONTINGENCY:	**$1,717,454**	**thousands of 2017 dollars**
TOTAL NRC LICENSE TERMINATION COST IS 64.04% OR:	**$1,099,775**	**thousands of 2017 dollars**
SPENT FUEL MANAGEMENT COST IS 32.18% OR:	**$552,724**	**thousands of 2017 dollars**
NON-NUCLEAR DEMOLITION COST IS 3.78% OR:	**$64,956**	**thousands of 2017 dollars**
TOTAL LOW-LEVEL RADIOACTIVE WASTE VOLUME BURIED (EXCLUDING GTCC):	**152,399**	**cubic feet**
TOTAL GREATER THAN CLASS C RADWASTE VOLUME GENERATED:	**1,547**	**cubic feet**
TOTAL SCRAP METAL REMOVED:	**22,696**	**tons**
TOTAL CRAFT LABOR REQUIREMENTS:	**1,025,076**	**man-hours**

End Notes:
n/a - indicates that this activity not charged as decommissioning expense
a - indicates that this activity performed by decommissioning staff
0 - indicates that this value is less than 0.5 but is non-zero
A cell containing " - " indicates a zero value

APPENDIX J

ISFSI DECOMMISSIONING

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Monticello Nuclear Generating Plant – Scenario 5 .....J-5

Table J-1
Monticello Nuclear Generating Plant
ISFSI Decommissioning Cost Estimate
Scenarios 1 and 6
(thousands of 2017 dollars)

Activity Description	Decon Costs	Removal Costs	Packaging Costs	Transport Costs	LLRW Disposal Costs	Other Costs	Total Costs	Burial Volume Class A (cubic feet)	Craft Manhours	Oversight and Contractor Manhours
Decommissioning Contractor										
Planning (characterization, specs and procedures)	-	-	-	-	-	241	241	-	-	1,072
Decontamination (activated disposition)	-	131	3	784	8,058	-	8,976	27,284	965	-
License Termination (radiological surveys)	-	-	-	-	-	1,245	1,245	-	10,057	-
Subtotal	**-**	**131**	**3**	**784**	**8,058**	**1,486**	**10,462**	**27,284**	**11,022**	**1,072**
Supporting Costs										
NRC and NRC Contractor Fees and Costs	-	-	-	-	-	364	364	-	-	776
Insurance	-	-	-	-	-	110	110	-	-	-
Property taxes	-	-	-	-	-	226	226	-	-	-
Plant energy budget	-	-	-	-	-	-	-	-	-	-
Fixed Overhead	-	-	-	-	-	82	82	-	-	-
Railroad Track Maintenance	-	-	-	-	-	38	38	-	-	-
Security Staff Cost	-	-	-	-	-	308	308	-	-	4,999
Oversight Staff	-	-	-	-	-	260	260	-	-	3,792
Subtotal	**-**	**-**	**-**	**-**	**-**	**1,389**	**1,389**	**-**	**-**	**9,568**
Total (w/o contingency)	**-**	**131**	**3**	**784**	**8,058**	**2,875**	**11,852**	**27,284**	**11,022**	**10,640**
Total (w/25% contingency)							**14,815**			

The application of contingency (25%) is consistent with the evaluation criteria referenced by the NRC in NUREG-1757 ("Consolidated Decommissioning Guidance, Financial Assurance, Recordkeeping, and Timeliness," U.S. NRC's Office of Nuclear Material Safety and Safeguards, NUREG-1757, Vol. 3, Rev. 1, February 2012)

Table J-2
Monticello Nuclear Generating Plant
ISFSI Decommissioning Cost Estimate
Scenarios 2 and 7
(thousands of 2017 dollars)

Activity Description	Decon Costs	Removal Costs	Packaging Costs	Transport Costs	LLRW Disposal Costs	Other Costs	Total Costs	Burial Volume Class A (cubic feet)	Craft Manhours	Oversight and Contractor Manhours
Decommissioning Contractor										
Planning (characterization, specs and procedures)	-	-	-	-	-	241	241	-	-	1,072
Decontamination (activated disposition)	-	131	3	784	8,058	-	8,976	27,284	965	-
License Termination (radiological surveys)	-	-	-	-	-	1,259	1,259	-	10,196	-
Subtotal	**-**	**131**	**3**	**784**	**8,058**	**1,500**	**10,476**	**27,284**	**11,160**	**1,072**
Supporting Costs										
NRC and NRC Contractor Fees and Costs	-	-	-	-	-	364	364	-	-	776
Insurance	-	-	-	-	-	110	110	-	-	-
Property taxes	-	-	-	-	-	244	244	-	-	-
Plant energy budget	-	-	-	-	-	-	-	-	-	-
Fixed Overhead	-	-	-	-	-	82	82	-	-	-
Railroad Track Maintenance	-	-	-	-	-	38	38	-	-	-
Security Staff Cost	-	-	-	-	-	308	308	-	-	4,999
Oversight Staff	-	-	-	-	-	260	260	-	-	3,792
Subtotal	**-**	**-**	**-**	**-**	**-**	**1,407**	**1,407**	**-**	**-**	**9,568**
Total (w/o contingency)	**-**	**131**	**3**	**784**	**8,058**	**2,907**	**11,883**	**27,284**	**11,160**	**10,640**
Total (w/25% contingency)							**14,854**			

The application of contingency (25%) is consistent with the evaluation criteria referenced by the NRC in NUREG-1757 ("Consolidated Decommissioning Guidance, Financial Assurance, Recordkeeping, and Timeliness," U.S. NRC's Office of Nuclear Material Safety and Safeguards, NUREG-1757, Vol. 3, Rev. 1, February 2012)

Table J-3
Monticello Nuclear Generating Plant
ISFSI Decommissioning Cost Estimate
Scenarios 3 and 4
(thousands of 2017 dollars)

Activity Description	Decon Costs	Removal Costs	Packaging Costs	Transport Costs	LLRW Disposal Costs	Other Costs	Total Costs	Burial Volume Class A (cubic feet)	Craft Manhours	Oversight and Contractor Manhours
Decommissioning Contractor										
Planning (characterization, specs and procedures)	-	-	-	-	-	241	241	-	-	1,072
Decontamination (activated disposition)	30	2	6	14	208	-	260	834	365	-
License Termination (radiological surveys)	-	-	-	-	-	1,262	1,262	-	10,268	-
Subtotal	**30**	**2**	**6**	**14**	**208**	**1,503**	**1,763**	**834**	**10,633**	**1,072**
Supporting Costs										
NRC and NRC Contractor Fees and Costs	-	-	-	-	-	364	364	-	-	776
Insurance	-	-	-	-	-	110	110	-	-	-
Property taxes	-	-	-	-	-	244	244	-	-	-
Plant energy budget	-	-	-	-	-	-	-	-	-	-
Fixed Overhead	-	-	-	-	-	82	82	-	-	-
Railroad Track Maintenance	-	-	-	-	-	38	38	-	-	-
Security Staff Cost	-	-	-	-	-	308	308	-	-	4,999
Oversight Staff	-	-	-	-	-	260	260	-	-	3,792
Subtotal	**-**	**-**	**-**	**-**	**-**	**1,407**	**1,407**	**-**	**-**	**9,568**
Total (w/o contingency)	**30**	**2**	**6**	**14**	**208**	**2,909**	**3,170**	**834**	**10,633**	**10,640**
Total (w/25% contingency)							**3,962**			

The application of contingency (25%) is consistent with the evaluation criteria referenced by the NRC in NUREG-1757 ("Consolidated Decommissioning Guidance, Financial Assurance, Recordkeeping, and Timeliness," U.S. NRC's Office of Nuclear Material Safety and Safeguards, NUREG-1757, Vol. 3, Rev. 1, February 2012)

Table J-4
Monticello Nuclear Generating Plant
ISFSI Decommissioning Cost Estimate
Scenario 5
(thousands of 2017 dollars)

Activity Description	Decon Costs	Removal Costs	Packaging Costs	Transport Costs	LLRW Disposal Costs	Other Costs	Total Costs	Burial Volume Class A (cubic feet)	Craft Manhours	Oversight and Contractor Manhours
Decommissioning Contractor										
Planning (characterization, specs and procedures)	-	-	-	-	-	241	241	-	-	1,072
Decontamination (activated disposition)	30	133	8	788	8,078	-	9,036	27,473	1,324	-
License Termination (radiological surveys)	-	-	-	-	-	1,259	1,259	-	10,196	-
Subtotal	**30**	**133**	**8**	**788**	**8,078**	**1,500**	**10,536**	**27,473**	**11,519**	**1,072**
Supporting Costs										
NRC and NRC Contractor Fees and Costs	-	-	-	-	-	364	364	-	-	776
Insurance	-	-	-	-	-	110	110	-	-	-
Property taxes	-	-	-	-	-	244	244	-	-	-
Plant energy budget	-	-	-	-	-	-	-	-	-	-
Fixed Overhead	-	-	-	-	-	82	82	-	-	-
Railroad Track Maintenance	-	-	-	-	-	38	38	-	-	-
Security Staff Cost	-	-	-	-	-	308	308	-	-	4,999
Oversight Staff	-	-	-	-	-	260	260	-	-	3,792
Subtotal	**-**	**-**	**-**	**-**	**-**	**1,407**	**1,407**	-	-	**9,568**
Total (w/o contingency)	**30**	**133**	**8**	**788**	**8,078**	**2,907**	**11,943**	**27,473**	**11,519**	**10,640**
Total (w/25% contingency)							**14,929**			

The application of contingency (25%) is consistent with the evaluation criteria referenced by the NRC in NUREG-1757 ("Consolidated Decommissioning Guidance, Financial Assurance, Recordkeeping, and Timeliness," U.S. NRC's Office of Nuclear Material Safety and Safeguards, NUREG-1757, Vol. 3, Rev. 1, February 2012)

CERTIFICATE OF SERVICE

I, Lynnette Sweet, hereby certify that I have this day served copies or summaries of the foregoing document on the attached list of persons.

xx by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States Mail at Minneapolis, Minnesota

xx electronic filing

Docket No. E002/M-14-761
Xcel Energy's Miscellaneous Electric Service List

Dated this 1st day of December 2017

/s/

Lynnette Sweet
Regulatory Administrator

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Document X01-1725-001, Rev. 0

DECOMMISSIONING COST ANALYSIS

for the

PRAIRIE ISLAND NUCLEAR GENERATING PLANT

prepared for

Xcel Energy

prepared by

TLG Services, Inc.
Bridgewater, Connecticut

October 2017

APPROVALS

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Project Engineer	**Jeffrey M. Martin**	**Date** 10/17/17
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EXECUTIVE SUMMARY

This report presents estimates of the cost to decommission the Prairie Island Nuclear Generating Plant (Prairie Island) for the identified decommissioning scenarios following a cessation of plant operations and the operation and eventual decommissioning of the on-site Independent Spent Fuel Storage Installation (ISFSI). The estimates are designed to provide Xcel Energy with the information to assess its current decommissioning liability, as it relates to Prairie Island.

The analysis relies upon site-specific, technical information from an evaluation prepared in 2014,[1] updated to reflect current assumptions pertaining to the disposition of the nuclear plant and relevant industry experience in undertaking such projects. The costs are based on several key assumptions in areas of regulation, component characterization, high-level radioactive waste management, low-level radioactive waste disposal, performance uncertainties (contingency) and site restoration requirements.

The analysis is not a detailed engineering evaluation, but an estimate prepared in advance of the detailed engineering required to carry out the decommissioning of the nuclear units. It may also not reflect the actual plan to decommission Prairie Island; the plan may differ from the assumptions made in this analysis based on facts that exist at the time of decommissioning.

The primary goal of the decommissioning is the removal and disposal of the contaminated systems and structures so that the plant's operating licenses can be terminated. The analysis recognizes that spent fuel will be stored at the site in the plant's storage pool and/or in an Independent Spent Fuel Storage Installation (ISFSI) until such time that it can be transferred to a Department of Energy (DOE) facility. Consequently, the estimates also include those costs to manage and subsequently decommission these storage facilities.

The current cost estimates assume that Prairie Island Unit 1 ceases operations in 2033, and 2034 for Unit 2. The cost estimates assume that the shutdown dates of the nuclear units are scheduled and pre-planned (i.e., there is no delay in transitioning the plant and workforce from operations or in obtaining regulatory relief from operating requirements, etc.). This estimate includes additional resources to support the engineering, planning, and licensing efforts for the station; this is done to support a decommissioning schedule similar to the prior estimate. The estimates include the continued operation of the auxiliary building as an interim wet fuel storage facility for

1 "Decommissioning Cost Analysis for the Prairie Island Nuclear Generating Plant," Document No. X01-1617-007, Rev. 0, TLG Services, Inc., September 2014

approximately five years after operations cease. The spent fuel will remain in the ISFSI until the DOE is able to complete the transfer of the fuel to a federal facility (e.g., a monitored retrievable storage facility).[2] The estimates also include the dismantling of non-essential structures and limited restoration of the site.

The costs to decommission Prairie Island, for the scenarios evaluated, are tabulated at the end of this section. Costs are reported in 2017 dollars and include monies anticipated to be spent for radiological remediation and operating license termination, spent fuel management, and site restoration activities.

A complete discussion of the assumptions relied upon in this analysis is provided in Section 3, along with schedules of annual expenditures for each scenario. A sequence of significant project activities is provided in Section 4 with a timeline for each scenario. Detailed cost reports used to generate the summary tables contained within this document are provided in Appendices C through J.

Alternatives and Regulations

The ultimate objective of the decommissioning process is to reduce the inventory of contaminated and activated material so that the licenses can be terminated. The Nuclear Regulatory Commission (NRC or Commission) provided initial decommissioning requirements in its rule adopted on June 27, 1988.[3] In this rule, the NRC set forth technical and financial criteria for decommissioning licensed nuclear power facilities. The regulations addressed planning needs, timing, funding methods, and environmental review requirements for decommissioning. The rule also defined three decommissioning alternatives as being acceptable to the NRC: DECON, SAFSTOR, and ENTOMB.

> DECON is defined as "the alternative in which the equipment, structures, and portions of a facility and site containing radioactive contaminants are removed or decontaminated to a level that permits the property to be released for unrestricted use shortly after cessation of operations."[4]

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2 Projected expenditures for spent fuel management identified in the cost analysis do not consider any compensation for damages with regard to the delays incurred by Xcel Energy in the timely removal of spent fuel by the DOE.

3 U.S. Code of Federal Regulations, Title 10, Parts 30, 40, 50, 51, 70 and 72, "General Requirements for Decommissioning Nuclear Facilities," Nuclear Regulatory Commission, 53 Fed. Reg. 24018, June 27, 1988

4 Ibid. Page FR24022, Column 3

SAFSTOR is defined as "the alternative in which the nuclear facility is placed and maintained in a condition that allows the nuclear facility to be safely stored and subsequently decontaminated (deferred decontamination) to levels that permit release for unrestricted use."[5] Decommissioning is to be completed within 60 years, although longer time periods will be considered when necessary to protect public health and safety.

ENTOMB is defined as "the alternative in which radioactive contaminants are encased in a structurally long-lived material, such as concrete; the entombed structure is appropriately maintained and continued surveillance is carried out until the radioactivity decays to a level permitting unrestricted release of the property."[6] As with the SAFSTOR alternative, decommissioning is currently required to be completed within 60 years, although longer time periods will also be considered when necessary to protect public health and safety.

The 60-year restriction has limited the practicality for the ENTOMB alternative at commercial reactors that generate significant amounts of long-lived radioactive material. In 1997, the Commission directed its staff to re-evaluate this alternative and identify the technical requirements and regulatory actions that would be necessary for entombment to become a viable option. The resulting evaluation provided several recommendations, however, rulemaking has been deferred based upon several factors (e.g., no licensee has committed to pursuing the entombment option, the unresolved issues associated with the disposition of greater-than-Class C material (GTCC), and the NRC's current priorities) at least until after the additional research studies are complete. The Commission concurred with the staff's recommendation. In a draft regulatory basis document published in March 2017 in support of rulemaking that would amend NRC regulations concerning nuclear plant decommissioning, the NRC staff proposes removing any discussion of the ENTOMB option from existing guidance documents since the method is not deemed practically feasible.

In 1996, the NRC published revisions to its general requirements for decommissioning nuclear power plants to clarify ambiguities and codify procedures and terminology as a means of enhancing efficiency and uniformity in the decommissioning process.[7] The amendments allow for greater public participation and better define the transition

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5 Ibid.

6 Ibid. Page FR24023, Column 2

7 U.S. Code of Federal Regulations, Title 10, Parts 2, 50 and 51, "Decommissioning of Nuclear Power Reactors," Nuclear Regulatory Commission, 61 Fed. Reg. 39278, July 29, 1996

process from operations to decommissioning. Regulatory Guide 1.184 Revision 1, issued in October 2013, further described the methods and procedures that are acceptable to the NRC staff for implementing the requirements of the 1996 revised rule that relate to the initial activities and the major phases of the decommissioning process. The costs and schedules presented in this analysis follow the general guidance and sequence in the amended regulations. The format and content of the estimates is also consistent with the recommendations of Regulatory Guide 1.202, issued February 2005.[8]

In 2011, the NRC published amended regulations to improve decommissioning planning and thereby reduce the likelihood that any current operating facility will become a legacy site.[9] The amended regulations require licensees to conduct their operations to minimize the introduction of residual radioactivity into the site, which includes the site's subsurface soil and groundwater. Licensees also may be required to perform site surveys to determine whether residual radioactivity is present in subsurface areas and to keep records of these surveys with records important for decommissioning. The amended regulations require licensees to report additional details in their decommissioning cost estimate as well as requiring additional financial reporting and assurances. These additional details are included in this analysis, including the ISFSI decommissioning estimate (Appendix J).

Decommissioning Scenarios

The following scenarios were evaluated and are intended to bound the liability associated with the removal of spent fuel from the site. The current operating licenses expires in 2033 and 2034 for Units 1 and 2, respectively. The scenarios consist of five DECON scenarios, with differing spent fuel management assumptions, but essentially no changes to the decommissioning costs and timing of the power block. There are also two SAFSTOR scenarios (Scenarios 6 and 7) each corresponding to the first two DECON scenario spent fuel management assumptions. The spent fuel in the plant's spent fuel storage pool is transferred to the ISFSI within the first five years. The equipment, structures, and portions of the plant containing radioactive contaminants are removed or decontaminated to a level that permits the facility to be released for unrestricted use. Non-essential structures are then demolished. Spent fuel storage operations continue at the ISFSI until the transfer of the fuel to the DOE is completed (2064 in Scenarios 1 & 6, 2077 in Scenarios 2, 5 & 7, 2117 in Scenario 3, and 2217 in Scenario 4).

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8 "Standard Format and Content of Decommissioning Cost Estimates for Nuclear Power Reactors," Regulatory Guide 1.202, Nuclear Regulatory Commission, February 2005

9 U.S. Code of Federal Regulations, Title 10, Parts 20, 30, 40, 50, 70, and 72, "Decommissioning Planning," Nuclear Regulatory Commission, Federal Register Volume 76, (p 35512 et seq.), June 17, 2011

Scenario	1st Spent Fuel Canister Replacement	1st Spent Fuel Assembly Removed from Prairie Island	Last Spent Fuel Assembly Removed from Prairie Island	Scenario Identification
1	n/a	2027	2064	DECON with 32 Year DFS+
2	n/a	2053	2077	DECON with 60 Year DFS
3	2045	2093	2117	DECON with 100 Year DFS
4	2045	2193	2217	DECON with 200 Year DFS
5	2045	2053	2077	DECON with 60 Year DFS and recasking
6	n/a	2027	2064	SAFSTOR with 32 Year DFS
7	n/a	2053	2077	SAFSTOR with 60 Year DFS

+ Dry Fuel Storage

For Scenarios 1 and 6, although they only provide a total fuel storage period of 32 years following plant shutdown, some of the Prairie Island casks have been in storage since 1995. Xcel Energy directed TLG Services to not include the cost of transferring the spent fuel in dry storage to new canisters for those casks that exceed 50 years. The assumption to not transfer spent fuel at 50 years total storage duration for these two scenarios was premised on the likelihood that the life of the canisters could be successfully managed for the additional years.

For Scenarios 2 and 7, although they provide a total fuel storage period of 60 years following plant shutdown, Xcel Energy directed TLG Services to not include the cost of transferring the spent fuel in dry storage to new canisters at 50 years after plant shutdown.

In Scenarios 3, 4 and 5, the DSCs are assumed to be replaced after fifty years of use. Since the auxiliary building spent fuel storage pool and fuel handling facilities are removed by the year 2040, a dry fuel transfer facility is assumed to be constructed on site to perform the transfers from the old to the new DSCs. For Scenarios 3 and 5, only one such transfer is needed over the time frame assumed (some fuel canisters in Scenario 5 will not require recasking). For Scenario 4, the spent fuel will be transferred three times following initial placement in the ISFSI.

Methodology

The methodology used to develop the estimates follows the basic approach originally presented in the cost estimating guidelines[10] developed by the Atomic Industrial Forum (now Nuclear Energy Institute). This reference describes a unit cost factor method for estimating decommissioning activity costs. The unit cost factors used in this analysis incorporate site-specific costs and the latest available information about worker productivity in decommissioning.

An activity duration critical path is used to determine the total decommissioning program schedule. This is required for calculating the carrying costs, which include program management, administration, field engineering, equipment rental, quality assurance, and security. This systematic approach for assembling decommissioning estimates ensures a high degree of confidence in the reliability of the resulting costs.

The estimates also reflect lessons learned from previously completed decommissioning projects, including TLG's involvement in the Shippingport Station decommissioning, completed in 1989, and the decommissioning of the Cintichem reactor, hot cells and associated facilities, completed in 1997. In addition, the planning and engineering for the Pathfinder, Shoreham, Rancho Seco, Trojan, Yankee Rowe, Big Rock Point, Maine Yankee, Humboldt Bay-3, Oyster Creek, Connecticut Yankee, Crystal River, Vermont Yankee and Fort Calhoun nuclear units have provided additional insight into the process, the regulatory aspects, and the technical challenges of decommissioning commercial nuclear units.

Contingency

Consistent with cost estimating practice, contingencies are applied to the decontamination and dismantling costs developed as "specific provision for unforeseeable elements of cost within the defined project scope, particularly important where previous experience relating estimates and actual costs has shown that unforeseeable events which will increase costs are likely to occur."[11] The cost elements in the estimates are based on ideal conditions; therefore, the types of unforeseeable events that are almost certain to occur in decommissioning, based on industry experience, are addressed through a percentage contingency applied on a line-item basis. This contingency factor is a nearly universal element in all large-scale construction and demolition projects. It should be noted that contingency, as used in

10 T.S. LaGuardia et al., "Guidelines for Producing Commercial Nuclear Power Plant Decommissioning Cost Estimates," AIF/NESP-036, May 1986

11 Project and Cost Engineers' Handbook, Second Edition, American Association of Cost Engineers, Marcel Dekker, Inc., New York, New York, p. 239

this analysis, does not account for price escalation and inflation in the cost of decommissioning over the remaining operating life of the station, or duration of the decommissioning program and dry fuel storage period.

Contingency funds are expected to be fully expended throughout the program. As such, inclusion of contingency is necessary to provide assurance that sufficient funding will be available to accomplish the intended tasks.

Low-Level Radioactive Waste Disposal

The contaminated and neutron-activated material generated in the decontamination and dismantling of a commercial nuclear reactor is classified as low-level (radioactive) waste, although not all of the material is suitable for "shallow-land" disposal. With the passage of the "Low-Level Radioactive Waste Policy Act" in 1980,[12] and its Amendments of 1985,[13] the states became ultimately responsible for the disposition of low-level radioactive waste generated within their own borders. It was expected that groups of states would combine together to jointly deal with their radioactive wastes; these organizations are referred to as waste disposal compacts.

With the exception of Texas, no new compact facilities have been successfully sited, licensed, and constructed. The Texas Compact disposal facility is now operational and waste is being accepted from generators within the Compact by the operator, Waste Control Specialists (WCS). The facility is also able to accept limited quantities of non-Compact waste.

Disposition of the various waste streams produced by the decommissioning process considered all options and services currently available to Xcel Energy. The majority of the low-level radioactive waste designated for direct disposal (Class A[14]) can be sent to Energy*Solutions*' facility in Clive, Utah. Therefore, disposal costs for Class A waste were based upon representative rates. This facility is not licensed to receive the higher activity portion (Classes B and C) of the decommissioning waste stream.

The Texas facility is licensed to receive the higher activity waste forms (Classes B and C). As such, for this analysis, disposal costs for the Class B and C waste were based upon the preliminary and indicative information on the cost for such from WCS.

12 "Low-Level Radioactive Waste Policy Act," Public Law 96-573, 1980

13 "Low-Level Radioactive Waste Policy Amendments Act of 1985," Public Law 99-240, 1986

14 Waste is classified in accordance with U.S. Code of Federal Regulations, Title 10, Part 61.55

The dismantling of the components residing closest to the reactor core generates radioactive waste considered unsuitable for shallow-land disposal (i.e., low-level radioactive waste with concentrations of radionuclides that exceed the limits established by the NRC for Class C radioactive waste (GTCC)). The Low-Level Radioactive Waste Policy Amendments Act of 1985 assigned the federal government the responsibility for the disposal of this material. The Act also stated that the beneficiaries of the activities resulting in the generation of such radioactive waste bear all reasonable costs of disposing of such waste. However, to date, the federal government has not identified a cost for disposing of GTCC or a schedule for acceptance.

For purposes of this analysis, the GTCC radioactive waste is assumed to be packaged and disposed of in a similar manner as high-level waste and at a cost equivalent to that envisioned for the spent fuel. The GTCC is packaged in the same canisters used for spent fuel and either stored on site or shipped directly to a DOE facility as it is generated (depending upon the timing of the decommissioning and whether the spent fuel has been removed from the site prior to the start of decommissioning).

A significant portion of the waste material generated during decommissioning may only be potentially contaminated by radioactive materials. This waste can be analyzed on site or shipped off site to licensed facilities for further analysis, for processing and/or for conditioning/recovery. Reduction in the volume of low-level radioactive waste requiring disposal in a licensed low-level radioactive waste disposal facility can be accomplished through a variety of methods, including analyses and surveys or decontamination to isolate the portion of waste that does not require disposal as radioactive waste, compaction, incineration or metal melt. The estimates reflect the savings from waste recovery/volume reduction.

<u>High-Level Radioactive Waste Management</u>

Congress passed the "Nuclear Waste Policy Act"[15] (NWPA) in 1982, assigning the federal government's long-standing responsibility for disposal of the spent nuclear fuel created by the commercial nuclear generating plants to the DOE. The NWPA provided that DOE would enter into contracts with utilities in which DOE would promise to take the utilities' spent fuel and high-level radioactive waste and utilities would pay the cost of the disposition services for that material. NWPA, along with the individual contracts with the utilities, specified that the DOE was to begin accepting spent fuel by January 31, 1998.

15 "Nuclear Waste Policy Act of 1982 and Amendments," DOE's Office of Civilian Radioactive Management, 1982

Since the original legislation, the DOE has announced several delays in the program schedule. By January 1998, the DOE had failed to accept any spent fuel or high-level waste, as required by the NWPA and utility contracts. Delays continue and, as a result, generators have initiated legal action against the DOE in an attempt to obtain compensation for DOE's partial breach of contract. To date no spent fuel has been accepted from commercial generating sites for disposal.

In 2010 the Obama Administration appointed a Blue Ribbon Commission on America's Nuclear Future (Blue Ribbon Commission) to make recommendations for a new plan for nuclear waste disposal. The Blue Ribbon Commission's charter includes a requirement that it consider "[o]ptions for safe storage of used nuclear fuel while final disposition pathways are selected and deployed."[16]

On January 26, 2012, the Blue Ribbon Commission issued its "Report to the Secretary of Energy" containing a number of recommendations on nuclear waste disposal. Two of the recommendations that may impact decommissioning planning are:

- "[T]he United States [should] establish a program that leads to the timely development of one or more consolidated storage facilities"[17]
- "[T]he United States should undertake an integrated nuclear waste management program that leads to the timely development of one or more permanent deep geological facilities for the safe disposal of spent fuel and high-level nuclear waste."[18]

In January 2013, the DOE issued the "Strategy for the Management and Disposal of Used Nuclear Fuel and High-Level Radioactive Waste," in response to the recommendations made by the Blue Ribbon Commission and as "a framework for moving toward a sustainable program to deploy an integrated system capable of transporting, storing, and disposing of used nuclear fuel..."[19] This document states:

"With the appropriate authorizations from Congress, the Obama Administration planned to implement a program over the next 10 years that would have:

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16 Charter of the Blue Ribbon Commission on America's Nuclear Future, "Objectives and Scope of Activities," 2010

17 "Blue Ribbon Commission on America's Nuclear Future, Report to the Secretary of Energy,", p. 32, January 2012

18 Ibid., p.27

19 "Strategy for the Management and Disposal of Used Nuclear Fuel and High-Level Radioactive Waste," U.S. DOE, January 11, 2013

- Sites, designs and licenses, constructs and begins operations of a pilot interim storage facility by 2021 with an initial focus on accepting used nuclear fuel from shut-down reactor sites;
- Advances toward the siting and licensing of a larger interim storage facility to be available by 2025 that will have sufficient capacity to provide flexibility in the waste management system and allows for acceptance of enough used nuclear fuel to reduce expected government liabilities; and
- Makes demonstrable progress on the siting and characterization of repository sites to facilitate the availability of a geologic repository by 2048."[20]

The NRC's review of DOE's license application to construct a geologic repository at Yucca Mountain was suspended in 2011 when the Obama Administration slashed the budget for completing that work. However, the US Court of Appeals for the District of Columbia Circuit issued a writ of mandamus (in August 2013) [21] ordering NRC to comply with federal law and restart its review of DOE's Yucca Mountain repository license application to the extent of previously appropriated funding for the review. That review is now complete with the publication of the five-volume safety evaluation report. A supplement to DOE's environmental impact statement and an adjudicatory hearing on the contentions filed by interested parties must be completed before a licensing decision can be made.

The state of Minnesota directed the Public Utilities Commission, "when considering approval of a plan for the accrual of funds for the decommissioning of nuclear facilities" …to "include an evaluation of the costs, if any, arising from storage of used nuclear fuel that may be incurred by the state of Minnesota, and any tribal community, county, city, or township where used nuclear fuel is located following the cessation of operations at a nuclear plant."[22]

The state of Minnesota statute also prescribed the parameters to be used in evaluating spent fuel management costs. "To assist the commission in making the determination … the filing shall provide cost estimates, including ratepayer impacts, assuming used

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20 Ibid., p.2

21 United States Court of Appeals for the District Of Columbia Circuit, In Re: Aiken County, et al, August 2013

22 Minnesota Statute 216B.1614, "Nuclear Power Plant Decommissioning and Storage of Used Nuclear Fuel"

nuclear fuel will be stored in the state for 60 years, 100 years, and 200 years following the cessation of operation of the nuclear plant." [23]

Xcel Energy's current spent fuel management plan for the Prairie Island spent fuel is based in general upon:

1) Fuel transferred from the pool to the ISFSI within 5 years of shutdown;
2) Exchange of Prairie Island and Monticello spent fuel acceptance rights to best manage the overall cost of spent fuel storage for both plants;
3) Fuel will be shipped in the existing NUHOMS DSCs (Scenarios 1, 2, 6, and 7); the canisters and NUHOMS are periodically replaced in Scenarios 3, 4 and 5. Canisters that are unloaded in the spent fuel transfer operation will be surveyed for neutron activation.
4) As an allowance, some of these canisters and NUHOMS modules from the first off-load operation are assumed to be mildly neutron activated and therefore must be disposed of as radioactive waste.

The NRC requires that licensees establish a program to manage and provide funding for the caretaking of all irradiated fuel at the reactor site until title of the fuel is transferred to the Secretary of Energy, pursuant to 10 CFR Part 50.54(bb).[24] This requirement is prepared for through inclusion of certain cost elements in the decommissioning estimates, for example, associated with the isolation and continued operation of the spent fuel pool and the ISFSI.

The spent fuel pool is expected to contain freshly discharged assemblies (from the most recent refueling cycles) as well as the final reactor cores at shutdown. The assemblies are packaged into dry shielded canisters (DSCs) over the first five years after shutdown for transfer to the ISFSI for interim storage. It is assumed that this period provides the necessary cooling for the final cores to meet the transport and/or storage requirements for decay heat.

An ISFSI, operated under a Part 72 Site Specific License (in accordance with 10 CFR 72[25]), has been constructed to support continued plant operations. The facility is assumed to be expanded to support decommissioning. This will allow decommissioning activities to proceed within the auxiliary building.

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23 Ibid.

24 U.S. Code of Federal Regulations, Title 10, Part 50, "Domestic Licensing of Production and Utilization Facilities," Subpart 54 (bb), "Conditions of Licenses"

25 U.S. Code of Federal Regulations, Title 10, Part 72.40

DOE has breached its obligations to remove fuel from reactor sites, and has also failed to provide the plant owners with information about how it will ultimately perform. DOE officials have stated that DOE does not have an obligation to accept already-canistered fuel without an amendment to DOE's contracts with plant licensees to remove the fuel (the "Standard Contract"), but DOE has not explained what any such amendment would involve. Consequently, Xcel Energy has no information or expectations on how DOE will remove fuel from the site in the future. In the absence of information about how DOE will perform, and for purposes of this analysis only, it is assumed that DOE will accept already-canistered fuel. If this assumption is incorrect, it is assumed that DOE will have liability for costs incurred to transfer the fuel to DOE-supplied containers.

Xcel Energy's position is that the DOE has a contractual obligation to accept Prairie Island's fuel earlier than the projections set out above consistent with its contract commitments. No assumption made in this study should be interpreted to be inconsistent with this claim. However, including the cost of storing spent fuel in this study is appropriate to ensure the availability of sufficient decommissioning funds at the end of the station's life if the DOE has not met its obligation. The cost for the interim storage of spent fuel has been calculated and is separately presented as "Spent Fuel Management" expenditures in this report.

Site Restoration

The efficient removal of the contaminated materials at the site may result in damage to many of the site structures. Blasting, coring, drilling, and the other decontamination activities can substantially damage power block structures, potentially weakening the footings and structural supports. It is unreasonable to anticipate that these structures would be repaired and preserved after the radiological contamination is removed. The cost to dismantle site structures with a work force already mobilized is more efficient and less costly than if the process were deferred. Experience at shutdown generating stations has shown that plant facilities quickly degrade without maintenance, adding additional expense and creating potential hazards to the public and the demolition work force.

This estimate assumes that some site features will remain following the decommissioning project. These include the existing electrical switchyard, which is assumed to remain functional in support of the regional electrical distribution system. The existing shoreline will also be left intact.

Consequently, non-essential site structures addressed by this analysis are completely removed (including foundations) as required by Minnesota statute [26].

[26] Minnesota Administrative Rule part 7035.0400 "General Requirements"

The site is then graded and stabilized. The cost for the site restoration of non-essential and/or non-contaminated structures has been calculated and is separately presented as "Site Restoration" expenditures in this report.

Summary

The costs to decommission the Prairie Island station were evaluated for several decommissioning scenarios, based upon the DECON and SAFSTOR decommissioning alternatives. Regardless of the timing of the decommissioning activities, the estimates to decommission Prairie Island assume the removal of all contaminated and activated plant components and structural materials such that Xcel Energy may then have unrestricted use of the site with no further requirements for any operating license. In most of the scenarios, spent fuel remains on site following the decommissioning and site restoration of the power block structures. The spent fuel remains in storage at the site until such time that the transfer to a DOE facility can be completed. Once the transfer is complete, the storage facilities are also decommissioned.

The alternatives evaluated in this analysis are described in Section 2. The assumptions are presented in Section 3, along with schedules of annual expenditures. The major cost contributors are identified in Section 6, with detailed activity costs, waste volumes, and associated manpower requirements delineated in Appendices C through J. The major cost components are also identified in the cost summary provided at the end of this section.

The estimates presented in this document reflects the total cost to decontaminate the nuclear units, manage the spent fuel until the DOE is able to complete the transfer to a federal facility, dismantle the plant and restore the site for alternative use.

The cost elements in the estimates for the five DECON and two SAFSTOR alternatives are assigned to one of three subcategories: NRC License Termination (radiological remediation), Spent Fuel Management, and Site Restoration. The subcategory “NRC License Termination” is used to accumulate costs that are consistent with “decommissioning” as defined by the NRC in its financial assurance regulations (i.e., 10 CFR §50.75). The cost reported for this subcategory is generally sufficient to terminate the unit’s operating license, recognizing that there may be some additional cost impact from spent fuel management. The License Termination cost subcategory also includes costs to decommission the ISFSI (as required by 10 CFR §72.30). Section 3.4.1 provides the basis for the ISFSI decommissioning cost.

The “Spent Fuel Management” subcategory contains costs associated with the containerization and transfer of spent fuel from the wet storage pool to a DOE

transport cask or to the ISFSI for interim storage, as well as the transfer of the spent fuel in storage at the ISFSI to the DOE. Costs are included for the operation of the storage pool and the management of the ISFSI until such time that the transfer is complete. It does not include any spent fuel management expenses incurred prior to the cessation of plant operations, nor does it include any costs related to the final disposal of the spent fuel.

"Site Restoration" is used to capture costs associated with the dismantling and demolition of buildings and facilities demonstrated to be free from contamination. This includes structures never exposed to radioactive materials, as well as those facilities that have been decontaminated to appropriate levels. Structures are completely removed (including foundations) and backfilled to conform to local surface elevation.

It should be noted that the costs assigned to these subcategories are allocations. Delegation of cost elements is for the purposes of comparison (e.g., with NRC financial guidelines) or to permit specific financial treatment (e.g., Asset Retirement Obligation determinations). In reality, there can be considerable interaction between the activities in the three subcategories. For example, Xcel Energy may decide to remove non-contaminated structures early in the project to improve access to highly contaminated facilities or plant components. In these instances, the non-contaminated removal costs could be reassigned from Site Restoration to an NRC License Termination support activity. However, in general, the allocations represent a reasonable accounting of those costs that can be expected to be incurred for the specific subcomponents of the total estimated program cost, if executed as described.

As noted within this document, the estimates were developed and costs are presented in 2017 dollars. As such, the estimates do not reflect the escalation of costs (due to inflationary and market forces) over the remaining operating life of the plant or during the decommissioning period.

SCENARIO 1: DECON WITH 32 YEARS DFS
DECOMMISSIONING COST ELEMENTS
(thousands of 2017 dollars)

Cost Element	Unit 1	Unit 2	Total
Decontamination	11,899	18,712	30,611
Removal	103,458	132,270	235,727
Packaging	37,613	37,981	75,594
Transportation	8,386	8,908	17,294
Waste Disposal	65,232	68,234	133,465
Off-site Waste Processing	13,548	16,016	29,565
Program Management [1]	224,195	206,995	431,191
Site Security	116,834	106,450	223,284
Spent Fuel Pool Isolation	13,445	8,963	22,409
Spent Fuel Management	120,903	118,936	239,839
Insurance and Regulatory Fees	17,840	15,425	33,266
Energy	9,248	8,349	17,597
Characterization and Licensing Surveys	17,216	19,157	36,374
Property Taxes	54,492	51,594	106,086
Miscellaneous	7,188	7,147	14,335
Railroad Track Maintenance	2,598	2,517	5,116
Retention and Severance	28,423	28,423	56,845
Security Modifications	5,000	5,000	10,000
Prairie Island Indian Community Payments	40,000	38,750	78,750
Total [3]	897,520	899,828	1,797,347

Cost Element	Unit 1	Unit 2	Total
NRC License Termination	571,980	561,832	1,133,812
Spent Fuel Management	274,479	271,262	545,741
Site Restoration	51,061	66,733	117,795
Total [3]	897,520	899,828	1,797,347

[1] Includes engineering costs

[2] Includes costs for the dry storage system components, spent fuel loading and transfer, spent fuel pool O&M and EP fees, but excludes program management costs (staffing), security and other related costs

[3] Columns may not add due to rounding

SCENARIO 2: DECON WITH 60 YEAR DFS
DECOMMISSIONING COST ELEMENTS
(thousands of 2017 dollars)

Cost Element	Unit 1	Unit 2	Total
Decontamination	11,899	18,711	30,610
Removal	103,561	132,372	235,933
Packaging	37,613	37,981	75,594
Transportation	8,386	8,908	17,294
Waste Disposal	65,232	68,234	133,465
Off-site Waste Processing	13,548	16,016	29,565
Program Management [1]	233,817	216,617	450,434
Site Security	146,769	136,385	283,153
Spent Fuel Pool Isolation	13,445	8,963	22,409
Spent Fuel Management	144,710	142,743	287,453
Insurance and Regulatory Fees	21,494	19,079	40,573
Energy	9,246	8,347	17,593
Characterization and Licensing Surveys	17,216	19,157	36,374
Property Taxes	69,785	66,180	135,965
Miscellaneous	7,187	7,145	14,332
Railroad Track Maintenance	3,461	3,380	6,841
Retention and Severance	28,423	28,423	56,845
Security Modifications	5,000	5,000	10,000
Prairie Island Indian Community Payments	56,250	55,000	111,250
Total [3]	997,041	998,643	1,995,684

Cost Element	Unit 1	Unit 2	Total
NRC License Termination	572,618	561,764	1,134,382
Spent Fuel Management	373,251	370,034	743,284
Site Restoration	51,173	66,845	118,017
Total [3]	997,041	998,643	1,995,684

[1] Includes engineering costs

[2] Includes costs for the dry storage system components, spent fuel loading and transfer, spent fuel pool O&M and EP fees, but excludes program management costs (staffing), security and other related costs

[3] Columns may not add due to rounding

SCENARIO 3: DECON WITH 100 YEAR DFS
DECOMMISSIONING COST ELEMENTS
(thousands of 2017 dollars)

Cost Element	Unit 1	Unit 2	Total
Decontamination	11,918	18,730	30,648
Removal	104,039	132,850	236,889
Packaging	37,611	37,979	75,590
Transportation	8,270	8,792	17,061
Waste Disposal	64,469	67,471	131,940
Off-site Waste Processing	13,548	16,016	29,565
Program Management [1]	294,495	277,295	571,790
Site Security	236,616	226,232	462,847
Spent Fuel Pool Isolation	13,445	8,963	22,409
Spent Fuel Management	592,003	590,037	1,182,040
Insurance and Regulatory Fees	32,742	30,327	63,069
Energy	9,246	8,347	17,593
Characterization and Licensing Surveys	17,216	19,157	36,374
Property Taxes	112,875	109,977	222,852
Miscellaneous	7,187	7,145	14,332
Railroad Track Maintenance	6,115	6,034	12,150
Retention and Severance	28,423	28,423	56,845
Security Modifications	5,000	5,000	10,000
Prairie Island Indian Community Payments	106,250	105,000	211,250
Total [3]	1,701,468	1,703,777	3,405,245

Cost Element	Unit 1	Unit 2	Total
NRC License Termination	568,261	558,114	1,126,374
Spent Fuel Management	1,082,353	1,079,137	2,161,490
Site Restoration	50,855	66,527	117,381
Total [3]	1,701,468	1,703,777	3,405,245

[1] Includes engineering costs

[2] Includes costs for the dry storage system components, spent fuel loading and transfer, spent fuel pool O&M and EP fees, but excludes program management costs (staffing), security and other related costs

[3] Columns may not add due to rounding

SCENARIO 4: DECON WITH 200 YEAR DFS
DECOMMISSIONING COST ELEMENTS
(thousands of 2017 dollars)

Cost Element	Unit 1	Unit 2	Total
Decontamination	11,918	18,730	30,648
Removal	104,037	132,849	236,887
Packaging	37,611	37,979	75,590
Transportation	8,270	8,792	17,061
Waste Disposal	64,469	67,471	131,940
Off-site Waste Processing	13,548	16,016	29,565
Program Management [1]	430,976	413,776	844,751
Site Security	466,998	456,614	923,613
Spent Fuel Pool Isolation	13,445	8,963	22,409
Spent Fuel Management	1,229,254	1,227,287	2,456,541
Insurance and Regulatory Fees	60,862	58,448	119,310
Energy	9,246	8,347	17,593
Characterization and Licensing Surveys	17,216	19,157	36,374
Property Taxes	225,076	222,177	447,253
Miscellaneous	7,187	7,145	14,332
Railroad Track Maintenance	12,752	12,671	25,422
Retention and Severance	28,423	28,423	56,845
Security Modifications	5,000	5,000	10,000
Prairie Island Indian Community Payments	231,250	230,000	461,250
Total [3]	2,977,539	2,979,847	5,957,385

Cost Element	Unit 1	Unit 2	Total
NRC License Termination	568,259	558,112	1,126,371
Spent Fuel Management	2,358,425	2,355,208	4,713,633
Site Restoration	50,855	66,527	117,381
Total [3]	2,977,539	2,979,847	5,957,385

[1] Includes engineering costs

[2] Includes costs for the dry storage system components, spent fuel loading and transfer, spent fuel pool O&M and EP fees, but excludes program management costs (staffing), security and other related costs

[3] Columns may not add due to rounding

SCENARIO 5: DECON WITH 60 YEAR DFS WITH RECASKING
DECOMMISSIONING COST ELEMENTS
(thousands of 2017 dollars)

Cost Element	Unit 1	Unit 2	Total
Decontamination	11,918	18,730	30,648
Removal	103,830	132,642	236,472
Packaging	37,614	37,982	75,596
Transportation	8,389	8,911	17,300
Waste Disposal	65,396	68,398	133,795
Off-site Waste Processing	13,548	16,016	29,565
Program Management [1]	233,817	216,617	450,434
Site Security	146,769	136,385	283,153
Spent Fuel Pool Isolation	13,445	8,963	22,409
Spent Fuel Management	230,141	228,174	458,315
Insurance and Regulatory Fees	21,494	19,079	40,573
Energy	9,246	8,347	17,593
Characterization and Licensing Surveys	17,216	19,157	36,374
Property Taxes	69,078	66,180	135,258
Miscellaneous	7,187	7,145	14,332
Railroad Track Maintenance	3,461	3,380	6,841
Retention and Severance	28,423	28,423	56,845
Security Modifications	5,000	5,000	10,000
Prairie Island Indian Community Payments	56,250	55,000	111,250
Total [3]	1,082,223	1,084,531	2,166,754

Cost Element	Unit 1	Unit 2	Total
NRC License Termination	572,323	562,164	1,134,487
Spent Fuel Management	458,457	455,241	913,698
Site Restoration	51,443	67,126	118,569
Total [3]	1,082,223	1,084,531	2,166,754

[1] Includes engineering costs

[2] Includes costs for the dry storage system components, spent fuel loading and transfer, spent fuel pool O&M and EP fees, but excludes program management costs (staffing), security and other related costs

[3] Columns may not add due to rounding

SCENARIO 6: SAFSTOR WITH 32 YEAR DFS
DECOMMISSIONING COST ELEMENTS
(thousands of 2017 dollars)

Cost Element	Unit 1	Unit 2	Total
Decontamination	7,828	16,467	24,295
Removal	108,449	137,038	245,487
Packaging	34,003	34,343	68,345
Transportation	6,683	7,171	13,854
Waste Disposal	53,612	55,346	108,959
Off-site Waste Processing	13,846	16,314	30,160
Program Management [1]	312,153	278,025	590,178
Site Security	194,238	129,474	323,713
Spent Fuel Pool Isolation	13,445	8,963	22,409
Spent Fuel Management	117,316	114,954	232,270
Insurance and Regulatory Fees	53,753	50,594	104,346
Energy	20,162	19,753	39,915
Characterization and Licensing Surveys	18,118	20,359	38,478
Property Taxes	156,602	156,387	312,989
Miscellaneous	17,651	21,979	39,630
Railroad Track Maintenance	4,362	4,281	8,644
Retention and Severance	28,423	28,423	56,845
Security Modifications	5,000	5,000	10,000
Prairie Island Indian Community Payments	40,000	38,750	78,750
Total [3]	1,205,645	1,143,621	2,349,266

Cost Element	Unit 1	Unit 2	Total
NRC License Termination	908,226	841,160	1,749,386
Spent Fuel Management	242,850	233,483	476,333
Site Restoration	54,569	68,978	123,547
Total [3]	1,205,645	1,143,621	2,349,266

[1] Includes engineering costs

[2] Includes costs for the dry storage system components, spent fuel loading and transfer, spent fuel pool O&M and EP fees, but excludes program management costs (staffing), security and other related costs

[3] Columns may not add due to rounding

SCENARIO 7: SAFSTOR WITH 60 YEAR DFS
DECOMMISSIONING COST ELEMENTS
(thousands of 2017 dollars)

Cost Element	Unit 1	Unit 2	Total
Decontamination	7,825	16,452	24,276
Removal	108,474	136,691	245,165
Packaging	34,003	34,343	68,346
Transportation	6,683	7,171	13,854
Waste Disposal	53,613	55,347	108,960
Off-site Waste Processing	13,846	16,314	30,160
Program Management [1]	313,922	284,127	598,049
Site Security	200,143	166,411	366,553
Spent Fuel Pool Isolation	13,445	8,963	22,409
Spent Fuel Management	138,784	136,422	275,207
Insurance and Regulatory Fees	54,180	50,827	105,007
Energy	20,134	19,489	39,623
Characterization and Licensing Surveys	18,118	20,359	38,478
Property Taxes	161,296	156,387	317,682
Miscellaneous	17,668	21,945	39,613
Railroad Track Maintenance	4,362	4,281	8,644
Retention and Severance	28,423	28,423	56,845
Security Modifications	5,000	5,000	10,000
Prairie Island Indian Community Payments	56,250	55,000	111,250
Total [3]	1,256,169	1,223,951	2,480,120

Cost Element	Unit 1	Unit 2	Total
NRC License Termination	883,602	846,342	1,729,944
Spent Fuel Management	317,887	308,520	626,407
Site Restoration	54,680	69,089	123,769
Total [3]	1,256,169	1,223,951	2,480,120

[1] Includes engineering costs

[2] Includes costs for the dry storage system components, spent fuel loading and transfer, spent fuel pool O&M and EP fees, but excludes program management costs (staffing), security and other related costs

[3] Columns may not add due to rounding

1. INTRODUCTION

This report presents estimates of the cost to decommission the Prairie Island Nuclear Generating Plant (Prairie Island) and the operation and eventual decommissioning of the on-site Independent Spent Fuel Storage Installation (ISFSI) for the selected decommissioning scenarios following the scheduled cessation of plant operations. The estimates are designed to provide Xcel Energy with the information to assess its current decommissioning liability, as it relates to Prairie Island.

The analysis relies upon site-specific, technical information from an earlier evaluation prepared in 2014,[1]* updated to reflect current assumptions pertaining to the disposition of the nuclear plant and relevant industry experience in undertaking such projects. The costs are based on several key assumptions in areas of regulation, component characterization, high-level radioactive waste management, low-level radioactive waste disposal, performance uncertainties (contingency) and site restoration requirements.

The analysis is not a detailed engineering evaluation, but an estimate prepared in advance of the detailed engineering required to carry out the decommissioning of the nuclear units. It may also not reflect the actual plan to decommission Prairie Island; the plan may differ from the assumptions made in this analysis based on facts that exist at the time of decommissioning.

The 2014 plant inventory was reviewed for this analysis. It serves as the basis for the decontamination and dismantling requirements, cost, and the decommissioning waste streams. The review confirmed that there were no substantive changes to the configuration of the plant or site facilities that would impact decommissioning over the last three years. Removal of new FLEX facilities was included.

1.1 OBJECTIVES OF STUDY

The objectives of this study are to prepare comprehensive estimates of the cost to decommission Prairie Island, to provide a sequence or schedule for the associated activities, and to develop waste stream projections from the decontamination and dismantling activities.

The operating licenses were originally issued for the plant in August 1973 and October 1974 for Units 1 and 2, respectively, and were valid for a period of 40

* Annotated references for citations in Sections 1-6 are provided in Section 7

years. In April 2008, Nuclear Management Company (as agent for Xcel Energy), submitted an application for renewed licenses (i.e., 20 year extensions). The application was approved by the NRC in June 2011. Therefore, for the purposes of this study, final shutdown dates (license expiration) for Unit 1 and Unit 2 are August 9, 2033 and October 29, 2034, respectively, assuming a 60-year operating life (the current operating licenses' expiration dates).

1.2 SITE DESCRIPTION

Prairie Island is located on the west bank of the Mississippi River, approximately 26 miles southeast of the Twin City Metropolitan Area and within the city limits of Red Wing. The site is in Goodhue County, Minnesota.

The Nuclear Steam Supply System (NSSS) consists of a pressurized water reactor and a two-loop reactor coolant system. The system is comprised of the reactor vessel and two closed reactor coolant loops connected in parallel to the reactor vessel, each containing a reactor coolant pump and a steam generator. An electrically heated pressurizer is connected to one of the loops.

The system is housed within the reactor containment vessel, a free-standing cylindrical steel shell with a hemispherical dome and ellipsoidal bottom designed to withstand the internal pressure accompanying a loss-of-coolant accident. The reactor containment vessel is surrounded by a cylindrical shield building constructed of reinforced concrete, which serves as a radiation shielding for normal operations and for the loss-of-coolant condition.

Heat produced in the reactor is converted to electrical energy by the plant's power conversion system. A turbine-generator converts the thermal energy of steam produced in the steam generators into mechanical shaft power and then into electrical energy. The turbine-generator consists of one high-pressure, double-flow and two low-pressure, double-flow elements driving a direct-coupled generator at 1800 rpm. The turbines are operated in a closed feedwater cycle in which the steam is condensed and returned to the steam generators by the feedwater system.

Heat rejected in the main condensers is removed by the circulating water system, which provides the heat sink for the removal of the waste heat in the power plant's thermal cycle. The majority of the heat is removed through dilution with river water in the discharge canal. Forced draft cooling towers provided supplemental heat removal.

1.3 REGULATORY GUIDANCE

The Nuclear Regulatory Commission (NRC or Commission) provided initial decommissioning requirements in its rule "General Requirements for Decommissioning Nuclear Facilities," issued in June 1988.[2] This rule set forth financial criteria for decommissioning licensed nuclear power facilities. The regulation addressed decommissioning planning needs, timing, funding methods, and environmental review requirements. The intent of the rule was to ensure that decommissioning would be accomplished in a safe and timely manner and that adequate funds would be available for this purpose. Subsequent to the rule, the NRC issued Regulatory Guide 1.159, "Assuring the Availability of Funds for Decommissioning Nuclear Reactors,[3]" which provided additional guidance to the licensees of nuclear facilities on the financial methods acceptable to the NRC staff for complying with the requirements of the rule. The regulatory guide addressed the funding requirements and provided guidance on the content and form of the financial assurance mechanisms indicated in the rule.

The rule defined three decommissioning alternatives as being acceptable to the NRC: DECON, SAFSTOR, and ENTOMB. The DECON alternative assumes that any contaminated or activated portion of the plant's systems, structures, and facilities are removed or decontaminated to levels that permit the site to be released for unrestricted use shortly after the cessation of plant operations while the SAFSTOR and ENTOMB alternatives defer the process.

The rule also placed limits on the time allowed to complete the decommissioning process. For the SAFSTOR alternative, the process is restricted in overall duration to 60 years, unless it can be shown that a longer duration is necessary to protect public health and safety. The guidelines for ENTOMB are similar, providing the NRC with both sufficient leverage and flexibility to ensure that these deferred options are only used in situations where it is reasonable and consistent with the definition of decommissioning. At the conclusion of a 50 to 60-year dormancy period (or longer for ENTOMB if the NRC approves such a case), the site would still require significant remediation to meet the unrestricted release limits for license termination.

The ENTOMB alternative has not been viewed as a viable option for power reactors due to the significant time required to isolate the long-lived radionuclides for decay to permissible levels. However, with rulemaking permitting the controlled release of a site,[4] the NRC did re-evaluate the alternative. The resulting feasibility study, based upon an assessment by Pacific Northwest National Laboratory, concluded that the method did have conditional merit for some, if not most reactors. The staff also found that

additional rulemaking would be needed before this option could be treated as a generic alternative.

The NRC had considered rulemaking to alter the 60-year time for completing decommissioning and to clarify the use of engineered barriers for reactor entombments.[5] However, the NRC's staff has recommended that rulemaking be deferred, based upon several factors, e.g., no licensee has committed to pursuing the entombment option, the unresolved issues associated with the disposition of greater-than-Class C material (GTCC), and the NRC's current priorities, at least until after the additional research studies are complete. The Commission concurred with the staff's recommendation. In a draft regulatory basis document published in March 2017 in support of rulemaking that would amend NRC regulations concerning nuclear plant decommissioning, the NRC staff proposes removing any discussion of the ENTOMB option from existing guidance documents since the method is not deemed practically feasible.

In 1996, the NRC published revisions to the general requirements for decommissioning nuclear power plants.[6] When the regulations were originally adopted in 1988, it was assumed that the majority of licensees would decommission at the end of the facility's operating licensed life. Since that time, several licensees permanently and prematurely ceased operations. Exemptions from certain operating requirements were required once the reactor was defueled to facilitate the decommissioning. Each case was handled individually, without clearly defined generic requirements. The NRC amended the decommissioning regulations in 1996 to clarify ambiguities and codify procedures and terminology as a means of enhancing efficiency and uniformity in the decommissioning process. The new amendments allow for greater public participation and better define the transition process from operations to decommissioning.

Under the revised regulations, licensees will submit written certification to the NRC within 30 days after permanent shutdown. Certification will also be required once the fuel is permanently removed from the reactor vessels. Submittal of these notices will entitle the licensee to a fee reduction and eliminate the obligation to follow certain requirements needed only during operation of the reactor. Within two years of submitting notice of permanent cessation of operations, the licensee is required to submit a Post-Shutdown Decommissioning Activities Report (PSDAR) to the NRC. The PSDAR describes the planned decommissioning activities, the associated sequence and schedule, and an estimate of expected costs. Prior to completing decommissioning, the licensee is required to submit applications to the NRC to terminate the license, which will include a License Termination Plan (LTP).

In 2011, the NRC published amended regulations to improve decommissioning planning and thereby reduce the likelihood that any current operating facility will become a legacy site.[7] The amended regulations require licensees to conduct their operations to minimize the introduction of residual radioactivity into the site, which includes the site's subsurface soil and groundwater. Licensees also may be required to perform site surveys to determine whether residual radioactivity is present in subsurface areas and to keep records of these surveys with records important for decommissioning. The amended regulations require licensees to report additional details in their decommissioning cost estimate as well as requiring additional financial reporting and assurances. These additional details, including an ISFSI decommissioning estimate, are included in this analysis.

1.3.1 High-Level Radioactive Waste Management

Congress passed the "Nuclear Waste Policy Act"[8] (NWPA) in 1982, assigning the federal government's long-standing responsibility for disposal of the spent nuclear fuel created by the commercial nuclear generating plants to the DOE. The NWPA provided that DOE would enter into contracts with utilities in which DOE would promise to take the utilities' spent fuel and high-level radioactive waste and utilities would pay the cost of the disposition services for that material. NWPA, along with the individual contracts with the utilities, specified that the DOE was to begin accepting spent fuel by January 31, 1998.

Since the original legislation, the DOE has announced several delays in the program schedule. By January 1998, the DOE had failed to accept any spent fuel or high level waste, as required by the NWPA and utility contracts. Delays continue and, as a result, generators have initiated legal action against the DOE in an attempt to obtain compensation for DOE's partial breach of contract. To date no spent fuel has been accepted from commercial generating sites for disposal.

In 2010, the Obama Administration appointed a Blue Ribbon Commission on America's Nuclear Future (Blue Ribbon Commission) to make recommendations for a new plan for nuclear waste disposal. The Blue Ribbon Commission's charter includes a requirement that it consider "[o]ptions for safe storage of used nuclear fuel while final disposition pathways are selected and deployed."[9]

On January 26, 2012, the Blue Ribbon Commission issued its "Report to the Secretary of Energy" containing a number of recommendations on

nuclear waste disposal. Two of the recommendations that may impact decommissioning planning are:

- "[T]he United States [should] establish a program that leads to the timely development of one or more consolidated storage facilities"[10]
- "[T]he United States should undertake an integrated nuclear waste management program that leads to the timely development of one or more permanent deep geological facilities for the safe disposal of spent fuel and high-level nuclear waste."

In January 2013, the DOE issued the "Strategy for the Management and Disposal of Used Nuclear Fuel and High-Level Radioactive Waste," in response to the recommendations made by the Blue Ribbon Commission and as "a framework for moving toward a sustainable program to deploy an integrated system capable of transporting, storing, and disposing of used nuclear fuel..."[11] This document states:

"With the appropriate authorizations from Congress, the Obama Administration planned to implement a program over the next 10 years that would have:

- Sites, designs and licenses, constructs and begins operations of a pilot interim storage facility by 2021 with an initial focus on accepting used nuclear fuel from shut-down reactor sites;
- Advances toward the siting and licensing of a larger interim storage facility to be available by 2025 that will have sufficient capacity to provide flexibility in the waste management system and allows for acceptance of enough used nuclear fuel to reduce expected government liabilities; and
- Makes demonstrable progress on the siting and characterization of repository sites to facilitate the availability of a geologic repository by 2048."

The NRC's review of DOE's license application to construct a geologic repository at Yucca Mountain was suspended in 2011 when the Obama Administration slashed the budget for completing that work. However, the US Court of Appeals for the District of Columbia Circuit issued a writ of mandamus (in August 2013) [12] ordering NRC to comply with federal law and restart its review of DOE's Yucca Mountain repository license application to the extent of previously appropriated funding for the review. That review is now complete with the publication of the five-

volume safety evaluation report. A supplement to DOE's environmental impact statement and an adjudicatory hearing on the contentions filed by interested parties must be completed before a licensing decision can be made.

The state of Minnesota directed the Public Utilities Commission, "when considering approval of a plan for the accrual of funds for the decommissioning of nuclear facilities" …to "include an evaluation of the costs, if any, arising from storage of used nuclear fuel that may be incurred by the state of Minnesota, and any tribal community, county, city, or township where used nuclear fuel is located following the cessation of operations at a nuclear plant."[13]

The state of Minnesota statute also prescribed the parameters to be used in evaluating spent fuel management costs. "To assist the commission in making the determination … the filing shall provide cost estimates, including ratepayer impacts, assuming used nuclear fuel will be stored in the state for 60 years, 100 years, and 200 years following the cessation of operation of the nuclear plant."

Xcel Energy's current spent fuel management plan for the Prairie Island spent fuel is based in general upon:

1) Fuel transferred from the pool to the ISFSI within 5 years of shutdown;
2) Exchange of Prairie Island and Monticello spent fuel acceptance rights to best manage the overall cost of spent fuel storage for both plants;
3) Fuel assemblies currently stored in the ISFSI use TN-40 casks. It's assumed that, starting with final shutdown, and for future recasking, that a NUHOMS system (with a capacity of 37 fuel assemblies, and similar in dimensions to the existing Monticello NUHOMS design) will be used instead of the TN-40 casks. Fuel will be shipped in the existing TN-40s or NUHOMS DSCs (Scenarios 1, 2, 6, and 7); the TN-40s are replaced with NUHOMS in Scenarios 3, 4 and 5. Canisters that are unloaded in the spent fuel transfer operation will be surveyed for neutron activation.
4) This estimate does not include any costs for replacing cask head bolts, gaskets, or installation of spacers within the existing TN-40 cask prior to shipment to DOE.

5) As an allowance, some of these canisters and NUHOMS modules from the first off-load operation are assumed to be mildly neutron activated and therefore must be disposed of as radioactive waste.

The NRC requires that licensees establish a program to manage and provide funding for the caretaking of all irradiated fuel at the reactor site until title of the fuel is transferred to the Secretary of Energy, pursuant to 10 CFR Part 50.54(bb).[14] This requirement is prepared for through inclusion of certain cost elements in the decommissioning estimates, for example, associated with the isolation and continued operation of the spent fuel pool and the ISFSI.

The spent fuel pool is expected to contain freshly discharged assemblies (from the most recent refueling cycles) as well as the final reactor cores at shutdown. In the DECON and SAFSTOR scenarios, the assemblies are packaged into dry shielded canisters (DSCs) over the first five years after shutdown for transfer to the ISFSI for interim storage. It is assumed that this period provides the necessary cooling for the final cores to meet the transport and/or storage requirements for decay heat.

An ISFSI, operated under a Part 72 Site Specific License (in accordance with 10 CFR 72[15]), has been constructed to support continued plant operations. The facility is assumed to be expanded to support decommissioning. This will allow decommissioning activities to proceed within the auxiliary building.

DOE has breached its obligations to remove fuel from reactor sites, and has also failed to provide the plant owners with information about how it will ultimately perform. DOE officials have stated that DOE does not have an obligation to accept already-canistered fuel without an amendment to DOE's contracts with plant licensees to remove the fuel (the "Standard Contract"), but DOE has not explained what any such amendment would involve. Consequently, Xcel Energy has no information or expectations on how DOE will remove fuel from the site in the future. In the absence of information about how DOE will perform, and for purposes of this analysis only, it is assumed that DOE will accept already-canistered fuel. If this assumption is incorrect, it is assumed that DOE will have liability for costs incurred to transfer the fuel to DOE-supplied containers.

Xcel Energy's position is that the DOE has a contractual obligation to accept Prairie Island's fuel earlier than the projections set out above, consistent with its contract commitments. No assumption made in this study should be interpreted to be inconsistent with this claim. However, including the cost of storing spent fuel in this study is appropriate to ensure the availability of sufficient decommissioning funds at the end of the station's life if the DOE has not met its obligation. The cost for the interim storage of spent fuel has been calculated and is separately presented as "Spent Fuel Management" expenditures in this report.

1.3.2 Low-Level Radioactive Waste Disposal

The contaminated and activated material generated in the decontamination and dismantling of a commercial nuclear reactor is classified as low-level (radioactive) waste, although not all of the material is suitable for "shallow-land" disposal. With the passage of the "Low-Level Radioactive Waste Policy Act" in 1980,[16] and its Amendments of 1985,[17] the states became ultimately responsible for the disposition of low-level radioactive waste generated within their own borders. It was expected that groups of states would combine together to jointly deal with their radioactive wastes; these organizations are referred to as waste disposal compacts.

With the exception of Texas, no new compact facilities have been successfully sited, licensed, and constructed. The Texas Compact disposal facility is now operational and waste is being accepted from generators within the Compact by the operator, Waste Control Specialists (WCS). The facility is also able to accept limited quantities of non-Compact waste.

Disposition of the various waste streams produced by the decommissioning process considered all options and services currently available to Xcel Energy. The majority of the low-level radioactive waste designated for direct disposal (Class A[18]) can be sent to Energy*Solutions*' facility in Clive, Utah. Therefore, disposal costs for Class A waste were based upon representative rates. This facility is not licensed to receive the higher activity portion (Classes B and C) of the decommissioning waste stream.

The Texas facility is licensed to receive the higher activity waste forms (Classes B and C). As such, for this analysis, disposal costs for the Class B and C waste were based upon the preliminary and indicative information on the cost for such from WCS.

The dismantling of the components residing closest to the reactor core generates radioactive waste considered unsuitable for shallow-land disposal (i.e., low-level radioactive waste with concentrations of radionuclides that exceed the limits established by the NRC for Class C radioactive waste (GTCC)). The Low-Level Radioactive Waste Policy Amendments Act of 1985 assigned the federal government the responsibility for the disposal of this material. The Act also stated that the beneficiaries of the activities resulting in the generation of such radioactive waste bear all reasonable costs of disposing of such waste. However, to date, the federal government has not identified a cost for disposing of GTCC or a schedule for acceptance.

For purposes of this analysis, the GTCC radioactive waste is assumed to be packaged and disposed of in a similar manner as high-level waste (i.e., in a geologic repository) and at a cost equivalent to that envisioned for the spent fuel. The GTCC is packaged in the same canisters used for spent fuel and either stored on site or shipped directly to a DOE facility as it is generated (depending upon the timing of the decommissioning and whether the spent fuel has been removed from the site prior to the start of decommissioning).

A significant portion of the metallic waste material generated during decommissioning may only be potentially contaminated by radioactive materials. This waste can be surveyed on site or shipped off site to licensed facilities for further analysis, for processing and/or for conditioning/recovery. Reduction in the volume of low-level radioactive waste requiring disposal in a licensed low-level radioactive waste disposal facility can be accomplished through a variety of methods, including analyses and surveys or decontamination to isolate the portion of waste that does not require disposal as radioactive waste, compaction, incineration or metal melt. The estimates reflect the savings from waste recovery/volume reduction.

1.3.3 Radiological Criteria for License Termination

In 1997, the NRC published Subpart E, "Radiological Criteria for License Termination,"[19] amending 10 CFR §20. This subpart provides radiological criteria for releasing a facility for unrestricted use. The regulation states that the site can be released for unrestricted use if radioactivity levels are such that the average member of a critical group would not receive a Total Effective Dose Equivalent (TEDE) in excess of 25 millirem per year, and provided that residual radioactivity has been reduced to levels that are As Low As Reasonably Achievable (ALARA).

The decommissioning estimates for Prairie Island assume that the site will be remediated to a residual level consistent with the NRC-prescribed level for radioactive material.

It should be noted that the NRC and the Environmental Protection Agency (EPA) differ on the amount of residual radioactivity considered acceptable in site remediation. The EPA has two limits that apply to radioactive materials. An EPA limit of 15 millirem per year is derived from criteria established by the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA or Superfund).[20] An additional and separate limit of 4 millirem per year, as defined in 40 CFR §141.66, is applied to drinking water.[21]

On October 9, 2002, the NRC signed an agreement with the EPA on the radiological decommissioning and decontamination of NRC-licensed sites. The Memorandum of Understanding (MOU)[22] provides that EPA will defer exercise of authority under CERCLA for the majority of facilities decommissioned under NRC authority. The MOU also includes provisions for NRC and EPA consultation for certain sites when, at the time of license termination, (1) groundwater contamination exceeds EPA-permitted levels; (2) NRC contemplates restricted release of the site; and/or (3) residual radioactive soil concentrations exceed levels defined in the MOU.

The MOU does not impose any new requirements on NRC licensees and should reduce the involvement of the EPA with NRC licensees who are decommissioning. Most sites are expected to meet the NRC criteria for unrestricted use, and the NRC believes that only a few sites will have groundwater or soil contamination in excess of the levels specified in the MOU that trigger consultation with the EPA. However, if there are other hazardous materials on the site, the EPA may be involved in the cleanup. As such, the possibility of dual regulation remains for certain licensees. The present study does not include any costs for this occurrence.

FIGURE 1.1
PRAIRIE ISLAND NUCLEAR GENERATING PLANT
GENERAL PLAN

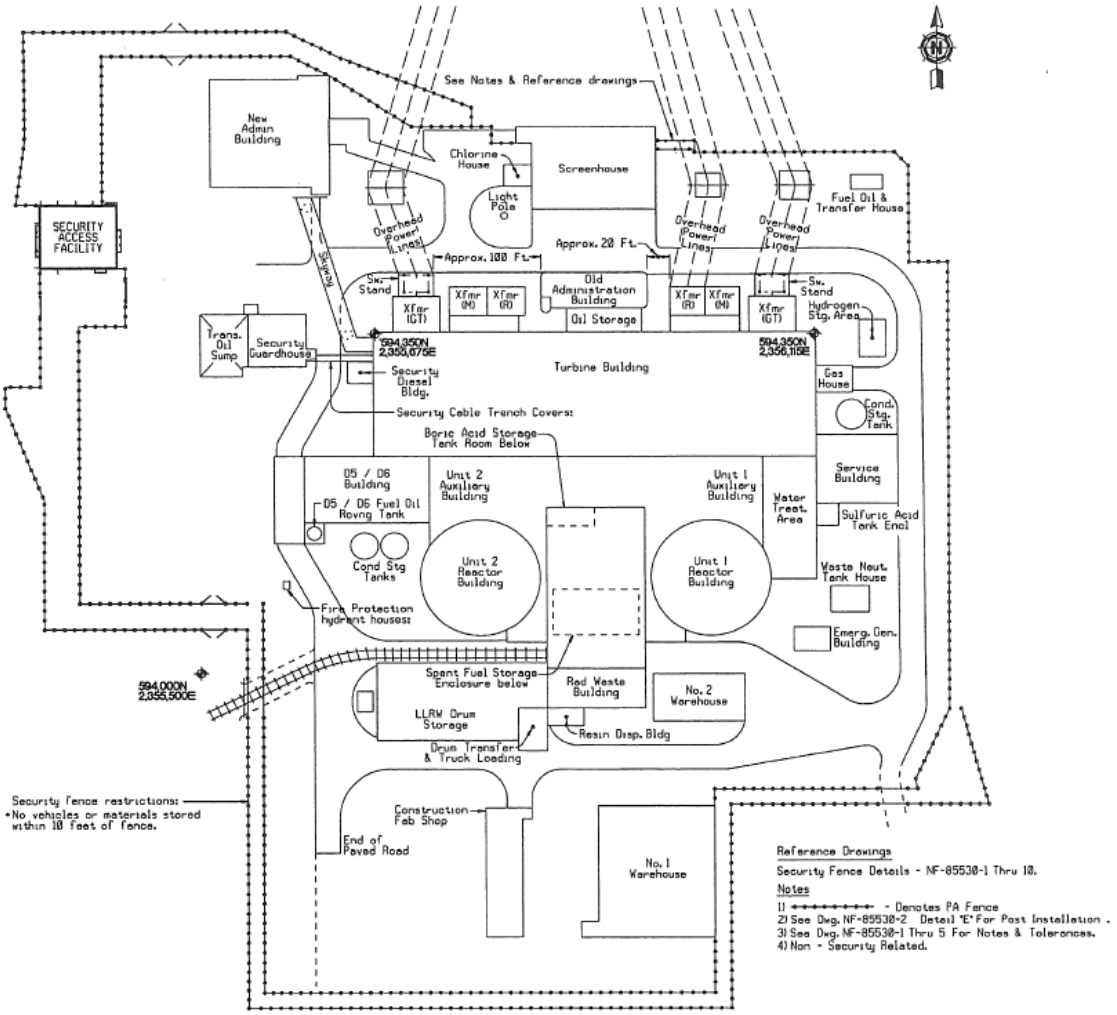
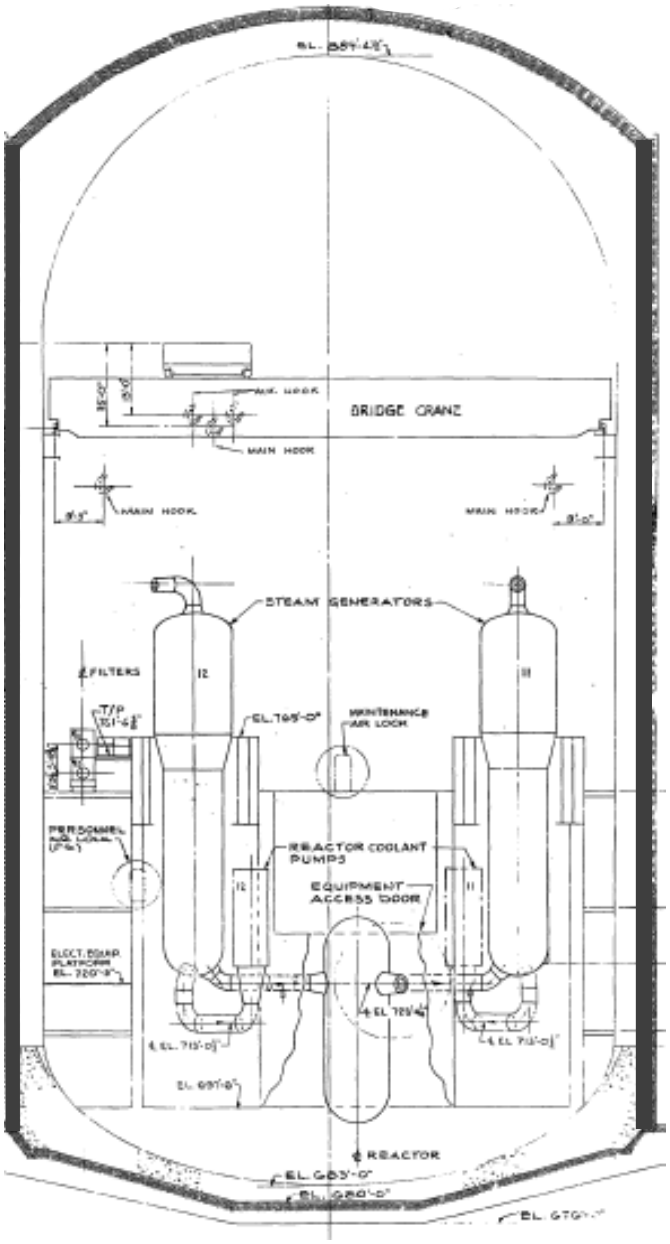


FIGURE 1.2
PRAIRIE ISLAND NUCLEAR GENERATING PLANT
AERIAL VIEW

FIGURE 1.3
PRAIRIE ISLAND NUCLEAR GENERATING PLANT
REACTOR BUILDING SECTION



2. DECOMMISSIONING ALTERNATIVES

Detailed cost estimates were developed to decommission Prairie Island based upon the approved decommissioning alternatives: DECON and SAFSTOR. Although the alternatives differ with respect to technique, process, cost, and schedule, they attain the same result: the ultimate release of the site for unrestricted use.

The following scenarios were evaluated and are intended to bound the liability associated with the removal of spent fuel from the site. The current operating licenses expire in 2033 and 2034. The scenarios consist of five DECON scenarios, with differing spent fuel management assumptions, but essentially no changes to the decommissioning costs and timing of the power block. There are also two SAFSTOR scenarios (Scenarios 6 and 7) each corresponding to the first two DECON scenario spent fuel management assumptions. The spent fuel in the plant's spent fuel storage pool is transferred to the ISFSI within the first five years. The equipment, structures, and portions of the plant containing radioactive contaminants are removed or decontaminated to a level that permits the facility to be released for unrestricted use. Non-essential structures are then demolished. Spent fuel storage operations continue at the ISFSI until the transfer of the fuel to the DOE is completed (2064 in Scenarios 1 & 6, 2077 in Scenarios 2, 5 & 7, 2117 in Scenario 3, and 2217 in Scenario 4).

Scenario	1st Spent Fuel Canister Replacement	1st Spent Fuel Assembly Removed from Prairie Island	Last Spent Fuel Assembly Removed from Prairie Island	Scenario Identification
1	n/a	2027	2064	DECON with 32 Year DFS+
2	n/a	2053	2077	DECON with 60 Year DFS
3	2045	2093	2117	DECON with 100 Year DFS
4	2045	2193	2217	DECON with 200 Year DFS
5	2045	2053	2077	DECON with 60 Year DFS and recasking
6	n/a	2027	2064	SAFSTOR with 32 Year DFS
7	n/a	2053	2077	SAFSTOR with 60 Year DFS

+ Dry Fuel Storage

For Scenarios 1 and 6, although they only provide a total fuel storage period of 32 years following plant shutdown, some of the Prairie Island casks have been in storage since 1995. Xcel Energy directed TLG Services to not include the cost of transferring the spent fuel in dry storage to new canisters for those casks that exceed 50 years. The assumption to not transfer spent fuel at 50 years total storage duration for these two scenarios was premised on the likelihood that the life of the canisters could be successfully managed for the additional years.

For Scenarios 2 and 7, although they provide a total fuel storage period of 60 years following plant shutdown, Xcel Energy directed TLG Services to not include the cost of transferring the spent fuel in dry storage to new canisters at 50 years after plant shutdown.

In Scenarios 3, 4 and 5, the DSCs are assumed to be replaced after fifty years of use. Since the auxiliary building spent fuel storage pool and fuel handling facilities are removed by the year 2040, a dry fuel transfer facility is assumed to be constructed on site to perform the transfers from the old to the new DSCs. For Scenarios 3 and 5, only one such transfer is needed over the time frame assumed (some fuel canisters in Scenario 5 will not require recasking). For Scenario 4, the spent fuel will be transferred three times following initial placement in the ISFSI.

The following sections describe the basic activities associated with each alternative. Although detailed procedures for each activity identified are not provided, and the actual sequence of work may vary, the activity descriptions provide a basis not only for estimating but also for the expected scope of work (i.e., engineering and planning at the time of decommissioning).

The conceptual approach that the NRC has described in its regulations divides decommissioning into three phases. The initial phase commences with the effective date of permanent cessation of operations and involves the transition of both plant and licensee from reactor operations (i.e., power production) to facilitate de-activation and closure. During the first phase, notification is to be provided to the NRC certifying the permanent cessation of operations and the removal of fuel from the reactor vessels. The licensee would then be prohibited from reactor operation.

The second phase encompasses activities during the storage period or during major decommissioning activities, or a combination of the two. The third phase pertains to the activities involved in license termination. The decommissioning estimates developed for Prairie Island are also divided into phases or periods; however, demarcation of the phases is based upon major milestones within the project or significant changes in the projected expenditures.

2.1 DECON

The DECON alternative, as defined by the NRC, is "the alternative in which the equipment, structures, and portions of a facility and site containing radioactive contaminants are removed or decontaminated to a level that permits the property to be released for unrestricted use shortly after cessation of operations." This study does not address the cost to dispose of the spent fuel residing at the site; such costs are funded through a surcharge on electrical generation. However, the study does estimate the costs incurred with the interim on-site storage of the fuel pending shipment by the DOE to an off-site disposal facility. Those costs are separately presented as "Spent Fuel Management" expenditures in this report.

2.1.1 Period 1 - Preparations

In anticipation of the cessation of plant operations, detailed preparations are undertaken to provide a smooth transition from plant operations to site decommissioning. Through implementation of a staffing transition plan, the organization required to manage the intended decommissioning activities is assembled from available plant staff and outside resources. Preparations include the planning for permanent defueling of the reactor, revision of technical specifications applicable to the operating conditions and requirements, a characterization of the facility and major components, and the development of the PSDAR.

Engineering and Planning

The PSDAR, required prior to, or within two years of permanent cessation of operations, provides a description of the licensee's planned decommissioning activities, a timetable, a site-specific decommissioning cost estimate, and the associated financial requirements of the intended decommissioning program. Upon receipt of the PSDAR, the NRC will make the document available to the public for comment in a local meeting to be held in the vicinity of the reactor site. Ninety days following submittal and NRC receipt of the PSDAR, the licensee may begin to perform major decommissioning activities under a modified 10 CFR §50.59 procedure, (10 CFR §50.59 establishes the conditions under which licensees may make changes to the facility or procedures and conduct test or experiments, i.e., without prior NRC approval). Major activities are defined as any activity that results in permanent removal of major radioactive components, permanently modifies the structure of the containment, or results in dismantling components (for shipment)

containing GTCC, as defined by 10 CFR §61. Major components are further defined as comprising the reactor vessel and internals, large bore reactor coolant system piping, and other large components that are radioactive. The NRC includes the following additional criteria for use of the §50.59 process in decommissioning. The proposed activity must not:

- foreclose release of the site for possible unrestricted use,
- significantly increase decommissioning costs,
- cause any significant environmental impact not previously reviewed, or
- result in there no longer being reasonable assurance that adequate funds will be available for decommissioning

Existing operational technical specifications are reviewed and modified to reflect plant conditions and the safety concerns associated with permanent cessation of operations. The environmental impact associated with the planned decommissioning activities is also considered. Typically, a licensee will not be allowed to proceed if the consequences of a particular decommissioning activity are greater than that bounded by previously evaluated environmental assessments or impact statements. In this instance, the licensee would have to submit a license amendment for the specific activity and update the environmental report.

The decommissioning program outlined in the PSDAR will be designed to accomplish the required tasks within the ALARA guidelines (as defined in 10 CFR §20) for protection of personnel from exposure to radiation hazards. It will also address the continued protection of the health and safety of the public and the environment during the dismantling activity. Consequently, with the development of the PSDAR, activity specifications, cost-benefit and safety analyses, and work packages and procedures, would be assembled to support the proposed decontamination and dismantling activities.

Site Preparations

Following final plant shutdown, and in preparation for actual decommissioning activities, the following activities are initiated:

- Characterization of the site and surrounding environs. This includes radiation surveys of work areas, major components (including the

reactor vessel and its internals), internal piping, and primary shield cores.

- An ISFSI has been constructed to support continued plant operation and will need to be expanded following the cessation of operations to offload the spent fuel pool in support of the decommissioning program.
- Isolation of the spent fuel storage pool and fuel handling systems, such that decommissioning operations can commence on the balance of the plant. Decommissioning operations are scheduled around the fuel handling area to optimize the overall project schedule. It is assumed that the fuel pool remains operational for the transfer of fuel for approximately five years following the cessation of operations.
- Specification of transport and disposal requirements for activated materials and/or hazardous materials, including shielding and waste stabilization.
- Development of procedures for occupational exposure control, control and release of liquid and gaseous effluent, processing of radwaste (including dry-active waste, resins, filter media, metallic and non-metallic components generated in decommissioning), site security and emergency programs, and industrial safety.
- Perform chemical decontamination of the NSSS to reduce radiation levels in support of removal operations

2.1.2 Period 2 - Decommissioning Operations

This period includes the physical decommissioning activities associated with the removal and disposal of contaminated and activated components and structures, including the successful amendment of the 10 CFR §50 operating licenses (releasing the site, exclusive of the ISFSI). Significant decommissioning activities in this phase include:

- Construction of temporary facilities and/or modification of existing facilities to support dismantling activities. This may include a centralized processing area to facilitate equipment removal and component preparations for off-site disposal.
- Reconfiguration and modification of site structures and facilities as needed to support decommissioning operations. This may include the upgrading of roads (on- and off-site) to facilitate hauling and transport. Modifications may be required to the containment

structure to facilitate access of large/heavy equipment. Modifications may also be required to the refueling area of the building to support the segmentation of the reactor vessel internals and component extraction.

- Transfer of the spent fuel from the storage pool to the ISFSI pad for interim storage.
- Design and fabrication of temporary and permanent shielding to support removal and transportation activities, construction of contamination control envelopes, and the procurement of specialty tooling.
- Procurement (lease or purchase) of shipping canisters, cask liners, and industrial packages.
- Decontamination of components and piping systems as required to control (minimize) worker exposure.
- Removal of piping and components no longer essential to support decommissioning operations.
- Removal of control rod drive housings and the head service structure from reactor vessel head. Segment the vessel closure head.
- Removal and segmentation of the upper internals assemblies. Segmentation will maximize the loading of the shielded transport casks, (i.e., by weight and activity). The operations are conducted under water using remotely operated tooling and contamination controls.
- Disassembly and segmentation of the remaining reactor internals, including the core former and lower core support assembly. Some material is expected to exceed Class C disposal requirements. As such, the segments will be packaged in modified spent fuel storage canisters for geologic disposal.
- Segmentation of the reactor vessel. A shielded platform is installed for segmentation as cutting operations are performed in air using remotely operated equipment within a contamination control envelope. The water level is maintained just below the cut to minimize the working area dose rates. Segments are transferred in-air to containers that are stored under water, for example, in an isolated area of the refueling canal.
- Removal of the activated portions of the concrete biological shield and accessible contaminated concrete surfaces. If dictated by the steam generator and pressurizer removal scenarios, those portions of the

associated cubicles necessary for access and component extraction are removed.

- Removal of the steam generators and pressurizer for material recovery and controlled disposal. The generators will be moved to an on-site processing center, the steam domes are removed and the internal components segregated for off-site processing. The lower shell and tube bundle will be packaged for direct disposal. These components can serve as their own burial containers provided that all penetrations are properly sealed and the internal contaminants are stabilized. Steel shielding is added, as necessary, to those external areas of the steam generators to meet transportation limits and regulations.
- Expansion of the ISFSI and transfer of the spent fuel from the storage pool to the ISFSI pad for interim storage. Spent fuel storage operations continue throughout the active decommissioning period. Fuel transfer to DOE is expected to be completed by the end of the year 2064 (Scenario 1).

At least two years prior to the anticipated date of license termination, an LTP is required. Submitted as a supplement to the Final Safety Analysis Report (FSAR) or its equivalent, the plan must include: a site characterization, description of the remaining dismantling activities, plans for site remediation, procedures for the final radiation survey, designation of the end use of the site, an updated cost estimate to complete the decommissioning, and any associated environmental concerns. The NRC will notice the receipt of the plan, make the plan available for public comment, and schedule a local meeting. LTP approval will be subject to any conditions and limitations as deemed appropriate by the Commission. The licensee may then commence with the final remediation of site facilities and services, including:

- Removal of remaining plant systems and associated components as they become nonessential to the decommissioning program or worker health and safety (e.g., waste collection and treatment systems, electrical power and ventilation systems).
- Removal of the steel liners from the refueling canal, disposing of the activated and contaminated sections as radioactive waste. Removal of any activated/contaminated concrete.
- Surveys of the decontaminated areas of the containment structure.
- Removal of the contaminated equipment and material from the auxiliary building and any other contaminated facility. Use radiation

and contamination control techniques until radiation surveys indicate that the structures can be released for unrestricted access and conventional demolition. This activity may necessitate the dismantling and disposition of most of the systems and components (both clean and contaminated) located within these buildings. This activity will facilitate surface decontamination and subsequent verification surveys required prior to obtaining release for demolition.

- Removal of the remaining components, equipment, and plant services in support of the area release survey(s).
- Routing of material removed in the decontamination and dismantling to a central processing area. Material certified to be free of contamination is released for unrestricted disposition, e.g., as scrap, recycle, or general disposal. Contaminated material is characterized and segregated for additional off-site processing (disassembly, chemical cleaning, volume reduction, and waste treatment), and/or packaged for controlled disposal at a low-level radioactive waste disposal facility.

Incorporated into the LTP is the Final Survey Plan. This plan identifies the radiological surveys to be performed once the decontamination activities are completed and is developed using the guidance provided in the "Multi-Agency Radiation Survey and Site Investigation Manual (MARSSIM)."[23] This document incorporates the statistical approaches to survey design and data interpretation used by the EPA. It also identifies commercially available instrumentation and procedures for conducting radiological surveys. Use of this guidance ensures that the surveys are conducted in a manner that provides a high degree of confidence that applicable NRC criteria are satisfied. Once the survey is complete, the results are provided to the NRC in a format that can be verified. The NRC then reviews and evaluates the information, performs an independent confirmation of radiological site conditions, and makes a determination on the requested change to the operating licenses (that would release the property, exclusive of the ISFSI, for unrestricted use).

The NRC will amend the operating licenses to reduce the licensed area to the ISFSI area if it determines that site remediation has been performed in accordance with the LTP, and that the terminal radiation survey and associated documentation demonstrate that the property (exclusive of the ISFSI) is suitable for release.

2.1.3 Period 3 - Site Restoration

Following completion of decommissioning operations, site restoration activities will begin. Efficient removal of the contaminated materials and verification that residual radionuclide concentrations are below the NRC limits will result in substantial damage to many of the structures. Although performed in a controlled and safe manner, blasting, coring, drilling, scarification (surface removal), and the other decontamination activities will substantially degrade power block structures including the reactor and auxiliary buildings. Under certain circumstances, verifying that subsurface radionuclide concentrations meet NRC site release requirements will require removal of grade slabs and lower floors, potentially weakening footings and structural supports. This removal activity will be necessary for those facilities and plant areas where historical records, when available, indicate the potential for radionuclides having been present in the soil, where system failures have been recorded, or where it is required to confirm that subsurface process and drain lines were not breached over the operating life of the station.

Dismantling of site structures following decommissioning is clearly the most appropriate and cost-effective option. It is unreasonable to anticipate that these structures would be repaired and preserved after the radiological contamination is removed. The effort to dismantle site structures with a work force already mobilized on site is more efficient than if the process were deferred. Site facilities quickly degrade without maintenance, adding additional expense and creating potential hazards to the public as well as to future workers. Abandonment creates a breeding ground for vermin infestation as well as other biological hazards.

This cost study presumes that non-essential structures and site facilities are dismantled as a continuation of the decommissioning activity. Foundations and exterior walls are completely removed, including foundations and basemats as required by Minnesota regulations. [24] Site areas affected by the dismantling activities are restored and the plant area graded as required to prevent ponding, establish erosion control by the planting of native vegetation, and inhibit the refloating of subsurface materials.

Non-contaminated concrete rubble produced by demolition activities is processed to remove reinforcing steel and miscellaneous embedments. All non-contaminated materials are trucked to an off-site area for

disposal as construction debris. Subgrade voids are backfilled with clean construction fill, suitable under Minnesota regulations.

2.1.4 ISFSI Operations and Decommissioning

The ISFSI will continue to operate under a site-specific license as authorized by 10 CFR Part 72 following the amendment of the operating license to release the adjacent (power block) property. Assuming that Prairie Island spent fuel shipments begin in 2027, the process is not expected to be completed until 2064 (Scenario 1). Any delay in the transfer process, for example, due to a delay in the scheduled opening of the geologic repository, a slower acceptance rate, or a combination of both, can result in a longer on-site residence time for the fuel discharge from the reactor, as well as additional caretaking expenses. Scenarios 3 and 4 address extended delay periods. Scenarios 3, 4 and 5 also reflect an assumption that the spent fuel DSCs will need to be replaced every fifty years.

The assumed design for the ISFSI is based upon the use of the existing TN-40 casks from Transnuclear, plus the use of a multi-purpose dry shielded storage canister and a horizontal storage module for pad storage for those fuel assemblies packaged after plant shutdown.

At the conclusion of the spent fuel transfer process, the ISFSI will be decommissioned. The Commission will terminate the license if it determines that the remediation of the ISFSI has been performed in accordance with an ISFSI license termination plan and that the final radiation survey and associated documentation demonstrate that the facility is suitable for release. Once the requirements are satisfied, the NRC can terminate the license for the ISFSI.

For purposes of this cost analysis, it is assumed that once the TN-40s and DSCs containing the spent fuel assemblies have been removed, any required decontamination is performed on the storage overpacks (some minor neutron-induced activation is assumed), and the license for the facility terminated, the concrete overpacks can be dismantled using conventional techniques for the demolition of reinforced concrete. The concrete storage pad is then removed and the area regraded. This topic is discussed in greater detail in section 3.4.1.

2.2 SAFSTOR

The NRC defines SAFSTOR as "the alternative in which the nuclear facility is placed and maintained in a condition that allows the nuclear facility to be safely stored and subsequently decontaminated (deferred decontamination) to levels that permit release for unrestricted use." The facility is left intact (during the dormancy period), with structures maintained in a sound condition. Systems not required to operate in support of the spent fuel pool or site surveillance and security are drained, de-energized, and secured. Minimal cleaning/removal of loose contamination and/or fixation and sealing of remaining contamination are performed. Access to contaminated areas is secured to provide controlled access for inspection and maintenance.

The engineering and planning requirements are similar to those for the DECON alternative. Site preparations are also similar to those for the DECON alternative. However, with the exception of the required radiation surveys and site characterizations, the mobilization and preparation of site facilities is less extensive.

2.2.1 Period 1 - Preparations

Preparations for long-term storage include the planning for permanent defueling of the reactors, revision of technical specifications appropriate to the operating conditions and requirements, a characterization of the facility and major components, and the development of the PSDAR.

The process of placing the plant in safe-storage includes, but is not limited to, the following activities:

- Isolation of the spent fuel storage services and fuel handling systems located in the auxiliary building so that safe-storage operations may commence on the balance of the plant. This activity may be carried out by plant personnel in accordance with existing operating technical specifications. Activities are scheduled around the fuel handling systems to the greatest extent possible.
- Draining and de-energizing of the non-contaminated systems not required to support continued site operations or maintenance.
- Disposing of contaminated filter elements and resin beds not required for processing wastes from layup activities for future operations.
- Draining of the reactor vessels, with the internals left in place and the vessel heads secured.

- Draining and de-energizing non-essential, contaminated systems with decontamination as required for future maintenance and inspection.
- Preparing lighting and alarm systems whose continued use is required; de-energizing portions of fire protection, electric power, and HVAC systems whose continued use is not required.
- Cleaning of the loose surface contamination from building access pathways.
- Performing an interim radiation survey of plant, posting warning signs where appropriate.
- Erecting physical barriers and/or securing all access to radioactive or contaminated areas, except as required for inspection and maintenance.
- Installing security and surveillance monitoring equipment and relocating security fence around secured structures, as required.

2.2.2 Period 2 - Dormancy

The second phase identified by the NRC in its rule addresses licensed activities during a storage period and is applicable to the dormancy phases of the deferred decommissioning alternatives. Dormancy activities include a 24-hour security force, preventive and corrective maintenance on security systems, area lighting, general building maintenance, heating and ventilation of buildings, routine radiological inspections of contaminated structures, maintenance of structural integrity, and a site environmental and radiation monitoring program. Resident maintenance personnel perform equipment maintenance, inspection activities, routine services to maintain safe conditions, adequate lighting, heating, and ventilation, and periodic preventive maintenance on essential site services.

An environmental surveillance program is carried out during the dormancy period to ensure that releases of radioactive material to the environment are prevented and/or detected and controlled. Appropriate emergency procedures are established and initiated for potential releases that exceed prescribed limits. The environmental surveillance program constitutes an abbreviated version of the program in effect during normal plant operations.

Security during the dormancy period is conducted primarily to protect the spent nuclear fuel while it is on site, prevent unauthorized entry,

and to protect the public from the consequences of their own actions. The security fence, sensors, alarms, and other surveillance equipment provide security. Fire and radiation alarms are also monitored and maintained. While remote surveillance is an option, it does not offer the immediate response time of a physical presence.

During Scenario 6, the transfer of the spent fuel to a DOE facility continues during this period until complete. In Scenario 7, ISFSI operations and fuel transfer to the DOE continue through delayed decommissioning.

The length of the dormancy period is such that decommissioning (license termination) of the station (excluding the ISFSI) is accomplished within 60 years of final shutdown. The Scenario 6 SAFSTOR has the site remain in dormancy following spent fuel removal to the maximum extent possible, such that the licenses are terminated within the required 60-year time period.

It is required that the licensee submit an application to terminate each license, along with a LTP (described in Section 2.1.2), thereby initiating the third phase.

2.2.3 Periods 3 and 4 - Delayed Decommissioning

Prior to the commencement of decommissioning operations, preparations are undertaken to reactivate site services and prepare for decommissioning. Preparations include engineering and planning, a detailed site characterization, and the assembly of a decommissioning management organization. Final planning for activities and the writing of activity specifications and detailed procedures are also initiated at this time.

Much of the work in developing a termination plan is relevant to the development of the detailed engineering plans and procedures. The activities associated with this phase and the follow-on decontamination and dismantling processes are detailed in Sections 2.1.1 and 2.1.2. The primary difference between the sequences anticipated for the DECON and SAFSTOR scenarios is the absence, in the latter, of any constraint on the availability of the fuel storage pool located within the auxiliary building for decommissioning.

ISFSI decommissioning begins immediately upon completion of final shipment of the spent fuel and GTCC canisters.

Variations in the length of the dormancy period are expected to have some effect upon the quantities of radioactive wastes generated from system and structure removal operations. However, given the levels of radioactivity and spectrum of radionuclides expected from approximately sixty years of plant operation, no plant process system identified as being contaminated upon final shutdown will become releasable due to the decay period alone. (i.e., there is no significant reduction in the waste generated from the decommissioning activities). Due to the lower activity levels, a greater percentage of the waste volume can be designated for off-site processing and recovery.

The delay in decommissioning also yields lower working area radiation levels. As such, the estimate for the delayed scenarios incorporate reduced ALARA controls for the SAFSTOR's lower occupational exposure potential.

Although the initial radiation levels due to ^{60}Co will substantially decrease during the dormancy period, the internal components of the reactor vessels will still exhibit sufficiently high radiation dose rates to require remote sectioning under water due to the presence of long-lived radionuclides such as ^{94}Nb, ^{59}Ni, and ^{63}Ni. Therefore, the dismantling procedures described for the DECON alternative would still be employed during this scenario. Portions of the biological shield wall will still be radioactive due to the presence of activated trace elements with long half-lives (^{152}Eu and ^{154}Eu). Decontamination will require controlled removal and disposal. It is assumed that radioactive corrosion products on inner surfaces of piping and components will not have decayed to levels that will permit unrestricted use or allow conventional removal. These systems and components will be surveyed as they are removed and disposed of in accordance with the existing radioactive release criteria.

2.2.4 Period 5 - Site Restoration

Following completion of decommissioning operations, site-restoration activities can begin. Dismantling, as a continuation of the decommissioning process, is a cost-effective option, as described in Section 2.1.3. The basis for the dismantling cost in this scenario is consistent with that described for DECON, presuming the removal of structures and site facilities to include the existing foundations and basemats, and the limited restoration of the site.

3. COST ESTIMATES

The cost estimates prepared for decommissioning Prairie Island consider the unique features of the site, including the NSSS, power generation systems, support services, site buildings, and ancillary facilities. The basis of the estimates, including the sources of information relied upon, the estimating methodology employed, site-specific considerations, and other pertinent assumptions, is described in this section.

3.1 BASIS OF ESTIMATES

The estimates were developed using the site-specific, technical information from the 2014 analysis. The plant inventory, the basis for the decontamination and dismantling requirements and cost, and the decommissioning waste streams, was reviewed for this analysis; no substantive changes were identified over the three-year period to the configuration of the plant or site facilities that would impact decommissioning. The site-specific considerations and assumptions used in the previous evaluation were also revisited; no necessary modifications were identified. Modifications such as new FLEX facilities were incorporated where new information was available or experience from ongoing decommissioning programs provided viable alternatives or improved processes.

3.2 METHODOLOGY

The methodology used to develop the estimates follows the basic approach originally presented in the AIF/NESP-036 study report, "Guidelines for Producing Commercial Nuclear Power Plant Decommissioning Cost Estimates,"[24] and the DOE "Decommissioning Handbook."[25] These documents present a unit factor method for estimating decommissioning activity costs, which simplifies the estimating calculations. Unit factors for concrete removal ($/cubic yard), steel removal ($/ton), and cutting costs ($/inch) were developed using local labor rates. The activity-dependent costs were estimated with the item quantities (cubic yards and tons), developed from plant drawings and inventory documents. Removal rates and material costs for the conventional disposition of components and structures relied upon information available in the industry publication, "Building Construction Cost Data," published by RSMeans.[26]

The unit factor method provides a demonstrable basis for establishing reliable cost estimates. The detail provided in the unit factors, including activity duration, labor costs (by craft), and equipment and consumable costs, ensures

that essential elements have not been omitted. Appendix A presents the detailed development of a typical unit factor. Appendix B provides the values contained within one set of factors developed for this analysis.

Regulatory Guide 1.184 [27] describes the methods and procedures that are acceptable to the NRC staff for implementing the requirements that relate to the initial activities and the major phases of the decommissioning process. The costs and schedules presented in this analysis follow the general guidance and sequence in the regulations. The format and content of the estimates is also consistent with the recommendations of Regulatory Guide 1.202. [28]

This analysis reflects lessons learned from TLG's involvement in the Shippingport Station Decommissioning Project, completed in 1989, as well as the decommissioning of the Cintichem reactor, hot cells, and associated facilities, completed in 1997. In addition, the planning and engineering for the Pathfinder, Shoreham, Rancho Seco, Trojan, Yankee Rowe, Big Rock Point, Maine Yankee, Humboldt Bay-3, Oyster Creek, Connecticut Yankee, Crystal River, Vermont Yankee and Fort Calhoun nuclear units have provided additional insight into the process, the regulatory aspects, and the technical challenges of decommissioning commercial nuclear units.

Work Difficulty Factors

TLG has historically applied work difficulty adjustment factors (WDFs) to account for the inefficiencies in working in a power plant environment. WDFs were assigned to each unique set of unit factors, commensurate with the inefficiencies associated with working in confined, hazardous environments. The ranges used for the WDFs are as follows:

- Access Factor 10% to 20%
- Respiratory Protection Factor 10% to 50%
- Radiation/ALARA Factor 10% to 40%
- Protective Clothing Factor 10% to 30%
- Work Break Factor 8.33%

The factors and their associated range of values were developed in conjunction with the AIF/NESP-036 study. The application of the factors is discussed in more detail in that publication.

Scheduling Program Durations

The unit factors, adjusted by the WDFs as described above, are applied against the inventory of materials to be removed in the radiologically controlled areas.

The resulting man-hours, or crew-hours, are used in the development of the decommissioning program schedule, using resource loading and event sequencing considerations. The scheduling of conventional removal and dismantling activities are based upon productivity information available from the RSMeans "Building Construction Cost Data" publication. Dismantling of the fuel handing systems and decontamination of the spent fuel pool is also dependent upon the timetable for the transfer of the spent fuel assemblies from the pool to the ISFSI or the DOE.

The program schedule is used to determine the period-dependent costs for program management, administration, field engineering, equipment rental, contracted services, etc. The study relies upon regional or site-specific salary and wage rates for the personnel associated with the intended program.

3.3 IMPACT OF DECOMMISSIONING MULTIPLE REACTOR UNITS

In estimating the near simultaneous decommissioning of two co-located reactor units there can be opportunities to achieve economies of scale, by sharing costs between units, and coordinating the sequence of work activities. There will also be schedule constraints, particularly where there are requirements for specialty equipment and staff, or practical limitations on when final status surveys can take place. For purposes of the estimates, Units 1 and 2 are assumed to be essentially identical. Common facilities have been assigned to Unit 2. A summary of the principal impacts is listed below.

- The sequence of work generally follows the principal that the work is done at Unit 1 first, followed by similar work at Unit 2. This permits the experience gained at Unit 1 to be applied by the workforce at the second unit. It should be noted however, that the estimates do not consider productivity improvements at the second unit, since there is little documented experience with decommissioning two units simultaneously. The work associated with developing activity specifications and procedures can be considered essentially identical between the two units, therefore the second unit costs are assumed to be a fraction of the first unit (~ 43%).
- Segmenting the reactor vessel and internals will require the use of special equipment. The cost of procuring that equipment is assumed to be shared on an equal basis between the two units. In addition, the decommissioning project will be scheduled such that Unit 2's reactor internals and vessel are segmented immediately after the activities at Unit 1 have been completed.
- Duplication of some program management and support costs, particularly costs associated with the more senior positions, can be avoided with two reactors undergoing decommissioning simultaneously. As a result, the

estimates are based on a "lead" unit that includes these senior positions, and a "second" unit that excludes these positions. The designation as lead is based on the unit undertaking the most complex tasks (for instance vessel segmentation) or performing tasks for the first time.

- The final radiological survey schedule is also affected by a two-unit decommissioning schedule. Trying to complete the final status survey of Unit 1, while Unit 2 still has ongoing radiological remediation work and waste handling in process is considered impractical. As a result, Unit 1 and Unit 2 delay durations awaiting spent fuel pool availability for decommissioning are synchronized, such that the spent fuel pool area decommissioning and subsequent final status survey can be completed for the station. During the spent fuel storage period, program management costs are reduced accordingly.
- The final demolition of buildings at Units 1 and 2 are considered to take place concurrently.
- Unit 1, as the first unit to enter decommissioning, incurs the majority of site characterization costs.
- Shared systems and structures are generally assigned to Unit 2.
- Station costs such as ISFSI operations, emergency response fees, regulatory agency fees, and insurance are generally allocated on an equal basis between the two units.

3.4 FINANCIAL COMPONENTS OF THE COST MODEL

TLG's proprietary decommissioning cost model, DECCER, produces a number of distinct cost elements. These direct expenditures, however, do not comprise the total cost to accomplish the project goal, i.e., license termination and site restoration.

3.4.1 Contingency

Inherent in any cost estimate that does not rely on historical data is the inability to specify the precise source of costs imposed by factors such as tool breakage, accidents, illnesses, weather delays, and labor stoppages. In the DECCER cost model, contingency fulfills this role. Contingency is added to each line item to account for costs that are difficult or impossible to develop analytically. Such costs are historically inevitable over the duration of a job of this magnitude; therefore, this cost analysis includes funds to cover these types of expenses.

The activity- and period-dependent costs are combined to develop the total decommissioning cost. A contingency is then applied on a line-item basis, using one or more of the contingency types listed in the AIF/NESP-036 study. "Contingencies" are defined in the American Association of Cost Engineers "Project and Cost Engineers' Handbook"[29] as "specific provision for unforeseeable elements of cost within the defined project scope; particularly important where previous experience relating estimates and actual costs has shown that unforeseeable events which will increase costs are likely to occur." The cost elements in this analysis are based upon ideal conditions and maximum efficiency; therefore, consistent with industry practice, a contingency factor has been applied. In the AIF/NESP-036 study, the types of unforeseeable events that are likely to occur in decommissioning are discussed and guidelines are provided for percentage contingency in each category. It should be noted that contingency, as used in this analysis, does not account for price escalation and inflation in the cost of decommissioning over the remaining operating life of the station.

The use and role of contingency within decommissioning estimates is not a "safety factor issue." Safety factors provide additional security and address situations that may never occur. Contingency funds are expected to be fully expended throughout the program. They also provide assurance that sufficient funding is available to accomplish the intended tasks. An estimate without contingency, or from which contingency has been removed, can disrupt the orderly progression of events and jeopardize a successful conclusion to the decommissioning process.

For example, the most technologically challenging task in decommissioning a commercial nuclear plant is the disposition of the reactor vessels and internal components, now highly radioactive after a lifetime of exposure to core activity. The disposition of these components forms the basis of the critical path (schedule) for decommissioning operations. Cost and schedule are interdependent, and any deviation in schedule has a significant impact on cost for performing a specific activity.

Disposition of the reactor vessel internals involves the underwater cutting of complex components that are highly radioactive. Costs are based upon optimum segmentation, handling, and packaging scenarios. The schedule is primarily dependent upon the turnaround time for the heavily shielded shipping casks, including preparation, loading, and decontamination of the containers for transport. The number of casks

required is a function of the pieces generated in the segmentation activity, a value calculated on optimum performance of the tooling employed in cutting the various subassemblies. The expected optimization, however, may not be achieved, resulting in delays and additional program costs. For this reason, contingency must be included to mitigate the consequences of the expected inefficiencies inherent in this complex activity, along with related concerns associated with the operation of highly specialized tooling, field conditions, and water clarity.

Contingency funds are an integral part of the total cost to complete the decommissioning process. Exclusion of this component puts at risk a successful completion of the intended tasks and, potentially, subsequent related activities. For this study, TLG examined the major activity-related problems (decontamination, segmentation, equipment handling, packaging, transport, and waste disposal) that necessitate a contingency. Individual activity contingencies ranged from 10% to 75%, depending on the degree of difficulty judged to be appropriate from TLG's actual decommissioning experience. The contingency values used in this study are as follows:

Decontamination	50%
Contaminated Component Removal	25%
Contaminated Component Packaging	10%
Contaminated Component Transport	15%
Low-Level Radioactive Waste Disposal	25%
Reactor Segmentation	75%
NSSS Component Removal	25%
Reactor Waste Packaging	25%
Reactor Waste Transport	25%
Reactor Vessel Component Disposal	50%
GTCC Disposal	15%
Non-Radioactive Component Removal	15%
Heavy Equipment and Tooling	15%
Supplies	25%
Engineering	15%
Energy	15%
Characterization and Termination Surveys	30%
Construction	15%
Asbestos	15%

Taxes and Fees	10%
Insurance	10%
Staffing	15%
Spent Fuel Storage (Dry) Systems	15%
Spent Fuel Transfer Costs	15%
Operations and Maintenance Expenses	15%
ISFSI Decommissioning	25%

The contingency values are applied to the appropriate components of the estimates on a line item basis. A composite value is then reported at the end of each detailed estimate (as provided in Appendices C through I). Appendix J, the ISFSI decommissioning calculation, uses a flat 25% contingency added at the end of the calculation.

3.4.2 Financial Risk

In addition to the routine uncertainties addressed by contingency, another cost element that is sometimes necessary to consider when bounding decommissioning costs relates to uncertainty, or risk. Examples can include changes in work scope, pricing, job performance, and other variations that could conceivably, but not necessarily, occur. Consideration is sometimes necessary to generate a level of confidence in the estimate, within a range of probabilities. TLG considers these types of costs under the broad term "financial risk." Included within the category of financial risk are:

- Transition activities and costs: ancillary expenses associated with eliminating 50% to 80% of the site labor force shortly after the cessation of plant operations, added cost for worker separation packages throughout the decommissioning program, national or company-mandated retraining, and retention incentives for key personnel.
- Delays in approval of the decommissioning plan due to intervention, public participation in local community meetings, legal challenges, and national and local hearings.
- Changes in the project work scope from the baseline estimate, involving the discovery of unexpected levels of contaminants, contamination in places not previously expected, contaminated soil previously undiscovered (either radioactive or hazardous material contamination), variations in plant inventory or configuration not indicated by the as-built drawings.

- Regulatory changes (e.g., affecting worker health and safety, site release criteria, waste transportation, and disposal).
- Policy decisions altering national commitments (e.g., in the ability to accommodate certain waste forms for disposition) or in the timetable for such, for example, the start and rate of acceptance of spent fuel by the DOE.
- Pricing changes for basic inputs such as labor, energy, materials, and disposal. Items subject to widespread price competition (such as materials) may not show significant variation; however, others such as waste disposal could exhibit large pricing uncertainties, particularly in markets where limited access to services is available.

This cost study does not add any additional costs to the estimate for financial risk, since there is insufficient historical data from which to project future liabilities. Consequently, the areas of uncertainty or risk are revisited periodically and addressed through repeated revisions or updates of the base estimates.

3.5 SITE-SPECIFIC CONSIDERATIONS

There are a number of site-specific considerations that affect the method for dismantling and removal of equipment from the site and the degree of restoration required. The cost impacts of the considerations identified below are included in this cost study.

3.5.1 Spent Fuel Management

The cost to dispose of spent fuel generated from plant operations is not reflected within the estimates to decommission Prairie Island. Ultimate disposition of the spent fuel is within the province of the DOE's Waste Management System, as defined by the Nuclear Waste Policy Act. As such, the disposal cost was financed by a 1 mill/kWhr surcharge paid into the DOE's waste fund during operations. On November 19, 2013, the U.S. Court of Appeals for the D.C. Circuit ordered the Secretary of the Department of Energy to suspend collecting annual fees for nuclear waste disposal from nuclear power plant operators until the DOE has conducted a legally adequate fee assessment.

The NRC does, however, require licensees to establish a program to manage and provide funding for the management of all irradiated fuel at the reactor site until title of the fuel is transferred to the Secretary of

Energy. This requirement is prepared for through inclusion of certain high-level waste cost elements within the estimates, as described below.

Xcel Energy's current spent fuel management plan for the Prairie Island spent fuel is based in general upon:

1) Fuel transferred from the pool to the ISFSI within 5 years of shutdown;
2) Exchange of Prairie Island and Monticello spent fuel acceptance rights to best manage the overall cost of spent fuel storage for both plants;
3) Fuel will be shipped in the existing Transnuclear TN-40 casks, plus NUHOMS DSCs for fuel removed after final plant shutdown (Scenarios 1, 2, 6, and 7); the canisters and NUHOMS are periodically replaced in Scenarios 3, 4 and 5. Spent fuel assemblies from TN-40 casks that are replaced will be put into NUHOMS DSCs. Canisters that are unloaded in the spent fuel transfer operation will be surveyed for neutron activation.
4) As an allowance, some of these canisters and NUHOMS modules from the first off-load operation are assumed to be mildly neutron activated and therefore must be disposed of as radioactive waste.

This analysis assumes that the existing ISFSI is modified at the cessation of plant operations to accommodate the fuel present in the storage pool at shutdown.

The DOE's repository program assumes that spent fuel will be accepted for disposal from the nation's commercial nuclear plants in the order (the "queue") in which it was removed from service ("oldest fuel first").[31] Repository operations were based upon annual industry-wide receipt of 400 Metric Tons Heavy Metal (MTHM) in the first year of operation, a total of 3,800 MTHM in years 2 through 4 and 3,000 MTHM for year 5 and beyond.[32] This logic supports the spent fuel schedules for Scenarios 1 and 6. All other spent fuel scenarios are consistent with those identified by the Minnesota PSC.

Operation and maintenance costs for the spent fuel pool and ISFSI are included within the estimates and address the costs for staffing the facility, as well as security, insurance, and licensing fees. The estimates also include the costs to purchase, load, and transfer the NUHOMs DSCs from the pool to the ISFSI. Costs are also provided for the final

disposition of the ISFSI once the transfer of the TN-40s and DSCs from the ISFSI to the DOE is complete.

Storage Canister Design

The design and capacity of the ISFSI is based upon the Transnuclear NUHOMS system (with a 61-fuel assembly capacity). The system consists of a multi-purpose (storage and transport) dry shielded storage canister (DSC) and a horizontal storage module (HSM). The existing TN-40 casks will remain in the ISFSI until either shipment to the DOE, or until recasked.

Canister Loading and Transfer

The estimates include an average cost of $1,000,000 for the labor to load/transport the spent fuel from the pool to the ISFSI pad. For estimating purposes an allowance of $332,800 is used for the cost to transfer each fuel canister from the ISFSI pad to the DOE transport vehicle.

Operations and Maintenance

An annual cost (excluding labor) of approximately $803,000 and $103,000 are used for operation and maintenance of the spent fuel pool and the ISFSI, respectively.

At shutdown, the spent fuel pool is expected to contain freshly discharged assemblies (from the most recent refueling cycles). Over the next five years the assemblies are packaged into DSCs for transfer to the ISFSI for transfer to the DOE. It is assumed that the five years provides the necessary cooling period for the final cores to meet the decay heat requirements for dry storage. Once the pool is emptied, the spent fuel storage and handling facilities are available for decommissioning.

Replacement of DSCs during ISFSI fuel storage period

Scenarios 1, 2, 6, and 7 do not assume any replacement of the spent fuel storage DSCs (recasking).

Three of the cost estimates, Scenarios 3, 4 and 5, include costs to recask the spent fuel, based upon an assumption that the DSC has a limited lifetime of approximately 50 years.

Scenario 3, which is 100 years (nominally) in length, considers a single repackaging effort for each DSC in the ISFSI.

Scenario 4, which is a (nominal) 200-year scenario, assumes that when any DSC in the ISFSI reaches the 50 years of storage milestone, the DSC is replaced. In Scenario 4, the fuel will be recasked three times following final shutdown of Prairie Island.

Scenario 5, which is 60 years (nominally) in length, considers a single repackaging effort for each DSC in the ISFSI. Not all fuel will be recasked.

Since the auxiliary building, spent fuel storage pool, and fuel handling facilities are removed by the year 2040, a dry fuel transfer facility is assumed to be constructed on site to perform the transfers from the old to the new DSCs. Scenarios 3, 4 and 5 include the cost to construct such a transfer facility, as well as additional staffing positions for support of the dry transfer activities, and additional NRC oversight associated with the transfer operations. The decommissioning of this transfer facility is also included in Scenarios 3, 4 and 5.

ISFSI Decommissioning

In accordance with 10 CFR §72.30, licensees must have a proposed decommissioning plan for the ISFSI site and facilities that includes a cost estimate for the plan. The plan should contain sufficient information on the proposed practices and procedures for the decontamination of the ISFSI and for the disposal of residual radioactive materials after all spent fuel, high-level radioactive waste, and reactor-related GTCC waste have been removed.

The NUHOMS multi-purpose dry shielded storage canister with a horizontal, reinforced concrete storage module is used as a basis for the ISFSI decommissioning cost analyses. The modules are assumed to have some level of neutron-induced activation, as a result of the long-term storage of the fuel, i.e., to levels exceeding free-release limits. As an allowance, 8 modules are assumed to require remediation, equivalent to the number of modules required to accommodate the final core offloads at Prairie Island (121 assemblies per unit). The cost of the disposition of this material, as well as the demolition of the ISFSI facility, is included in the estimates.

The existing ISFSI pad, supporting the TN-40 casks, is not expected to be contaminated and will be demolished accordingly after a confirmation survey.

In accordance with the specific requirements of 10 CFR §72.30 for the ISFSI work scope, the cost estimate for decommissioning the ISFSI reflects: 1) the cost of an independent contractor performing the decommissioning activities; 2) an adequate contingency factor; and 3) the cost of meeting the criteria for unrestricted use. The cost summary for decommissioning the ISFSI is presented in Appendix J. It contains four different scenarios reflecting the different number of casks present at the end of the ISFSI operations. The demolition of the ISFSI for all seven scenarios is reflected within the estimates.

GTCC

The dismantling of the reactor internals is expected to generate radioactive waste considered unsuitable for shallow land disposal (i.e., low-level radioactive waste with concentrations of radionuclides that exceed the limits established by the NRC for Class C radioactive waste (GTCC)). Although the material is not classified as high-level waste, federal regulations under the LLRW Policy Amendments Act specifies the GTCC LLRW is designated a federal responsibility under Section 3(b)(1)(D). However, the DOE has not been forthcoming with an acceptance criteria or disposition schedule for this material, and numerous questions remain as to the ultimate disposal cost and waste form requirements. As such, for purposes of this study, the GTCC has been packaged and disposed of in the same manner as high-level waste, at a cost equivalent to that envisioned for the spent fuel. This is consistent with the concept that the generator of GTCC waste will bear all reasonable costs of disposing of such wastes. [32]

The number of DSCs required and the packaged volume for GTCC was based upon experience at Maine Yankee (e.g., the constraints on loading as identified in the canister's certificate of compliance), but adjusted for the increased spent fuel capacity of the 32 assembly DSCs.

It is assumed that the DOE would not accept this waste prior to completing the transfer of spent fuel. Therefore, until such time the DOE is ready to accept GTCC waste, it is reasonable to assume that this material would remain in storage at Prairie Island (for the DECON alternatives). In the SAFSTOR alternatives, the GTCC material is shipped directly to a DOE facility as it is generated. GTCC costs have

been segregated and included within the "License Termination" expenditures.

3.5.2 Reactor Vessel and Internal Components

The reactor pressure vessel and internal components are segmented for disposal in shielded, reusable transportation casks. Segmentation is performed underwater in the refueling canal, where a turntable and remote cutter are installed. The vessels are segmented in place, using a mast-mounted cutter supported off the lower head and directed from a shielded work platform installed overhead in the reactor cavity. Transportation cask specifications and transportation regulations dictate the segmentation and packaging methodology. The control elements are disposed of along with the spent fuel; there is no additional cost provided for their disposal.

Intact disposal of reactor vessel shells has been successfully demonstrated at several of the sites that have been decommissioned. Access to navigable waterways has allowed these large packages to be transported to the Barnwell disposal site with minimal overland travel. Intact disposal of the reactor vessel and internal components can provide savings in cost and worker exposure by eliminating the complex segmentation requirements, isolation of the GTCC material, and transport/storage of the resulting waste packages. Portland General Electric (PGE) was able to dispose of the Trojan reactor as an intact package (including the internals). However, its location on the Columbia River simplified the transportation analysis since:

- the reactor package could be secured to the transport vehicle for the entire journey, i.e., the package was not lifted during transport,
- there were no man-made or natural terrain features between the plant site and the disposal location that could produce a large drop, and
- transport speeds were very low, limited by the overland transport vehicle and the river barge.

As a member of the Northwest Compact, PGE had a site available for disposal of the package - the US Ecology facility in Washington State. The characteristics of this arid site proved favorable in demonstrating compliance with land disposal regulations.

It is not known whether this option will be available when Prairie Island ceases operation. Future viability of this option will depend upon the ultimate location of the disposal site, as well as the disposal site licensee's ability to accept highly radioactive packages and effectively isolate them from the environment. As such, the estimates assume segmentation of the reactor vessel, as a bounding condition. With lower levels of activation, the vessel shell can be packaged more efficiently than the curie-limited internal components. This will allow the use of more conventional waste packages rather than shielded casks for transport.

3.5.3 Primary System Components

The reactor coolant system components are assumed to be decontaminated using chemical agents prior to the start of cutting operations. This type of decontamination can be expected to have a significant ALARA impact in the DECON scenario, since in this scenario the removal work is done within the first few years of shutdown. A decontamination factor (average reduction) of 10 is assumed for the process. Disposal of the decontamination solution effluent is included within the estimate as a "process liquid waste" charge. The SAFSTOR scenarios do not include any decontamination of the reactor system; radioactive decay from the delay period in the dormancy results in similar results.

The following discussion deals with the removal and disposition of the steam generators, but the techniques involved are also applicable to other large radioactively-contaminated components, such as heat exchangers, component coolers, and the pressurizer. The steam generators' size and weight, their location within the reactor building, as well as the disposal facility waste acceptance criteria, and access to transportation will ultimately determine the removal, transportation, and disposal strategy.

A trolley crane is set up for the removal of the generators. It can also be used to move portions of the steam generator cubicle walls and floor slabs from the reactor building to a location where they can be decontaminated and transported to the material handling area. Interferences within the work area, such as grating, piping, and other components are removed to create sufficient lay-down space for processing these large components.

The generators are rigged for removal, disconnected from the surrounding piping and supports, and maneuvered into the open area where they are lowered onto a down-ending cradle. Each generator is rotated into the horizontal position for extraction from the containment and placed onto a multi-wheeled vehicle for transport to an on-site preparation area.

The generators are disassembled on-site with the outer shell and lightly contaminated subassemblies designated for off-site recycling. The more highly contaminated tube sheet and tube bundle are packaged for direct disposal.

Disposal costs are based upon the displaced volume and weight of the primary side portions of the steam generators. Each component is then loaded onto a rail car for transport to the disposal facility. The secondary side is assumed to be sent to an off-site waste processor.

Reactor coolant piping is cut from the reactor vessel once the water level in the vessel (used for personnel shielding during dismantling and cutting operations in and around the vessel) is dropped below the nozzle zone. The piping is boxed and transported by shielded van. The reactor coolant pumps and motors are lifted out intact, packaged, and transported for processing and/or disposal.

3.5.4 Main Turbine and Condenser

The main turbine and condenser are assumed to have only minor levels of contamination. As such, the components are dismantled using conventional maintenance procedures. The turbine rotors and shafts will be removed to a laydown area. The lower turbine casings will be removed from their anchors by controlled demolition. The main condensers will also be disassembled and moved to a laydown area. Material is then prepared for transportation to an off-site recycling facility where it will be surveyed and designated for either decontamination or volume reduction, or controlled disposal. Components will be packaged and readied for transport in accordance with the intended disposition.

3.5.5 Transportation Methods

Contaminated piping, components, and structural material other than the highly activated reactor vessels and internal components will qualify as LSA-I, II or III or Surface Contaminated Object, SCO-I or II, as

described in Title 49. [34] The contaminated material will be packaged in Industrial Packages (IP-1, IP-2, or IP-3, as defined in subpart 173.411) for transport unless demonstrated to qualify as their own shipping containers. The reactor vessel and internal components are expected to be transported in accordance with 10 CFR Part 71, as Type B. It is conceivable that the reactor, due to its limited specific activity, could qualify as LSA II or III. However, the high radiation levels on the outer surface would require that additional shielding be incorporated within the packaging so as to attenuate the dose to levels acceptable for transport.

Any fuel cladding failure that occurred during the lifetime of the plant is assumed to have released fission products at sufficiently low levels that the buildup of quantities of long-lived isotopes (e.g., ^{137}Cs, ^{90}Sr, or transuranics) has been prevented from reaching levels exceeding those that permit the major reactor components to be shipped under current transportation regulations and disposal requirements.

Transport of the highly activated metal, produced in the segmentation of the reactor vessel and internal components, will be by shielded truck cask. Cask shipments may exceed 95,000 pounds, including vessel segment(s), supplementary shielding, cask tie-downs, and tractor-trailer. The maximum level of activity per shipment assumed permissible was based upon the license limits of the available shielded transport casks. The segmentation scheme for the vessel and internal segments is designed to meet these limits.

The transport of large intact components (e.g., large heat exchangers and other oversized components) will be by a combination of truck, rail, and/or multi-wheeled transporter. Transportation costs for Class A radioactive material requiring controlled disposal are based upon the mileage to the Energy*Solutions* facility in Clive, Utah. Transportation costs for the higher activity Class B and C radioactive material are based upon the mileage to the WCS facility in Andrews County, Texas. The transportation cost for the GTCC material is assumed to be contained within the disposal cost. Transportation costs for off-site waste processing are based upon the mileage to Oak Ridge, Tennessee. Truck transport costs were estimated using published tariffs from Tri-State Motor Transit. [35]

3.5.6 Low-Level Radioactive Waste Disposal

To the greatest extent practical, metallic material generated in the decontamination and dismantling processes is processed to reduce the total cost of controlled disposal. Material meeting the regulatory and/or site release criterion, is released as scrap, requiring no further cost consideration. Conditioning (preparing the material to meet the waste acceptance criteria of the disposal site) and recovery of the waste stream is performed off site at a licensed processing center. Any material leaving the site is subject to a survey and release charge, at a minimum.

The mass of radioactive waste generated during the various decommissioning activities at the site is shown on a line-item basis in the detailed Appendices C through J, and summarized in Section 5. The quantified waste summaries shown in these tables are consistent with 10 CFR Part 61 classifications. Commercially available steel containers are presumed to be used for the disposal of piping, small components, and concrete. Larger components can serve as their own containers, with proper closure of all openings, access ways, and penetrations. The volumes are calculated based on the exterior package dimensions for containerized material or a specific calculation for components serving as their own waste containers.

The more highly activated reactor components will be shipped in reusable, shielded truck casks with disposable liners. In calculating disposal costs, the burial fees are applied against the liner volume and weight, with surcharges added for the special handling requirements and the radiological characteristics of the payload. Packaging efficiencies are lower for the highly activated materials (greater than Type A quantity waste), where high concentrations of gamma-emitting radionuclides limit the capacity of the shipping canisters.

The cost to dispose of the lowest level and majority of the material generated from the decontamination and dismantling activities is based upon representative costs for disposal at Energy*Solutions* facility in Clive, Utah. Disposal costs for the higher activity waste (Class B and C) were based upon preliminary and indicative information from WCS for the Andrews County facility

Material exceeding Class C limits (limited to material closest to the reactor core and comprising less than 1% of the total waste volume) is generally not suitable for shallow-land disposal. This material is

packaged in the same multipurpose canisters used for spent fuel storage/transport, for eventual transfer to the DOE for disposal.

3.5.7 Site Conditions Following Decommissioning

The NRC will amend or terminate each unit's license if it determines that site remediation has been performed in accordance with the license termination plan, and that the terminal radiation survey and associated documentation demonstrate that the facility is suitable for release. The NRC's involvement in the decommissioning process will end at this point. Building codes and environmental regulations will dictate the next step in the decommissioning process, as well as Xcel Energy's own future plans for the site, e.g., the electrical switchyard will remain in support of the regional transmission and distribution system.

Asphalt surfaces in the immediate vicinity of site buildings are broken up and the material disposed of as construction debris. The site access road will remain.

Only existing site structures are considered in the dismantling cost. All subgrade structures are removed. The voids are backfilled with clean debris and capped with soil. The site is then re-graded to conform to the adjacent landscape. Vegetation is established to inhibit erosion. These "non-radiological costs" are included in the total cost of decommissioning.

Bulk excavation of soil and material in the immediate vicinity of the power block is included to remove various duct banks, catch basins, and underground utilities that may exist.

The estimates do not assume the remediation of any significant volume of contaminated soil. This assumption may be affected by continued plant operations and/or future regulatory actions, such as the development of site-specific release criteria.

3.6 ASSUMPTIONS

The following are the major assumptions made in the development of the estimates for decommissioning the site.

3.6.1 Estimating Basis

The study follows the principles of ALARA through the use of work duration adjustment factors. These factors address the impact of

activities such as radiological protection instruction, mock-up training, and the use of respiratory protection and protective clothing. The factors lengthen a task's duration, increasing costs and lengthening the overall schedule. ALARA planning is considered in the costs for engineering and planning, and in the development of activity specifications and detailed procedures. Changes to worker exposure limits may impact the decommissioning cost and project schedule.

3.6.2 Labor Costs

For purposes of this analysis, it is assumed that Xcel Energy will hire a Decommissioning Operations Contractor (DOC) to manage the decommissioning. Xcel Energy will provide site security, radiological health and safety, quality assurance and overall site administration during the decommissioning and demolition phases. Contract personnel will provide engineering services (e.g., for preparing the activity specifications, work procedures, neutron activation, and structural analyses) under the direction of Xcel Energy.

Utility labor costs were provided by Xcel Energy. Average costs were provided by department or work group and included payroll overheads. Decommissioning Operations Contractor (DOC) labor costs were based on utility labor costs with modified markups to account for employee benefits, DOC overhead and profit.

The craft labor required to decontaminate and dismantle the nuclear station will be acquired through standard site contracting practices. Craft labor costs were based upon information from Xcel Energy. Craft labor costs include applicable overheads and profit.

Security, while reduced from operating levels, is maintained throughout the decommissioning for access control, material control, and to safeguard the spent fuel.

Staffing levels are assigned by sub-period and functional area. Economies of a multi-unit decommissioning are recognized by establishing a primary and a secondary staff level. The unit assigned the primary staff will include common supervisory positions and positions that may be shared across both units. The types of positions and staffing levels are adjusted based upon the type of activity occurring in each sub-period.

Representative profiles of the staffing level for decommissioning, including contractors and craft, is provided in Figures 3.1 and 3.2 for the DECON (Scenario 2) and SAFSTOR (Scenario 7) estimates. Utility staffing levels will gradually decrease after completing the removal of physical systems. Staffing levels and management support will vary based upon the amount and type of decommissioning work. Craft manpower levels decrease after systems removal and structures decontamination and drop substantially during the delay period and the license termination survey period. However, craft levels increase again during the site restoration period due to the work associated with structures demolition. During SAFSTOR dormancy, following transfer of the spent fuel to the ISFSI, staffing levels for the power block are reduced to a minimum, then rise as the delayed dismantling operations begin.

Security, while reduced from operating levels, is maintained throughout the decommissioning for access control, material control, and to safeguard the spent fuel (in accordance with the requirements of 10 CFR Part 37, Part 72, and Part 73). Once the fuel has been transferred to the DOE, the security organization will be reduced to Part 37 requirements for Scenario 6.

3.6.3 Design Conditions

Any fuel cladding failure that occurred during the lifetime of the plant is assumed to have released fission products at sufficiently low levels that the buildup of quantities of long-lived isotopes (e.g., ^{137}Cs, ^{90}Sr, or transuranics) has been prevented from reaching levels exceeding those that permit the major NSSS components to be shipped under current transportation regulations and disposal requirements.

The curie contents of the vessels and internals at final shutdown are derived from those listed in NUREG/CR-3474.[35] Actual estimates are derived from the curie/gram values contained therein and adjusted for the different mass of the Prairie Island components, projected operating life, and different periods of decay. Additional short-lived isotopes were derived from NUREG/CR-0130[36] and NUREG/CR-0672,[37] and benchmarked to the long-lived values from NUREG/CR-3474.

It is anticipated that there will be control element assemblies (CEAs) in the spent fuel pool at the cessation of operations, including those CEAs from the final core. This analysis assumes that the CEAs can be

disposed of along with the spent fuel at no additional cost (in accordance with Appendix E of the Standard Contract [38])

Neutron activation of the reactor building structure is confined to the reactor biological shield.

3.6.4 General

Transition Activities

Existing warehouses will be cleared of non-essential material and remain for use by Xcel Energy and subcontractors. The plant's operating staff will perform the following activities at no additional cost or credit to the project during the transition period:

- Drain and collect fuel oils, lubricating oils, and transformer oils for recycle and/or sale.
- Drain and collect acids, caustics, and other chemical stores for recycle and/or sale.
- Processes operating waste inventories, i.e., the estimates do not address the disposition of any legacy wastes; the disposal of operating wastes during this initial period is not considered a decommissioning expense.

Scrap and Salvage

The existing plant equipment is considered obsolete and suitable for scrap as deadweight quantities only. Xcel Energy will make economically reasonable efforts to salvage equipment following final plant shutdown. However, dismantling techniques assumed by TLG for equipment in this analysis are not consistent with removal techniques required for salvage (resale) of equipment. Experience has indicated that some buyers wanted equipment stripped down to very specific requirements before they would consider purchase. This required expensive rework after the equipment had been removed from its installed location. Since placing a salvage value on this machinery and equipment would be speculative, and the value would be small in comparison to the overall decommissioning expenses, this analysis does not attempt to quantify the possible salvage value that Xcel Energy may realize based upon those efforts.

It is assumed, for purposes of this analysis, that any value received from the sale of scrap generated in the dismantling process would be offset by the on-site processing costs. The dismantling techniques assumed in the decommissioning estimates do not include the additional cost for size reduction and preparation to meet "furnace ready" conditions. For example, the recovery of copper from electrical cabling may require the removal and disposition of any contaminated insulation, an added expense. With a volatile market, the potential profit margin in scrap recovery is highly speculative, regardless of the ability to free release this material. This assumption is an implicit recognition of scrap value in the disposal of clean metallic waste at no additional cost to the project.

Furniture, tools, mobile equipment such as forklifts, trucks, bulldozers, and other property will be removed at no cost or credit to the decommissioning project. Disposition may include relocation to other facilities. Spare parts will also be made available for alternative use.

The concrete debris resulting from building demolition activities is crushed on site to reduce the size of the debris. The resulting crushed concrete is disposed offsite as construction debris. The rebar removed from the concrete crushing process is disposed of as scrap steel in a similar fashion as other scrap metal as discussed previously.

Asbestos

At the time of Prairie Island's construction, asbestos was still being used for system component and piping insulation, and as fireproofing material for structures. No inventory of asbestos at Prairie Island was available, so TLG developed an estimated quantity. The allowance for the remediation of this asbestos is captured in the detailed cost analyses (Appendices C through I).

Energy

For estimating purposes, the plant is assumed to be de-energized, with the exception of those facilities associated with spent fuel storage. Replacement power costs are used for the cost of energy consumption during decommissioning for tooling, lighting, ventilation, and essential services.

Emergency Planning

FEMA and state fees associated with emergency planning are assumed to continue for approximately 18 months following the cessation of operations. At this time, the FEMA fees are discontinued. The timing is based upon the anticipated condition of the spent fuel (i.e., the hottest spent fuel assemblies are assumed to be cool enough that no substantial Zircaloy oxidation and off-site event would occur with the loss of spent fuel pool water). State and local fees are continued until all spent fuel is transferred out of the spent fuel pool.

Insurance

Costs for continuing coverage (nuclear liability and property insurance) following cessation of plant operations and during decommissioning are included and based upon current operating premiums. Reductions in premiums throughout the decommissioning process are based upon guidance provided by Xcel Energy. Reductions in premiums, throughout the decommissioning process, are based upon the guidance provided in SECY-00-0145, "Integrated Rulemaking Plan for Nuclear Power Plant Decommissioning."[39] The NRC's financial protection requirements are based on various reactor (and spent fuel) configurations.

Xcel Energy Corporate Overhead

Corporate overhead charges for site support activities are not included in these estimates.

Site Non-Labor Overhead

These estimates include costs for site non-labor overhead charges. These costs include telephones, copy machines, computers, IT infrastructure, office supplies, janitorial supplies, training expenses, etc. Xcel Energy provided a two-part cost to address these costs. A variable charge of $3,936 per person per year of the Xcel Energy staff is included throughout the estimate. A fixed annual overhead charge is also included, starting at $1.5 million per reactor at the time of unit shut down and decreasing to approximately $467 thousand per reactor.

Taxes

Property taxes are included for all decommissioning periods. Xcel Energy provided a schedule of decreasing tax payments against the

current tax assessment. These payments are maintained for the balance of the decommissioning program.

NRC Fees

These estimates include charges from the NRC to support the Prairie Island decommissioning program. Charges are included for the yearly license held by Xcel Energy for the Part 50 licenses, as well as engineering support charges by the NRC to review activities at the site. The Part 50 license fee for a reactor in a decommissioning or possession-only status and which has spent fuel onsite is $194 thousand per year. Once the reactors have been decommissioned, the site Part 50 license continues at the same fee until final removal of the spent fuel. The hourly rate for NRC review is $267.00. The level of effort of NRC participation is commensurate with the decommissioning alternative and schedule. For example, Scenario 2 has an estimated NRC support requirement of approximately 16,800 hours from Unit 1 shutdown until termination of the ISFSI license

Disposal of Processed Water

This estimate assumes that processed water which meets state and federal release limits can be disposed of without additional cost.

Site Modifications

The perimeter fence and in-plant security barriers will be moved, as appropriate, to conform to the Site Security Plan in force during the various stages of the project.

Prairie Island Indian Community Payments

This estimate includes a $2.5 million annual payment to the Prairie Island Indian Community while spent fuel is still on the Prairie Island site.

Minnesota state regulations regarding concrete

This estimate complies with the Minnesota state regulations regarding the removal of all subterranean concrete during demolition, plus the survey and confirmation of the suitability of the clean fill used for backfill of the subgrade structures following concrete removal.

3.7 COST ESTIMATE SUMMARY

The estimates presented in this document reflects the total cost to decontaminate the nuclear units, manage the spent fuel until the DOE is able to complete the transfer to a federal facility, dismantle the plant and restore the site for alternative use.

Schedules of expenditures are provided in Tables 3.1 through 3.14. The tables delineate the cost contributors by year of expenditures as well as cost contributor (e.g., labor, materials, and waste disposal).

Additional tables in Appendices C through I provide detailed costs elements. The cost elements are also assigned to one of three subcategories: "License Termination," "Spent Fuel Management," and "Site Restoration." The subcategory "License Termination" is used to accumulate costs that are consistent with "decommissioning" as defined by the NRC in its financial assurance regulations (i.e., 10 CFR §50.75). In situations where the long-term management of spent fuel is not an issue, the cost reported for this subcategory is generally sufficient to terminate each unit's operating license, recognizing that there may be some additional cost impact from spent fuel management.

The "Spent Fuel Management" subcategory contains costs associated with the containerization and transfer of spent fuel from the pool to the DOE or to the ISFSI for interim storage, and the transfer of the multipurpose canisters from the ISFSI to the DOE. Costs are also included for the operations of the pool and management of the ISFSI until such time that the transfer of all fuel from this facility to an off-site location (e.g., interim storage facility) is complete.

"Site Restoration" is used to capture costs associated with the dismantling and demolition of buildings and facilities demonstrated to be free from contamination. This includes structures never exposed to radioactive materials, as well as those facilities that have been decontaminated to appropriate levels. Structures are completely removed, including foundations and basemats and backfilled to conform to local grade.

As discussed in Section 3.5.1, it is assumed that the DOE will not accept the GTCC waste prior to completing the transfer of spent fuel. Therefore, the cost of GTCC disposal is shown in the final year of ISFSI operation (for the DECON alternative). While designated for disposal at a federal facility along with the spent fuel, GTCC waste is still classified as low-level radioactive waste and, as such, included as a "License Termination" expense.

Decommissioning costs are reported in 2017 dollars. Costs are not inflated, escalated, or discounted over the period of expenditure (or projected lifetime of the plant).

TABLE 3.1
SCENARIO 1: DECON WITH 32 YEAR DFS, UNIT 1
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2033	22,324	776	692	25	9,206	33,023
2034	63,582	8,741	2,434	4,050	18,997	97,804
2035	66,069	37,773	1,850	20,920	22,520	149,133
2036	57,951	22,861	1,465	22,493	20,601	125,370
2037	38,254	6,920	984	15,000	15,667	76,825
2038	10,524	808	348	38	10,999	22,718
2039	35,902	65,387	409	817	10,713	113,229
2040	32,068	4,105	560	2,732	7,666	47,132
2041	19,800	6,499	235	16	4,502	31,053
2042	14,925	8,952	174	0	4,223	28,275
2043	8,672	4,303	82	0	3,719	16,776
2044	3,150	287	0	0	3,279	6,716
2045	3,142	287	0	0	3,270	6,699
2046	3,046	0	0	0	3,270	6,316
2047	3,046	0	0	0	3,270	6,316
2048	3,055	0	0	0	3,279	6,333
2049	3,046	0	0	0	3,270	6,316
2050	3,142	287	0	0	3,270	6,699
2051	3,142	287	0	0	3,270	6,699
2052	3,150	287	0	0	3,279	6,716
2053	3,142	287	0	0	3,270	6,699
2054	3,142	287	0	0	3,270	6,699
2055	3,142	287	0	0	3,270	6,699
2056	3,150	287	0	0	3,279	6,716
2057	3,142	287	0	0	3,270	6,699
2058	3,142	287	0	0	3,270	6,699
2059	3,142	287	0	0	3,270	6,699
2060	3,150	287	0	0	3,279	6,716
2061	3,142	287	0	0	3,270	6,699
2062	3,142	287	0	0	3,270	6,699

TABLE 3.1 (continued)
SCENARIO 1: DECON WITH 32 YEAR DFS, UNIT 1
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2063	3,142	287	0	0	3,270	6,699
2064	3,147	1,940	0	0	13,259	18,345
2065	796	381	15	2,697	1,418	5,306
Total	436,517	174,040	9,248	68,788	208,927	897,520

Note: Columns may not add due to rounding

TABLE 3.2
SCENARIO 1: DECON WITH 32 YEAR DFS, UNIT 2
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2034	7,760	336	305	10	5,078	13,490
2035	47,103	6,322	2,047	1,819	27,237	84,528
2036	67,705	41,230	2,261	23,855	20,777	155,828
2037	71,040	25,567	1,413	27,883	17,376	143,278
2038	43,920	7,411	847	13,940	13,784	79,901
2039	40,527	65,576	409	930	11,387	118,830
2040	37,549	4,783	560	3,109	7,440	53,440
2041	23,571	10,022	235	16	4,588	38,433
2042	16,800	14,214	174	0	4,470	35,659
2043	9,556	6,782	82	0	3,836	20,256
2044	3,150	287	0	0	3,279	6,716
2045	3,142	287	0	0	3,270	6,699
2046	3,046	0	0	0	3,270	6,316
2047	3,046	0	0	0	3,270	6,316
2048	3,055	0	0	0	3,279	6,333
2049	3,046	0	0	0	3,270	6,316
2050	3,142	287	0	0	3,270	6,699
2051	3,142	287	0	0	3,270	6,699
2052	3,150	287	0	0	3,279	6,716
2053	3,142	287	0	0	3,270	6,699
2054	3,142	287	0	0	3,270	6,699
2055	3,142	287	0	0	3,270	6,699
2056	3,150	287	0	0	3,279	6,716
2057	3,142	287	0	0	3,270	6,699
2058	3,142	287	0	0	3,270	6,699
2059	3,142	287	0	0	3,270	6,699
2060	3,150	287	0	0	3,279	6,716
2061	3,142	287	0	0	3,270	6,699
2062	3,142	287	0	0	3,270	6,699
2063	3,142	287	0	0	3,270	6,699

TABLE 3.2 (continued)
SCENARIO 1: DECON WITH 32 YEAR DFS, UNIT 2
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2064	3,147	1,940	0	0	13,259	18,345
2065	796	381	15	2,697	1,418	5,306
Total	431,975	189,158	8,349	74,258	196,087	899,828

Note: Columns may not add due to rounding

TABLE 3.3
SCENARIO 2: DECON WITH 60 YEAR DFS, UNIT 1
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2033	22,324	776	692	25	9,486	33,303
2034	63,582	8,741	2,434	4,050	19,423	98,230
2035	65,877	37,199	1,850	20,920	22,520	148,367
2036	57,759	22,286	1,465	22,493	20,601	124,604
2037	38,111	6,490	984	15,000	15,667	76,251
2038	13,208	8,859	348	38	10,999	33,453
2039	36,036	65,782	409	820	10,715	113,763
2040	31,920	3,668	559	2,729	7,660	46,535
2041	19,571	5,945	235	16	4,500	30,267
2042	14,782	8,522	174	0	4,223	27,701
2043	8,544	3,992	82	0	3,669	16,287
2044	3,055	0	0	0	3,189	6,244
2045	3,046	0	0	0	3,180	6,227
2046	3,046	0	0	0	3,180	6,227
2047	3,046	0	0	0	3,180	6,227
2048	3,055	0	0	0	3,189	6,244
2049	3,046	0	0	0	3,180	6,227
2050	3,046	0	0	0	3,180	6,227
2051	3,046	0	0	0	3,180	6,227
2052	3,055	0	0	0	3,189	6,244
2053	3,142	287	0	0	3,180	6,609
2054	3,238	574	0	0	3,180	6,992
2055	3,238	574	0	0	3,180	6,992
2056	3,294	718	0	0	3,189	7,201
2057	3,190	431	0	0	3,180	6,801
2058	3,334	861	0	0	3,180	7,375
2059	3,190	431	0	0	3,180	6,801
2060	3,150	287	0	0	3,189	6,627
2061	3,238	574	0	0	3,180	6,992
2062	3,238	574	0	0	3,180	6,992

TABLE 3.3 (continued)
SCENARIO 2: DECON WITH 60 YEAR DFS, UNIT 1
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2063	3,190	431	0	0	3,180	6,801
2064	3,246	574	0	0	3,189	7,009
2065	3,238	574	0	0	3,180	6,992
2066	3,190	431	0	0	3,180	6,801
2067	3,238	574	0	0	3,180	6,992
2068	3,246	574	0	0	3,189	7,009
2069	3,190	431	0	0	3,180	6,801
2070	3,238	574	0	0	3,180	6,992
2071	3,238	574	0	0	3,180	6,992
2072	3,246	574	0	0	3,189	7,009
2073	3,238	574	0	0	3,180	6,992
2074	3,238	574	0	0	3,180	6,992
2075	3,570	1,570	0	0	3,180	8,320
2076	3,246	574	0	0	3,189	7,009
2077	3,238	2,238	0	0	13,165	18,641
2078	833	455	15	2,697	1,453	5,453
Total	481,032	188,867	9,246	68,788	249,109	997,041

Note: Columns may not add due to rounding

TABLE 3.4
SCENARIO 2: DECON WITH 60 YEAR DFS, UNIT 2
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2034	7,760	336	305	10	5,078	13,490
2035	46,911	5,748	2,047	1,819	27,237	83,763
2036	67,514	40,656	2,261	23,855	20,777	155,063
2037	70,896	25,136	1,413	27,883	17,376	142,704
2038	46,604	15,462	847	13,940	13,784	90,636
2039	40,664	65,972	409	933	11,388	119,366
2040	37,417	4,345	559	3,106	7,433	52,861
2041	23,328	9,482	235	16	4,587	37,648
2042	16,657	13,784	174	0	4,471	35,086
2043	9,423	6,458	82	0	3,785	19,747
2044	3,055	0	0	0	3,189	6,244
2045	3,046	0	0	0	3,180	6,227
2046	3,046	0	0	0	3,180	6,227
2047	3,046	0	0	0	3,180	6,227
2048	3,055	0	0	0	3,189	6,244
2049	3,046	0	0	0	3,180	6,227
2050	3,046	0	0	0	3,180	6,227
2051	3,046	0	0	0	3,180	6,227
2052	3,055	0	0	0	3,189	6,244
2053	3,142	287	0	0	3,180	6,609
2054	3,238	574	0	0	3,180	6,992
2055	3,238	574	0	0	3,180	6,992
2056	3,294	718	0	0	3,189	7,201
2057	3,190	431	0	0	3,180	6,801
2058	3,334	861	0	0	3,180	7,375
2059	3,190	431	0	0	3,180	6,801
2060	3,150	287	0	0	3,189	6,627
2061	3,238	574	0	0	3,180	6,992
2062	3,238	574	0	0	3,180	6,992
2063	3,190	431	0	0	3,180	6,801

TABLE 3.4 (continued)
SCENARIO 2: DECON WITH 60 YEAR DFS, UNIT 2
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2064	3,246	574	0	0	3,189	7,009
2065	3,238	574	0	0	3,180	6,992
2066	3,190	431	0	0	3,180	6,801
2067	3,238	574	0	0	3,180	6,992
2068	3,246	574	0	0	3,189	7,009
2069	3,190	431	0	0	3,180	6,801
2070	3,238	574	0	0	3,180	6,992
2071	3,238	574	0	0	3,180	6,992
2072	3,246	574	0	0	3,189	7,009
2073	3,238	574	0	0	3,180	6,992
2074	3,238	574	0	0	3,180	6,992
2075	3,570	1,570	0	0	3,180	8,320
2076	3,246	574	0	0	3,189	7,009
2077	3,238	2,238	0	0	13,164	18,640
2078	833	455	15	2,697	1,453	5,453
Total	476,490	203,985	8,347	74,258	235,562	998,643

Note: Columns may not add due to rounding

TABLE 3.5
SCENARIO 3: DECON WITH 100 YEAR DFS, UNIT 1
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2033	22,324	776	692	25	9,206	33,023
2034	63,582	8,741	2,434	4,050	18,997	97,804
2035	65,877	37,199	1,850	20,920	22,520	148,367
2036	57,759	22,286	1,465	22,493	20,601	124,604
2037	39,808	11,582	984	15,000	15,667	83,040
2038	13,208	8,859	348	38	10,999	33,453
2039	35,713	64,815	409	820	10,715	112,472
2040	31,920	3,668	559	2,729	7,660	46,535
2041	19,625	5,945	235	16	4,500	30,321
2042	14,864	8,522	174	0	4,223	27,782
2043	8,912	3,992	82	0	3,646	16,633
2044	3,676	0	0	0	3,147	6,823
2045	5,973	6,921	0	0	3,138	16,032
2046	5,204	4,614	0	0	3,138	12,956
2047	5,204	4,614	0	0	3,138	12,956
2048	3,676	0	0	0	3,147	6,823
2049	5,204	4,614	0	0	3,138	12,956
2050	5,973	6,921	0	0	3,138	16,032
2051	5,779	6,339	0	0	3,138	15,256
2052	5,983	6,921	0	0	3,147	16,051
2053	3,666	0	0	0	3,138	6,805
2054	3,666	0	0	0	3,138	6,805
2055	5,973	6,921	0	0	3,138	16,032
2056	5,214	4,614	0	0	3,147	12,975
2057	5,204	4,614	0	0	3,138	12,956
2058	3,666	0	0	0	3,138	6,805
2059	5,010	4,032	0	0	3,138	12,180
2060	5,214	4,614	0	0	3,147	12,975
2061	5,204	4,614	0	0	3,138	12,956
2062	3,666	0	0	0	3,138	6,805

TABLE 3.5 (continued)
SCENARIO 3: DECON WITH 100 YEAR DFS, UNIT 1
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2063	8,280	13,841	0	0	3,138	25,259
2064	6,558	8,646	0	0	3,147	18,351
2065	5,204	4,614	0	0	3,138	12,956
2066	3,666	0	0	0	3,138	6,805
2067	3,666	0	0	0	3,138	6,805
2068	6,752	9,227	0	0	3,147	19,126
2069	5,973	6,921	0	0	3,138	16,032
2070	3,666	0	0	0	3,138	6,805
2071	3,666	0	0	0	3,138	6,805
2072	7,327	10,952	0	0	3,147	21,426
2073	3,666	0	0	0	3,138	6,805
2074	3,666	0	0	0	3,138	6,805
2075	7,843	12,530	0	0	3,138	23,511
2076	3,676	0	0	0	3,147	6,823
2077	3,666	0	0	0	3,138	6,805
2078	7,511	11,534	0	0	3,138	22,184
2079	3,666	0	0	0	3,138	6,805
2080	3,676	0	0	0	3,147	6,823
2081	3,666	0	0	0	3,138	6,805
2082	7,123	10,371	0	0	3,138	20,632
2083	3,666	0	0	0	3,138	6,805
2084	3,676	0	0	0	3,147	6,823
2085	3,666	0	0	0	3,138	6,805
2086	3,666	0	0	0	3,138	6,805
2087	3,666	0	0	0	3,138	6,805
2088	3,676	0	0	0	3,147	6,823
2089	26,816	69,448	0	1,934	3,138	101,337
2090	3,666	0	0	0	3,138	6,805
2091	3,666	0	0	0	3,138	6,805
2092	3,676	0	0	0	3,147	6,823

TABLE 3.5 (continued)
SCENARIO 3: DECON WITH 100 YEAR DFS, UNIT 1
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2093	3,050	287	0	0	2,934	6,271
2094	3,146	574	0	0	2,934	6,653
2095	5,453	7,495	0	0	2,934	15,881
2096	4,740	5,331	0	0	2,942	13,013
2097	4,636	5,044	0	0	2,934	12,614
2098	3,241	861	0	0	2,934	7,036
2099	3,098	431	0	0	2,934	6,462
2100	5,357	7,208	0	0	2,934	15,498
2101	5,453	7,495	0	0	2,934	15,881
2102	5,453	7,495	0	0	2,934	15,881
2103	3,098	431	0	0	2,934	6,462
2104	3,154	574	0	0	2,942	6,670
2105	5,453	7,495	0	0	2,934	15,881
2106	4,636	5,044	0	0	2,934	12,614
2107	4,684	5,188	0	0	2,934	12,805
2108	3,154	574	0	0	2,942	6,670
2109	4,636	5,044	0	0	2,934	12,614
2110	4,677	5,166	0	0	2,934	12,776
2111	4,669	5,145	0	0	2,934	12,748
2112	3,140	531	0	0	2,942	6,612
2113	7,745	14,372	0	0	2,934	25,051
2114	6,207	9,759	0	0	2,934	18,899
2115	5,001	6,140	0	0	2,934	14,075
2116	3,140	2,195	0	0	12,934	18,268
2117	3,128	520	0	0	2,934	6,582
2118	1,058	725	15	0	1,545	3,343
Total	740,717	515,942	9,246	68,025	367,538	1,701,468

Note: Columns may not add due to rounding

TABLE 3.6
SCENARIO 3: DECON WITH 100 YEAR DFS, UNIT 2
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2034	7,760	336	305	10	5,078	13,490
2035	46,911	5,748	2,047	1,819	27,237	83,763
2036	67,514	40,656	2,261	23,855	20,777	155,063
2037	72,593	30,228	1,413	27,883	17,376	149,494
2038	46,604	15,462	847	13,940	13,784	90,636
2039	40,341	65,004	409	933	11,388	118,076
2040	37,417	4,345	559	3,106	7,433	52,861
2041	23,381	9,482	235	16	4,587	37,701
2042	16,739	13,784	174	0	4,471	35,167
2043	9,791	6,458	82	0	3,763	20,092
2044	3,676	0	0	0	3,147	6,823
2045	5,973	6,921	0	0	3,138	16,032
2046	5,204	4,614	0	0	3,138	12,956
2047	5,204	4,614	0	0	3,138	12,956
2048	3,676	0	0	0	3,147	6,823
2049	5,204	4,614	0	0	3,138	12,956
2050	5,973	6,921	0	0	3,138	16,032
2051	5,779	6,339	0	0	3,138	15,256
2052	5,983	6,921	0	0	3,147	16,051
2053	3,666	0	0	0	3,138	6,805
2054	3,666	0	0	0	3,138	6,805
2055	5,973	6,921	0	0	3,138	16,032
2056	5,214	4,614	0	0	3,147	12,975
2057	5,204	4,614	0	0	3,138	12,956
2058	3,666	0	0	0	3,138	6,805
2059	5,010	4,032	0	0	3,138	12,180
2060	5,214	4,614	0	0	3,147	12,975
2061	5,204	4,614	0	0	3,138	12,956
2062	3,666	0	0	0	3,138	6,805
2063	8,280	13,841	0	0	3,138	25,259

TABLE 3.6 (continued)
SCENARIO 3: DECON WITH 100 YEAR DFS, UNIT 2
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2064	6,558	8,646	0	0	3,147	18,351
2065	5,204	4,614	0	0	3,138	12,956
2066	3,666	0	0	0	3,138	6,805
2067	3,666	0	0	0	3,138	6,805
2068	6,752	9,227	0	0	3,147	19,126
2069	5,973	6,921	0	0	3,138	16,032
2070	3,666	0	0	0	3,138	6,805
2071	3,666	0	0	0	3,138	6,805
2072	7,327	10,952	0	0	3,147	21,426
2073	3,666	0	0	0	3,138	6,805
2074	3,666	0	0	0	3,138	6,805
2075	7,843	12,530	0	0	3,138	23,511
2076	3,676	0	0	0	3,147	6,823
2077	3,666	0	0	0	3,138	6,805
2078	7,511	11,534	0	0	3,138	22,184
2079	3,666	0	0	0	3,138	6,805
2080	3,676	0	0	0	3,147	6,823
2081	3,666	0	0	0	3,138	6,805
2082	7,123	10,371	0	0	3,138	20,632
2083	3,666	0	0	0	3,138	6,805
2084	3,676	0	0	0	3,147	6,823
2085	3,666	0	0	0	3,138	6,805
2086	3,666	0	0	0	3,138	6,805
2087	3,666	0	0	0	3,138	6,805
2088	3,676	0	0	0	3,147	6,823
2089	26,816	69,448	0	0	3,138	99,403
2090	3,666	0	0	1,934	3,138	8,739
2091	3,666	0	0	0	3,138	6,805
2092	3,676	0	0	0	3,147	6,823
2093	3,050	287	0	0	2,934	6,271

TABLE 3.6 (continued)
SCENARIO 3: DECON WITH 100 YEAR DFS, UNIT 2
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2094	3,146	574	0	0	2,934	6,653
2095	5,453	7,495	0	0	2,934	15,881
2096	4,740	5,331	0	0	2,942	13,013
2097	4,636	5,044	0	0	2,934	12,614
2098	3,241	861	0	0	2,934	7,036
2099	3,098	431	0	0	2,934	6,462
2100	5,357	7,208	0	0	2,934	15,498
2101	5,453	7,495	0	0	2,934	15,881
2102	5,453	7,495	0	0	2,934	15,881
2103	3,098	431	0	0	2,934	6,462
2104	3,154	574	0	0	2,942	6,670
2105	5,453	7,495	0	0	2,934	15,881
2106	4,636	5,044	0	0	2,934	12,614
2107	4,684	5,188	0	0	2,934	12,805
2108	3,154	574	0	0	2,942	6,670
2109	4,636	5,044	0	0	2,934	12,614
2110	4,677	5,166	0	0	2,934	12,776
2111	4,669	5,145	0	0	2,934	12,748
2112	3,140	531	0	0	2,942	6,612
2113	7,745	14,372	0	0	2,934	25,051
2114	6,207	9,759	0	0	2,934	18,899
2115	5,001	6,140	0	0	2,934	14,075
2116	3,140	2,195	0	0	12,934	18,268
2117	3,128	520	0	0	2,934	6,582
2118	1,058	725	15	0	1,545	3,343
Total	736,175	531,061	8,347	73,496	354,698	1,703,777

Note: Columns may not add due to rounding

TABLE 3.7
SCENARIO 4: DECON WITH 200 YEAR DFS, UNIT 1
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2033	22,324	776	692	25	9,206	33,023
2034	63,582	8,741	2,434	4,050	18,997	97,804
2035	65,877	37,199	1,850	20,920	22,520	148,367
2036	57,759	22,286	1,465	22,493	20,601	124,604
2037	39,808	11,582	984	15,000	15,667	83,040
2038	13,208	8,859	348	38	10,999	33,453
2039	35,713	64,815	409	820	10,715	112,472
2040	31,920	3,668	559	2,729	7,660	46,535
2041	19,625	5,945	235	16	4,500	30,321
2042	14,864	8,522	174	0	4,223	27,782
2043	8,912	3,992	82	0	3,608	16,594
2044	3,676	0	0	0	3,075	6,751
2045	5,973	6,921	0	0	3,066	15,960
2046	5,204	4,614	0	0	3,066	12,884
2047	5,204	4,614	0	0	3,066	12,884
2048	3,676	0	0	0	3,075	6,751
2049	5,204	4,614	0	0	3,066	12,884
2050	5,973	6,921	0	0	3,066	15,960
2051	5,779	6,339	0	0	3,066	15,184
2052	5,983	6,921	0	0	3,075	15,979
2053	3,666	0	0	0	3,066	6,733
2054	3,666	0	0	0	3,066	6,733
2055	5,973	6,921	0	0	3,066	15,960
2056	5,214	4,614	0	0	3,075	12,903
2057	5,204	4,614	0	0	3,066	12,884
2058	3,666	0	0	0	3,066	6,733
2059	5,010	4,032	0	0	3,066	12,109
2060	5,214	4,614	0	0	3,075	12,903
2061	5,204	4,614	0	0	3,066	12,884
2062	3,666	0	0	0	3,066	6,733

TABLE 3.7 (continued)
SCENARIO 4: DECON WITH 200 YEAR DFS, UNIT 1
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2063	8,280	13,841	0	0	3,066	25,188
2064	6,558	8,646	0	0	3,075	18,279
2065	5,204	4,614	0	0	3,066	12,884
2066	3,666	0	0	0	3,066	6,733
2067	3,666	0	0	0	3,066	6,733
2068	6,752	9,227	0	0	3,075	19,054
2069	5,973	6,921	0	0	3,066	15,960
2070	3,666	0	0	0	3,066	6,733
2071	3,666	0	0	0	3,066	6,733
2072	7,327	10,952	0	0	3,075	21,354
2073	3,666	0	0	0	3,066	6,733
2074	3,666	0	0	0	3,066	6,733
2075	7,843	12,530	0	0	3,066	23,439
2076	3,676	0	0	0	3,075	6,751
2077	3,666	0	0	0	3,066	6,733
2078	7,511	11,534	0	0	3,066	22,112
2079	3,666	0	0	0	3,066	6,733
2080	3,676	0	0	0	3,075	6,751
2081	3,666	0	0	0	3,066	6,733
2082	7,123	10,371	0	0	3,066	20,560
2083	3,666	0	0	0	3,066	6,733
2084	3,676	0	0	0	3,075	6,751
2085	3,666	0	0	0	3,066	6,733
2086	3,666	0	0	0	3,066	6,733
2087	3,666	0	0	0	3,066	6,733
2088	3,676	0	0	0	3,075	6,751
2089	26,770	69,311	0	1,934	3,214	101,230
2090	3,666	0	0	0	3,066	6,733
2091	3,666	0	0	0	3,066	6,733
2092	3,676	0	0	0	3,075	6,751

TABLE 3.7 (continued)
SCENARIO 4: DECON WITH 200 YEAR DFS, UNIT 1
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2093	3,666	0	0	0	3,066	6,733
2094	3,666	0	0	0	3,066	6,733
2095	5,973	6,921	0	0	3,066	15,960
2096	5,214	4,614	0	0	3,075	12,903
2097	5,204	4,614	0	0	3,066	12,884
2098	3,666	0	0	0	3,066	6,733
2099	3,666	0	0	0	3,066	6,733
2100	5,973	6,921	0	0	3,066	15,960
2101	5,973	6,921	0	0	3,066	15,960
2102	5,973	6,921	0	0	3,066	15,960
2103	3,666	0	0	0	3,066	6,733
2104	3,676	0	0	0	3,075	6,751
2105	5,973	6,921	0	0	3,066	15,960
2106	5,204	4,614	0	0	3,066	12,884
2107	5,204	4,614	0	0	3,066	12,884
2108	3,676	0	0	0	3,075	6,751
2109	5,204	4,614	0	0	3,066	12,884
2110	5,204	4,614	0	0	3,066	12,884
2111	5,204	4,614	0	0	3,066	12,884
2112	3,676	0	0	0	3,075	6,751
2113	8,280	13,841	0	0	3,066	25,188
2114	6,742	9,227	0	0	3,066	19,036
2115	5,536	5,609	0	0	3,066	14,212
2116	3,676	0	0	0	3,075	6,751
2117	3,666	0	0	0	3,066	6,733
2118	6,742	9,227	0	0	3,066	19,036
2119	5,973	6,921	0	0	3,066	15,960
2120	3,676	0	0	0	3,075	6,751
2121	3,666	0	0	0	3,066	6,733
2122	7,511	11,534	0	0	3,066	22,112

TABLE 3.7 (continued)
SCENARIO 4: DECON WITH 200 YEAR DFS, UNIT 1
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2123	3,666	0	0	0	3,066	6,733
2124	3,676	0	0	0	3,075	6,751
2125	7,511	11,534	0	0	3,066	22,112
2126	3,666	0	0	0	3,066	6,733
2127	3,666	0	0	0	3,066	6,733
2128	7,521	11,534	0	0	3,075	22,130
2129	3,666	0	0	0	3,066	6,733
2130	3,666	0	0	0	3,066	6,733
2131	3,666	0	0	0	3,066	6,733
2132	7,521	11,534	0	0	3,075	22,130
2133	3,666	0	0	0	3,066	6,733
2134	3,666	0	0	0	3,066	6,733
2135	3,666	0	0	0	3,066	6,733
2136	3,676	0	0	0	3,075	6,751
2137	3,666	0	0	0	3,066	6,733
2138	3,666	0	0	0	3,066	6,733
2139	26,781	69,344	0	0	3,066	99,191
2140	3,676	0	0	0	3,075	6,751
2141	3,666	0	0	0	3,066	6,733
2142	3,666	0	0	0	3,066	6,733
2143	3,666	0	0	0	3,066	6,733
2144	3,676	0	0	0	3,075	6,751
2145	5,973	6,921	0	0	3,066	15,960
2146	5,204	4,614	0	0	3,066	12,884
2147	5,204	4,614	0	0	3,066	12,884
2148	3,676	0	0	0	3,075	6,751
2149	3,666	0	0	0	3,066	6,733
2150	5,973	6,921	0	0	3,066	15,960
2151	5,973	6,921	0	0	3,066	15,960
2152	5,983	6,921	0	0	3,075	15,979

TABLE 3.7 (continued)
SCENARIO 4: DECON WITH 200 YEAR DFS, UNIT 1
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2153	3,666	0	0	0	3,066	6,733
2154	3,666	0	0	0	3,066	6,733
2155	6,305	7,916	0	0	3,066	17,287
2156	5,214	4,614	0	0	3,075	12,903
2157	5,204	4,614	0	0	3,066	12,884
2158	3,666	0	0	0	3,066	6,733
2159	5,204	4,614	0	0	3,066	12,884
2160	5,214	4,614	0	0	3,075	12,903
2161	5,204	4,614	0	0	3,066	12,884
2162	3,666	0	0	0	3,066	6,733
2163	8,280	13,841	0	0	3,066	25,188
2164	6,752	9,227	0	0	3,075	19,054
2165	5,204	4,614	0	0	3,066	12,884
2166	3,666	0	0	0	3,066	6,733
2167	3,666	0	0	0	3,066	6,733
2168	6,752	9,227	0	0	3,075	19,054
2169	5,973	6,921	0	0	3,066	15,960
2170	3,666	0	0	0	3,066	6,733
2171	3,666	0	0	0	3,066	6,733
2172	7,521	11,534	0	0	3,075	22,130
2173	3,666	0	0	0	3,066	6,733
2174	3,666	0	0	0	3,066	6,733
2175	7,511	11,534	0	0	3,066	22,112
2176	3,676	0	0	0	3,075	6,751
2177	3,666	0	0	0	3,066	6,733
2178	7,511	11,534	0	0	3,066	22,112
2179	3,666	0	0	0	3,066	6,733
2180	3,676	0	0	0	3,075	6,751
2181	3,666	0	0	0	3,066	6,733
2182	7,511	11,534	0	0	3,066	22,112

TABLE 3.7 (continued)
SCENARIO 4: DECON WITH 200 YEAR DFS, UNIT 1
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2183	3,666	0	0	0	3,066	6,733
2184	3,676	0	0	0	3,075	6,751
2185	3,666	0	0	0	3,066	6,733
2186	3,666	0	0	0	3,066	6,733
2187	3,666	0	0	0	3,066	6,733
2188	3,676	0	0	0	3,075	6,751
2189	26,781	69,344	0	0	3,066	99,191
2190	3,666	0	0	0	3,066	6,733
2191	3,666	0	0	0	3,066	6,733
2192	3,676	0	0	0	3,075	6,751
2193	3,050	287	0	0	2,934	6,271
2194	3,146	574	0	0	2,934	6,653
2195	5,784	8,490	0	0	2,934	17,208
2196	4,740	5,331	0	0	2,942	13,013
2197	4,636	5,044	0	0	2,934	12,614
2198	3,241	861	0	0	2,934	7,036
2199	3,098	431	0	0	2,934	6,462
2200	5,357	7,208	0	0	2,934	15,498
2201	5,453	7,495	0	0	2,934	15,881
2202	5,453	7,495	0	0	2,934	15,881
2203	3,098	431	0	0	2,934	6,462
2204	3,154	574	0	0	2,942	6,670
2205	5,453	7,495	0	0	2,934	15,881
2206	4,636	5,044	0	0	2,934	12,614
2207	4,684	5,188	0	0	2,934	12,805
2208	3,154	574	0	0	2,942	6,670
2209	4,636	5,044	0	0	2,934	12,614
2210	4,677	5,166	0	0	2,934	12,776
2211	4,669	5,145	0	0	2,934	12,748
2212	3,140	531	0	0	2,942	6,612

TABLE 3.7 (continued)
SCENARIO 4: DECON WITH 200 YEAR DFS, UNIT 1
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2213	7,745	14,372	0	0	2,934	25,051
2214	6,207	9,759	0	0	2,934	18,899
2215	4,669	5,145	0	0	2,934	12,748
2216	3,140	2,195	0	0	12,934	18,268
2217	3,146	574	0	0	2,934	6,653
2218	1,058	724	15	0	1,545	3,342
Total	1,259,023	970,270	9,246	68,025	670,974	2,977,538

Note: Columns may not add due to rounding

TABLE 3.8
SCENARIO 4: DECON WITH 200 YEAR DFS, UNIT 2
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2034	7,760	336	305	10	5,078	13,490
2035	46,911	5,748	2,047	1,819	27,237	83,763
2036	67,514	40,656	2,261	23,855	20,777	155,063
2037	72,593	30,228	1,413	27,883	17,376	149,494
2038	46,604	15,462	847	13,940	13,784	90,636
2039	40,341	65,004	409	933	11,388	118,076
2040	37,417	4,345	559	3,106	7,433	52,861
2041	23,381	9,482	235	16	4,587	37,701
2042	16,739	13,784	174	0	4,471	35,167
2043	9,791	6,458	82	0	3,725	20,055
2044	3,676	0	0	0	3,076	6,752
2045	5,973	6,921	0	0	3,067	15,961
2046	5,204	4,614	0	0	3,067	12,885
2047	5,204	4,614	0	0	3,067	12,885
2048	3,676	0	0	0	3,076	6,752
2049	5,204	4,614	0	0	3,067	12,885
2050	5,973	6,921	0	0	3,067	15,961
2051	5,779	6,339	0	0	3,067	15,185
2052	5,983	6,921	0	0	3,076	15,980
2053	3,666	0	0	0	3,067	6,734
2054	3,666	0	0	0	3,067	6,734
2055	5,973	6,921	0	0	3,067	15,961
2056	5,214	4,614	0	0	3,076	12,904
2057	5,204	4,614	0	0	3,067	12,885
2058	3,666	0	0	0	3,067	6,734
2059	5,010	4,032	0	0	3,067	12,110
2060	5,214	4,614	0	0	3,076	12,904
2061	5,204	4,614	0	0	3,067	12,885
2062	3,666	0	0	0	3,067	6,734
2063	8,280	13,841	0	0	3,067	25,189

TABLE 3.8 (continued)
SCENARIO 4: DECON WITH 200 YEAR DFS, UNIT 2
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2064	6,558	8,646	0	0	3,076	18,280
2065	5,204	4,614	0	0	3,067	12,885
2066	3,666	0	0	0	3,067	6,734
2067	3,666	0	0	0	3,067	6,734
2068	6,752	9,227	0	0	3,076	19,055
2069	5,973	6,921	0	0	3,067	15,961
2070	3,666	0	0	0	3,067	6,734
2071	3,666	0	0	0	3,067	6,734
2072	7,327	10,952	0	0	3,076	21,355
2073	3,666	0	0	0	3,067	6,734
2074	3,666	0	0	0	3,067	6,734
2075	7,843	12,530	0	0	3,067	23,440
2076	3,676	0	0	0	3,076	6,752
2077	3,666	0	0	0	3,067	6,734
2078	7,511	11,534	0	0	3,067	22,113
2079	3,666	0	0	0	3,067	6,734
2080	3,676	0	0	0	3,076	6,752
2081	3,666	0	0	0	3,067	6,734
2082	7,123	10,371	0	0	3,067	20,561
2083	3,666	0	0	0	3,067	6,734
2084	3,676	0	0	0	3,076	6,752
2085	3,666	0	0	0	3,067	6,734
2086	3,666	0	0	0	3,067	6,734
2087	3,666	0	0	0	3,067	6,734
2088	3,676	0	0	0	3,076	6,752
2089	26,770	69,311	0	1,934	3,067	101,083
2090	3,666	0	0	0	3,067	6,734
2091	3,666	0	0	0	3,067	6,734
2092	3,676	0	0	0	3,076	6,752
2093	3,666	0	0	0	3,067	6,734

TABLE 3.8 (continued)
SCENARIO 4: DECON WITH 200 YEAR DFS, UNIT 2
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2094	3,666	0	0	0	3,067	6,734
2095	5,973	6,921	0	0	3,067	15,961
2096	5,214	4,614	0	0	3,076	12,904
2097	5,204	4,614	0	0	3,067	12,885
2098	3,666	0	0	0	3,067	6,734
2099	3,666	0	0	0	3,067	6,734
2100	5,973	6,921	0	0	3,067	15,961
2101	5,973	6,921	0	0	3,067	15,961
2102	5,973	6,921	0	0	3,067	15,961
2103	3,666	0	0	0	3,067	6,734
2104	3,676	0	0	0	3,076	6,752
2105	5,973	6,921	0	0	3,067	15,961
2106	5,204	4,614	0	0	3,067	12,885
2107	5,204	4,614	0	0	3,067	12,885
2108	3,676	0	0	0	3,076	6,752
2109	5,204	4,614	0	0	3,067	12,885
2110	5,204	4,614	0	0	3,067	12,885
2111	5,204	4,614	0	0	3,067	12,885
2112	3,676	0	0	0	3,076	6,752
2113	8,280	13,841	0	0	3,067	25,189
2114	6,742	9,227	0	0	3,067	19,037
2115	5,536	5,609	0	0	3,067	14,213
2116	3,676	0	0	0	3,076	6,752
2117	3,666	0	0	0	3,067	6,734
2118	6,742	9,227	0	0	3,067	19,037
2119	5,973	6,921	0	0	3,067	15,961
2120	3,676	0	0	0	3,076	6,752
2121	3,666	0	0	0	3,067	6,734
2122	7,511	11,534	0	0	3,067	22,113
2123	3,666	0	0	0	3,067	6,734

TABLE 3.8 (continued)
SCENARIO 4: DECON WITH 200 YEAR DFS, UNIT 2
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2124	3,676	0	0	0	3,076	6,752
2125	7,511	11,534	0	0	3,067	22,113
2126	3,666	0	0	0	3,067	6,734
2127	3,666	0	0	0	3,067	6,734
2128	7,521	11,534	0	0	3,076	22,131
2129	3,666	0	0	0	3,067	6,734
2130	3,666	0	0	0	3,067	6,734
2131	3,666	0	0	0	3,067	6,734
2132	7,521	11,534	0	0	3,076	22,131
2133	3,666	0	0	0	3,067	6,734
2134	3,666	0	0	0	3,067	6,734
2135	3,666	0	0	0	3,067	6,734
2136	3,676	0	0	0	3,076	6,752
2137	3,666	0	0	0	3,067	6,734
2138	3,666	0	0	0	3,067	6,734
2139	26,781	69,344	0	0	3,067	99,192
2140	3,676	0	0	0	3,076	6,752
2141	3,666	0	0	0	3,067	6,734
2142	3,666	0	0	0	3,067	6,734
2143	3,666	0	0	0	3,067	6,734
2144	3,676	0	0	0	3,076	6,752
2145	5,973	6,921	0	0	3,067	15,961
2146	5,204	4,614	0	0	3,067	12,885
2147	5,204	4,614	0	0	3,067	12,885
2148	3,676	0	0	0	3,076	6,752
2149	3,666	0	0	0	3,067	6,734
2150	5,973	6,921	0	0	3,067	15,961
2151	5,973	6,921	0	0	3,067	15,961
2152	5,983	6,921	0	0	3,076	15,980
2153	3,666	0	0	0	3,067	6,734

TABLE 3.8 (continued)
SCENARIO 4: DECON WITH 200 YEAR DFS, UNIT 2
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2154	3,666	0	0	0	3,067	6,734
2155	6,305	7,916	0	0	3,067	17,288
2156	5,214	4,614	0	0	3,076	12,904
2157	5,204	4,614	0	0	3,067	12,885
2158	3,666	0	0	0	3,067	6,734
2159	5,204	4,614	0	0	3,067	12,885
2160	5,214	4,614	0	0	3,076	12,904
2161	5,204	4,614	0	0	3,067	12,885
2162	3,666	0	0	0	3,067	6,734
2163	8,280	13,841	0	0	3,067	25,189
2164	6,752	9,227	0	0	3,076	19,055
2165	5,204	4,614	0	0	3,067	12,885
2166	3,666	0	0	0	3,067	6,734
2167	3,666	0	0	0	3,067	6,734
2168	6,752	9,227	0	0	3,076	19,055
2169	5,973	6,921	0	0	3,067	15,961
2170	3,666	0	0	0	3,067	6,734
2171	3,666	0	0	0	3,067	6,734
2172	7,521	11,534	0	0	3,076	22,131
2173	3,666	0	0	0	3,067	6,734
2174	3,666	0	0	0	3,067	6,734
2175	7,511	11,534	0	0	3,067	22,113
2176	3,676	0	0	0	3,076	6,752
2177	3,666	0	0	0	3,067	6,734
2178	7,511	11,534	0	0	3,067	22,113
2179	3,666	0	0	0	3,067	6,734
2180	3,676	0	0	0	3,076	6,752
2181	3,666	0	0	0	3,067	6,734
2182	7,511	11,534	0	0	3,067	22,113
2183	3,666	0	0	0	3,067	6,734

TABLE 3.8 (continued)
SCENARIO 4: DECON WITH 200 YEAR DFS, UNIT 2
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2184	3,676	0	0	0	3,076	6,752
2185	3,666	0	0	0	3,067	6,734
2186	3,666	0	0	0	3,067	6,734
2187	3,666	0	0	0	3,067	6,734
2188	3,676	0	0	0	3,076	6,752
2189	26,781	69,344	0	0	3,067	99,192
2190	3,666	0	0	0	3,067	6,734
2191	3,666	0	0	0	3,067	6,734
2192	3,676	0	0	0	3,076	6,752
2193	3,050	287	0	0	2,934	6,271
2194	3,146	574	0	0	2,934	6,653
2195	5,784	8,490	0	0	2,934	17,208
2196	4,740	5,331	0	0	2,942	13,013
2197	4,636	5,044	0	0	2,934	12,614
2198	3,241	861	0	0	2,934	7,036
2199	3,098	431	0	0	2,934	6,462
2200	5,357	7,208	0	0	2,934	15,498
2201	5,453	7,495	0	0	2,934	15,881
2202	5,453	7,495	0	0	2,934	15,881
2203	3,098	431	0	0	2,934	6,462
2204	3,154	574	0	0	2,942	6,670
2205	5,453	7,495	0	0	2,934	15,881
2206	4,636	5,044	0	0	2,934	12,614
2207	4,684	5,188	0	0	2,934	12,805
2208	3,154	574	0	0	2,942	6,670
2209	4,636	5,044	0	0	2,934	12,614
2210	4,677	5,166	0	0	2,934	12,776
2211	4,669	5,145	0	0	2,934	12,748
2212	3,140	531	0	0	2,942	6,612
2213	7,745	14,372	0	0	2,934	25,051

TABLE 3.8 (continued)
SCENARIO 4: DECON WITH 200 YEAR DFS, UNIT 2
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2214	6,207	9,759	0	0	2,934	18,899
2215	4,669	5,145	0	0	2,934	12,748
2216	3,140	2,195	0	0	12,934	18,268
2217	3,146	574	0	0	2,934	6,653
2218	1,058	724	15	0	1,545	3,342
2214	6,207	9,759	0	0	2,934	18,899
2215	4,669	5,145	0	0	2,934	12,748
2216	3,140	2,195	0	0	12,934	18,268
2217	3,146	574	0	0	2,934	6,653
2218	1,058	724	15	0	1,545	3,342
Total	1,254,481	985,388	8,347	73,496	658,134	2,979,847

Note: Columns may not add due to rounding

TABLE 3.9
SCENARIO 5: DECON WITH 60 YEAR DFS WITH RECASKING, UNIT 1
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2033	22,324	776	692	25	9,206	33,023
2034	63,582	8,741	2,434	4,050	18,997	97,804
2035	65,877	37,199	1,850	20,920	22,520	148,367
2036	57,759	22,286	1,465	22,493	20,601	124,604
2037	39,808	11,582	984	15,000	15,667	83,040
2038	13,208	8,859	348	38	10,999	33,453
2039	36,036	65,782	409	820	10,715	113,763
2040	31,920	3,668	559	2,729	7,660	46,535
2041	19,571	5,945	235	16	4,500	30,267
2042	14,782	8,522	174	0	4,223	27,701
2043	8,544	3,992	82	0	3,669	16,287
2044	3,055	0	0	0	3,189	6,244
2045	5,353	6,921	0	0	3,180	15,454
2046	4,584	4,614	0	0	3,180	12,378
2047	4,584	4,614	0	0	3,180	12,378
2048	3,055	0	0	0	3,189	6,244
2049	4,584	4,614	0	0	3,180	12,378
2050	5,353	6,921	0	0	3,180	15,454
2051	5,159	6,339	0	0	3,180	14,678
2052	5,362	6,921	0	0	3,189	15,471
2053	3,142	287	0	0	3,180	6,609
2054	3,238	574	0	0	3,180	6,992
2055	5,545	7,495	0	0	3,180	16,220
2056	4,832	5,331	0	0	3,189	13,352
2057	5,303	6,769	0	0	3,180	15,253
2058	3,334	861	0	0	3,180	7,375
2059	3,190	431	0	0	3,180	6,801
2060	3,150	287	0	0	3,189	6,627
2061	3,238	574	0	0	3,180	6,992
2062	3,238	574	0	0	3,180	6,992

TABLE 3.9 (continued)
SCENARIO 5: DECON WITH 60 YEAR DFS WITH RECASKING, UNIT 1
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2063	3,190	431	0	0	3,180	6,801
2064	3,246	574	0	0	3,189	7,009
2065	3,238	574	0	0	3,180	6,992
2066	3,190	431	0	0	3,180	6,801
2067	3,238	574	0	0	3,180	6,992
2068	3,246	574	0	0	3,189	7,009
2069	3,190	431	0	0	3,180	6,801
2070	3,238	574	0	0	3,180	6,992
2071	3,238	574	0	0	3,180	6,992
2072	3,246	574	0	0	3,189	7,009
2073	3,238	574	0	0	3,180	6,992
2074	3,238	574	0	0	3,180	6,992
2075	3,570	1,570	0	0	3,180	8,320
2076	3,246	574	0	0	3,189	7,009
2077	3,238	2,238	0	0	13,164	18,641
2078	983	594	15	2,862	1,678	6,132
Total	502,484	252,913	9,246	68,953	248,627	1,082,223

Note: Columns may not add due to rounding

TABLE 3.10
SCENARIO 5: DECON WITH 60 YEAR DFS WITH RECASKING, UNIT 2
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2034	7,760	336	305	10	5,078	13,490
2035	46,911	5,748	2,047	1,819	27,237	83,763
2036	67,514	40,656	2,261	23,855	20,777	155,063
2037	72,593	30,228	1,413	27,883	17,376	149,494
2038	46,604	15,462	847	13,940	13,784	90,636
2039	40,664	65,972	409	933	11,388	119,366
2040	37,417	4,345	559	3,106	7,433	52,861
2041	23,328	9,482	235	16	4,587	37,648
2042	16,657	13,784	174	0	4,471	35,086
2043	9,423	6,458	82	0	3,785	19,747
2044	3,055	0	0	0	3,189	6,244
2045	5,353	6,921	0	0	3,180	15,454
2046	4,584	4,614	0	0	3,180	12,378
2047	4,584	4,614	0	0	3,180	12,378
2048	3,055	0	0	0	3,189	6,244
2049	4,584	4,614	0	0	3,180	12,378
2050	5,353	6,921	0	0	3,180	15,454
2051	5,159	6,339	0	0	3,180	14,678
2052	5,362	6,921	0	0	3,189	15,471
2053	3,142	287	0	0	3,180	6,609
2054	3,238	574	0	0	3,180	6,992
2055	5,545	7,495	0	0	3,180	16,220
2056	4,832	5,331	0	0	3,189	13,352
2057	5,303	6,769	0	0	3,180	15,253
2058	3,334	861	0	0	3,180	7,375
2059	3,190	431	0	0	3,180	6,801
2060	3,150	287	0	0	3,189	6,627
2061	3,238	574	0	0	3,180	6,992
2062	3,238	574	0	0	3,180	6,992
2063	3,190	431	0	0	3,180	6,801

TABLE 3.10 (continued)
SCENARIO 5: DECON WITH 60 YEAR DFS WITH RECASKING, UNIT 2
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2064	3,246	574	0	0	3,189	7,009
2065	3,238	574	0	0	3,180	6,992
2066	3,190	431	0	0	3,180	6,801
2067	3,238	574	0	0	3,180	6,992
2068	3,246	574	0	0	3,189	7,009
2069	3,190	431	0	0	3,180	6,801
2070	3,238	574	0	0	3,180	6,992
2071	3,238	574	0	0	3,180	6,992
2072	3,246	574	0	0	3,189	7,009
2073	3,238	574	0	0	3,180	6,992
2074	3,238	574	0	0	3,180	6,992
2075	3,570	1,570	0	0	3,180	8,320
2076	3,246	574	0	0	3,189	7,009
2077	3,238	2,238	0	0	13,164	18,641
2078	983	594	15	2,862	1,678	6,132
Total	497,942	268,032	8,347	74,423	235,787	1,084,531

Note: Columns may not add due to rounding

TABLE 3.11
SCENARIO 6: SAFSTOR WITH 32 YEAR DFS, UNIT 1
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2033	18,447	579	692	25	4,145	23,888
2034	46,143	3,822	1,742	503	24,345	76,555
2035	16,590	2,662	497	150	14,007	33,906
2036	12,851	1,279	349	21	13,950	28,450
2037	12,769	1,134	348	21	13,912	28,184
2038	12,721	990	348	21	13,912	27,992
2039	32,557	64,654	318	19	12,377	109,925
2040	4,748	727	175	11	5,173	10,832
2041	4,783	870	174	11	5,159	10,996
2042	4,735	726	174	11	5,159	10,804
2043	4,687	582	174	11	5,159	10,613
2044	4,700	583	175	11	5,173	10,641
2045	4,687	582	174	11	5,159	10,613
2046	4,592	295	174	11	5,159	10,230
2047	4,592	295	174	11	5,159	10,230
2048	4,604	296	175	11	5,173	10,258
2049	4,592	295	174	11	5,159	10,230
2050	4,687	582	174	11	5,159	10,613
2051	4,687	582	174	11	5,159	10,613
2052	4,700	583	175	11	5,173	10,641
2053	4,687	582	174	11	5,159	10,613
2054	4,687	582	174	11	5,159	10,613
2055	4,687	582	174	11	5,159	10,613
2056	4,700	583	175	11	5,173	10,641
2057	4,687	582	174	11	5,159	10,613
2058	4,687	582	174	11	5,159	10,613
2059	4,687	582	174	11	5,159	10,613
2060	4,700	583	175	11	5,173	10,641
2061	4,687	582	174	11	5,159	10,613
2062	4,687	582	174	11	5,159	10,613

TABLE 3.11 (continued)
SCENARIO 6: SAFSTOR WITH 32 YEAR DFS, UNIT 1
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2063	4,687	582	174	11	5,159	10,613
2064	4,696	572	175	11	5,173	10,626
2065	3,942	294	174	10	3,247	7,668
2066	3,942	294	174	10	3,247	7,668
2067	3,942	294	174	10	3,247	7,668
2068	3,953	295	175	10	3,256	7,689
2069	3,942	294	174	10	3,247	7,668
2070	3,942	294	174	10	3,247	7,668
2071	3,942	294	174	10	3,247	7,668
2072	3,953	295	175	10	3,256	7,689
2073	3,942	294	174	10	3,247	7,668
2074	3,942	294	174	10	3,247	7,668
2075	3,942	294	174	10	3,247	7,668
2076	3,953	295	175	10	3,256	7,689
2077	3,942	294	174	10	3,247	7,668
2078	3,942	294	174	10	3,247	7,668
2079	3,942	294	174	10	3,247	7,668
2080	3,953	295	175	10	3,256	7,689
2081	3,942	294	174	10	3,247	7,668
2082	3,942	294	174	10	3,247	7,668
2083	3,942	294	174	10	3,247	7,668
2084	3,953	295	175	10	3,256	7,689
2085	3,942	294	174	10	3,247	7,668
2086	3,942	294	174	10	3,247	7,668
2087	18,999	2,111	758	729	3,199	25,796
2088	45,688	5,640	1,747	1,239	3,031	57,345
2089	52,326	36,394	1,665	20,208	15,137	125,731
2090	41,397	18,920	1,422	17,534	10,610	89,883
2091	35,648	8,162	1,306	14,802	7,509	67,427
2092	8,980	1,167	197	1,677	3,040	15,061

TABLE 3.11 (continued)
SCENARIO 6: SAFSTOR WITH 32 YEAR DFS, UNIT 1
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2093	18,089	3,901	279	27	2,021	24,317
2094	12,585	8,129	174	0	962	21,849
2095	9,102	5,880	126	0	695	15,803
Total	598,752	185,878	20,162	57,466	343,387	1,205,645

Note: Columns may not add due to rounding

TABLE 3.12
SCENARIO 6: SAFSTOR WITH 32 YEAR DFS, UNIT 2
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2034	7,249	254	305	11	3,507	11,325
2035	45,009	5,734	1,742	336	26,288	79,109
2036	23,213	3,341	807	447	17,173	44,981
2037	10,905	1,140	348	19	12,561	24,974
2038	10,857	996	348	19	12,561	24,782
2039	31,030	64,662	318	18	11,274	107,302
2040	4,803	745	175	11	5,235	10,969
2041	4,838	888	174	11	5,221	11,132
2042	4,791	744	174	11	5,221	10,941
2043	4,743	601	174	11	5,221	10,749
2044	4,756	602	175	11	5,235	10,778
2045	4,743	601	174	11	5,221	10,749
2046	4,647	314	174	11	5,221	10,367
2047	4,647	314	174	11	5,221	10,367
2048	4,660	315	175	11	5,235	10,395
2049	4,647	314	174	11	5,221	10,367
2050	4,743	601	174	11	5,221	10,749
2051	4,743	601	174	11	5,221	10,749
2052	4,756	602	175	11	5,235	10,778
2053	4,743	601	174	11	5,221	10,749
2054	4,743	601	174	11	5,221	10,749
2055	4,743	601	174	11	5,221	10,749
2056	4,756	602	175	11	5,235	10,778
2057	4,743	601	174	11	5,221	10,749
2058	4,743	601	174	11	5,221	10,749
2059	4,743	601	174	11	5,221	10,749
2060	4,756	602	175	11	5,235	10,778
2061	4,743	601	174	11	5,221	10,749
2062	4,743	601	174	11	5,221	10,749
2063	4,743	601	174	11	5,221	10,749

TABLE 3.12 (continued)
SCENARIO 6: SAFSTOR WITH 32 YEAR DFS, UNIT 2
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2064	4,752	590	175	11	5,235	10,762
2065	823	308	174	10	3,355	4,670
2066	823	308	174	10	3,355	4,670
2067	823	308	174	10	3,355	4,670
2068	826	308	175	10	3,365	4,683
2069	823	308	174	10	3,355	4,670
2070	823	308	174	10	3,355	4,670
2071	823	308	174	10	3,355	4,670
2072	826	308	175	10	3,365	4,683
2073	823	308	174	10	3,355	4,670
2074	823	308	174	10	3,355	4,670
2075	823	308	174	10	3,355	4,670
2076	826	308	175	10	3,365	4,683
2077	823	308	174	10	3,355	4,670
2078	823	308	174	10	3,355	4,670
2079	823	308	174	10	3,355	4,670
2080	826	308	175	10	3,365	4,683
2081	823	308	174	10	3,355	4,670
2082	823	308	174	10	3,355	4,670
2083	823	308	174	10	3,355	4,670
2084	826	308	175	10	3,365	4,683
2085	823	308	174	10	3,355	4,670
2086	823	308	174	10	3,355	4,670
2087	823	308	174	10	3,355	4,670
2088	16,232	2,279	1,042	1,079	3,151	23,784
2089	30,943	7,318	1,737	2,199	3,588	45,784
2090	57,907	44,332	1,655	23,815	17,213	144,922
2091	55,239	13,374	1,333	18,095	8,227	96,268
2092	51,390	9,469	1,171	15,116	6,778	83,924
2093	23,224	6,185	279	27	1,746	31,462

TABLE 3.12 (continued)
SCENARIO 6: SAFSTOR WITH 32 YEAR DFS, UNIT 2
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2094	14,461	13,418	174	0	594	28,648
2095	10,459	9,705	126	0	430	20,720
Total	525,529	203,731	19,753	61,668	332,940	1,143,621

Note: Columns may not add due to rounding

TABLE 3.13
SCENARIO 7: SAFSTOR WITH 60 YEAR DFS, UNIT 1
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2033	18,447	579	692	25	4,145	23,888
2034	46,143	3,822	1,742	503	24,345	76,555
2035	16,399	2,087	497	150	14,007	33,141
2036	12,660	705	349	21	13,950	27,684
2037	12,625	704	348	21	13,912	27,610
2038	15,404	9,041	348	21	13,912	38,727
2039	32,688	65,048	318	19	12,390	110,463
2040	4,604	296	175	11	5,246	10,331
2041	4,592	295	174	11	5,231	10,303
2042	4,592	295	174	11	5,231	10,303
2043	4,592	295	174	11	5,231	10,303
2044	4,604	296	175	11	5,246	10,331
2045	4,592	295	174	11	5,231	10,303
2046	4,592	295	174	11	5,231	10,303
2047	4,592	295	174	11	5,231	10,303
2048	4,604	296	175	11	5,246	10,331
2049	4,592	295	174	11	5,231	10,303
2050	4,592	295	174	11	5,231	10,303
2051	4,592	295	174	11	5,231	10,303
2052	4,604	296	175	11	5,246	10,331
2053	4,687	582	174	11	5,231	10,686
2054	4,783	870	174	11	5,231	11,069
2055	4,783	870	174	11	5,231	11,069
2056	4,843	1,014	175	11	5,246	11,288
2057	4,735	726	174	11	5,231	10,877
2058	4,879	1,157	174	11	5,231	11,451
2059	4,735	726	174	11	5,231	10,877
2060	4,700	583	175	11	5,246	10,714
2061	4,783	870	174	11	5,231	11,069
2062	4,783	870	174	11	5,231	11,069

TABLE 3.13 (continued)
SCENARIO 7: SAFSTOR WITH 60 YEAR DFS, UNIT 1
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2063	4,735	726	174	11	5,231	10,877
2064	4,796	870	175	11	5,246	11,097
2065	4,783	870	174	11	5,231	11,069
2066	4,735	726	174	11	5,231	10,877
2067	4,783	870	174	11	5,231	11,069
2068	4,796	870	175	11	5,246	11,097
2069	4,735	726	174	11	5,231	10,877
2070	4,783	870	174	11	5,231	11,069
2071	4,783	870	174	11	5,231	11,069
2072	4,796	870	175	11	5,246	11,097
2073	4,783	870	174	11	5,231	11,069
2074	4,783	870	174	11	5,231	11,069
2075	5,115	1,865	174	11	5,231	12,396
2076	4,796	870	175	11	5,246	11,097
2077	4,783	870	174	11	5,231	11,069
2078	3,942	294	174	10	2,778	7,199
2079	3,942	294	174	10	2,778	7,199
2080	3,953	295	175	10	2,786	7,219
2081	3,942	294	174	10	2,778	7,199
2082	3,942	294	174	10	2,778	7,199
2083	3,942	294	174	10	2,778	7,199
2084	3,953	295	175	10	2,786	7,219
2085	3,942	294	174	10	2,778	7,199
2086	3,942	294	174	10	2,778	7,199
2087	11,803	1,243	479	386	2,844	16,754
2088	45,111	5,423	1,747	1,574	3,061	56,916
2089	51,818	31,091	1,681	16,603	12,903	114,096
2090	44,188	24,104	1,471	19,038	12,141	100,943
2091	35,668	8,206	1,306	14,802	7,520	67,503
2092	13,716	2,324	383	3,784	3,768	23,975

TABLE 3.13 (continued)
SCENARIO 7: SAFSTOR WITH 60 YEAR DFS, UNIT 1
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2093	18,089	3,901	279	27	2,021	24,317
2094	12,585	8,129	174	0	962	21,849
2095	9,102	5,880	126	0	695	15,803
Total	611,385	200,655	20,134	57,467	366,528	1,256,169

Note: Columns may not add due to rounding

TABLE 3.14
SCENARIO 7: SAFSTOR WITH 60 YEAR DFS, UNIT 2
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2034	7,249	254	305	11	3,507	11,325
2035	44,818	5,160	1,742	336	26,288	78,343
2036	23,021	2,767	807	447	17,173	44,216
2037	10,761	710	348	19	12,561	24,400
2038	13,540	9,047	348	19	12,561	35,517
2039	31,161	65,056	318	18	11,274	107,827
2040	4,660	315	175	11	5,236	10,395
2041	4,647	314	174	11	5,221	10,367
2042	4,647	314	174	11	5,221	10,367
2043	4,647	314	174	11	5,221	10,367
2044	4,660	315	175	11	5,236	10,395
2045	4,647	314	174	11	5,221	10,367
2046	4,647	314	174	11	5,221	10,367
2047	4,647	314	174	11	5,221	10,367
2048	4,660	315	175	11	5,236	10,395
2049	4,647	314	174	11	5,221	10,367
2050	4,647	314	174	11	5,221	10,367
2051	4,647	314	174	11	5,221	10,367
2052	4,660	315	175	11	5,236	10,395
2053	4,743	601	174	11	5,221	10,750
2054	4,838	888	174	11	5,221	11,132
2055	4,838	888	174	11	5,221	11,132
2056	4,899	1,032	175	11	5,236	11,352
2057	4,791	744	174	11	5,221	10,941
2058	4,934	1,175	174	11	5,221	11,515
2059	4,791	744	174	11	5,221	10,941
2060	4,756	602	175	11	5,236	10,778
2061	4,838	888	174	11	5,221	11,132
2062	4,838	888	174	11	5,221	11,132
2063	4,791	744	174	11	5,221	10,941

TABLE 3.14 (continued)
SCENARIO 7: SAFSTOR WITH 60 YEAR DFS, UNIT 2
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

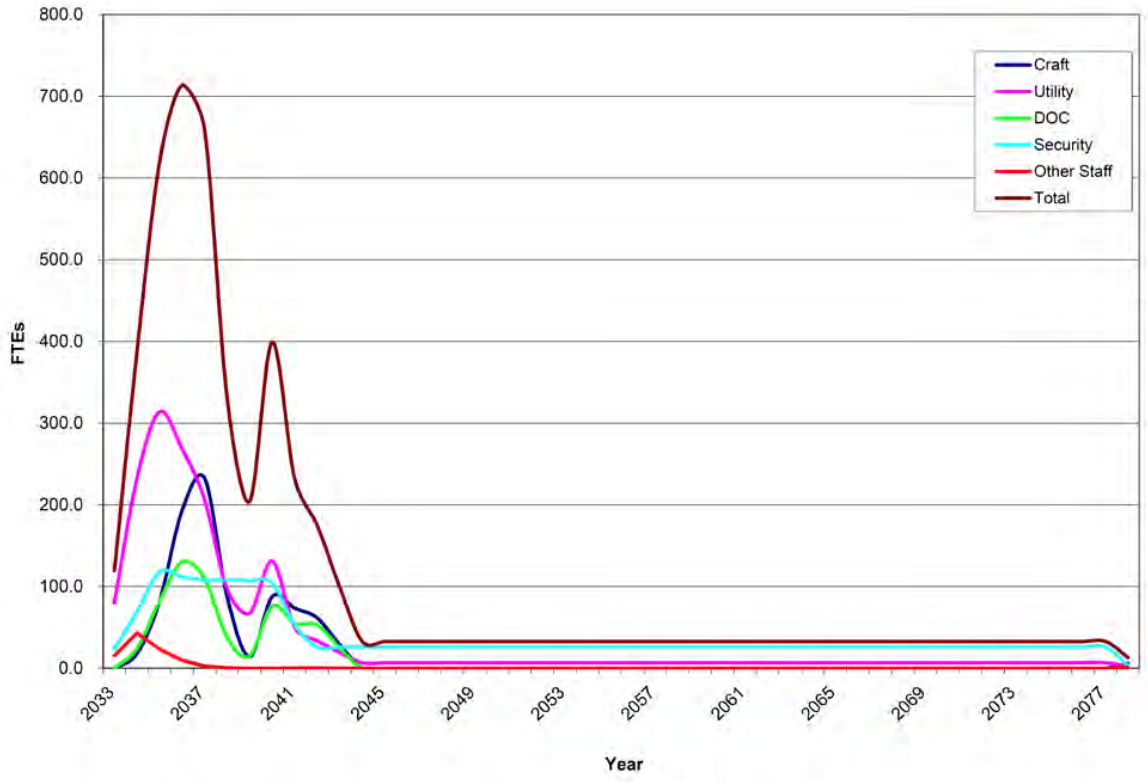
Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2064	4,851	889	175	11	5,236	11,161
2065	4,838	888	174	11	5,221	11,132
2066	4,791	744	174	11	5,221	10,941
2067	4,838	888	174	11	5,221	11,132
2068	4,851	889	175	11	5,236	11,161
2069	4,791	744	174	11	5,221	10,941
2070	4,838	888	174	11	5,221	11,132
2071	4,838	888	174	11	5,221	11,132
2072	4,851	889	175	11	5,236	11,161
2073	4,838	888	174	11	5,221	11,132
2074	4,838	888	174	11	5,221	11,132
2075	5,170	1,883	174	11	5,221	12,460
2076	4,851	889	175	11	5,236	11,161
2077	4,838	888	174	11	5,221	11,132
2078	823	308	174	10	2,781	4,096
2079	823	308	174	10	2,781	4,096
2080	826	308	175	10	2,789	4,107
2081	823	308	174	10	2,781	4,096
2082	823	308	174	10	2,781	4,096
2083	823	308	174	10	2,781	4,096
2084	826	308	175	10	2,789	4,107
2085	823	308	174	10	2,781	4,096
2086	823	308	174	10	2,781	4,096
2087	823	308	174	10	2,781	4,096
2088	11,275	1,645	763	735	2,844	17,262
2089	29,172	4,796	1,742	1,233	2,820	39,763
2090	57,665	46,374	1,665	24,775	17,714	148,193
2091	55,538	14,003	1,333	18,435	8,446	97,755
2092	51,408	9,507	1,171	15,116	6,795	83,997
2093	23,224	6,185	279	27	1,746	31,462

TABLE 3.14 (continued)
SCENARIO 7: SAFSTOR WITH 60 YEAR DFS, UNIT 2
TOTAL ANNUAL EXPENDITURES
(thousands, 2017 dollars)

Year	Labor	Equipment & Materials	Energy	Burial	Other	Total
2094	14,461	13,418	174	0	594	28,648
2095	10,459	9,705	126	0	430	20,720
Total	573,537	218,128	19,489	61,669	351,128	1,223,951

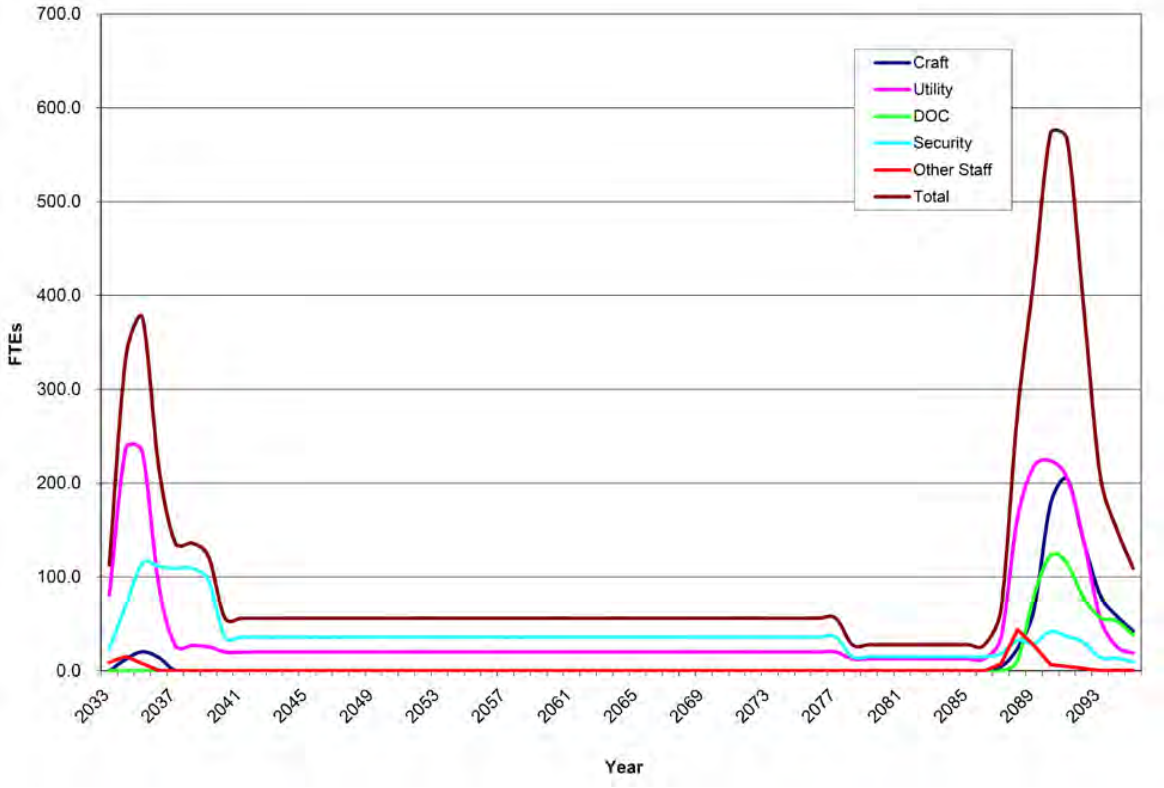
Note: Columns may not add due to rounding

FIGURE 3.1
SCENARIO 2: DECON WITH 60 YEAR DFS
PRAIRIE ISLAND NUCLEAR GENERATING PLANT
MANPOWER LEVELS



Note that the labor hour basis of this chart was taken from Appendix D; however not all line items in Appendix D have labor hour values available (e.g. spent fuel canister loading estimates from Xcel Energy)

FIGURE 3.2
SCENARIO 7: SAFSTOR WITH 60 YEAR DFS
PRAIRIE ISLAND NUCLEAR GENERATING PLANT
MANPOWER LEVELS



Note that the labor hour basis of this chart was taken from Appendix I; however not all line items in Appendix I have labor hour values available (e.g. spent fuel canister loading estimates from Xcel Energy)

4. SCHEDULE ESTIMATE

The schedules for the decommissioning scenarios considered in this study follow the sequence presented in the AIF/NESP-036 study, with minor changes to reflect recent experience and site-specific constraints. In addition, the scheduling has been revised to reflect the spent fuel management plans described in Section 3.4.1.

A schedule or sequence of activities for the DECON alternative is presented in Figure 4.1. The schedule is also representative of the work activities identified in the delayed dismantling scenarios, absent any spent fuel constraints. The scheduling sequence is based on the fuel being removed from the spent fuel pool within the first five years after operations cease. The key activities listed in the schedule do not reflect a one-to-one correspondence with those activities in the cost tables, but reflect dividing some activities for clarity and combining others for convenience. The schedule was prepared using the "Microsoft Project Professional" computer software.[40]

4.1 SCHEDULE ESTIMATE ASSUMPTIONS

The schedule reflects the results of a precedence network developed for the site decommissioning activities, i.e., a PERT (Program Evaluation and Review Technique) Software Package. The work activity durations used in the precedence network reflect the actual man-hour estimates from the cost table, adjusted by stretching certain activities over their slack range and shifting the start and end dates of others. The following assumptions were made in the development of the decommissioning schedule:

- The fuel handling area of the auxiliary building is isolated until such time that all spent fuel has been discharged from the storage pool to the DOE or to the ISFSI. Decontamination and dismantling of the spent fuel storage pool is initiated once the transfer of spent fuel is complete (DECON option).
- All work (except vessel and internals removal) is performed during an 8-hour workday, 5 days per week, with no overtime. There are eleven paid holidays per year.
- Reactor and internals removal activities are performed by using separate crews for different activities working on different shifts, with a corresponding backshift charge for the second shift.
- Multiple crews work parallel activities to the maximum extent possible, consistent with optimum efficiency, adequate access for cutting, removal and laydown space, and with the stringent safety measures necessary during demolition of heavy components and structures.

- For plant systems removal, the systems with the longest removal durations in areas on the critical path are considered to determine the duration of the activity.

4.2 PROJECT SCHEDULE

The period-dependent costs presented in the detailed cost tables are based upon the durations developed in the schedules for decommissioning Prairie Island. Durations are established between several milestones in each project period; these durations are used to establish a critical path for the entire project. In turn, the critical path duration for each period is used as the basis for determining the period-dependent costs. A second parallel path is also shown for the spent fuel cooling period, which determines the release of the auxiliary building for final decontamination.

Project timelines are provided in Figures 4.2 through 4.8, with milestone dates based on a 2033/2034 shutdown dates. The fuel pool is emptied approximately five years after shutdown, while ISFSI operations continue until the DOE completes the transfer of assemblies. Deferred decommissioning operations in the SAFSTOR scenarios are assumed to commence so that the operating licenses are terminated within a 60-year period from the cessation of operations

FIGURE 4.1
DECON ACTIVITY SCHEDULE

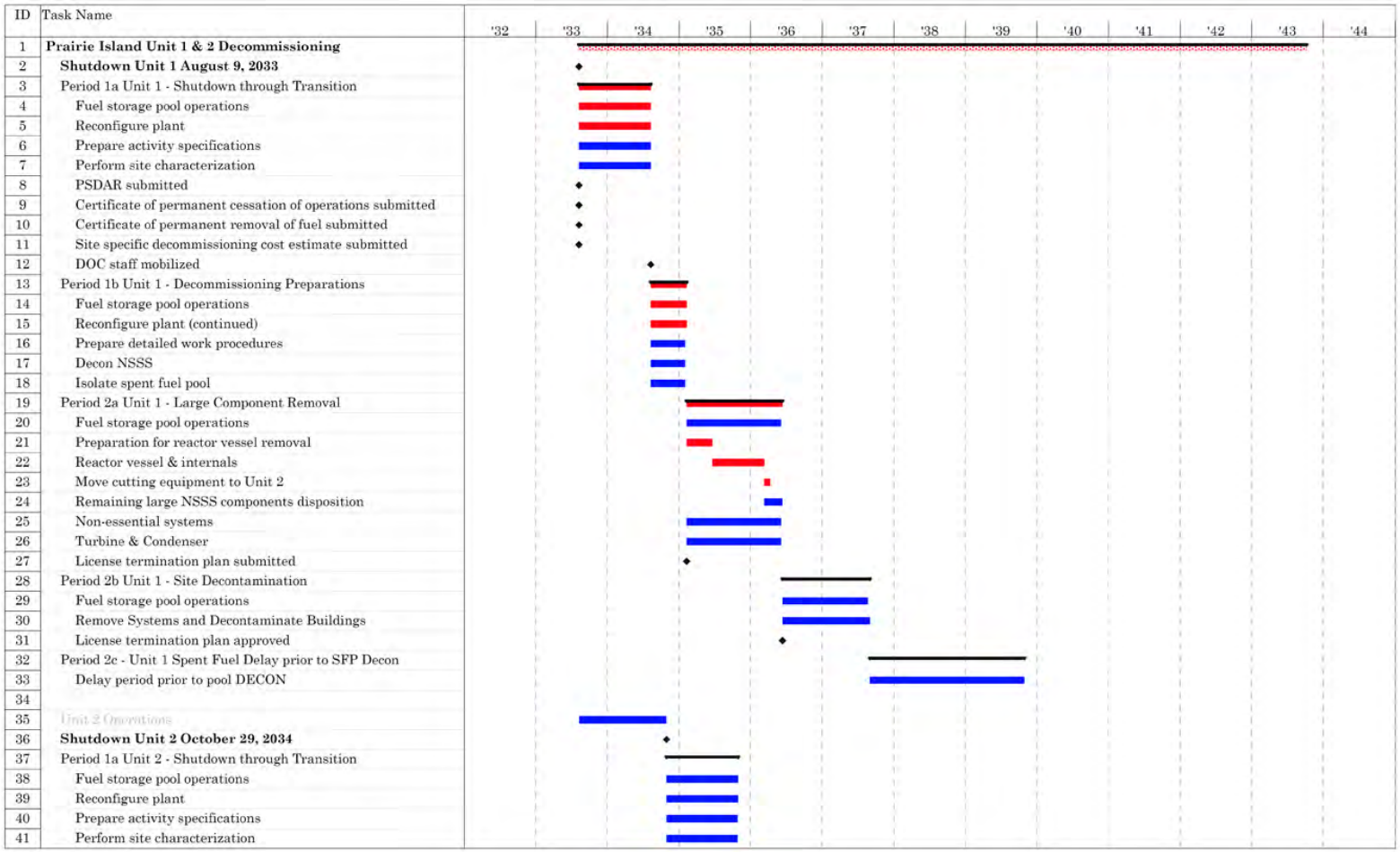


FIGURE 4.1 (continued)
DECON ACTIVITY SCHEDULE

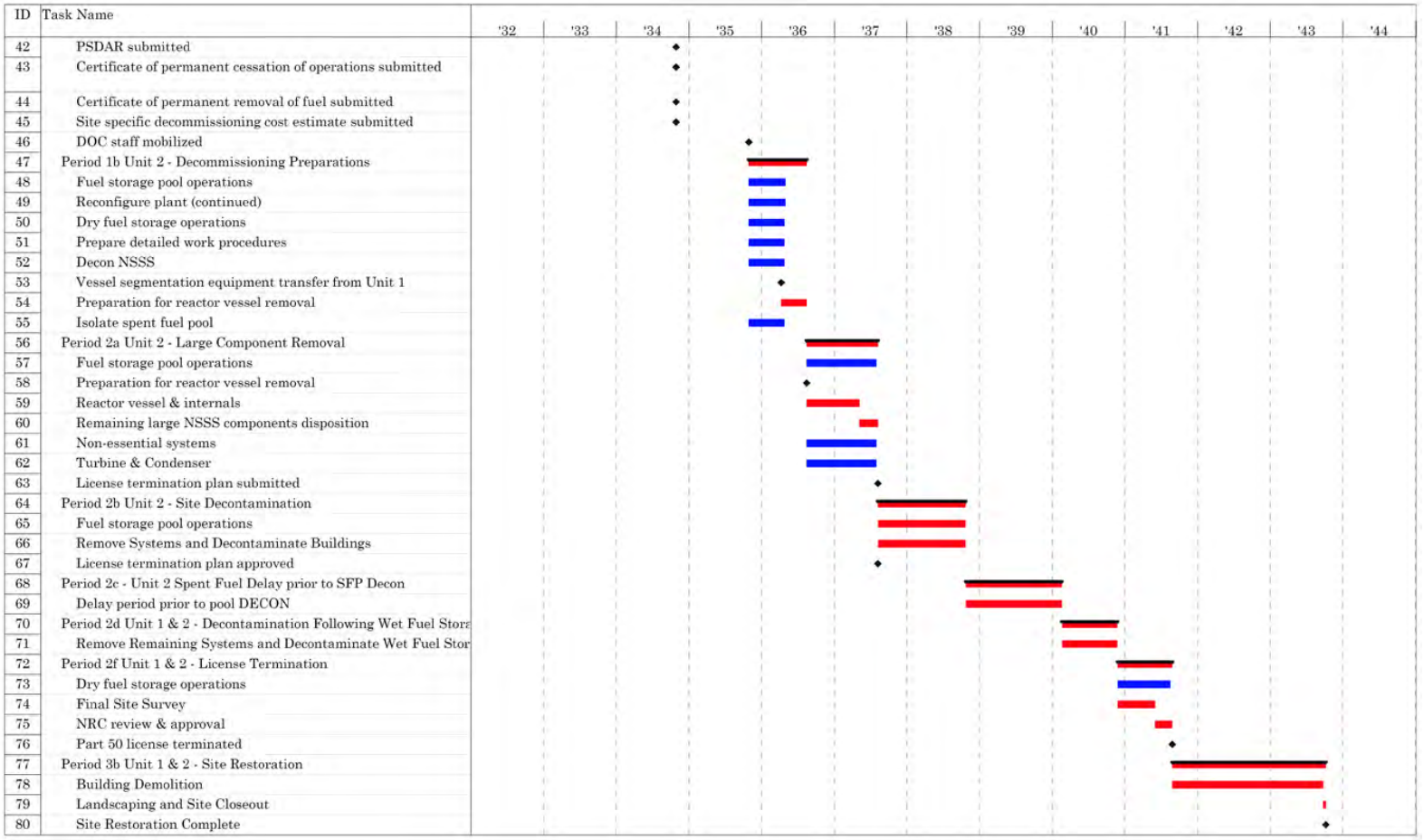


FIGURE 4.1 (continued)
LEGEND

1. Red scheduling bars indicate critical path activities
2. Blue scheduling bars associated with non-critical path activities
3. Diamond symbols indicate major milestones

FIGURE 4.2
SCENARIO 1: DECON WITH 32 YEAR DFS
DECOMMISSIONING TIMELINE
(not to scale)

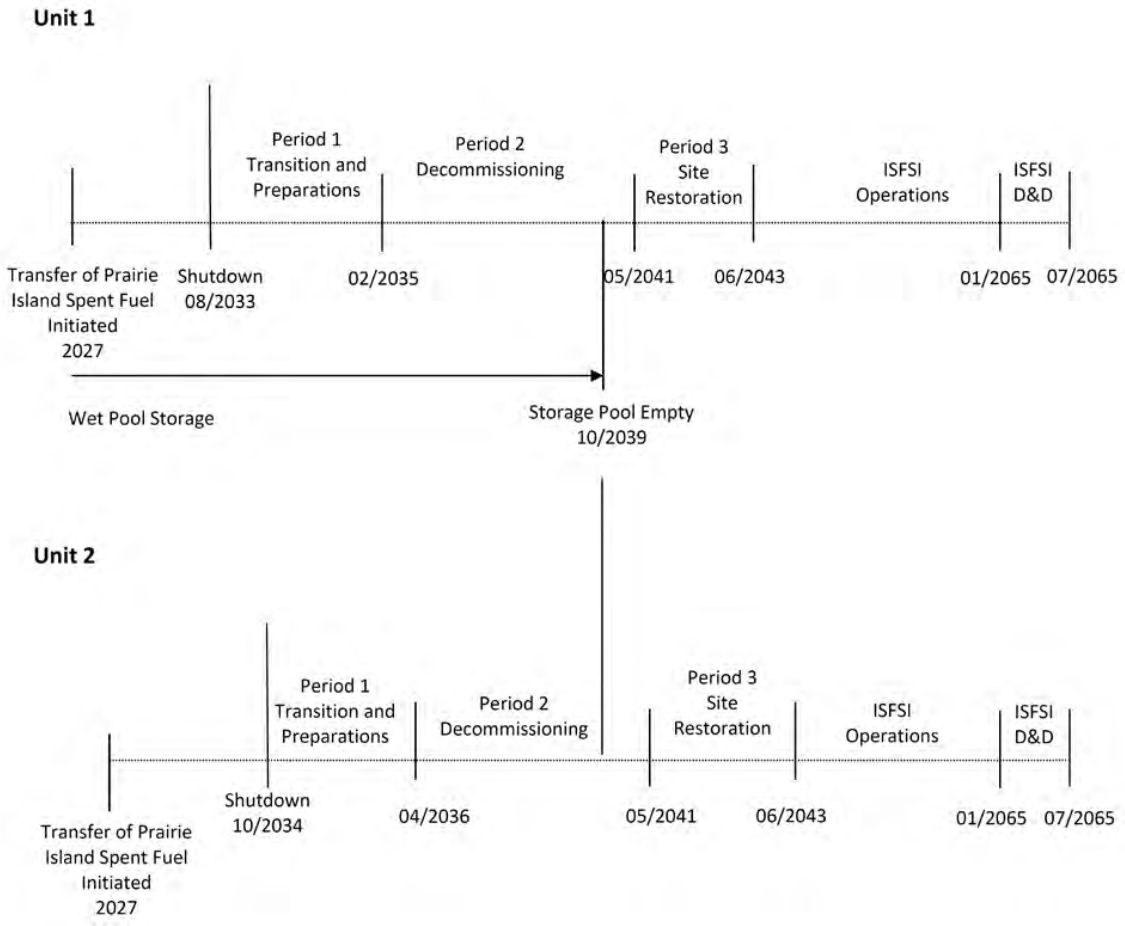


FIGURE 4.3
SCENARIO 2: DECON WITH 60 YEAR DFS
DECOMMISSIONING TIMELINE
(not to scale)

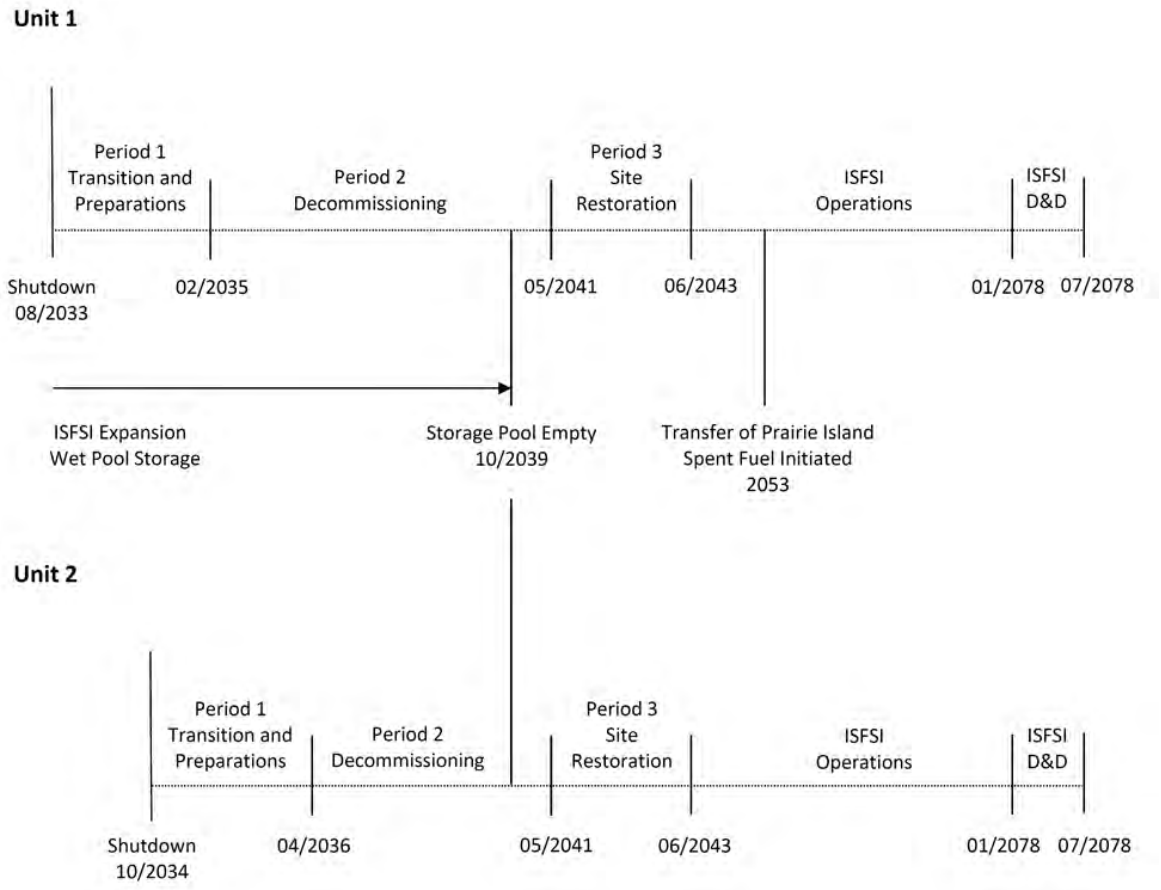


FIGURE 4.4
SCENARIO 3: DECON WITH 100 YEAR DFS
DECOMMISSIONING TIMELINE
(not to scale)

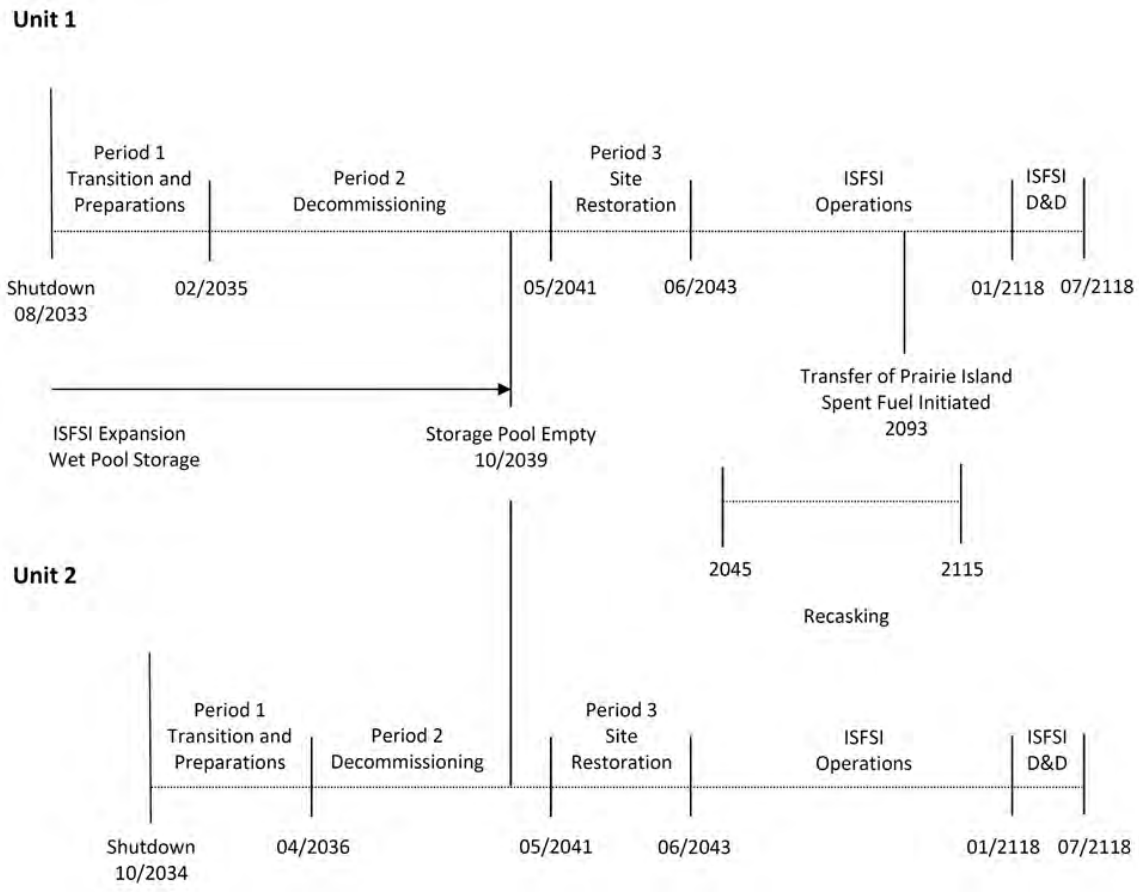


FIGURE 4.5
SCENARIO 4: DECON WITH 200 YEAR DFS
DECOMMISSIONING TIMELINE
(not to scale)

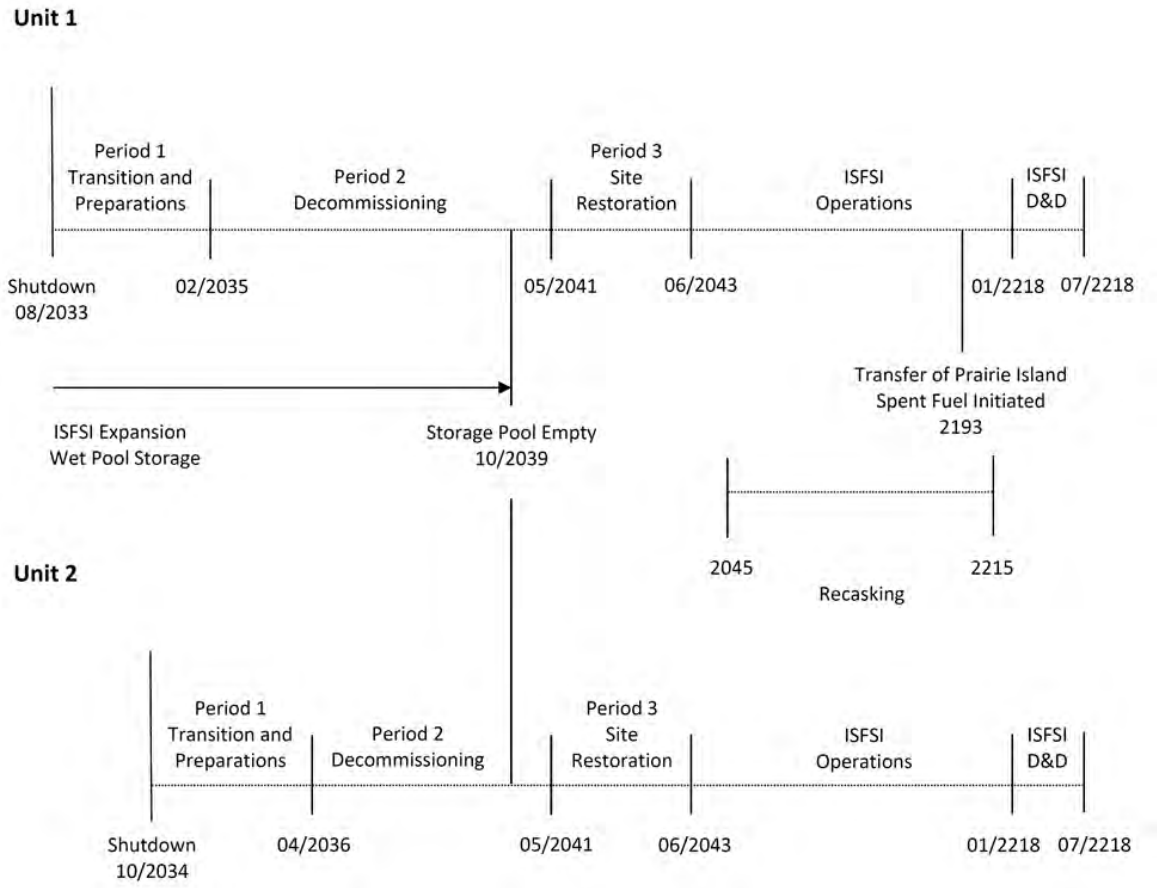


FIGURE 4.6
SCENARIO 5: DECON WITH 60 YEAR DFS WITH RECASKING
DECOMMISSIONING TIMELINE
(not to scale)

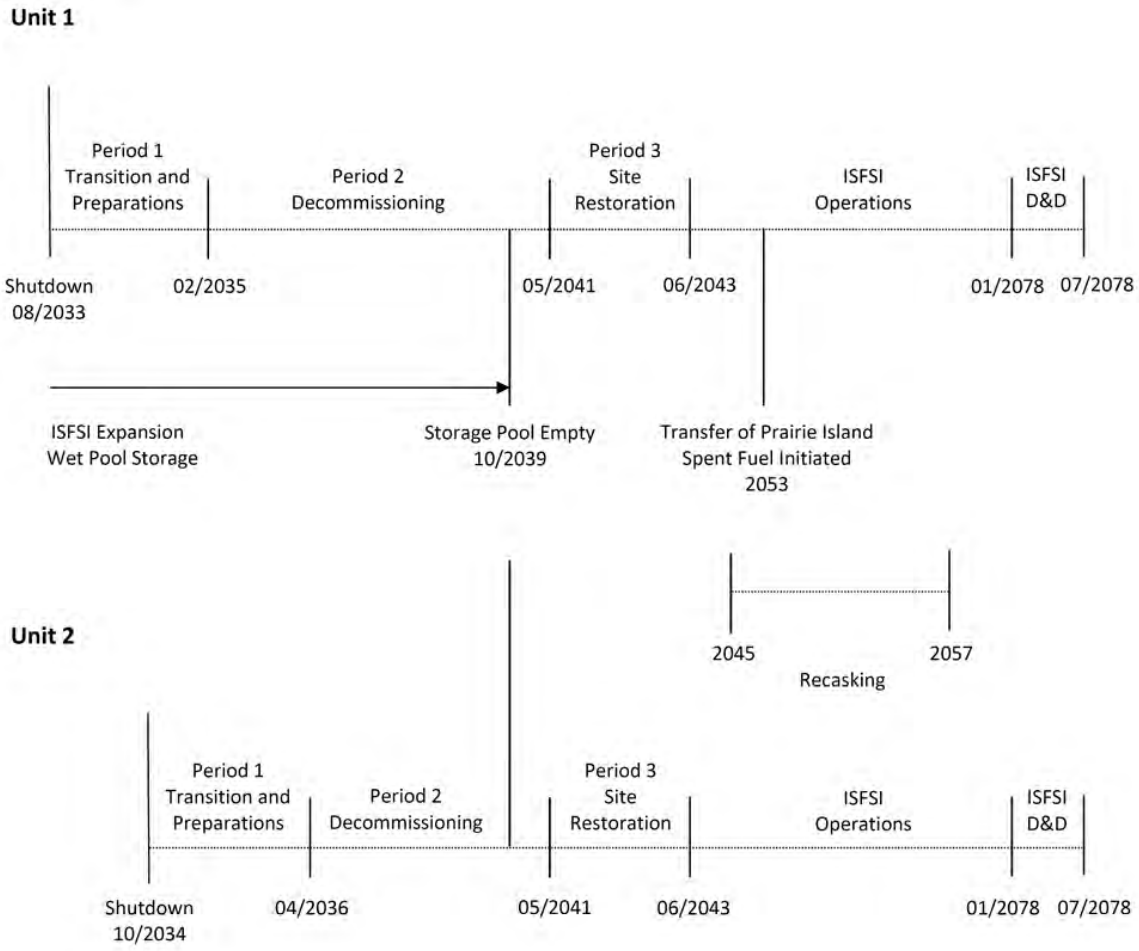


FIGURE 4.7
SCENARIO 6: SAFSTOR WITH 32 YEAR DFS
DECOMMISSIONING TIMELINE
(not to scale)

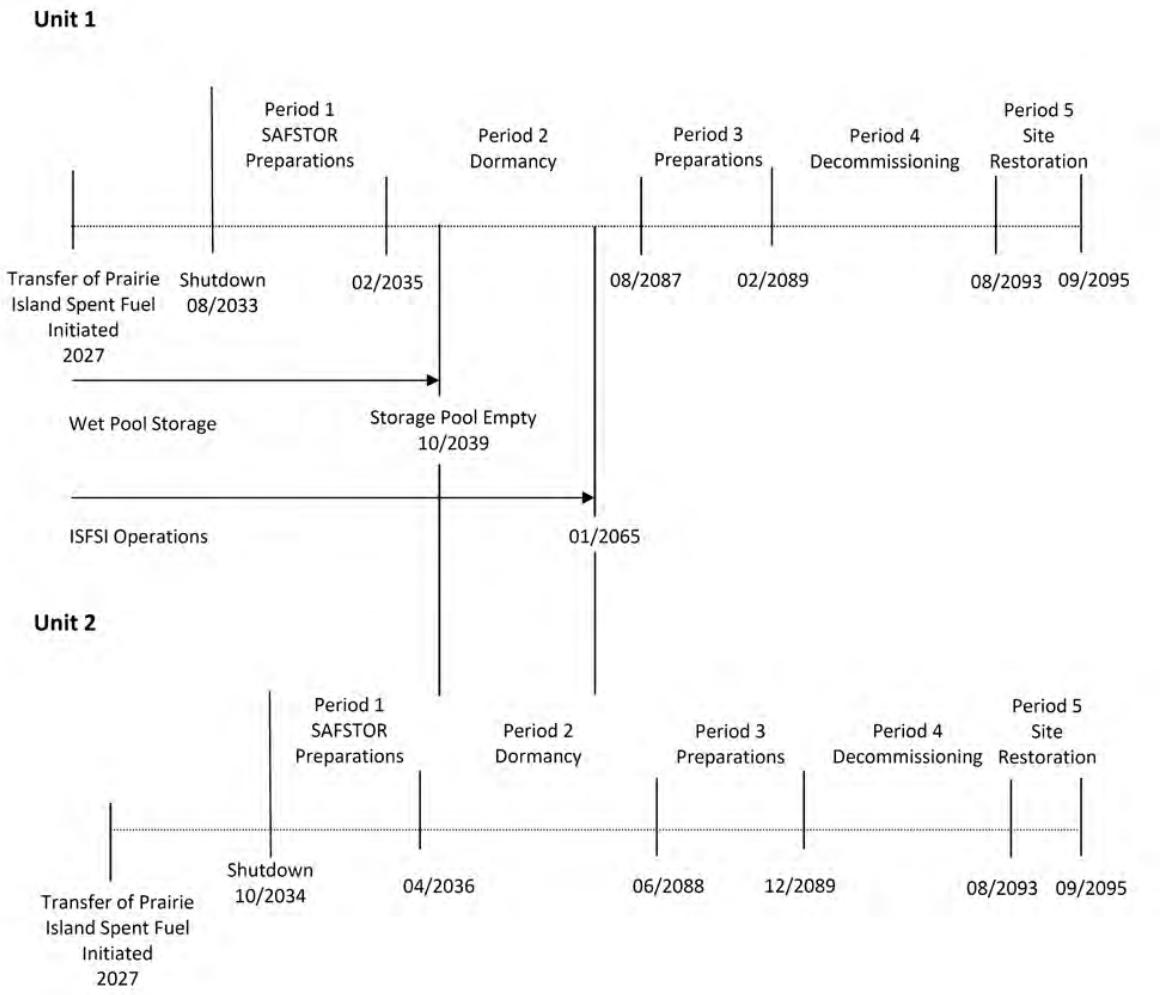
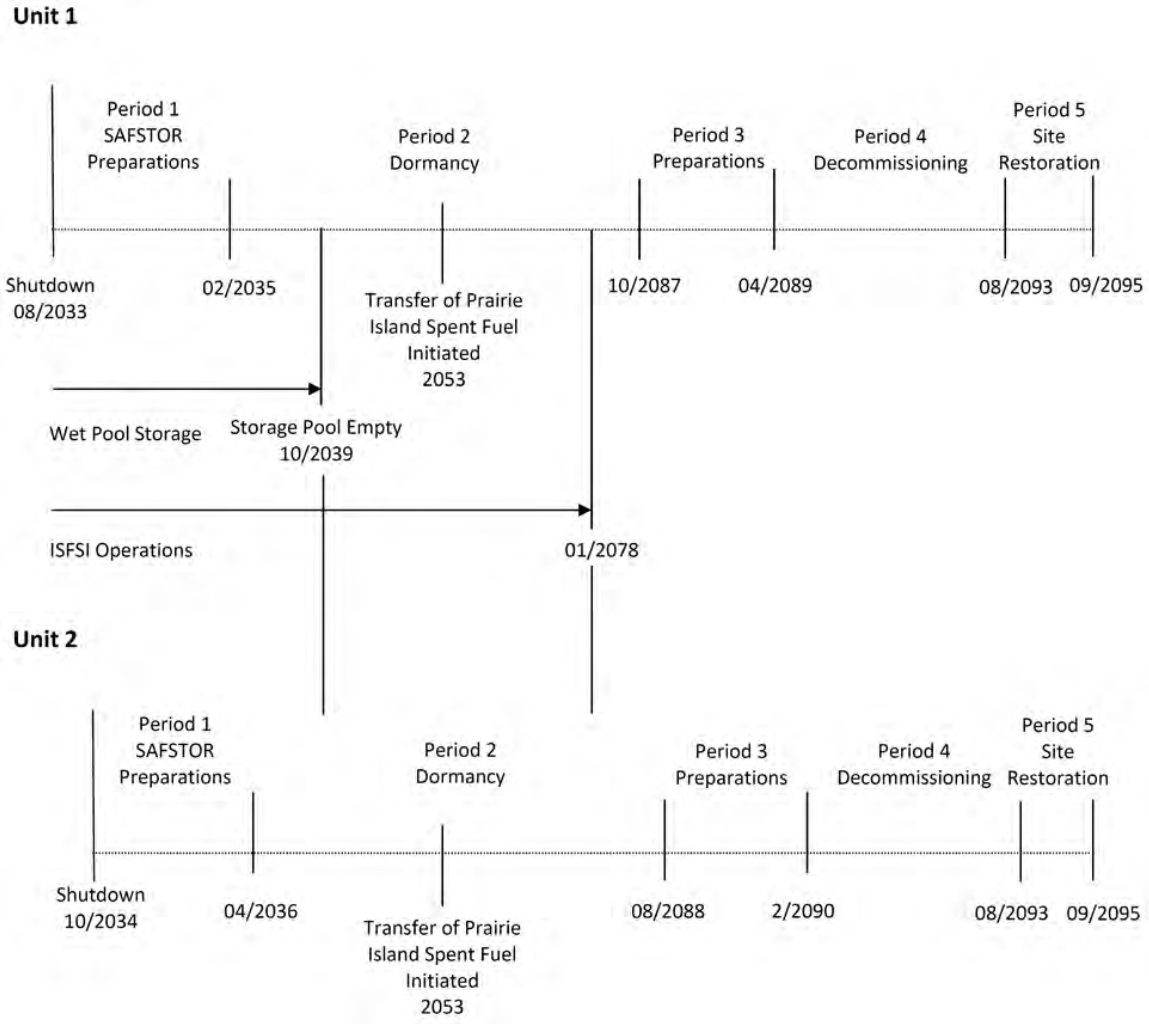


FIGURE 4.8
SCENARIO 7: SAFSTOR WITH 60 YEAR DFS
DECOMMISSIONING TIMELINE
(not to scale)



5. RADIOACTIVE WASTES

The objectives of the decommissioning process are the removal of all radioactive material from the site that would restrict its future use and the termination of the NRC licenses. This currently requires the remediation of all radioactive material at the site in excess of applicable legal limits. Under the Atomic Energy Act,[41] the NRC is responsible for protecting the public from sources of ionizing radiation. Title 10 of the Code of Federal Regulations delineates the production, utilization, and disposal of radioactive materials and processes. In particular, Part 71 defines radioactive material as it pertains to transportation and Part 61 specifies its disposition.

Most of the materials being transported for controlled burial are categorized as Low Specific Activity (LSA) or Surface Contaminated Object (SCO) materials containing Type A quantities, as defined in 49 CFR Parts 173-178. Shipping containers are required to be Industrial Packages (IP-1, IP-2 or IP-3, as defined in 10 CFR §173.411). For this study, commercially available steel containers are presumed to be used for the disposal of piping, small components, and concrete. Larger components can serve as their own containers, with proper closure of all openings, access ways, and penetrations.

The destinations for the various waste streams from decommissioning are identified in Figures 5.1 and 5.2. The volumes of radioactive waste generated during the various decommissioning activities at the site are shown on a line-item basis in Appendices C through J and summarized in Tables 5.1 through 5.7. The quantified waste volume summaries shown in these tables are consistent with §61 classifications. The volumes are calculated based on the exterior dimensions for containerized material and on the displaced volume of components serving as their own waste containers.

The reactor vessel and internals are categorized as large quantity shipments and, accordingly, will be shipped in reusable, shielded truck casks with disposable liners. In calculating disposal costs, the burial fees are applied against the liner volume, as well as the special handling requirements of the payload. Packaging efficiencies are lower for the highly activated materials (greater than Type A quantity waste), where high concentrations of gamma-emitting radionuclides limit the capacity of the shipping canisters.

No process system containing/handling radioactive substances at shutdown is presumed to meet material release criteria by decay alone, i.e., systems radioactive at shutdown will still be radioactive over the time period during which the decommissioning is accomplished, due to the presence of long-lived radionuclides.

While the dose rates decrease with time, radionuclides such as ^{137}Cs will still control the disposition requirements.

The waste material generated in the decontamination and dismantling of Prairie Island is primarily generated during Period 2 of the DECON alternatives and Period 4 of the SAFSTOR alternatives. Material that is considered potentially contaminated when removed from the radiologically controlled area is sent to processing facilities in Tennessee for conditioning and disposal. Heavily contaminated components and activated materials are routed for controlled disposal. The disposal volumes reported in the tables reflect the savings resulting from reprocessing and recycling.

Disposal fees are calculated using representative costs, with surcharges added for the highly activated components, for example, generated in the segmentation of the reactor vessels. The cost to dispose of the majority of the material generated from the decontamination and dismantling activities is based upon representative rates.

Energy*Solutions* is not able to accept the higher activity waste (Class B and C) generated in the decontamination of the NSSS and segmentation of the components closest to the core. Waste disposal costs for the higher activity waste (Class B and C) are based upon preliminary and indicative information on the cost for such from WCS.

A small quantity of material generated during the Prairie Island decommissioning will not be considered suitable for near-surface disposal, and is assumed to be disposed of in a geologic repository, in a manner similar to that envisioned for spent fuel disposal. Such material, known as Greater-Than-Class-C or GTCC material, is estimated to require eight spent fuel storage canisters (or the equivalent) to dispose of the most radioactive portions of the reactor vessel internals. The volume and weight reported in Tables 5.1 through 5.7 represent the packaged weight and volume of the spent fuel storage canisters.

FIGURE 5.1
RADIOACTIVE WASTE DISPOSITION

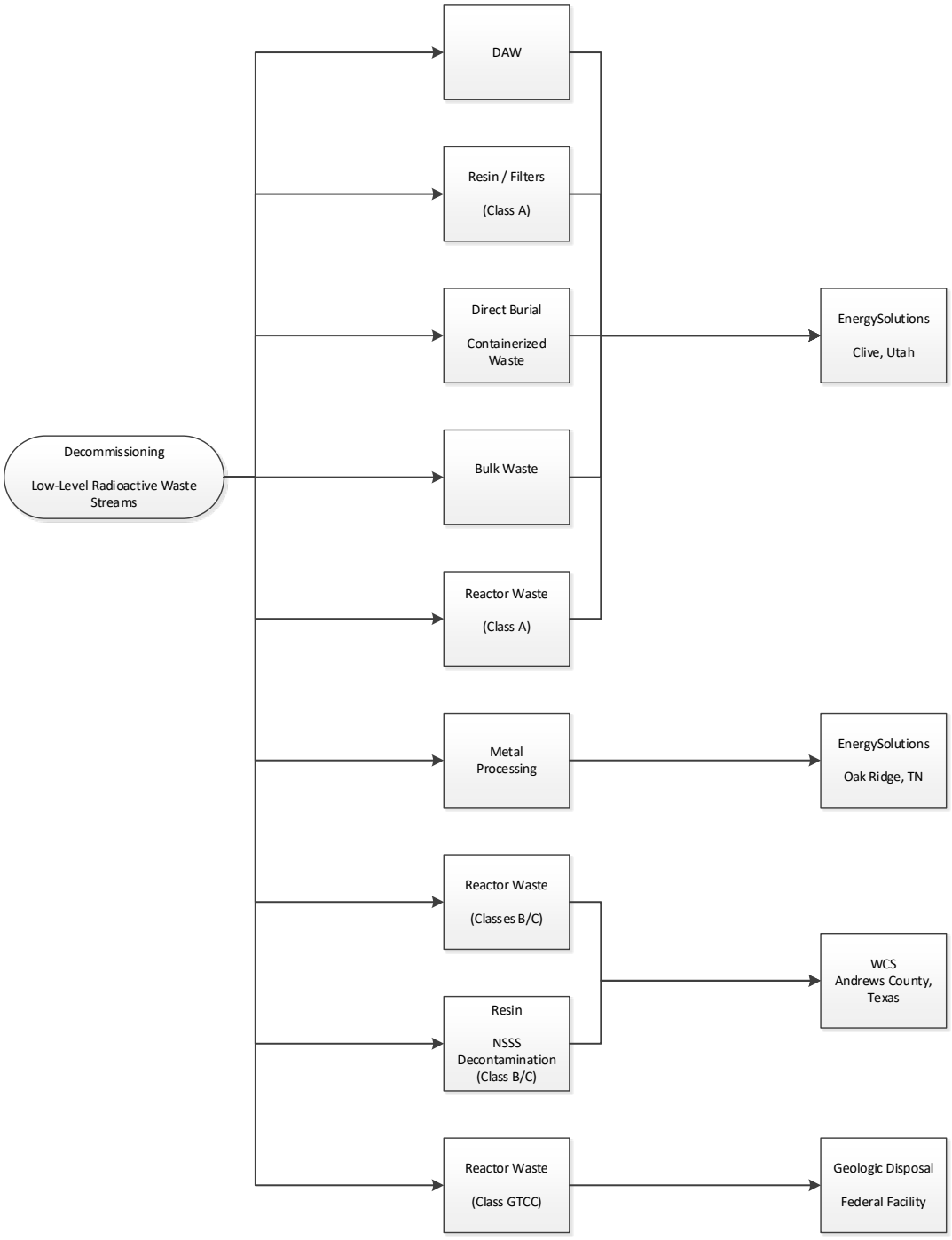
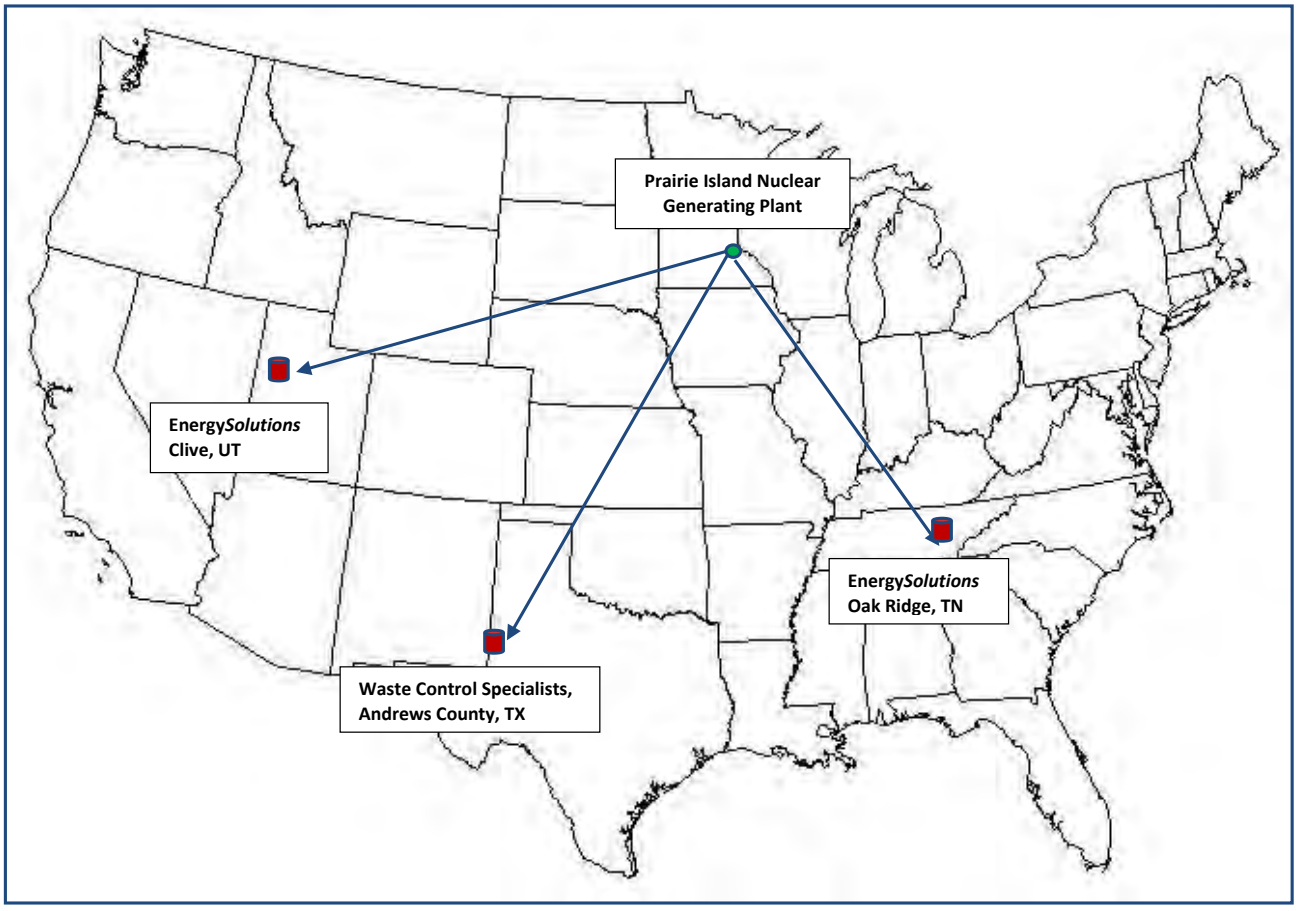


FIGURE 5.2
DECOMMISSIONING WASTE DESTINATIONS
RADIOLOGICAL



The figure indicates the destinations for the low-level radioactive waste designated for direct disposal (Clive, Utah) and processing/recovery (Oak Ridge, Tennessee).

Disposition of the Class B and C low-level radioactive waste will be at the Waste Control Specialists site in Andrews County, Texas.

Disposal options (and destinations) for GTCC are still being evaluated.

TABLE 5.1
SCENARIO 1: DECON WITH 32 YEAR DFS
DECOMMISSIONING WASTE SUMMARY

Waste	Cost Basis	Class [1]	Waste Volume (cubic feet)	Mass (pounds)
Low-Level Radioactive Waste (near-surface disposal)	Energy*Solutions* Containerized	A	183,939	12,318,693
	Energy*Solutions* Bulk	A	105,585	6,473,765
	Future LLRW Disposal Facility (Proxy)	B	1,677	168,873
	Future LLRW Disposal Facility (Proxy)	C	1,346	199,444
Greater than Class C (geologic repository)	Spent Fuel Equivalent	GTCC	7,493	1,675,192
Total [2]			300,041	20,835,967
Processed/Conditioned (off-site recycling center)	Recycling Vendors	A	314,393	12,585,953
Scrap Metal				148,880,000

[1] Waste is classified according to the requirements as delineated in Title 10 CFR, Part 61.55
[2] Columns may not add due to rounding

TABLE 5.2
SCENARIO 2: DECON WITH 60 YEAR DFS
DECOMMISSIONING WASTE SUMMARY

Waste	Cost Basis	Class [1]	Waste Volume (cubic feet)	Mass (pounds)
Low-Level Radioactive Waste (near-surface disposal)	Energy*Solutions* Containerized	A	183,940	12,318,700
	Energy*Solutions* Bulk	A	105,582	6,473,709
	Future LLRW Disposal Facility (Proxy)	B	1,677	168,873
	Future LLRW Disposal Facility (Proxy)	C	1,346	199,444
Greater than Class C (geologic repository)	Spent Fuel Equivalent	GTCC	7,493	1,675,192
Total [2]			300,038	20,835,918
Processed/Conditioned (off-site recycling center)	Recycling Vendors	A	314,393	12,585,953
Scrap Metal				148,880,000

[1] Waste is classified according to the requirements as delineated in Title 10 CFR, Part 61.55
[2] Columns may not add due to rounding

TABLE 5.3
SCENARIO 3: DECON WITH 100 YEAR DFS
DECOMMISSIONING WASTE SUMMARY

Waste	Cost Basis	Class [1]	Waste Volume (cubic feet)	Mass (pounds)
Low-Level Radioactive Waste (near-surface disposal)	Energy*Solutions* Containerized	A	191,080	13,155,878
	Energy*Solutions* Bulk	A	93,337	4,645,691
	Future LLRW Disposal Facility (Proxy)	B	1,677	168,873
	Future LLRW Disposal Facility (Proxy)	C	1,346	199,444
Greater than Class C (geologic repository)	Spent Fuel Equivalent	GTCC	7,493	1,675,192
Total [2]			294,934	19,845,078
Processed/Conditioned (off-site recycling center)	Recycling Vendors	A	314,393	12,585,953
Scrap Metal				148,880,000

[1] Waste is classified according to the requirements as delineated in Title 10 CFR, Part 61.55
[2] Columns may not add due to rounding

TABLE 5.4
SCENARIO 4: DECON WITH 200 YEAR DFS
DECOMMISSIONING WASTE SUMMARY

Waste	Cost Basis	Class [1]	Waste Volume (cubic feet)	Mass (pounds)
Low-Level Radioactive Waste (near-surface disposal)	Energy*Solutions* Containerized	A	191,080	13,155,878
	Energy*Solutions* Bulk	A	93,337	4,645,691
	Future LLRW Disposal Facility (Proxy)	B	1,677	168,873
	Future LLRW Disposal Facility (Proxy)	C	1,346	199,444
Greater than Class C (geologic repository)	Spent Fuel Equivalent	GTCC	7,493	1,675,192
Total [2]			294,934	19,845,078
Processed/Conditioned (off-site recycling center)	Recycling Vendors	A	314,393	12,585,953
Scrap Metal				148,880,000

[1] Waste is classified according to the requirements as delineated in Title 10 CFR, Part 61.55
[2] Columns may not add due to rounding

TABLE 5.5
SCENARIO 5: DECON WITH 60 YEAR DFS WITH RECASKING
DECOMMISSIONING WASTE SUMMARY

Waste	Cost Basis	Class [1]	Waste Volume (cubic feet)	Mass (pounds)
Low-Level Radioactive Waste (near-surface disposal)	Energy*Solutions* Containerized	A	185,223	12,395,738
	Energy*Solutions* Bulk	A	105,840	6,491,706
	Future LLRW Disposal Facility (Proxy)	B	1,677	168,873
	Future LLRW Disposal Facility (Proxy)	C	1,346	199,444
Greater than Class C (geologic repository)	Spent Fuel Equivalent	GTCC	7,493	1,675,192
Total [2]			301,580	20,930,953
Processed/Conditioned (off-site recycling center)	Recycling Vendors	A	314,393	12,585,953
Scrap Metal				148,880,000

[1] Waste is classified according to the requirements as delineated in Title 10 CFR, Part 61.55
[2] Columns may not add due to rounding

TABLE 5.6
SCENARIO 6: SAFSTOR WITH 32 YEAR DFS
DECOMMISSIONING WASTE SUMMARY

Waste	Cost Basis	Class [1]	Waste Volume (cubic feet)	Mass (pounds)
Low-Level Radioactive Waste (near-surface disposal)	Energy*Solutions* Containerized	A	93,221	7,572,368
	Energy*Solutions* Bulk	A	149,706	9,708,164
	Future LLRW Disposal Facility (Proxy)	B	250	22,188
	Future LLRW Disposal Facility (Proxy)	C	1,416	199,712
Greater than Class C (geologic repository)	Spent Fuel Equivalent	GTCC	7,493	1,675,192
Total [2]			252,086	19,177,624
Processed/Conditioned (off-site recycling center)	Recycling Vendors	A	319,773	12,829,050
Scrap Metal				149,192,000

[1] Waste is classified according to the requirements as delineated in Title 10 CFR, Part 61.55
[2] Columns may not add due to rounding

TABLE 5.7
SCENARIO 7: SAFSTOR WITH 60 YEAR DFS
DECOMMISSIONING WASTE SUMMARY

Waste	Cost Basis	Class [1]	Waste Volume (cubic feet)	Mass (pounds)
Low-Level Radioactive Waste (near-surface disposal)	Energy*Solutions* Containerized	A	93,221	7,572,361
	Energy*Solutions* Bulk	A	149,713	9,708,310
	Future LLRW Disposal Facility (Proxy)	B	250	22,188
	Future LLRW Disposal Facility (Proxy)	C	1,416	199,712
Greater than Class C (geologic repository)	Spent Fuel Equivalent	GTCC	7,493	1,675,192
Total [2]			252,093	19,177,763
Processed/Conditioned (off-site recycling center)	Recycling Vendors	A	319,773	12,829,050
Scrap Metal				149,192,000

[1] Waste is classified according to the requirements as delineated in Title 10 CFR, Part 61.55
[2] Columns may not add due to rounding

6. RESULTS

This report presents estimates of the cost to decommission Prairie Island for the selected decommissioning scenarios following the cessation of plant operations. The estimates are based on numerous fundamental assumptions, including regulatory requirements, project contingencies, low-level radioactive waste disposal practices, high-level radioactive waste management options, and site restoration requirements. While not an engineering study, the estimates provide Xcel Energy with sufficient information to assess their financial obligations, as they pertain to the eventual decommissioning of the nuclear station.

The decommissioning scenarios assume continued operation of the station's spent fuel pool for a minimum of five years following the cessation of operations for continued cooling of the assemblies. The existing ISFSI is expanded to accommodate the spent fuel, once sufficiently cooled, until such time that the DOE can complete the transfer of the assemblies to its repository.

Using Scenario 2 as the base case, the cost projected to promptly decommission the station, restore the site, and manage the spent fuel is estimated to be $1.996 billion (2017 dollars). The majority of this cost (approximately 56.8%) is associated with the physical decontamination and dismantling of the nuclear plant so that the operating licenses can be terminated. Another 37.2% is associated with the management, interim storage, and eventual transfer of the spent fuel. The remaining 5.9% is for the demolition of the designated structures and limited restoration of the site.

The primary cost contributors, identified in Tables 6.1 through 6.7, are either labor-related or associated with the management and disposition of the spent fuel or radioactive waste. Program management (including security) is the largest single contributor to the overall cost. The magnitude of the expense is a function of both the size of the organization required to manage the decommissioning, as well as the duration of the program. It is assumed, for purposes of this analysis, that Xcel Energy will hire a contractor to manage the decommissioning labor force. The size and composition of the management organizations varies with the decommissioning phase and associated site activities. However, once the operating licenses are amended or terminated, the staff is substantially reduced for the conventional demolition and restoration of the site, and the long-term care of the spent fuel (for the DECON alternative).

As described in this report, the spent fuel pool will remain operational for a minimum of five years following the cessation of operations. The pool will be isolated and an independent spent fuel island created. This will allow

decommissioning operations to proceed in and around the pool areas. Over the five-year period, the spent fuel will be packaged into transportable canisters for future loading into a DOE-provided transport cask or relocation to the ISFSI (DECON and both SAFSTOR alternatives). The canisters will be stored in horizontal storage casks at the ISFSI until the DOE is able to receive them. Dry storage of the fuel provides additional flexibility in the event the DOE is not able to meet the current timetable for completing the transfer of assemblies to an off-site facility and minimizes the associated caretaking expenses.

The cost for waste disposal includes only those costs associated with the controlled disposition of the low-level radioactive waste generated from decontamination and dismantling activities, including plant equipment and components, structural material, filters, resins and dry-active waste. As described in Section 5, disposition of the majority of the low-level radioactive material requiring controlled disposal is at the Energy*Solutions* facility, with higher-activity waste sent to the WCS facility. Highly activated components, requiring additional isolation from the environment (GTCC), are packaged for geologic disposal. The cost of geologic disposal is based upon a cost equivalent for spent fuel.

A significant portion of the metallic waste is designated for additional processing and treatment at an off-site facility. Processing reduces the volume of material requiring controlled disposal through such techniques and processes as survey and sorting, decontamination, and volume reduction. The material that cannot be unconditionally released is packaged for controlled disposal at one of the currently operating facilities. The cost identified in the summary tables for processing is all-inclusive, incorporating the ultimate disposition of the material.

Removal costs reflect the labor-intensive nature of the decommissioning process, as well as the management controls required to ensure a safe and successful program. Decontamination and packaging costs also have a large labor component that is based upon prevailing wages. Non-radiological demolition is a natural extension of the decommissioning process. The methods employed in decontamination and dismantling are generally destructive and indiscriminate in inflicting collateral damage. With a work force mobilized to support decommissioning operations, non-radiological demolition can be an integrated activity and a logical expansion of the work being performed in the process of terminating the operating licenses.

The reported cost for transport includes the tariffs and surcharges associated with moving large components and/or overweight shielded casks overland, as well as the general expense, e.g., labor and fuel, of transporting material to the destinations identified in this report. For purposes of this analysis, material is moved overland by truck.

Decontamination is used to reduce the plant's radiation fields and minimize worker exposure. Slightly contaminated material or material located within a contaminated area is sent to an off-site processing center, i.e., this analysis does not assume that contaminated plant components and equipment can be decontaminated for uncontrolled release in-situ. Centralized processing centers have proven to be a more economical means of handling the large volumes of material produced in the dismantling of a nuclear plant.

License termination survey costs are associated with the labor intensive and complex activity of verifying that contamination has been removed from the site to the levels specified by the regulating agency. This process involves a systematic survey of all remaining plant surface areas and surrounding environs, sampling, isotopic analysis, and documentation of the findings. The status of any plant components and materials not removed in the decommissioning process will also require confirmation and will add to the expense of surveying the facilities alone.

The remaining costs include allocations for heavy equipment and temporary services, as well as for other expenses such as regulatory fees and the premiums for nuclear insurance. While site operating costs are greatly reduced following the final cessation of plant operations, certain administrative functions do need to be maintained either at a basic functional or regulatory level.

TABLE 6.1
SCENARIO 1: DECON WITH 32 YEAR DFS
DECOMMISSIONING COST ELEMENTS
(thousands of 2017 dollars)

Cost Element	Unit 1	Unit 2	Total	Percentage
Decontamination	11,899	18,712	30,611	1.7%
Removal	103,458	132,270	235,727	13.1%
Packaging	37,613	37,981	75,594	4.2%
Transportation	8,386	8,908	17,294	1.0%
Waste Disposal	65,232	68,234	133,465	7.4%
Off-site Waste Processing	13,548	16,016	29,565	1.6%
Program Management [1]	224,195	206,995	431,191	24.0%
Security	116,834	106,450	223,284	12.4%
Spent Fuel Pool Isolation	13,445	8,963	22,409	1.2%
Spent Fuel Storage (Direct Costs) [2]	120,903	118,936	239,839	13.3%
Insurance and Regulatory Fees	17,840	15,425	33,266	1.9%
Energy	9,248	8,349	17,597	1.0%
Characterization and Licensing Surveys	17,216	19,157	36,374	2.0%
Property Taxes	54,492	51,594	106,086	5.9%
Miscellaneous	7,188	7,147	14,335	0.8%
Railroad Track Maintenance	2,598	2,517	5,116	0.3%
Retention and Severance	28,423	28,423	56,845	3.2%
Security Modifications	5,000	5,000	10,000	0.6%
Prairie Island Indian Community Payments	40,000	38,750	78,750	4.4%
Total [2]	897,520	899,828	1,797,347	100.0%

Cost Element	Unit 1	Unit 2	Total	Percentage
NRC License Termination	571,980	561,832	1,133,812	63.1%
Spent Fuel Management	274,479	271,262	545,741	30.4%
Site Restoration	51,061	66,733	117,795	6.6%
Total [3]	897,520	899,828	1,797,347	100.0%

[1] Includes engineering

[2] Includes costs for the dry storage system components, spent fuel loading and transfer, spent fuel pool O&M and EP fees, but excludes program management costs (staffing), security and other related costs

[3] Columns may not add due to rounding

TABLE 6.2
SCENARIO 2: DECON WITH 60 YEAR DFS
DECOMMISSIONING COST ELEMENTS
(thousands of 2017 dollars)

Cost Element	Unit 1	Unit 2	Total	Percentage
Decontamination	11,899	18,711	30,610	1.5%
Removal	103,561	132,372	235,933	11.8%
Packaging	37,613	37,981	75,594	3.8%
Transportation	8,386	8,908	17,294	0.9%
Waste Disposal	65,232	68,234	133,465	6.7%
Off-site Waste Processing	13,548	16,016	29,565	1.5%
Program Management [1]	233,817	216,617	450,434	22.6%
Security	146,769	136,385	283,153	14.2%
Spent Fuel Pool Isolation	13,445	8,963	22,409	1.1%
Spent Fuel Storage (Direct Costs) [2]	144,710	142,743	287,453	14.4%
Insurance and Regulatory Fees	21,494	19,079	40,573	2.0%
Energy	9,246	8,347	17,593	0.9%
Characterization and Licensing Surveys	17,216	19,157	36,374	1.8%
Property Taxes	69,785	66,180	135,965	6.8%
Miscellaneous	7,187	7,145	14,332	0.7%
Railroad Track Maintenance	3,461	3,380	6,841	0.3%
Retention and Severance	28,423	28,423	56,845	2.8%
Security Modifications	5,000	5,000	10,000	0.5%
Prairie Island Indian Community Payments	56,250	55,000	111,250	5.6%
Total [3]	997,041	998,643	1,995,684	100.0%

Cost Element	Unit 1	Unit 2	Total	Percentage
NRC License Termination	572,618	561,764	1,134,382	56.8%
Spent Fuel Management	373,251	370,034	743,284	37.2%
Site Restoration	51,173	66,845	118,017	5.9%
Total [3]	997,041	998,643	1,995,684	100.0%

[1] Includes engineering

[2] Includes costs for the dry storage system components, spent fuel loading and transfer, spent fuel pool O&M and EP fees, but excludes program management costs (staffing), security and other related costs

[3] Columns may not add due to rounding

TABLE 6.3
SCENARIO 3: DECON WITH 100 YEAR DFS
DECOMMISSIONING COST ELEMENTS
(thousands of 2017 dollars)

Cost Element	Unit 1	Unit 2	Total	Percentage
Decontamination	11,918	18,730	30,648	0.9%
Removal	104,039	132,850	236,889	7.0%
Packaging	37,611	37,979	75,590	2.2%
Transportation	8,270	8,792	17,061	0.5%
Waste Disposal	64,469	67,471	131,940	3.9%
Off-site Waste Processing	13,548	16,016	29,565	0.9%
Program Management [1]	294,495	277,295	571,790	16.8%
Security	236,616	226,232	462,847	13.6%
Spent Fuel Pool Isolation	13,445	8,963	22,409	0.7%
Spent Fuel Storage (Direct Costs) [2]	592,003	590,037	1,182,040	34.7%
Insurance and Regulatory Fees	32,742	30,327	63,069	1.9%
Energy	9,246	8,347	17,593	0.5%
Characterization and Licensing Surveys	17,216	19,157	36,374	1.1%
Property Taxes	112,875	109,977	222,852	6.5%
Miscellaneous	7,187	7,145	14,332	0.4%
Railroad Track Maintenance	6,115	6,034	12,150	0.4%
Retention and Severance	28,423	28,423	56,845	1.7%
Security Modifications	5,000	5,000	10,000	0.3%
Prairie Island Indian Community Payments	106,250	105,000	211,250	6.2%
Total [3]	1,701,468	1,703,777	3,405,245	100.0%

Cost Element	Unit 1	Unit 2	Total	Percentage
NRC License Termination	568,261	558,114	1,126,374	33.1%
Spent Fuel Management	1,082,353	1,079,137	2,161,490	63.5%
Site Restoration	50,855	66,527	117,381	3.4%
Total [3]	1,701,468	1,703,777	3,405,245	100.0%

[1] Includes engineering

[2] Includes costs for the dry storage system components, spent fuel loading and transfer, spent fuel pool O&M and EP fees, but excludes program management costs (staffing), security and other related costs

[3] Columns may not add due to rounding

TABLE 6.4
SCENARIO 4: DECON WITH 200 YEAR DFS
DECOMMISSIONING COST ELEMENTS
(thousands of 2017 dollars)

Cost Element	Unit 1	Unit 2	Total	Percentage
Decontamination	11,918	18,730	30,648	0.5%
Removal	104,037	132,849	236,887	4.0%
Packaging	37,611	37,979	75,590	1.3%
Transportation	8,270	8,792	17,061	0.3%
Waste Disposal	64,469	67,471	131,940	2.2%
Off-site Waste Processing	13,548	16,016	29,565	0.5%
Program Management [1]	430,976	413,776	844,751	14.2%
Security	466,998	456,614	923,613	15.5%
Spent Fuel Pool Isolation	13,445	8,963	22,409	0.4%
Spent Fuel Storage (Direct Costs) [2]	1,229,254	1,227,287	2,456,541	41.2%
Insurance and Regulatory Fees	60,862	58,448	119,310	2.0%
Energy	9,246	8,347	17,593	0.3%
Characterization and Licensing Surveys	17,216	19,157	36,374	0.6%
Property Taxes	225,076	222,177	447,253	7.5%
Miscellaneous	7,187	7,145	14,332	0.2%
Railroad Track Maintenance	12,752	12,671	25,422	0.4%
Retention and Severance	28,423	28,423	56,845	1.0%
Security Modifications	5,000	5,000	10,000	0.2%
Prairie Island Indian Community Payments	231,250	230,000	461,250	7.7%
Total [3]	2,977,539	2,979,847	5,957,385	100.0%

Cost Element	Unit 1	Unit 2	Total	Percentage
NRC License Termination	568,259	558,112	1,126,371	18.9%
Spent Fuel Management	2,358,425	2,355,208	4,713,633	79.1%
Site Restoration	50,855	66,527	117,381	2.0%
Total [3]	2,977,539	2,979,847	5,957,385	100.0%

[1] Includes engineering

[2] Includes costs for the dry storage system components, spent fuel loading and transfer, spent fuel pool O&M and EP fees, but excludes program management costs (staffing), security and other related costs

[3] Columns may not add due to rounding

TABLE 6.5
SCENARIO 5: DECON WITH 60 YEAR DFS WITH RECASKING
DECOMMISSIONING COST ELEMENTS
(thousands of 2017 dollars)

Cost Element	Unit 1	Unit 2	Total	Percentage
Decontamination	11,918	18,730	30,648	1.4%
Removal	103,830	132,642	236,472	10.9%
Packaging	37,614	37,982	75,596	3.5%
Transportation	8,389	8,911	17,300	0.8%
Waste Disposal	65,396	68,398	133,795	6.2%
Off-site Waste Processing	13,548	16,016	29,565	1.4%
Program Management [1]	233,817	216,617	450,434	20.8%
Security	146,769	136,385	283,153	13.1%
Spent Fuel Pool Isolation	13,445	8,963	22,409	1.0%
Spent Fuel Storage (Direct Costs) [2]	230,141	228,174	458,315	21.2%
Insurance and Regulatory Fees	21,494	19,079	40,573	1.9%
Energy	9,246	8,347	17,593	0.8%
Characterization and Licensing Surveys	17,216	19,157	36,374	1.7%
Property Taxes	69,078	66,180	135,258	6.2%
Miscellaneous	7,187	7,145	14,332	0.7%
Railroad Track Maintenance	3,461	3,380	6,841	0.3%
Retention and Severance	28,423	28,423	56,845	2.6%
Security Modifications	5,000	5,000	10,000	0.5%
Prairie Island Indian Community Payments	56,250	55,000	111,250	5.1%
Total [3]	1,082,223	1,084,531	2,166,754	100.0%

Cost Element	Unit 1	Unit 2	Total	Percentage
NRC License Termination	572,323	562,164	1,134,487	52.4%
Spent Fuel Management	458,457	455,241	913,698	42.2%
Site Restoration	51,443	67,126	118,569	5.5%
Total [3]	1,082,223	1,084,531	2,166,754	100.0%

[1] Includes engineering

[2] Includes costs for the dry storage system components, spent fuel loading and transfer, spent fuel pool O&M and EP fees, but excludes program management costs (staffing), security and other related costs

[3] Columns may not add due to rounding

TABLE 6.6
SCENARIO 6: SAFSTOR WITH 32 YEAR DFS
DECOMMISSIONING COST ELEMENTS
(thousands of 2017 dollars)

Cost Element	Unit 1	Unit 2	Total	Percentage
Decontamination	7,828	16,467	24,295	1.0%
Removal	108,449	137,038	245,487	10.4%
Packaging	34,003	34,343	68,345	2.9%
Transportation	6,683	7,171	13,854	0.6%
Waste Disposal	53,612	55,346	108,959	4.6%
Off-site Waste Processing	13,846	16,314	30,160	1.3%
Program Management [1]	312,153	278,025	590,178	25.1%
Security	194,238	129,474	323,713	13.8%
Spent Fuel Pool Isolation	13,445	8,963	22,409	1.0%
Spent Fuel Storage (Direct Costs) [2]	117,316	114,954	232,270	9.9%
Insurance and Regulatory Fees	53,753	50,594	104,346	4.4%
Energy	20,162	19,753	39,915	1.7%
Characterization and Licensing Surveys	18,118	20,359	38,478	1.6%
Property Taxes	156,602	156,387	312,989	13.3%
Miscellaneous	17,651	21,979	39,630	1.7%
Railroad Track Maintenance	4,362	4,281	8,644	0.4%
Retention and Severance	28,423	28,423	56,845	2.4%
Security Modifications	5,000	5,000	10,000	0.4%
Prairie Island Indian Community Payments	40,000	38,750	78,750	3.4%
Total [3]	1,205,645	1,143,621	2,349,266	100.0%

Cost Element	Unit 1	Unit 2	Total	Percentage
NRC License Termination	908,226	841,160	1,749,386	74.5%
Spent Fuel Management	242,850	233,483	476,333	20.3%
Site Restoration	54,569	68,978	123,547	5.3%
Total [3]	1,205,645	1,143,621	2,349,266	100.0%

[1] Includes engineering

[2] Includes costs for the dry storage system components, spent fuel loading and transfer, spent fuel pool O&M and EP fees, but excludes program management costs (staffing), security and other related costs

[3] Columns may not add due to rounding

TABLE 6.7
SCENARIO 7: SAFSTOR WITH 60 YEAR DFS
DECOMMISSIONING COST ELEMENTS
(thousands of 2017 dollars)

Cost Element	Unit 1	Unit 2	Total	Percentage
Decontamination	7,825	16,452	24,276	1.0%
Removal	108,474	136,691	245,165	9.9%
Packaging	34,003	34,343	68,346	2.8%
Transportation	6,683	7,171	13,854	0.6%
Waste Disposal	53,613	55,347	108,960	4.4%
Off-site Waste Processing	13,846	16,314	30,160	1.2%
Program Management [1]	313,922	284,127	598,049	24.1%
Security	200,143	166,411	366,553	14.8%
Spent Fuel Pool Isolation	13,445	8,963	22,409	0.9%
Spent Fuel Storage (Direct Costs) [2]	138,784	136,422	275,207	11.1%
Insurance and Regulatory Fees	54,180	50,827	105,007	4.2%
Energy	20,134	19,489	39,623	1.6%
Characterization and Licensing Surveys	18,118	20,359	38,478	1.6%
Property Taxes	161,296	156,387	317,682	12.8%
Miscellaneous	17,668	21,945	39,613	1.6%
Railroad Track Maintenance	4,362	4,281	8,644	0.3%
Retention and Severance	28,423	28,423	56,845	2.3%
Security Modifications	5,000	5,000	10,000	0.4%
Prairie Island Indian Community Payments	56,250	55,000	111,250	4.5%
Total [3]	1,256,169	1,223,951	2,480,120	100.0%

Cost Element	Unit 1	Unit 2	Total	Percentage
NRC License Termination	883,602	846,342	1,729,944	69.8%
Spent Fuel Management	317,887	308,520	626,407	25.3%
Site Restoration	54,680	69,089	123,769	5.0%
Total [3]	1,256,169	1,223,951	2,480,120	100.0%

[1] Includes engineering costs

[2] Includes costs for the dry storage system components, spent fuel loading and transfer, spent fuel pool O&M and EP fees, but excludes program management costs (staffing), security and other related costs

[3] Columns may not add due to rounding

7. REFERENCES

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3. U.S. Nuclear Regulatory Commission, Regulatory Guide 1.159, "Assuring the Availability of Funds for Decommissioning Nuclear Reactors," Rev. 2, October 2011 [Open]

4. U.S. Code of Federal Regulations, Title 10, Part 20, Subpart E, "Radiological Criteria for License Termination" [Open]

5. U.S. Code of Federal Regulations, Title 10, Parts 20 and 50, "Entombment Options for Power Reactors," Advance Notice of Proposed Rulemaking, 66 Fed. Reg. 52551, October 16, 2001 [Open]

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APPENDIX A

UNIT COST FACTOR DEVELOPMENT

APPENDIX A
UNIT COST FACTOR DEVELOPMENT

Example: Unit Factor for Removal of Contaminated Heat Exchanger < 3,000 lbs.

1. SCOPE

Heat exchangers weighing < 3,000 lbs. will be removed in one piece using a crane or small hoist. They will be disconnected from the inlet and outlet piping. The heat exchanger will be sent to the waste processing area.

2. CALCULATIONS

Act ID	Activity Description	Activity Duration (minutes)	Critical Duration (minutes)*
a	Remove insulation	60	(b)
b	Mount pipe cutters	60	60
c	Install contamination controls	20	(b)
d	Disconnect inlet and outlet lines	60	60
e	Cap openings	20	(d)
f	Rig for removal	30	30
g	Unbolt from mounts	30	30
h	Remove contamination controls	15	15
i	Remove, wrap, send to waste processing area	60	60
	Totals (Activity/Critical)	355	255

Duration adjustment(s):	
+ Respiratory protection adjustment (50 of critical duration)	128
+ Radiation/ALARA adjustment (37.1 of critical duration)	95
Adjusted work duration	478
+ Protective clothing adjustment (30 of adjusted duration)	143
Productive work duration	621
+ Work break adjustment (8.33 of productive duration)	52
Total work duration (minutes)	673

***** Total duration = 11.217 hr *****

* alpha designators indicate activities that can be performed in parallel

APPENDIX A
(continued)

3. LABOR REQUIRED

Crew	Number	Duration (hours)	Rate ($/hr)	Cost
Laborers	3.00	11.217	$52.61	$1,770.38
Craftsmen	2.00	11.217	$68.16	$1,529.10
Foreman	1.00	11.217	$71.37	$800.56
General Foreman	0.25	11.217	$73.67	$206.59
Fire Watch	0.05	11.217	$52.61	$29.61
Health Physics Technician	1.00	11.217	$76.50	$858.10
Total Labor Cost				$5,194.24

4. EQUIPMENT & CONSUMABLES COSTS

Equipment Costs none

Consumables/Materials Costs

- Universal Sorbent 50 @ $0.61 sq ft {1} $30.50
- Tarpaulins (oil resistant/fire retardant) 50 @ $0.46/sq ft {2} $23.00
- Gas torch consumables 1 @ $20.45/hr x 1 hr {3} $20.45

Subtotal cost of equipment and materials $73.95
Overhead & profit on equipment and materials @ 16.88% $12.48

Total costs, equipment & material $86.43

TOTAL COST:

Removal of contaminated heat exchanger <3000 pounds: $5,280.67

Total labor cost: $5,194.24
Total equipment/material costs: $86.43
Total craft labor man-hours required per unit: 81.88

5. NOTES AND REFERENCES

- Work difficulty factors were developed in conjunction with the Atomic Industrial Forum's (now NEI) program to standardize nuclear decommissioning cost estimates and are delineated in Volume 1, Chapter 5 of the "Guidelines for Producing Commercial Nuclear Power Plant Decommissioning Cost Estimates," AIF/NESP-036, May 1986.

- References for equipment & consumables costs:

    1. www.mcmaster.com online catalog, McMaster Carr Spill Control (7193T88)
    2. R.S. Means (2017) Division 01 56, Section 13.60-0600, page 23
    3. R.S. Means (2017) Division 01 54 33, Section 40-6360, page 718

- Material and consumable costs were adjusted using the regional indices for Minneapolis, Minnesota.

APPENDIX B

UNIT COST FACTOR LISTING
(DECON: Power Block Structures Only)

APPENDIX B

UNIT COST FACTOR LISTING
(Power Block Structures Only)

Unit Cost Factor	Cost/Unit
Removal of clean instrument and sampling tubing, $/linear foot	0.58
Removal of clean pipe 0.25 to 2 inches diameter, $/linear foot	6.16
Removal of clean pipe >2 to 4 inches diameter, $/linear foot	8.78
Removal of clean pipe >4 to 8 inches diameter, $/linear foot	17.10
Removal of clean pipe >8 to 14 inches diameter, $/linear foot	33.02
Removal of clean pipe >14 to 20 inches diameter, $/linear foot	42.99
Removal of clean pipe >20 to 36 inches diameter, $/linear foot	63.24
Removal of clean pipe >36 inches diameter, $/linear foot	75.11
Removal of clean valve >2 to 4 inches	113.25
Removal of clean valve >4 to 8 inches	171.03
Removal of clean valve >8 to 14 inches	330.21
Removal of clean valve >14 to 20 inches	429.92
Removal of clean valve >20 to 36 inches	632.40
Removal of clean valve >36 inches	751.10
Removal of clean pipe hanger for small bore piping	39.61
Removal of clean pipe hanger for large bore piping	140.05
Removal of clean pump, <300 pound	289.85
Removal of clean pump, 300-1000 pound	801.33
Removal of clean pump, 1000-10,000 pound	3,160.77
Removal of clean pump, >10,000 pound	6,117.66
Removal of clean pump motor, 300-1000 pound	334.27
Removal of clean pump motor, 1000-10,000 pound	1,312.24
Removal of clean pump motor, >10,000 pound	2,952.53
Removal of clean heat exchanger <3000 pound	1,698.90
Removal of clean heat exchanger >3000 pound	4,283.30
Removal of clean feedwater heater/deaerator	12,062.93
Removal of clean moisture separator/reheater	24,783.03
Removal of clean tank, <300 gallons	372.70
Removal of clean tank, 300-3000 gallon	1,172.60
Removal of clean tank, >3000 gallons, $/square foot surface area	9.85

APPENDIX B

UNIT COST FACTOR LISTING
(Power Block Structures Only)

Unit Cost Factor	Cost/Unit
Removal of clean electrical equipment, <300 pound	156.50
Removal of clean electrical equipment, 300-1000 pound	544.23
Removal of clean electrical equipment, 1000-10,000 pound	1,088.45
Removal of clean electrical equipment, >10,000 pound	2,584.37
Removal of clean electrical transformer < 30 tons	1,794.81
Removal of clean electrical transformer > 30 tons	5,168.70
Removal of clean standby diesel generator, <100 kW	1,833.23
Removal of clean standby diesel generator, 100 kW to 1 MW	4,091.90
Removal of clean standby diesel generator, >1 MW	8,471.05
Removal of clean electrical cable tray, $/linear foot	14.76
Removal of clean electrical conduit, $/linear foot	6.45
Removal of clean mechanical equipment, <300 pound	156.50
Removal of clean mechanical equipment, 300-1000 pound	544.23
Removal of clean mechanical equipment, 1000-10,000 pound	1,088.45
Removal of clean mechanical equipment, >10,000 pound	2,584.37
Removal of clean HVAC equipment, <300 pound	189.24
Removal of clean HVAC equipment, 300-1000 pound	653.93
Removal of clean HVAC equipment, 1000-10,000 pound	1,303.28
Removal of clean HVAC equipment, >10,000 pound	2,584.37
Removal of clean HVAC ductwork, $/pound	0.61
Removal of contaminated instrument and sampling tubing, $/linear foot	1.95
Removal of contaminated pipe 0.25 to 2 inches diameter, $/linear foot	26.56
Removal of contaminated pipe >2 to 4 inches diameter, $/linear foot	45.20
Removal of contaminated pipe >4 to 8 inches diameter, $/linear foot	72.68
Removal of contaminated pipe >8 to 14 inches diameter, $/linear foot	141.06
Removal of contaminated pipe >14 to 20 inches diameter, $/linear foot	169.46
Removal of contaminated pipe >20 to 36 inches diameter, $/linear foot	234.41
Removal of contaminated pipe >36 inches diameter, $/linear foot	276.97
Removal of contaminated valve >2 to 4 inches	553.32
Removal of contaminated valve >4 to 8 inches	662.47

APPENDIX B

UNIT COST FACTOR LISTING
(Power Block Structures Only)

Unit Cost Factor	Cost/Unit
Removal of contaminated valve >8 to 14 inches	1,348.03
Removal of contaminated valve >14 to 20 inches	1,713.56
Removal of contaminated valve >20 to 36 inches	2,281.53
Removal of contaminated valve >36 inches	2,707.15
Removal of contaminated pipe hanger for small bore piping	184.64
Removal of contaminated pipe hanger for large bore piping	596.64
Removal of contaminated pump, <300 pound	1,182.71
Removal of contaminated pump, 300-1000 pound	2,706.17
Removal of contaminated pump, 1000-10,000 pound	8,653.74
Removal of contaminated pump, >10,000 pound	21,079.34
Removal of contaminated pump motor, 300-1000 pound	1,153.25
Removal of contaminated pump motor, 1000-10,000 pound	3,525.11
Removal of contaminated pump motor, >10,000 pound	7,914.39
Removal of contaminated heat exchanger <3000 pound	5,280.67
Removal of contaminated heat exchanger >3000 pound	15,319.98
Removal of contaminated tank, <300 gallons	1,966.05
Removal of contaminated tank, >300 gallons, $/square foot	37.92
Removal of contaminated electrical equipment, <300 pound	917.52
Removal of contaminated electrical equipment, 300-1000 pound	2,207.05
Removal of contaminated electrical equipment, 1000-10,000 pound	4,251.16
Removal of contaminated electrical equipment, >10,000 pound	8,289.57
Removal of contaminated electrical cable tray, $/linear foot	44.36
Removal of contaminated electrical conduit, $/linear foot	21.71
Removal of contaminated mechanical equipment, <300 pound	1,020.69
Removal of contaminated mechanical equipment, 300-1000 pound	2,437.14
Removal of contaminated mechanical equipment, 1000-10,000 pound	4,686.67
Removal of contaminated mechanical equipment, >10,000 pound	8,289.57
Removal of contaminated HVAC equipment, <300 pound	1,020.69
Removal of contaminated HVAC equipment, 300-1000 pound	2,437.14
Removal of contaminated HVAC equipment, 1000-10,000 pound	4,686.67

APPENDIX B

UNIT COST FACTOR LISTING
(Power Block Structures Only)

Unit Cost Factor	Cost/Unit
Removal of contaminated HVAC equipment, >10,000 pound	8,289.57
Removal of contaminated HVAC ductwork, $/pound	2.66
Removal/plasma arc cut of contaminated thin metal components, $/linear in.	4.78
Additional decontamination of surface by washing, $/square foot	9.88
Additional decontamination of surfaces by hydrolasing, $/square foot	42.77
Decontamination rig hook up and flush, $/ 250-foot length	8,602.39
Chemical flush of components/systems, $/gallon	20.62
Removal of clean standard reinforced concrete, $/cubic yard	76.22
Removal of grade slab concrete, $/cubic yard	86.70
Removal of clean concrete floors, $/cubic yard	424.96
Removal of sections of clean concrete floors, $/cubic yard	1,277.24
Removal of clean heavily rein concrete w/#9 rebar, $/cubic yard	110.08
Removal of contaminated heavily rein concrete w/#9 rebar, $/cubic yard	2,525.79
Removal of clean heavily rein concrete w/#18 rebar, $/cubic yard	149.21
Removal of contaminated heavily rein concrete w/#18 rebar, $/cubic yard	3,340.90
Removal heavily rein concrete w/#18 rebar & steel embedments, $/cubic yard	518.41
Removal of below-grade suspended floors, $/cubic yard	209.25
Removal of clean monolithic concrete structures, $/cubic yard	1,049.70
Removal of contaminated monolithic concrete structures, $/cubic yard	2,512.62
Removal of clean foundation concrete, $/cubic yard	825.21
Removal of contaminated foundation concrete, $/cubic yard	2,340.94
Explosive demolition of bulk concrete, $/cubic yard	56.10
Removal of clean hollow masonry block wall, $/cubic yard	26.77
Removal of contaminated hollow masonry block wall, $/cubic yard	71.77
Removal of clean solid masonry block wall, $/cubic yard	26.77
Removal of contaminated solid masonry block wall, $/cubic yard	71.77
Backfill of below-grade voids, $/cubic yard	32.20
Removal of subterranean tunnels/voids, $/linear foot	131.51
Placement of concrete for below-grade voids, $/cubic yard	150.52
Excavation of clean material, $/cubic yard	3.35

APPENDIX B

UNIT COST FACTOR LISTING
(Power Block Structures Only)

Unit Cost Factor	Cost/Unit
Excavation of contaminated material, $/cubic yard	48.54
Removal of clean concrete rubble (tipping fee included), $/cubic yard	27.60
Removal of contaminated concrete rubble, $/cubic yard	30.99
Removal of building by volume, $/cubic foot	0.35
Removal of clean building metal siding, $/square foot	1.58
Removal of contaminated building metal siding, $/square foot	5.71
Removal of standard asphalt roofing, $/square foot	2.70
Removal of transite panels, $/square foot	2.45
Scarifying contaminated concrete surfaces (drill & spall), $/square foot	14.89
Scabbling contaminated concrete floors, $/square foot	9.21
Scabbling contaminated concrete walls, $/square foot	24.59
Scabbling contaminated ceilings, $/square foot	84.63
Scabbling structural steel, $/square foot	7.64
Removal of clean overhead crane/monorail < 10 ton capacity	759.93
Removal of contaminated overhead crane/monorail < 10 ton capacity	2,265.36
Removal of clean overhead crane/monorail >10-50 ton capacity	1,823.83
Removal of contaminated overhead crane/monorail >10-50 ton capacity	5,435.94
Removal of polar crane > 50 ton capacity	7,608.99
Removal of gantry crane > 50 ton capacity	32,304.44
Removal of structural steel, $/pound	0.23
Removal of clean steel floor grating, $/square foot	5.53
Removal of contaminated steel floor grating, $/square foot	16.69
Removal of clean free-standing steel liner, $/square foot	14.77
Removal of contaminated free-standing steel liner, $/square foot	44.38
Removal of clean concrete-anchored steel liner, $/square foot	7.39
Removal of contaminated concrete-anchored steel liner, $/square foot	51.73
Placement of scaffolding in clean areas, $/square foot	17.11
Placement of scaffolding in contaminated areas, $/square foot	30.30
Landscaping with topsoil, $/acre	24,605.57
Cost of CPC B-88 LSA box & preparation for use	2,083.43

APPENDIX B

UNIT COST FACTOR LISTING
(Power Block Structures Only)

Unit Cost Factor	Cost/Unit
Cost of CPC B-25 LSA box & preparation for use	1,963.90
Cost of CPC B-12V 12-gauge LSA box & preparation for use	1,565.90
Cost of CPC B-144 LSA box & preparation for use	10,460.39
Cost of LSA drum & preparation for use	230.20
Cost of cask liner for CNSI 8 120A cask (resins)	12,394.60
Cost of cask liner for CNSI 8 120A cask (filters)	8,981.65
Decontamination of surfaces with vacuuming, $/square foot	0.93

APPENDIX C

DETAILED COST ANALYSIS

SCENARIO 1: DECON with 32 Year DFS

Page

Prairie Island Nuclear Generating Plant, Unit 1 ..... C-2

Prairie Island Nuclear Generating Plant, Unit 2 ..... C-11

Table C-1
Prairie Island Nuclear Generating Plant, Unit 1
DECON Decommissioning Cost Estimate with DOE Pickup of Industry Spent Fuel Starting in 2025
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
PERIOD 1a - Shutdown through Transition																					
Period 1a Direct Decommissioning Activities																					
1a.1.1	Prepare preliminary decommissioning cost	-	-	-	-	-	-	153	23	175	175	-	-	-	-	-	-	-	-	-	1,300
1a.1.2	Notification of Cessation of Operations									a											
1a.1.3	Remove fuel & source material									n/a											
1a.1.4	Notification of Permanent Defueling									a											
1a.1.5	Deactivate plant systems & process waste									a											
1a.1.6	Prepare and submit PSDAR	-	-	-	-	-	-	235	35	270	270	-	-	-	-	-	-	-	-	-	2,000
1a.1.7	Review plant dwgs & specs.	-	-	-	-	-	-	540	81	621	621	-	-	-	-	-	-	-	-	-	4,600
1a.1.8	Perform detailed rad survey									a											
1a.1.9	Estimate by-product inventory	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1a.1.10	End product description	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1a.1.11	Detailed by-product inventory	-	-	-	-	-	-	153	23	175	175	-	-	-	-	-	-	-	-	-	1,300
1a.1.12	Define major work sequence	-	-	-	-	-	-	880	132	1,012	1,012	-	-	-	-	-	-	-	-	-	7,500
1a.1.13	Perform SER and EA	-	-	-	-	-	-	364	55	418	418	-	-	-	-	-	-	-	-	-	3,100
1a.1.14	Prepare/submit Defueled Technical Specifications	-	-	-	-	-	-	880	132	1,012	1,012	-	-	-	-	-	-	-	-	-	7,500
1a.1.15	Perform Site-Specific Cost Study	-	-	-	-	-	-	587	88	675	675	-	-	-	-	-	-	-	-	-	5,000
1a.1.16	Prepare/submit Irradiated Fuel Management Plan	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
Activity Specifications																					
1a.1.17.1	Plant & temporary facilities	-	-	-	-	-	-	578	87	664	598	-	66	-	-	-	-	-	-	-	4,920
1a.1.17.2	Plant systems	-	-	-	-	-	-	489	73	562	506	-	56	-	-	-	-	-	-	-	4,167
1a.1.17.3	NSSS Decontamination Flush	-	-	-	-	-	-	59	9	67	67	-	-	-	-	-	-	-	-	-	500
1a.1.17.4	Reactor internals	-	-	-	-	-	-	833	125	958	958	-	-	-	-	-	-	-	-	-	7,100
1a.1.17.5	Reactor vessel	-	-	-	-	-	-	763	114	877	877	-	-	-	-	-	-	-	-	-	6,500
1a.1.17.6	Biological shield	-	-	-	-	-	-	59	9	67	67	-	-	-	-	-	-	-	-	-	500
1a.1.17.7	Steam generators	-	-	-	-	-	-	366	55	421	421	-	-	-	-	-	-	-	-	-	3,120
1a.1.17.8	Reinforced concrete	-	-	-	-	-	-	188	28	216	108	-	108	-	-	-	-	-	-	-	1,600
1a.1.17.9	Main Turbine	-	-	-	-	-	-	47	7	54	-	-	54	-	-	-	-	-	-	-	400
1a.1.17.10	Main Condensers	-	-	-	-	-	-	47	7	54	-	-	54	-	-	-	-	-	-	-	400
1a.1.17.11	Plant structures & buildings	-	-	-	-	-	-	366	55	421	211	-	211	-	-	-	-	-	-	-	3,120
1a.1.17.12	Waste management	-	-	-	-	-	-	540	81	621	621	-	-	-	-	-	-	-	-	-	4,600
1a.1.17.13	Facility & site closeout	-	-	-	-	-	-	106	16	121	61	-	61	-	-	-	-	-	-	-	900
1a.1.17	Total	-	-	-	-	-	-	4,440	666	5,106	4,496	-	610	-	-	-	-	-	-	-	37,827
Planning & Site Preparations																					
1a.1.18	Prepare dismantling sequence	-	-	-	-	-	-	282	42	324	324	-	-	-	-	-	-	-	-	-	2,400
1a.1.19	Plant prep. & temp. svces	-	-	-	-	-	-	3,300	495	3,795	3,795	-	-	-	-	-	-	-	-	-	-
1a.1.20	Design water clean-up system	-	-	-	-	-	-	164	25	189	189	-	-	-	-	-	-	-	-	-	1,400
1a.1.21	Rigging/Cont. Cntrl Envlps/tooling/etc.	-	-	-	-	-	-	2,300	345	2,645	2,645	-	-	-	-	-	-	-	-	-	-
1a.1.22	Procure casks/liners & containers	-	-	-	-	-	-	144	22	166	166	-	-	-	-	-	-	-	-	-	1,230
1a.1	Subtotal Period 1a Activity Costs	-	-	-	-	-	-	14,774	2,216	16,990	16,380	-	610	-	-	-	-	-	-	-	78,157
Period 1a Additional Costs																					
1a.2.1	Spent Fuel Pool Isolation	-	-	-	-	-	-	11,691	1,754	13,445	13,445	-	-	-	-	-	-	-	-	-	-
1a.2	Subtotal Period 1a Additional Costs	-	-	-	-	-	-	11,691	1,754	13,445	13,445	-	-	-	-	-	-	-	-	-	-
Period 1a Collateral Costs																					
1a.3.1	Prairie Island Indian Community Payments	-	-	-	-	-	-	2,003	-	2,003	-	2,003	-	-	-	-	-	-	-	-	-
1a.3	Subtotal Period 1a Collateral Costs	-	-	-	-	-	-	2,003	-	2,003	-	2,003	-	-	-	-	-	-	-	-	-
Period 1a Period-Dependent Costs																					
1a.4.1	Insurance	-	-	-	-	-	-	1,730	173	1,903	1,903	-	-	-	-	-	-	-	-	-	-
1a.4.2	Property taxes	-	-	-	-	-	-	2,040	204	2,244	2,244	-	-	-	-	-	-	-	-	-	-
1a.4.3	Health physics supplies	-	515	-	-	-	-	-	129	644	644	-	-	-	-	-	-	-	-	-	-
1a.4.4	Heavy equipment rental	-	567	-	-	-	-	-	85	652	652	-	-	-	-	-	-	-	-	-	-
1a.4.5	Disposal of DAW generated	-	-	13	4	-	50	-	14	81	81	-	-	-	610	-	-	-	12,190	20	-
1a.4.6	Plant energy budget	-	-	-	-	-	-	1,515	227	1,742	1,742	-	-	-	-	-	-	-	-	-	-
1a.4.7	NRC Fees	-	-	-	-	-	-	1,110	111	1,221	1,221	-	-	-	-	-	-	-	-	-	-
1a.4.8	Emergency Planning Fees	-	-	-	-	-	-	1,604	160	1,765	-	1,765	-	-	-	-	-	-	-	-	-
1a.4.9	Fixed Overhead	-	-	-	-	-	-	1,470	220	1,690	1,690	-	-	-	-	-	-	-	-	-	-
1a.4.10	Spent Fuel Pool O&M	-	-	-	-	-	-	401	60	461	-	461	-	-	-	-	-	-	-	-	-
1a.4.11	ISFSI Operating Costs	-	-	-	-	-	-	52	8	59	-	59	-	-	-	-	-	-	-	-	-
1a.4.12	Railroad Track Maintenance	-	-	-	-	-	-	58	9	66	66	-	-	-	-	-	-	-	-	-	-
1a.4.13	Security Staff Cost	-	-	-	-	-	-	7,390	1,108	8,498	8,498	-	-	-	-	-	-	-	-	-	122,720
1a.4.14	Utility Staff Cost	-	-	-	-	-	-	25,791	3,869	29,660	29,660	-	-	-	-	-	-	-	-	-	422,240
1a.4	Subtotal Period 1a Period-Dependent Costs	-	1,083	13	4	-	50	43,160	6,378	50,687	48,402	2,286	-	-	610	-	-	-	12,190	20	544,960

Table C-1
Prairie Island Nuclear Generating Plant, Unit 1
DECON Decommissioning Cost Estimate with DOE Pickup of Industry Spent Fuel Starting in 2025
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
1a.0	TOTAL PERIOD 1a COST	-	1,083	13	4	-	50	71,629	10,348	83,126	78,227	4,289	610	-	610	-	-	-	12,190	20	623,117
PERIOD 1b - Decommissioning Preparations																					
Period 1b Direct Decommissioning Activities																					
Detailed Work Procedures																					
1b.1.1.1	Plant systems	-	-	-	-	-	-	556	83	639	575	-	64	-	-	-	-	-	-	-	4,733
1b.1.1.2	NSSS Decontamination Flush	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1b.1.1.3	Reactor internals	-	-	-	-	-	-	293	44	337	337	-	-	-	-	-	-	-	-	-	2,500
1b.1.1.4	Remaining buildings	-	-	-	-	-	-	158	24	182	46	-	137	-	-	-	-	-	-	-	1,350
1b.1.1.5	CRD cooling assembly	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1b.1.1.6	CRD housings & ICI tubes	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1b.1.1.7	Incore instrumentation	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1b.1.1.8	Reactor vessel	-	-	-	-	-	-	426	64	490	490	-	-	-	-	-	-	-	-	-	3,630
1b.1.1.9	Facility closeout	-	-	-	-	-	-	141	21	162	81	-	81	-	-	-	-	-	-	-	1,200
1b.1.1.10	Missile shields	-	-	-	-	-	-	53	8	61	61	-	-	-	-	-	-	-	-	-	450
1b.1.1.11	Biological shield	-	-	-	-	-	-	141	21	162	162	-	-	-	-	-	-	-	-	-	1,200
1b.1.1.12	Steam generators	-	-	-	-	-	-	540	81	621	621	-	-	-	-	-	-	-	-	-	4,600
1b.1.1.13	Reinforced concrete	-	-	-	-	-	-	117	18	135	67	-	67	-	-	-	-	-	-	-	1,000
1b.1.1.14	Main Turbine	-	-	-	-	-	-	183	27	211	-	-	211	-	-	-	-	-	-	-	1,560
1b.1.1.15	Main Condensers	-	-	-	-	-	-	183	27	211	-	-	211	-	-	-	-	-	-	-	1,560
1b.1.1.16	Auxiliary building	-	-	-	-	-	-	320	48	369	332	-	37	-	-	-	-	-	-	-	2,730
1b.1.1.17	Reactor building	-	-	-	-	-	-	320	48	369	332	-	37	-	-	-	-	-	-	-	2,730
1b.1.1	Total	-	-	-	-	-	-	3,902	585	4,487	3,643	-	844	-	-	-	-	-	-	-	33,243
1b.1.2	Decon primary loop	552	-	-	-	-	-	-	276	828	828	-	-	-	-	-	-	-	-	1,067	-
1b.1	Subtotal Period 1b Activity Costs	552	-	-	-	-	-	3,902	861	5,315	4,471	-	844	-	-	-	-	-	-	1,067	33,243
Period 1b Additional Costs																					
1b.2.1	Site Characterization	-	-	-	-	-	-	3,700	1,110	4,810	4,810	-	-	-	-	-	-	-	-	21,020	8,332
1b.2.2	Mixed/Hazardous Waste	-	-	318	75	164	-	-	68	624	624	-	-	6,133	-	-	-	-	351,986	2,361	-
1b.2.3	Asbestos Abatement	-	2,364	2	110	-	1,359	-	947	4,782	4,782	-	-	-	12,843	-	-	-	166,959	20,907	-
1b.2	Subtotal Period 1b Additional Costs	-	2,364	320	185	164	1,359	3,700	2,125	10,216	10,216	-	-	6,133	12,843	-	-	-	518,945	44,288	8,332
Period 1b Collateral Costs																					
1b.3.1	Decon equipment	973	-	-	-	-	-	-	146	1,119	1,119	-	-	-	-	-	-	-	-	-	-
1b.3.2	DOC staff relocation expenses	-	-	-	-	-	-	1,189	178	1,367	1,367	-	-	-	-	-	-	-	-	-	-
1b.3.3	Process decommissioning water waste	24	-	16	41	-	64	-	36	180	180	-	-	-	152	-	-	-	9,121	30	-
1b.3.4	Process decommissioning chemical flush waste	2	-	58	220	-	2,471	-	657	3,408	3,408	-	-	-	-	588	-	-	62,689	110	-
1b.3.5	Small tool allowance	-	34	-	-	-	-	-	5	39	39	-	-	-	-	-	-	-	-	-	-
1b.3.6	Pipe cutting equipment	-	1,200	-	-	-	-	-	180	1,380	1,380	-	-	-	-	-	-	-	-	-	-
1b.3.7	Decon rig	1,987	-	-	-	-	-	-	298	2,285	2,285	-	-	-	-	-	-	-	-	-	-
1b.3.8	Spent Fuel Capital and Transfer	-	-	-	-	-	-	230	35	265	-	265	-	-	-	-	-	-	-	-	-
1b.3.9	Retention and Severance	-	-	-	-	-	-	1,088	163	1,251	1,251	-	-	-	-	-	-	-	-	-	-
1b.3.10	Prairie Island Indian Community Payments	-	-	-	-	-	-	630	-	630	-	630	-	-	-	-	-	-	-	-	-
1b.3	Subtotal Period 1b Collateral Costs	2,986	1,234	74	261	-	2,534	3,136	1,698	11,923	11,028	895	-	-	152	588	-	-	71,810	140	-
Period 1b Period-Dependent Costs																					
1b.4.1	Decon supplies	35	-	-	-	-	-	-	9	44	44	-	-	-	-	-	-	-	-	-	-
1b.4.2	Insurance	-	-	-	-	-	-	872	87	959	959	-	-	-	-	-	-	-	-	-	-
1b.4.3	Property taxes	-	-	-	-	-	-	1,352	135	1,487	1,487	-	-	-	-	-	-	-	-	-	-
1b.4.4	Health physics supplies	-	402	-	-	-	-	-	101	503	503	-	-	-	-	-	-	-	-	-	-
1b.4.5	Heavy equipment rental	-	286	-	-	-	-	-	43	329	329	-	-	-	-	-	-	-	-	-	-
1b.4.6	Disposal of DAW generated	-	-	8	2	-	29	-	8	48	48	-	-	-	360	-	-	-	7,197	12	-
1b.4.7	Plant energy budget	-	-	-	-	-	-	1,527	229	1,756	1,756	-	-	-	-	-	-	-	-	-	-
1b.4.8	NRC Fees	-	-	-	-	-	-	323	32	355	355	-	-	-	-	-	-	-	-	-	-
1b.4.9	Emergency Planning Fees	-	-	-	-	-	-	809	81	890	-	890	-	-	-	-	-	-	-	-	-
1b.4.10	Fixed Overhead	-	-	-	-	-	-	741	111	852	852	-	-	-	-	-	-	-	-	-	-
1b.4.11	Spent Fuel Pool O&M	-	-	-	-	-	-	202	30	233	-	233	-	-	-	-	-	-	-	-	-
1b.4.12	ISFSI Operating Costs	-	-	-	-	-	-	26	4	30	-	30	-	-	-	-	-	-	-	-	-
1b.4.13	Railroad Track Maintenance	-	-	-	-	-	-	29	4	33	33	-	-	-	-	-	-	-	-	-	-
1b.4.14	Security Staff Cost	-	-	-	-	-	-	3,725	559	4,284	4,284	-	-	-	-	-	-	-	-	-	61,864
1b.4.15	DOC Staff Cost	-	-	-	-	-	-	5,656	848	6,504	6,504	-	-	-	-	-	-	-	-	-	63,961
1b.4.16	Utility Staff Cost	-	-	-	-	-	-	13,074	1,961	15,035	15,035	-	-	-	-	-	-	-	-	-	213,904
1b.4	Subtotal Period 1b Period-Dependent Costs	35	688	8	2	-	29	28,336	4,243	33,341	32,189	1,152	-	-	360	-	-	-	7,197	12	339,730
1b.0	TOTAL PERIOD 1b COST	3,573	4,286	402	447	164	3,923	39,074	8,927	60,795	57,904	2,047	844	6,133	13,355	588	-	-	597,952	45,506	381,305

Table C-1
Prairie Island Nuclear Generating Plant, Unit 1
DECON Decommissioning Cost Estimate with DOE Pickup of Industry Spent Fuel Starting in 2025
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
PERIOD 1 TOTALS		3,573	5,368	415	451	164	3,972	110,702	19,275	143,921	136,131	6,336	1,454	6,133	13,964	588	-	-	610,142	45,526	1,004,421
PERIOD 2a - Large Component Removal																					
Period 2a Direct Decommissioning Activities																					
Nuclear Steam Supply System Removal																					
2a.1.1.1	Reactor Coolant Piping	51	45	6	8	-	150	-	76	336	336	-	-	-	305	-	-	-	34,809	1,414	-
2a.1.1.2	Pressurizer Relief Tank	22	20	4	5	-	100	-	42	193	193	-	-	-	203	-	-	-	23,193	625	-
2a.1.1.3	Reactor Coolant Pumps & Motors	54	63	101	83	-	736	-	249	1,287	1,287	-	-	-	2,332	-	-	-	295,800	2,049	100
2a.1.1.4	Pressurizer	48	68	467	88	-	693	-	274	1,639	1,639	-	-	-	2,196	-	-	-	185,015	2,355	938
2a.1.1.5	Steam Generators	225	2,943	2,093	1,638	1,246	3,570	-	2,383	14,097	14,097	-	-	18,672	11,316	-	-	-	1,668,341	14,819	2,875
2a.1.1.6	CRDMs/ICIs/Service Structure Removal	286	277	211	48	-	763	-	431	2,016	2,016	-	-	-	4,797	-	-	-	177,400	8,104	-
2a.1.1.7	Reactor Vessel Internals	78	4,468	21,874	1,072	-	7,946	277	13,141	48,856	48,856	-	-	-	501	125	673	-	164,987	23,040	1,080
2a.1.1.8	Reactor Vessel	89	5,717	1,754	719	-	1,956	277	5,970	16,483	16,483	-	-	-	5,690	-	-	-	570,074	23,040	1,080
2a.1.1	Totals	855	13,600	26,512	3,662	1,246	15,913	553	22,568	84,908	84,908	-	-	18,672	27,341	125	673	-	3,119,620	75,446	6,073
Removal of Major Equipment																					
2a.1.2	Main Turbine/Generator	-	305	189	55	272	306	-	221	1,348	1,348	-	-	2,131	1,187	-	-	-	206,316	4,667	-
2a.1.3	Main Condensers	-	2,532	121	49	364	451	-	820	4,336	4,336	-	-	3,800	1,587	-	-	-	275,903	39,151	-
Cascading Costs from Clean Building Demolition																					
2a.1.4.1	Reactor	-	728	-	-	-	-	-	109	837	837	-	-	-	-	-	-	-	-	7,589	-
2a.1.4	Totals	-	728	-	-	-	-	-	109	837	837	-	-	-	-	-	-	-	-	7,589	-
Disposal of Plant Systems																					
2a.1.5.1	Air Removal	-	27	-	-	-	-	-	4	31	-	-	31	-	-	-	-	-	-	452	-
2a.1.5.2	Auxiliary Feedwater	-	40	-	-	-	-	-	6	46	-	-	46	-	-	-	-	-	-	670	-
2a.1.5.3	Auxiliary Feedwater - RCA	-	45	0	1	19	-	-	14	79	79	-	-	215	-	-	-	-	8,722	601	-
2a.1.5.4	Bleed Steam	-	78	-	-	-	-	-	12	90	-	-	90	-	-	-	-	-	-	1,335	-
2a.1.5.5	Caustic Addition - RCA	-	36	0	1	20	-	-	12	71	71	-	-	233	-	-	-	-	9,453	444	-
2a.1.5.6	Chemical Feed	-	17	-	-	-	-	-	3	20	-	-	20	-	-	-	-	-	-	304	-
2a.1.5.7	Chemical Feed - RCA	-	1	0	0	1	-	-	0	2	2	-	-	6	-	-	-	-	243	12	-
2a.1.5.8	Circulating Water	-	37	-	-	-	-	-	6	42	-	-	42	-	-	-	-	-	-	619	-
2a.1.5.9	Condensate	-	414	-	-	-	-	-	62	476	-	-	476	-	-	-	-	-	-	6,837	-
2a.1.5.10	Condensate Polishing	-	205	-	-	-	-	-	31	236	-	-	236	-	-	-	-	-	-	3,420	-
2a.1.5.11	Condensate Polishing - RCA	-	176	4	12	180	-	-	73	444	444	-	-	2,078	-	-	-	-	84,395	2,329	-
2a.1.5.12	Electro-hydraulic	-	8	-	-	-	-	-	1	9	-	-	9	-	-	-	-	-	-	127	-
2a.1.5.13	Feedwater	-	133	-	-	-	-	-	20	153	-	-	153	-	-	-	-	-	-	2,215	-
2a.1.5.14	Feedwater - RCA	-	186	6	19	278	-	-	91	579	579	-	-	3,208	-	-	-	-	130,294	2,651	-
2a.1.5.15	Gland Seal	-	29	-	-	-	-	-	4	34	-	-	34	-	-	-	-	-	-	505	-
2a.1.5.16	Heater Drain	-	349	-	-	-	-	-	52	401	-	-	401	-	-	-	-	-	-	5,881	-
2a.1.5.17	Internal Circ Water & CDSR	-	23	-	-	-	-	-	3	27	-	-	27	-	-	-	-	-	-	389	-
2a.1.5.18	Main Gen/Exciter/Transformer	-	0	-	-	-	-	-	0	0	-	-	0	-	-	-	-	-	-	5	-
2a.1.5.19	Main Steam	-	101	-	-	-	-	-	15	116	-	-	116	-	-	-	-	-	-	1,690	-
2a.1.5.20	Main Steam - RCA	-	350	9	29	436	-	-	158	983	983	-	-	5,044	-	-	-	-	204,825	4,956	-
2a.1.5.21	Steam Generator Blowdown	-	459	21	22	176	195	-	195	1,067	1,067	-	-	2,031	686	-	-	-	127,773	6,667	-
2a.1.5.22	Steam Generators	-	5	-	-	-	-	-	1	5	-	-	5	-	-	-	-	-	-	75	-
2a.1.5.23	Turbine & Moisture Separators	-	337	-	-	-	-	-	51	388	-	-	388	-	-	-	-	-	-	5,609	-
2a.1.5.24	Turbine Oil Purification	-	61	-	-	-	-	-	9	71	-	-	71	-	-	-	-	-	-	1,003	-
2a.1.5	Totals	-	3,117	40	85	1,108	195	-	825	5,370	3,226	-	2,145	12,815	686	-	-	-	565,705	48,794	-
2a.1.6	Scaffolding in support of decommissioning	-	854	3	1	13	3	-	217	1,092	1,092	-	-	138	12	-	-	-	7,016	6,368	-
2a.1	Subtotal Period 2a Activity Costs	855	21,136	26,865	3,852	3,004	16,868	553	24,759	97,891	95,747	-	2,145	37,556	30,812	125	673	-	4,174,560	182,015	6,073
Period 2a Additional Costs																					
2a.2.1	Remedial Action Surveys	-	-	-	-	-	-	2,126	638	2,764	2,764	-	-	-	-	-	-	-	-	27,791	-
2a.2.2	Retired RPV upper internals package	1	659	785	107	-	1,439	-	1,437	4,427	4,427	-	-	-	2,097	125	-	-	205,890	2,175	87
2a.2	Subtotal Period 2a Additional Costs	1	659	785	107	-	1,439	2,126	2,075	7,191	7,191	-	-	-	2,097	125	-	-	205,890	29,966	87
Period 2a Collateral Costs																					
2a.3.1	Process decommissioning water waste	47	-	31	81	-	126	-	70	356	356	-	-	-	302	-	-	-	18,119	59	-
2a.3.3	Small tool allowance	-	223	-	-	-	-	-	33	257	231	-	26	-	-	-	-	-	-	-	-
2a.3.4	Spent Fuel Capital and Transfer	-	-	-	-	-	-	2,365	355	2,720	-	2,720	-	-	-	-	-	-	-	-	-
2a.3.5	Retention and Severance	-	-	-	-	-	-	12,156	1,823	13,980	13,980	-	-	-	-	-	-	-	-	-	-
2a.3.6	Prairie Island Indian Community Payments	-	-	-	-	-	-	1,670	-	1,670	-	1,670	-	-	-	-	-	-	-	-	-
2a.3	Subtotal Period 2a Collateral Costs	47	223	31	81	-	126	16,191	2,282	18,982	14,567	4,390	26	-	302	-	-	-	18,119	59	-

Table C-1
Prairie Island Nuclear Generating Plant, Unit 1
DECON Decommissioning Cost Estimate with DOE Pickup of Industry Spent Fuel Starting in 2025
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 2a Period-Dependent Costs																					
2a.4.1	Decon supplies	93	-	-	-	-	-	-	23	116	116	-	-	-	-	-	-	-	-	-	-
2a.4.2	Insurance	-	-	-	-	-	-	683	68	751	751	-	-	-	-	-	-	-	-	-	-
2a.4.3	Property taxes	-	-	-	-	-	-	3,542	354	3,896	3,896	-	-	-	-	-	-	-	-	-	-
2a.4.4	Health physics supplies	-	1,717	-	-	-	-	-	429	2,146	2,146	-	-	-	-	-	-	-	-	-	-
2a.4.5	Heavy equipment rental	-	2,935	-	-	-	-	-	440	3,376	3,376	-	-	-	-	-	-	-	-	-	-
2a.4.6	Disposal of DAW generated	-	-	79	23	-	295	-	85	482	482	-	-	-	3,623	-	-	-	72,452	118	-
2a.4.7	Plant energy budget	-	-	-	-	-	-	1,924	289	2,212	2,212	-	-	-	-	-	-	-	-	-	-
2a.4.8	NRC Fees	-	-	-	-	-	-	774	77	851	851	-	-	-	-	-	-	-	-	-	-
2a.4.9	Emergency Planning Fees	-	-	-	-	-	-	1,717	172	1,888	-	1,888	-	-	-	-	-	-	-	-	-
2a.4.10	Fixed Overhead	-	-	-	-	-	-	1,655	248	1,904	1,904	-	-	-	-	-	-	-	-	-	-
2a.4.11	Spent Fuel Pool O&M	-	-	-	-	-	-	537	80	617	-	617	-	-	-	-	-	-	-	-	-
2a.4.12	ISFSI Operating Costs	-	-	-	-	-	-	69	10	79	-	79	-	-	-	-	-	-	-	-	-
2a.4.13	Railroad Track Maintenance	-	-	-	-	-	-	286	43	328	328	-	-	-	-	-	-	-	-	-	-
2a.4.14	Security Staff Cost	-	-	-	-	-	-	9,811	1,472	11,283	11,283	-	-	-	-	-	-	-	-	-	162,878
2a.4.15	DOC Staff Cost	-	-	-	-	-	-	18,392	2,759	21,150	21,150	-	-	-	-	-	-	-	-	-	211,351
2a.4.16	Utility Staff Cost	-	-	-	-	-	-	24,265	3,640	27,904	27,904	-	-	-	-	-	-	-	-	-	392,305
2a.4	Subtotal Period 2a Period-Dependent Costs	93	4,652	79	23	-	295	63,653	10,190	78,986	76,401	2,585	-	-	3,623	-	-	-	72,452	118	766,534
2a.0	TOTAL PERIOD 2a COST	995	26,670	27,760	4,062	3,004	18,729	82,524	39,305	203,050	193,905	6,974	2,170	37,556	36,834	250	673	-	4,471,020	212,158	772,694
PERIOD 2b - Site Decontamination																					
Period 2b Direct Decommissioning Activities																					
Disposal of Plant Systems																					
2b.1.1.1	Aux Bldg Normal Ventilation	-	2	0	0	0	-	-	1	3	3	-	-	3	-	-	-	-	140	29	-
2b.1.1.2	Battery Rm Special Ventilation	-	0	-	-	-	-	-	0	0	-	-	0	-	-	-	-	-	-	6	-
2b.1.1.3	Buildings Maintenance	-	4	-	-	-	-	-	1	5	-	-	5	-	-	-	-	-	-	65	-
2b.1.1.4	Chemical & Volume Control	1,077	1,331	83	69	389	802	-	1,149	4,901	4,901	-	-	4,498	2,846	-	-	-	369,246	34,533	-
2b.1.1.5	Component Cooling - RCA	-	821	22	72	1,075	-	-	379	2,369	2,369	-	-	12,427	-	-	-	-	504,675	11,242	-
2b.1.1.6	Containment Cooling	-	65	-	-	-	-	-	10	74	-	-	74	-	-	-	-	-	-	1,086	-
2b.1.1.7	Containment Cooling - RCA	-	290	6	20	294	-	-	120	730	730	-	-	3,400	-	-	-	-	138,090	3,971	-
2b.1.1.8	Containment Hydrogen Control - RCA	-	29	0	1	9	-	-	9	48	48	-	-	105	-	-	-	-	4,278	401	-
2b.1.1.9	Containment Spray - RCA	-	90	2	5	75	-	-	35	206	206	-	-	868	-	-	-	-	35,249	1,217	-
2b.1.1.10	Containment Ventilation	-	243	24	40	428	209	-	186	1,130	1,130	-	-	4,951	737	-	-	-	249,786	3,668	-
2b.1.1.11	Cooling Water	-	142	-	-	-	-	-	21	163	-	-	163	-	-	-	-	-	-	2,396	-
2b.1.1.12	Cooling Water - RCA	-	629	14	45	668	-	-	266	1,622	1,622	-	-	7,728	-	-	-	-	313,832	8,594	-
2b.1.1.13	D1 Emergency Diesel	-	44	-	-	-	-	-	7	50	-	-	50	-	-	-	-	-	-	730	-
2b.1.1.14	D2 Emergency Diesel	-	31	-	-	-	-	-	5	36	-	-	36	-	-	-	-	-	-	522	-
2b.1.1.15	Diesel Rooms Ventilation	-	8	-	-	-	-	-	1	10	-	-	10	-	-	-	-	-	-	135	-
2b.1.1.16	Electrical - Clean	-	1,669	-	-	-	-	-	250	1,919	-	-	1,919	-	-	-	-	-	-	26,981	-
2b.1.1.17	Electrical - Contaminated	-	592	6	16	219	27	-	191	1,051	1,051	-	-	2,527	95	-	-	-	108,935	8,377	-
2b.1.1.18	Electrical - Decontaminated	-	3,674	41	137	2,037	-	-	1,249	7,138	7,138	-	-	23,551	-	-	-	-	956,401	49,378	-
2b.1.1.19	Fuel Handling	-	116	6	9	79	62	-	58	329	329	-	-	908	218	-	-	-	51,280	1,784	-
2b.1.1.20	Fuel Oil	-	106	-	-	-	-	-	16	122	-	-	122	-	-	-	-	-	-	1,697	-
2b.1.1.21	HVAC - Clean	-	105	-	-	-	-	-	16	121	-	-	121	-	-	-	-	-	-	1,891	-
2b.1.1.22	HVAC - Contaminated	-	371	8	21	282	35	-	148	864	864	-	-	3,261	123	-	-	-	140,573	5,032	-
2b.1.1.23	Incore Instrumentation	0	27	1	1	5	16	-	12	64	64	-	-	60	57	-	-	-	6,177	425	-
2b.1.1.24	Misc Drains & Vents	-	222	14	10	34	146	-	100	527	527	-	-	390	514	-	-	-	49,900	3,091	-
2b.1.1.25	Reactor Coolant	148	298	21	14	30	221	-	213	945	945	-	-	344	777	-	-	-	65,413	6,470	-
2b.1.1.26	Reactor Hot Sampling	144	131	11	6	6	98	-	132	527	527	-	-	66	342	-	-	-	25,347	3,946	-
2b.1.1.27	Reactor Makeup	-	64	-	-	-	-	-	10	73	-	-	73	-	-	-	-	-	-	1,042	-
2b.1.1.28	Reactor Vessel	9	20	1	0	2	4	-	11	47	47	-	-	26	14	-	-	-	2,011	425	-
2b.1.1.29	Residual Heat Removal	344	399	85	66	250	926	-	559	2,630	2,630	-	-	2,895	3,252	-	-	-	332,849	7,621	-
2b.1.1.30	Safeguards Chilled Water	-	15	-	-	-	-	-	2	18	-	-	18	-	-	-	-	-	-	259	-
2b.1.1.31	Safety Injection	-	853	40	57	587	327	-	396	2,261	2,261	-	-	6,788	1,156	-	-	-	351,793	12,561	-
2b.1.1.32	Sampling	-	58	4	2	5	31	-	23	122	122	-	-	59	107	-	-	-	9,505	811	-
2b.1.1.33	Shield Bldg Ventilation	-	133	14	20	186	139	-	100	593	593	-	-	2,152	491	-	-	-	119,838	2,030	-
2b.1.1.34	Station & Instrument Air	-	17	-	-	-	-	-	3	20	-	-	20	-	-	-	-	-	-	300	-
2b.1.1.35	Station & Instrument Air - RCA	-	79	1	2	29	-	-	24	135	135	-	-	332	-	-	-	-	13,496	1,053	-
2b.1.1.36	Turbine Bldg Traps & Drains	-	44	-	-	-	-	-	7	50	-	-	50	-	-	-	-	-	-	767	-
2b.1.1.37	Unit Coolers	-	37	-	-	-	-	-	6	42	-	-	42	-	-	-	-	-	-	611	-
2b.1.1.38	Unit Coolers - RCA	-	53	0	1	20	-	-	16	91	91	-	-	230	-	-	-	-	9,348	683	-
2b.1.1	Totals	1,724	12,813	403	614	6,710	3,044	-	5,730	31,037	28,333	-	2,704	77,571	10,728	-	-	-	3,858,165	205,829	-
2b.1.2	Scaffolding in support of decommissioning	-	1,067	4	1	17	4	-	271	1,364	1,364	-	-	173	15	-	-	-	8,770	7,960	-

Table C-1
Prairie Island Nuclear Generating Plant, Unit 1
DECON Decommissioning Cost Estimate with DOE Pickup of Industry Spent Fuel Starting in 2025
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Decontamination of Site Buildings																					
2b.1.3.1	Reactor	1,150	2,623	139	852	193	11,079	-	4,171	20,208	20,208	-	-	2,230	57,414	-	-	-	3,559,624	50,842	-
2b.1.3.2	Backwash Waste Receiving Tank	-	27	1	11	-	87	-	30	158	158	-	-	-	507	-	-	-	43,896	299	-
2b.1.3	Totals	1,150	2,650	141	864	193	11,166	-	4,202	20,366	20,366	-	-	2,230	57,921	-	-	-	3,603,520	51,140	-
2b.1.4	Prepare/submit License Termination Plan	-	-	-	-	-	-	481	72	553	553	-	-	-	-	-	-	-	-	-	4,096
2b.1.5	Receive NRC approval of termination plan									a											
2b.1	Subtotal Period 2b Activity Costs	2,874	16,530	547	1,479	6,919	14,215	481	10,275	53,320	50,616	-	2,704	79,974	68,664	-	-	-	7,470,455	264,930	4,096
Period 2b Additional Costs																					
2b.2.1	Remedial Action Surveys	-	-	-	-	-	-	1,943	583	2,526	2,526	-	-	-	-	-	-	-	-	25,399	-
2b.2.2	Operational Equipment	-	-	9	29	312	-	-	52	402	402	-	-	5,855	-	-	-	-	146,375	16	-
2b.2	Subtotal Period 2b Additional Costs	-	-	9	29	312	-	1,943	635	2,928	2,928	-	-	5,855	-	-	-	-	146,375	25,415	-
Period 2b Collateral Costs																					
2b.3.1	Process decommissioning water waste	105	-	70	182	-	285	-	158	800	800	-	-	-	680	-	-	-	40,799	133	-
2b.3.2	Process decommissioning chemical flush waste	3	-	87	327	-	651	-	222	1,289	1,289	-	-	-	875	-	-	-	93,252	164	-
2b.3.3	Small tool allowance	-	289	-	-	-	-	-	43	332	332	-	-	-	-	-	-	-	-	-	-
2b.3.4	Spent Fuel Capital and Transfer	-	-	-	-	-	-	1,109	166	1,275	-	1,275	-	-	-	-	-	-	-	-	-
2b.3.5	Retention and Severance	-	-	-	-	-	-	6,994	1,049	8,043	8,043	-	-	-	-	-	-	-	-	-	-
2b.3.6	Prairie Island Indian Community Payments	-	-	-	-	-	-	1,525	-	1,525	-	1,525	-	-	-	-	-	-	-	-	-
2b.3	Subtotal Period 2b Collateral Costs	107	289	157	509	-	936	9,628	1,638	13,264	10,463	2,801	-	-	1,555	-	-	-	134,051	296	-
Period 2b Period-Dependent Costs																					
2b.4.1	Decon supplies	482	-	-	-	-	-	-	121	603	603	-	-	-	-	-	-	-	-	-	-
2b.4.2	Insurance	-	-	-	-	-	-	624	62	687	687	-	-	-	-	-	-	-	-	-	-
2b.4.3	Property taxes	-	-	-	-	-	-	3,099	310	3,409	3,409	-	-	-	-	-	-	-	-	-	-
2b.4.4	Health physics supplies	-	1,969	-	-	-	-	-	492	2,461	2,461	-	-	-	-	-	-	-	-	-	-
2b.4.5	Heavy equipment rental	-	2,759	-	-	-	-	-	414	3,173	3,173	-	-	-	-	-	-	-	-	-	-
2b.4.6	Disposal of DAW generated	-	-	78	23	-	293	-	85	479	479	-	-	-	3,600	-	-	-	71,996	117	-
2b.4.7	Plant energy budget	-	-	-	-	-	-	1,388	208	1,596	1,596	-	-	-	-	-	-	-	-	-	-
2b.4.8	NRC Fees	-	-	-	-	-	-	707	71	778	778	-	-	-	-	-	-	-	-	-	-
2b.4.9	Emergency Planning Fees	-	-	-	-	-	-	1,569	157	1,726	-	1,726	-	-	-	-	-	-	-	-	-
2b.4.10	Fixed Overhead	-	-	-	-	-	-	1,513	227	1,740	1,740	-	-	-	-	-	-	-	-	-	-
2b.4.11	Spent Fuel Pool O&M	-	-	-	-	-	-	490	74	564	-	564	-	-	-	-	-	-	-	-	-
2b.4.12	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	247	37	284	284	-	-	-	-	-	-	-	-	-	-
2b.4.13	ISFSI Operating Costs	-	-	-	-	-	-	63	9	73	-	73	-	-	-	-	-	-	-	-	-
2b.4.14	Railroad Track Maintenance	-	-	-	-	-	-	70	11	81	81	-	-	-	-	-	-	-	-	-	-
2b.4.15	Security Staff Cost	-	-	-	-	-	-	8,299	1,245	9,544	9,544	-	-	-	-	-	-	-	-	-	137,246
2b.4.16	DOC Staff Cost	-	-	-	-	-	-	11,450	1,718	13,168	13,168	-	-	-	-	-	-	-	-	-	137,246
2b.4.17	Utility Staff Cost	-	-	-	-	-	-	15,293	2,294	17,586	17,586	-	-	-	-	-	-	-	-	-	255,430
2b.4	Subtotal Period 2b Period-Dependent Costs	482	4,728	78	23	-	293	44,813	7,533	57,951	55,588	2,362	-	-	3,600	-	-	-	71,996	117	529,921
2b.0	TOTAL PERIOD 2b COST	3,464	21,546	792	2,040	7,231	15,444	56,865	20,081	127,463	119,596	5,163	2,704	85,829	73,819	-	-	-	7,822,876	290,758	534,017
PERIOD 2c - Spent fuel delay prior to SFP decon																					
Period 2c Direct Decommissioning Activities																					
Period 2c Additional Costs																					
2c.2.1	Security Modifications	-	-	-	-	-	-	4,348	652	5,000	5,000	-	-	-	-	-	-	-	-	-	-
2c.2	Subtotal Period 2c Additional Costs	-	-	-	-	-	-	4,348	652	5,000	5,000	-	-	-	-	-	-	-	-	-	-
Period 2c Collateral Costs																					
2c.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	62,386	9,358	71,744	-	71,744	-	-	-	-	-	-	-	-	-
2c.3.2	Retention and Severance	-	-	-	-	-	-	4,478	672	5,149	5,149	-	-	-	-	-	-	-	-	-	-
2c.3.3	Prairie Island Indian Community Payments	-	-	-	-	-	-	2,702	-	2,702	-	2,702	-	-	-	-	-	-	-	-	-
2c.3	Subtotal Period 2c Collateral Costs	-	-	-	-	-	-	69,565	10,030	79,595	5,149	74,446	-	-	-	-	-	-	-	-	-
Period 2c Period-Dependent Costs																					
2c.4.1	Insurance	-	-	-	-	-	-	1,104	110	1,215	1,215	-	-	-	-	-	-	-	-	-	-
2c.4.2	Property taxes	-	-	-	-	-	-	5,154	515	5,669	5,669	-	-	-	-	-	-	-	-	-	-
2c.4.3	Health physics supplies	-	390	-	-	-	-	-	98	488	488	-	-	-	-	-	-	-	-	-	-
2c.4.4	Disposal of DAW generated	-	-	18	5	-	66	-	19	108	108	-	-	-	809	-	-	-	16,171	26	-
2c.4.5	Plant energy budget	-	-	-	-	-	-	655	98	753	753	-	-	-	-	-	-	-	-	-	-
2c.4.6	NRC Fees	-	-	-	-	-	-	555	55	610	610	-	-	-	-	-	-	-	-	-	-
2c.4.7	Emergency Planning Fees	-	-	-	-	-	-	2,776	278	3,053	-	3,053	-	-	-	-	-	-	-	-	-

Table C-1
Prairie Island Nuclear Generating Plant, Unit 1
DECON Decommissioning Cost Estimate with DOE Pickup of Industry Spent Fuel Starting in 2025
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Period 2c Period-Dependent Costs (continued)																					
2c.4.8	Fixed Overhead	-	-	-	-	-	-	2,676	401	3,078	3,078	-	-	-	-	-	-	-	-	-	-
2c.4.9	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	87	13	101	101	-	-	-	-	-	-	-	-	-	-
2c.4.10	ISFSI Operating Costs	-	-	-	-	-	-	112	17	128	-	128	-	-	-	-	-	-	-	-	-
2c.4.11	Railroad Track Maintenance	-	-	-	-	-	-	125	19	143	143	-	-	-	-	-	-	-	-	-	-
2c.4.12	Security Staff Cost	-	-	-	-	-	-	14,681	2,202	16,883	16,883	-	-	-	-	-	-	-	-	-	242,796
2c.4.13	Utility Staff Cost	-	-	-	-	-	-	2,064	310	2,374	2,374	-	-	-	-	-	-	-	-	-	33,722
2c.4	Subtotal Period 2c Period-Dependent Costs	-	390	18	5	-	66	29,988	4,135	34,602	31,421	3,181	-	-	809	-	-	-	16,171	26	276,518
2c.0	TOTAL PERIOD 2c COST	-	390	18	5	-	66	103,902	14,817	119,197	41,570	77,627	-	-	809	-	-	-	16,171	26	276,518
PERIOD 2d - Decontamination Following Wet Fuel Storage																					
Period 2d Direct Decommissioning Activities																					
2d.1.1	Remove spent fuel racks	328	32	94	32	-	595	-	335	1,416	1,416	-	-	-	2,092	-	-	-	138,298	576	-
Disposal of Plant Systems																					
2d.1.2.1	Electrical - Contaminated - Fuel Pool	-	147	2	4	53	7	-	47	259	259	-	-	615	23	-	-	-	26,508	2,077	-
2d.1.2.2	Electrical - Decontaminated - Fuel Pool	-	918	10	34	510	-	-	312	1,785	1,785	-	-	5,893	-	-	-	-	239,327	12,340	-
2d.1.2.3	HVAC - Contaminated - Fuel Pool	-	159	3	9	121	15	-	63	370	370	-	-	1,398	53	-	-	-	60,246	2,157	-
2d.1.2.4	Safeguards Chilled Water - RCA	-	82	1	3	43	-	-	27	155	155	-	-	495	-	-	-	-	20,100	1,019	-
2d.1.2.5	Spent Fuel Pool Cooling	293	342	34	25	70	377	-	344	1,484	1,484	-	-	806	1,325	-	-	-	120,439	7,613	-
2d.1.2.6	Station & Instrument Air - RCA Fuel Pool	-	20	0	0	7	-	-	6	34	34	-	-	83	-	-	-	-	3,374	263	-
2d.1.2	Totals	293	1,668	50	75	804	399	-	800	4,088	4,088	-	-	9,290	1,401	-	-	-	469,994	25,468	-
2d.1.4	Scaffolding in support of decommissioning	-	213	1	0	3	1	-	54	273	273	-	-	35	3	-	-	-	1,754	1,592	-
2d.1	Subtotal Period 2d Activity Costs	621	1,913	145	107	807	994	-	1,189	5,777	5,777	-	-	9,325	3,496	-	-	-	610,046	27,637	-
Period 2d Additional Costs																					
2d.2.1	License Termination Survey Planning	-	-	-	-	-	-	845	253	1,098	1,098	-	-	-	-	-	-	-	-	-	6,240
2d.2.2	Remedial Action Surveys	-	-	-	-	-	-	1,237	371	1,608	1,608	-	-	-	-	-	-	-	-	16,173	-
2d.2	Subtotal Period 2d Additional Costs	-	-	-	-	-	-	2,082	625	2,706	2,706	-	-	-	-	-	-	-	-	16,173	6,240
Period 2d Collateral Costs																					
2d.3.1	Process decommissioning water waste	27	-	18	48	-	75	-	41	209	209	-	-	-	179	-	-	-	10,721	35	-
2d.3.2	Process decommissioning chemical flush waste	1	-	32	121	-	241	-	82	478	478	-	-	-	324	-	-	-	34,576	61	-
2d.3.3	Small tool allowance	-	35	-	-	-	-	-	5	41	41	-	-	-	-	-	-	-	-	-	-
2d.3.4	Decommissioning Equipment Disposition	-	-	144	55	575	150	-	147	1,071	1,071	-	-	6,000	529	-	-	-	304,968	88	-
2d.3.5	Spent Fuel Capital and Transfer	-	-	-	-	-	-	13,365	2,005	15,370	-	15,370	-	-	-	-	-	-	-	-	-
2d.3.6	Prairie Island Indian Community Payments	-	-	-	-	-	-	974	-	974	-	974	-	-	-	-	-	-	-	-	-
2d.3	Subtotal Period 2d Collateral Costs	27	35	194	224	575	467	14,339	2,280	18,142	1,798	16,344	-	6,000	1,032	-	-	-	350,265	184	-
Period 2d Period-Dependent Costs																					
2d.4.1	Decon supplies	54	-	-	-	-	-	-	14	68	68	-	-	-	-	-	-	-	-	-	-
2d.4.2	Insurance	-	-	-	-	-	-	399	40	439	439	-	-	-	-	-	-	-	-	-	-
2d.4.3	Property taxes	-	-	-	-	-	-	1,746	175	1,921	1,921	-	-	-	-	-	-	-	-	-	-
2d.4.4	Health physics supplies	-	560	-	-	-	-	-	140	700	700	-	-	-	-	-	-	-	-	-	-
2d.4.5	Heavy equipment rental	-	1,763	-	-	-	-	-	264	2,027	2,027	-	-	-	-	-	-	-	-	-	-
2d.4.6	Disposal of DAW generated	-	-	18	5	-	68	-	20	111	111	-	-	-	830	-	-	-	16,609	27	-
2d.4.7	Plant energy budget	-	-	-	-	-	-	473	71	544	544	-	-	-	-	-	-	-	-	-	-
2d.4.8	NRC Fees	-	-	-	-	-	-	382	38	420	420	-	-	-	-	-	-	-	-	-	-
2d.4.9	Emergency Planning Fees	-	-	-	-	-	-	1,003	100	1,103	-	1,103	-	-	-	-	-	-	-	-	-
2d.4.10	Fixed Overhead	-	-	-	-	-	-	967	145	1,112	1,112	-	-	-	-	-	-	-	-	-	-
2d.4.11	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	316	47	363	363	-	-	-	-	-	-	-	-	-	-
2d.4.12	ISFSI Operating Costs	-	-	-	-	-	-	40	6	46	-	46	-	-	-	-	-	-	-	-	-
2d.4.13	Railroad Track Maintenance	-	-	-	-	-	-	45	7	52	52	-	-	-	-	-	-	-	-	-	-
2d.4.14	Security Staff Cost	-	-	-	-	-	-	5,141	771	5,912	5,912	-	-	-	-	-	-	-	-	-	84,454
2d.4.15	DOC Staff Cost	-	-	-	-	-	-	6,087	913	7,000	7,000	-	-	-	-	-	-	-	-	-	70,243
2d.4.16	Utility Staff Cost	-	-	-	-	-	-	7,824	1,174	8,997	8,557	441	-	-	-	-	-	-	-	-	126,681
2d.4	Subtotal Period 2d Period-Dependent Costs	54	2,323	18	5	-	68	24,422	3,924	30,815	29,225	1,590	-	-	830	-	-	-	16,609	27	281,377
2d.0	TOTAL PERIOD 2d COST	703	4,272	357	337	1,382	1,528	40,843	8,018	57,440	39,507	17,934	-	15,325	5,359	-	-	-	976,920	44,021	287,617

Table C-1
Prairie Island Nuclear Generating Plant, Unit 1
DECON Decommissioning Cost Estimate with DOE Pickup of Industry Spent Fuel Starting in 2025
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
PERIOD 2f - License Termination																					
Period 2f Direct Decommissioning Activities																					
2f.1.1	ORISE confirmatory survey	-	-	-	-	-	-	176	53	229	229	-	-	-	-	-	-	-	-	-	-
2f.1.2	Terminate license									a											
2f.1	Subtotal Period 2f Activity Costs	-	-	-	-	-	-	176	53	229	229	-	-	-	-	-	-	-	-	-	-
Period 2f Additional Costs																					
2f.2.1	License Termination Survey	-	-	-	-	-	-	3,217	965	4,182	4,182	-	-	-	-	-	-	-	-	40,172	3,120
2f.2	Subtotal Period 2f Additional Costs	-	-	-	-	-	-	3,217	965	4,182	4,182	-	-	-	-	-	-	-	-	40,172	3,120
Period 2f Collateral Costs																					
2f.3.1	DOC staff relocation expenses	-	-	-	-	-	-	1,189	178	1,367	1,367	-	-	-	-	-	-	-	-	-	-
2f.3.2	Spent Fuel Capital and Transfer	-	-	-	-	-	-	431	65	496	-	496	-	-	-	-	-	-	-	-	-
2f.3.3	Prairie Island Indian Community Payments	-	-	-	-	-	-	934	-	934	-	934	-	-	-	-	-	-	-	-	-
2f.3	Subtotal Period 2f Collateral Costs	-	-	-	-	-	-	2,553	243	2,796	1,367	1,429	-	-	-	-	-	-	-	-	-
Period 2f Period-Dependent Costs																					
2f.4.1	Insurance	-	-	-	-	-	-	382	38	420	420	-	-	-	-	-	-	-	-	-	-
2f.4.2	Property taxes	-	-	-	-	-	-	1,626	163	1,789	1,789	-	-	-	-	-	-	-	-	-	-
2f.4.3	Health physics supplies	-	420	-	-	-	-	-	105	524	524	-	-	-	-	-	-	-	-	-	-
2f.4.4	Disposal of DAW generated	-	-	7	2	-	27	-	8	44	44	-	-	-	334	-	-	-	6,685	11	-
2f.4.5	Plant energy budget	-	-	-	-	-	-	227	34	261	261	-	-	-	-	-	-	-	-	-	-
2f.4.6	NRC Fees	-	-	-	-	-	-	417	42	459	459	-	-	-	-	-	-	-	-	-	-
2f.4.7	Emergency Planning Fees	-	-	-	-	-	-	51	5	56	-	56	-	-	-	-	-	-	-	-	-
2f.4.8	Fixed Overhead	-	-	-	-	-	-	926	139	1,065	1,065	-	-	-	-	-	-	-	-	-	-
2f.4.9	ISFSI Operating Costs	-	-	-	-	-	-	39	6	44	-	44	-	-	-	-	-	-	-	-	-
2f.4.10	Railroad Track Maintenance	-	-	-	-	-	-	43	6	50	50	-	-	-	-	-	-	-	-	-	-
2f.4.11	Security Staff Cost	-	-	-	-	-	-	4,924	739	5,663	5,663	-	-	-	-	-	-	-	-	-	80,898
2f.4.12	DOC Staff Cost	-	-	-	-	-	-	4,101	615	4,716	4,716	-	-	-	-	-	-	-	-	-	46,283
2f.4.13	Utility Staff Cost	-	-	-	-	-	-	3,854	578	4,433	4,007	426	-	-	-	-	-	-	-	-	59,507
2f.4	Subtotal Period 2f Period-Dependent Costs	-	420	7	2	-	27	16,590	2,477	19,524	18,998	526	-	-	334	-	-	-	6,685	11	186,687
2f.0	TOTAL PERIOD 2f COST	-	420	7	2	-	27	22,537	3,738	26,731	24,776	1,956	-	-	334	-	-	-	6,685	40,183	189,807
PERIOD 2 TOTALS		5,162	53,298	28,935	6,446	11,617	35,794	306,671	85,960	533,881	419,353	109,654	4,875	138,709	117,154	250	673	-	13,293,670	587,146	2,060,653
PERIOD 3b - Site Restoration																					
Period 3b Direct Decommissioning Activities																					
Demolition of Remaining Site Buildings																					
3b.1.1.1	Reactor	-	4,255	-	-	-	-	-	638	4,894	-	-	4,894	-	-	-	-	-	-	44,669	-
3b.1.1.2	Condensate Storage Tank Foundation	-	3	-	-	-	-	-	0	4	-	-	4	-	-	-	-	-	-	16	-
3b.1.1.3	Structures below 3' below grade	-	1,581	-	-	-	-	-	237	1,818	-	-	1,818	-	-	-	-	-	-	8,411	-
3b.1.1.4	Turbine	-	1,983	-	-	-	-	-	297	2,280	-	-	2,280	-	-	-	-	-	-	22,040	-
3b.1.1.5	Turbine Pedestal	-	349	-	-	-	-	-	52	402	-	-	402	-	-	-	-	-	-	1,857	-
3b.1.1	Totals	-	8,171	-	-	-	-	-	1,226	9,397	-	-	9,397	-	-	-	-	-	-	76,993	-
Site Closeout Activities																					
3b.1.2	Grade & landscape site	-	431	-	-	-	-	-	65	495	-	-	495	-	-	-	-	-	-	921	-
3b.1.3	Final report to NRC	-	-	-	-	-	-	183	27	211	211	-	-	-	-	-	-	-	-	-	1,560
3b.1	Subtotal Period 3b Activity Costs	-	8,602	-	-	-	-	183	1,318	10,102	211	-	9,892	-	-	-	-	-	-	77,914	1,560
Period 3b Additional Costs																					
3b.2.1	Clean Concrete Disposal	-	2,213	-	-	-	-	3	332	2,549	-	-	2,549	-	-	-	-	-	-	8,386	-
3b.2.2	Underground Services Excavations	-	811	-	-	-	-	520	200	1,531	-	-	1,531	-	-	-	-	-	-	7,407	-
3b.2.3	Intake Structure Cofferdam	-	596	-	-	-	-	-	89	686	-	-	686	-	-	-	-	-	-	5,168	-
3b.2.4	Construction Debris	-	-	-	-	-	-	10	2	12	-	-	12	-	-	-	-	-	-	-	-
3b.2.5	Backfill	-	2,751	-	-	-	-	-	413	3,164	-	-	3,164	-	-	-	-	-	-	2,904	-
3b.2	Subtotal Period 3b Additional Costs	-	6,371	-	-	-	-	534	1,036	7,941	-	-	7,941	-	-	-	-	-	-	23,865	-
Period 3b Collateral Costs																					
3b.3.1	Small tool allowance	-	110	-	-	-	-	-	16	126	-	-	126	-	-	-	-	-	-	-	-
3b.3.2	Spent Fuel Capital and Transfer	-	-	-	-	-	-	1,088	163	1,252	-	1,252	-	-	-	-	-	-	-	-	-
3b.3.3	Prairie Island Indian Community Payments	-	-	-	-	-	-	2,651	-	2,651	-	2,651	-	-	-	-	-	-	-	-	-
3b.3	Subtotal Period 3b Collateral Costs	-	110	-	-	-	-	3,739	180	4,028	-	3,902	126	-	-	-	-	-	-	-	-

Table C-1
Prairie Island Nuclear Generating Plant, Unit 1
DECON Decommissioning Cost Estimate with DOE Pickup of Industry Spent Fuel Starting in 2025
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 3b Period-Dependent Costs																					
3b.4.1	Insurance	-	-	-	-	-	-	542	54	596	-	596	-	-	-	-	-	-	-	-	-
3b.4.2	Property taxes	-	-	-	-	-	-	4,333	433	4,767	-	4,767	-	-	-	-	-	-	-	-	-
3b.4.3	Heavy equipment rental	-	6,670	-	-	-	-	-	1,000	7,670	-	-	7,670	-	-	-	-	-	-	-	-
3b.4.4	Plant energy budget	-	-	-	-	-	-	321	48	369	-	-	369	-	-	-	-	-	-	-	-
3b.4.5	NRC ISFSI Fees	-	-	-	-	-	-	236	24	259	-	259	-	-	-	-	-	-	-	-	-
3b.4.6	Emergency Planning Fees	-	-	-	-	-	-	145	14	159	-	159	-	-	-	-	-	-	-	-	-
3b.4.7	Fixed Overhead	-	-	-	-	-	-	990	148	1,138	-	-	1,138	-	-	-	-	-	-	-	-
3b.4.8	ISFSI Operating Costs	-	-	-	-	-	-	109	16	126	-	126	-	-	-	-	-	-	-	-	-
3b.4.9	Railroad Track Maintenance	-	-	-	-	-	-	331	50	380	-	-	380	-	-	-	-	-	-	-	-
3b.4.10	Security Staff Cost	-	-	-	-	-	-	4,245	637	4,882	-	4,882	-	-	-	-	-	-	-	-	57,340
3b.4.11	DOC Staff Cost	-	-	-	-	-	-	10,467	1,570	12,038	-	-	12,038	-	-	-	-	-	-	-	116,885
3b.4.12	Utility Staff Cost	-	-	-	-	-	-	4,813	722	5,535	(0)	1,207	4,329	-	-	-	-	-	-	-	74,431
3b.4	Subtotal Period 3b Period-Dependent Costs	-	6,670	-	-	-	-	26,533	4,718	37,920	(0)	11,996	25,924	-	-	-	-	-	-	-	248,656
3b.0	TOTAL PERIOD 3b COST	-	21,752	-	-	-	-	30,989	7,251	59,992	211	15,899	43,882	-	-	-	-	-	-	101,779	250,216
PERIOD 3c - Fuel Storage Operations/Shipping																					
Period 3c Direct Decommissioning Activities																					
Period 3c Collateral Costs																					
3c.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	5,808	871	6,679	-	6,679	-	-	-	-	-	-	-	-	-
3c.3.2	Prairie Island Indian Community Payments	-	-	-	-	-	-	26,863	-	26,863	-	26,863	-	-	-	-	-	-	-	-	-
3c.3	Subtotal Period 3c Collateral Costs	-	-	-	-	-	-	32,671	871	33,543	-	33,543	-	-	-	-	-	-	-	-	-
Period 3c Period-Dependent Costs																					
3c.4.1	Insurance	-	-	-	-	-	-	5,494	549	6,044	-	6,044	-	-	-	-	-	-	-	-	-
3c.4.2	Property taxes	-	-	-	-	-	-	26,564	2,656	29,221	-	29,221	-	-	-	-	-	-	-	-	-
3c.4.4	NRC ISFSI Fees	-	-	-	-	-	-	3,519	352	3,871	-	3,871	-	-	-	-	-	-	-	-	-
3c.4.5	Emergency Planning Fees	-	-	-	-	-	-	1,471	147	1,618	-	1,618	-	-	-	-	-	-	-	-	-
3c.4.6	Fixed Overhead	-	-	-	-	-	-	3,281	492	3,774	-	3,774	-	-	-	-	-	-	-	-	-
3c.4.7	ISFSI Operating Costs	-	-	-	-	-	-	1,110	167	1,277	-	1,277	-	-	-	-	-	-	-	-	-
3c.4.8	Railroad Track Maintenance	-	-	-	-	-	-	1,240	186	1,426	-	1,426	-	-	-	-	-	-	-	-	-
3c.4.9	Security Staff Cost	-	-	-	-	-	-	43,057	6,459	49,516	-	49,516	-	-	-	-	-	-	-	-	581,545
3c.4.10	Utility Staff Cost	-	-	-	-	-	-	10,635	1,595	12,230	-	12,230	-	-	-	-	-	-	-	-	150,978
3c.4	Subtotal Period 3c Period-Dependent Costs	-	-	-	-	-	-	96,373	12,603	108,976	-	108,976	-	-	-	-	-	-	-	-	732,523
3c.0	TOTAL PERIOD 3c COST	-	-	-	-	-	-	129,044	13,475	142,519	-	142,519	-	-	-	-	-	-	-	-	732,523
PERIOD 3d - GTCC shipping																					
Period 3d Direct Decommissioning Activities																					
Nuclear Steam Supply System Removal																					
3d.1.1.1	Vessel & Internals GTCC Disposal	-	-	1,331	-	-	8,689	-	1,636	11,656	11,656	-	-	-	-	-	-	3,746	837,596	-	-
3d.1.1	Totals	-	-	1,331	-	-	8,689	-	1,636	11,656	11,656	-	-	-	-	-	-	3,746	837,596	-	-
3d.1	Subtotal Period 3d Activity Costs	-	-	1,331	-	-	8,689	-	1,636	11,656	11,656	-	-	-	-	-	-	3,746	837,596	-	-
Period 3d Collateral Costs																					
3d.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	12	2	14	-	14	-	-	-	-	-	-	-	-	-
3d.3.2	Prairie Island Indian Community Payments	-	-	-	-	-	-	48	-	48	-	48	-	-	-	-	-	-	-	-	-
3d.3	Subtotal Period 3d Collateral Costs	-	-	-	-	-	-	60	2	62	-	62	-	-	-	-	-	-	-	-	-
Period 3d Period-Dependent Costs																					
3d.4.1	Insurance	-	-	-	-	-	-	10	1	11	11	-	-	-	-	-	-	-	-	-	-
3d.4.2	Property taxes	-	-	-	-	-	-	39	4	43	43	-	-	-	-	-	-	-	-	-	-
3d.4.4	NRC ISFSI Fees	-	-	-	-	-	-	4	0	5	-	5	-	-	-	-	-	-	-	-	-
3d.4.5	Emergency Planning Fees	-	-	-	-	-	-	3	0	3	-	3	-	-	-	-	-	-	-	-	-
3d.4.6	Fixed Overhead	-	-	-	-	-	-	6	1	7	7	-	-	-	-	-	-	-	-	-	-
3d.4.7	ISFSI Operating Costs	-	-	-	-	-	-	2	0	2	-	2	-	-	-	-	-	-	-	-	-
3d.4.8	Railroad Track Maintenance	-	-	-	-	-	-	2	0	3	3	-	-	-	-	-	-	-	-	-	-
3d.4.9	Security Staff Cost	-	-	-	-	-	-	77	12	88	88	-	-	-	-	-	-	-	-	-	1,037
3d.4.10	Utility Staff Cost	-	-	-	-	-	-	19	3	22	22	-	-	-	-	-	-	-	-	-	269
3d.4	Subtotal Period 3d Period-Dependent Costs	-	-	-	-	-	-	162	21	183	173	10	-	-	-	-	-	-	-	-	1,306
3d.0	TOTAL PERIOD 3d COST	-	-	1,331	-	-	8,689	222	1,659	11,901	11,829	72	-	-	-	-	-	3,746	837,596	-	1,306

Table C-1
Prairie Island Nuclear Generating Plant, Unit 1
DECON Decommissioning Cost Estimate with DOE Pickup of Industry Spent Fuel Starting in 2025
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
PERIOD 3e - ISFSI Decontamination																					
Period 3e Direct Decommissioning Activities																					
Period 3e Additional Costs																					
3e.2.1	License Termination ISFSI	-	37	2	211	-	2,157	682	772	3,861	3,861	-	-	-	7,458	-	-	-	1,071,985	3,403	888
3e.2	Subtotal Period 3e Additional Costs	-	37	2	211	-	2,157	682	772	3,861	3,861	-	-	-	7,458	-	-	-	1,071,985	3,403	888
Period 3e Period-Dependent Costs																					
3e.4.1	Insurance	-	-	-	-	-	-	96	24	121	121	-	-	-	-	-	-	-	-	-	-
3e.4.2	Property taxes	-	-	-	-	-	-	26	6	32	32	-	-	-	-	-	-	-	-	-	-
3e.4.4	Fixed Overhead	-	-	-	-	-	-	51	13	63	63	-	-	-	-	-	-	-	-	-	-
3e.4.5	Railroad Track Maintenance	-	-	-	-	-	-	19	5	24	24	-	-	-	-	-	-	-	-	-	-
3e.4.6	Security Staff Cost	-	-	-	-	-	-	154	38	192	192	-	-	-	-	-	-	-	-	-	2,500
3e.4.7	Utility Staff Cost	-	-	-	-	-	-	130	33	163	163	-	-	-	-	-	-	-	-	-	1,896
3e.4	Subtotal Period 3e Period-Dependent Costs	-	-	-	-	-	-	476	119	595	595	-	-	-	-	-	-	-	-	-	4,396
3e.0	TOTAL PERIOD 3e COST	-	37	2	211	-	2,157	1,158	891	4,456	4,456	-	-	-	7,458	-	-	-	1,071,985	3,403	5,284
PERIOD 3f - ISFSI Site Restoration																					
Period 3f Direct Decommissioning Activities																					
Period 3f Additional Costs																					
3f.2.1	Demolition and Site Restoration of ISFSI	-	399	-	-	-	-	87	73	558	-	-	558	-	-	-	-	-	-	1,900	160
3f.2	Subtotal Period 3f Additional Costs	-	399	-	-	-	-	87	73	558	-	-	558	-	-	-	-	-	-	1,900	160
Period 3f Collateral Costs																					
3f.3.1	Small tool allowance	-	3	-	-	-	-	-	0	3	-	-	3	-	-	-	-	-	-	-	-
3f.3	Subtotal Period 3f Collateral Costs	-	3	-	-	-	-	-	0	3	-	-	3	-	-	-	-	-	-	-	-
Period 3f Period-Dependent Costs																					
3f.4.2	Property taxes	-	-	-	-	-	-	13	1	14	-	-	14	-	-	-	-	-	-	-	-
3f.4.3	Heavy equipment rental	-	62	-	-	-	-	-	9	71	-	-	71	-	-	-	-	-	-	-	-
3f.4.4	Plant energy budget	-	-	-	-	-	-	13	2	15	-	-	15	-	-	-	-	-	-	-	-
3f.4.5	Fixed Overhead	-	-	-	-	-	-	25	4	29	-	-	29	-	-	-	-	-	-	-	-
3f.4.6	Railroad Track Maintenance	-	-	-	-	-	-	10	1	11	-	-	11	-	-	-	-	-	-	-	-
3f.4.7	Security Staff Cost	-	-	-	-	-	-	78	12	89	-	-	89	-	-	-	-	-	-	-	1,260
3f.4.8	Utility Staff Cost	-	-	-	-	-	-	52	8	60	-	-	60	-	-	-	-	-	-	-	782
3f.4	Subtotal Period 3f Period-Dependent Costs	-	62	-	-	-	-	190	37	289	-	-	289	-	-	-	-	-	-	-	2,042
3f.0	TOTAL PERIOD 3f COST	-	463	-	-	-	-	277	110	851	-	-	851	-	-	-	-	-	-	1,900	2,202
PERIOD 3 TOTALS		-	22,252	1,333	211	-	10,846	161,689	23,386	219,717	16,495	158,489	44,733	-	7,458	-	-	3,746	1,909,581	107,082	991,531
TOTAL COST TO DECOMMISSION		**8,734**	**80,918**	**30,683**	**7,109**	**11,781**	**50,612**	**579,062**	**128,621**	**897,520**	**571,980**	**274,479**	**51,061**	**144,842**	**138,577**	**839**	**673**	**3,746**	**15,813,390**	**739,753**	**4,056,605**

TOTAL COST TO DECOMMISSION WITH 16.73% CONTINGENCY:	**$897,520**	**thousands of 2017 dollars**
TOTAL NRC LICENSE TERMINATION COST IS 63.73% OR:	**$571,980**	**thousands of 2017 dollars**
SPENT FUEL MANAGEMENT COST IS 30.58% OR:	**$274,479**	**thousands of 2017 dollars**
NON-NUCLEAR DEMOLITION COST IS 5.69% OR:	**$51,061**	**thousands of 2017 dollars**
TOTAL LOW-LEVEL RADIOACTIVE WASTE VOLUME BURIED (EXCLUDING GTCC):	**140,089**	**cubic feet**
TOTAL GREATER THAN CLASS C RADWASTE VOLUME GENERATED:	**3,746**	**cubic feet**
TOTAL SCRAP METAL REMOVED:	**32,925**	**tons**
TOTAL CRAFT LABOR REQUIREMENTS:	**739,753**	**man-hours**

End Notes:
n/a - indicates that this activity not charged as decommissioning expense
a - indicates that this activity performed by decommissioning staff
0 - indicates that this value is less than 0.5 but is non-zero
A cell containing " - " indicates a zero value

Table C-2
Prairie Island Nuclear Generating Plant, Unit 2
DECON Decommissioning Cost Estimate with DOE Pickup of Industry Spent Fuel Starting in 2025
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
PERIOD 1a - Shutdown through Transition																					
Period 1a Direct Decommissioning Activities																					
1a.1.1	Prepare preliminary decommissioning cost	-	-	-	-	-	-	65	10	75	75	-	-	-	-	-	-	-	-	-	556
1a.1.2	Notification of Cessation of Operations									a											
1a.1.3	Remove fuel & source material									n/a											
1a.1.4	Notification of Permanent Defueling									a											
1a.1.5	Deactivate plant systems & process waste									a											
1a.1.6	Prepare and submit PSDAR	-	-	-	-	-	-	100	15	115	115	-	-	-	-	-	-	-	-	-	855
1a.1.7	Review plant dwgs & specs.	-	-	-	-	-	-	231	35	266	266	-	-	-	-	-	-	-	-	-	1,967
1a.1.8	Perform detailed rad survey									a											
1a.1.9	Estimate by-product inventory	-	-	-	-	-	-	50	8	58	58	-	-	-	-	-	-	-	-	-	428
1a.1.10	End product description	-	-	-	-	-	-	50	8	58	58	-	-	-	-	-	-	-	-	-	428
1a.1.11	Detailed by-product inventory	-	-	-	-	-	-	65	10	75	75	-	-	-	-	-	-	-	-	-	556
1a.1.12	Define major work sequence	-	-	-	-	-	-	376	56	433	433	-	-	-	-	-	-	-	-	-	3,207
1a.1.13	Perform SER and EA	-	-	-	-	-	-	156	23	179	179	-	-	-	-	-	-	-	-	-	1,326
1a.1.14	Prepare/submit Defueled Technical Specifications	-	-	-	-	-	-	376	56	433	433	-	-	-	-	-	-	-	-	-	3,207
1a.1.15	Perform Site-Specific Cost Study	-	-	-	-	-	-	251	38	289	289	-	-	-	-	-	-	-	-	-	2,138
1a.1.16	Prepare/submit Irradiated Fuel Management Plan	-	-	-	-	-	-	50	8	58	58	-	-	-	-	-	-	-	-	-	428
Activity Specifications																					
1a.1.17.1	Plant & temporary facilities	-	-	-	-	-	-	247	37	284	256	-	28	-	-	-	-	-	-	-	2,104
1a.1.17.2	Plant systems	-	-	-	-	-	-	209	31	241	216	-	24	-	-	-	-	-	-	-	1,782
1a.1.17.3	NSSS Decontamination Flush	-	-	-	-	-	-	25	4	29	29	-	-	-	-	-	-	-	-	-	214
1a.1.17.4	Reactor internals	-	-	-	-	-	-	356	53	410	410	-	-	-	-	-	-	-	-	-	3,036
1a.1.17.5	Reactor vessel	-	-	-	-	-	-	326	49	375	375	-	-	-	-	-	-	-	-	-	2,779
1a.1.17.6	Biological shield	-	-	-	-	-	-	25	4	29	29	-	-	-	-	-	-	-	-	-	214
1a.1.17.7	Steam generators	-	-	-	-	-	-	157	23	180	180	-	-	-	-	-	-	-	-	-	1,334
1a.1.17.8	Reinforced concrete	-	-	-	-	-	-	80	12	92	46	-	46	-	-	-	-	-	-	-	684
1a.1.17.9	Main Turbine	-	-	-	-	-	-	20	3	23	-	-	23	-	-	-	-	-	-	-	171
1a.1.17.10	Main Condensers	-	-	-	-	-	-	20	3	23	-	-	23	-	-	-	-	-	-	-	171
1a.1.17.11	Plant structures & buildings	-	-	-	-	-	-	157	23	180	90	-	90	-	-	-	-	-	-	-	1,334
1a.1.17.12	Waste management	-	-	-	-	-	-	231	35	266	266	-	-	-	-	-	-	-	-	-	1,967
1a.1.17.13	Facility & site closeout	-	-	-	-	-	-	45	7	52	26	-	26	-	-	-	-	-	-	-	385
1a.1.17	Total	-	-	-	-	-	-	1,899	285	2,183	1,923	-	261	-	-	-	-	-	-	-	16,175
Planning & Site Preparations																					
1a.1.18	Prepare dismantling sequence	-	-	-	-	-	-	120	18	139	139	-	-	-	-	-	-	-	-	-	1,026
1a.1.19	Plant prep. & temp. svces	-	-	-	-	-	-	3,300	495	3,795	3,795	-	-	-	-	-	-	-	-	-	-
1a.1.20	Design water clean-up system	-	-	-	-	-	-	70	11	81	81	-	-	-	-	-	-	-	-	-	599
1a.1.21	Rigging/Cont. Cntrl Envlps/tooling/etc.	-	-	-	-	-	-	2,300	345	2,645	2,645	-	-	-	-	-	-	-	-	-	-
1a.1.22	Procure casks/liners & containers	-	-	-	-	-	-	62	9	71	71	-	-	-	-	-	-	-	-	-	526
1a.1	Subtotal Period 1a Activity Costs	-	-	-	-	-	-	9,523	1,428	10,951	10,690	-	261	-	-	-	-	-	-	-	33,420
Period 1a Additional Costs																					
1a.2.1	Spent Fuel Pool Isolation	-	-	-	-	-	-	7,794	1,169	8,963	8,963	-	-	-	-	-	-	-	-	-	-
1a.2	Subtotal Period 1a Additional Costs	-	-	-	-	-	-	7,794	1,169	8,963	8,963	-	-	-	-	-	-	-	-	-	-
Period 1a Collateral Costs																					
1a.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	1,776	266	2,042	-	2,042	-	-	-	-	-	-	-	-	-
1a.3.2	Retention and Severance	-	-	-	-	-	-	8,394	1,259	9,653	9,653	-	-	-	-	-	-	-	-	-	-
1a.3.3	Prairie Island Indian Community Payments	-	-	-	-	-	-	2,281	-	2,281	-	2,281	-	-	-	-	-	-	-	-	-
1a.3	Subtotal Period 1a Collateral Costs	-	-	-	-	-	-	12,450	1,525	13,976	9,653	4,323	-	-	-	-	-	-	-	-	-
Period 1a Period-Dependent Costs																					
1a.4.1	Insurance	-	-	-	-	-	-	1,730	173	1,903	1,903	-	-	-	-	-	-	-	-	-	-
1a.4.2	Property taxes	-	-	-	-	-	-	2,682	268	2,950	2,950	-	-	-	-	-	-	-	-	-	-
1a.4.3	Health physics supplies	-	485	-	-	-	-	-	121	606	606	-	-	-	-	-	-	-	-	-	-
1a.4.4	Heavy equipment rental	-	567	-	-	-	-	-	85	652	652	-	-	-	-	-	-	-	-	-	-
1a.4.5	Disposal of DAW generated	-	-	12	4	-	46	-	13	75	75	-	-	-	565	-	-	-	11,299	18	-
1a.4.6	Plant energy budget	-	-	-	-	-	-	1,515	227	1,742	1,742	-	-	-	-	-	-	-	-	-	-
1a.4.7	NRC Fees	-	-	-	-	-	-	778	78	855	855	-	-	-	-	-	-	-	-	-	-
1a.4.8	Emergency Planning Fees	-	-	-	-	-	-	1,604	160	1,765	-	1,765	-	-	-	-	-	-	-	-	-
1a.4.9	Fixed Overhead	-	-	-	-	-	-	1,470	220	1,690	1,690	-	-	-	-	-	-	-	-	-	-
1a.4.10	Spent Fuel Pool O&M	-	-	-	-	-	-	401	60	461	-	461	-	-	-	-	-	-	-	-	-
1a.4.11	ISFSI Operating Costs	-	-	-	-	-	-	52	8	59	-	59	-	-	-	-	-	-	-	-	-
1a.4.12	Railroad Track Maintenance	-	-	-	-	-	-	58	9	66	66	-	-	-	-	-	-	-	-	-	-
1a.4.13	Security Staff Cost	-	-	-	-	-	-	7,390	1,108	8,498	8,498	-	-	-	-	-	-	-	-	-	122,720

Table C-2
Prairie Island Nuclear Generating Plant, Unit 2
DECON Decommissioning Cost Estimate with DOE Pickup of Industry Spent Fuel Starting in 2025
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 1a Period-Dependent Costs (continued)																					
1a.4.14	Utility Staff Cost	-	-	-	-	-	-	20,662	3,099	23,761	23,761	-	-	-	-	-	-	-	-	-	345,280
1a.4	Subtotal Period 1a Period-Dependent Costs	-	1,052	12	4	-	46	38,340	5,631	45,085	42,800	2,286	-	-	565	-	-	-	11,299	18	468,000
1a.0	TOTAL PERIOD 1a COST	-	1,052	12	4	-	46	68,108	9,754	78,976	72,107	6,608	261	-	565	-	-	-	11,299	18	501,420
PERIOD 1b - Decommissioning Preparations																					
Period 1b Direct Decommissioning Activities																					
Detailed Work Procedures																					
1b.1.1.1	Plant systems	-	-	-	-	-	-	238	36	273	246	-	27	-	-	-	-	-	-	-	2,024
1b.1.1.2	NSSS Decontamination Flush	-	-	-	-	-	-	50	8	58	58	-	-	-	-	-	-	-	-	-	428
1b.1.1.3	Reactor internals	-	-	-	-	-	-	125	19	144	144	-	-	-	-	-	-	-	-	-	1,069
1b.1.1.4	Remaining buildings	-	-	-	-	-	-	68	10	78	19	-	58	-	-	-	-	-	-	-	577
1b.1.1.5	CRD cooling assembly	-	-	-	-	-	-	50	8	58	58	-	-	-	-	-	-	-	-	-	428
1b.1.1.6	CRD housings & ICI tubes	-	-	-	-	-	-	50	8	58	58	-	-	-	-	-	-	-	-	-	428
1b.1.1.7	Incore instrumentation	-	-	-	-	-	-	50	8	58	58	-	-	-	-	-	-	-	-	-	428
1b.1.1.8	Reactor vessel	-	-	-	-	-	-	182	27	210	210	-	-	-	-	-	-	-	-	-	1,552
1b.1.1.9	Facility closeout	-	-	-	-	-	-	60	9	69	35	-	35	-	-	-	-	-	-	-	513
1b.1.1.10	Missile shields	-	-	-	-	-	-	23	3	26	26	-	-	-	-	-	-	-	-	-	192
1b.1.1.11	Biological shield	-	-	-	-	-	-	60	9	69	69	-	-	-	-	-	-	-	-	-	513
1b.1.1.12	Steam generators	-	-	-	-	-	-	231	35	266	266	-	-	-	-	-	-	-	-	-	1,967
1b.1.1.13	Reinforced concrete	-	-	-	-	-	-	50	8	58	29	-	29	-	-	-	-	-	-	-	428
1b.1.1.14	Main Turbine	-	-	-	-	-	-	78	12	90	-	-	90	-	-	-	-	-	-	-	667
1b.1.1.15	Main Condensers	-	-	-	-	-	-	78	12	90	-	-	90	-	-	-	-	-	-	-	667
1b.1.1.16	Auxiliary building	-	-	-	-	-	-	137	21	158	142	-	16	-	-	-	-	-	-	-	1,167
1b.1.1.17	Reactor building	-	-	-	-	-	-	137	21	158	142	-	16	-	-	-	-	-	-	-	1,167
1b.1.1	Total	-	-	-	-	-	-	1,669	250	1,919	1,558	-	361	-	-	-	-	-	-	-	14,215
1b.1.2	Decon primary loop	552	-	-	-	-	-	-	276	828	828	-	-	-	-	-	-	-	-	1,067	-
1b.1	Subtotal Period 1b Activity Costs	552	-	-	-	-	-	1,669	526	2,747	2,386	-	361	-	-	-	-	-	-	1,067	14,215
Period 1b Additional Costs																					
1b.2.1	Site Characterization	-	-	-	-	-	-	1,582	475	2,057	2,057	-	-	-	-	-	-	-	-	8,988	3,563
1b.2.2	Mixed/Hazardous Waste	-	-	326	75	169	-	-	69	639	639	-	-	6,324	-	-	-	-	362,914	2,410	-
1b.2.3	Asbestos Abatement	-	2,364	2	110	-	1,359	-	947	4,782	4,782	-	-	-	12,843	-	-	-	166,959	20,907	-
1b.2	Subtotal Period 1b Additional Costs	-	2,364	328	185	169	1,359	1,582	1,491	7,478	7,478	-	-	6,324	12,843	-	-	-	529,873	32,305	3,563
Period 1b Collateral Costs																					
1b.3.1	Decon equipment	973	-	-	-	-	-	-	146	1,119	1,119	-	-	-	-	-	-	-	-	-	-
1b.3.2	DOC staff relocation expenses	-	-	-	-	-	-	1,189	178	1,367	1,367	-	-	-	-	-	-	-	-	-	-
1b.3.3	Process decommissioning water waste	24	-	16	41	-	64	-	36	180	180	-	-	-	152	-	-	-	9,121	30	-
1b.3.4	Process decommissioning chemical flush waste	2	-	58	220	-	2,471	-	657	3,408	3,408	-	-	-	-	588	-	-	62,689	110	-
1b.3.5	Small tool allowance	-	34	-	-	-	-	-	5	39	39	-	-	-	-	-	-	-	-	-	-
1b.3.6	Pipe cutting equipment	-	1,200	-	-	-	-	-	180	1,380	1,380	-	-	-	-	-	-	-	-	-	-
1b.3.7	Decon rig	1,987	-	-	-	-	-	-	298	2,285	2,285	-	-	-	-	-	-	-	-	-	-
1b.3.8	Spent Fuel Capital and Transfer	-	-	-	-	-	-	705	106	811	-	811	-	-	-	-	-	-	-	-	-
1b.3.9	Retention and Severance	-	-	-	-	-	-	4,055	608	4,664	4,664	-	-	-	-	-	-	-	-	-	-
1b.3.10	Prairie Island Indian Community Payments	-	-	-	-	-	-	629	-	629	-	629	-	-	-	-	-	-	-	-	-
1b.3	Subtotal Period 1b Collateral Costs	2,986	1,234	74	261	-	2,534	6,578	2,214	15,881	14,441	1,440	-	-	152	588	-	-	71,810	140	-
Period 1b Period-Dependent Costs																					
1b.4.1	Decon supplies	35	-	-	-	-	-	-	9	44	44	-	-	-	-	-	-	-	-	-	-
1b.4.2	Insurance	-	-	-	-	-	-	872	87	959	959	-	-	-	-	-	-	-	-	-	-
1b.4.3	Property taxes	-	-	-	-	-	-	1,319	132	1,451	1,451	-	-	-	-	-	-	-	-	-	-
1b.4.4	Health physics supplies	-	380	-	-	-	-	-	95	475	475	-	-	-	-	-	-	-	-	-	-
1b.4.5	Heavy equipment rental	-	286	-	-	-	-	-	43	329	329	-	-	-	-	-	-	-	-	-	-
1b.4.6	Disposal of DAW generated	-	-	7	2	-	27	-	8	44	44	-	-	-	327	-	-	-	6,541	11	-
1b.4.7	Plant energy budget	-	-	-	-	-	-	1,527	229	1,756	1,756	-	-	-	-	-	-	-	-	-	-
1b.4.8	NRC Fees	-	-	-	-	-	-	214	21	236	236	-	-	-	-	-	-	-	-	-	-
1b.4.9	Emergency Planning Fees	-	-	-	-	-	-	809	81	890	-	890	-	-	-	-	-	-	-	-	-
1b.4.10	Fixed Overhead	-	-	-	-	-	-	741	111	852	852	-	-	-	-	-	-	-	-	-	-
1b.4.11	Spent Fuel Pool O&M	-	-	-	-	-	-	202	30	233	-	233	-	-	-	-	-	-	-	-	-
1b.4.12	ISFSI Operating Costs	-	-	-	-	-	-	26	4	30	-	30	-	-	-	-	-	-	-	-	-
1b.4.13	Railroad Track Maintenance	-	-	-	-	-	-	29	4	33	33	-	-	-	-	-	-	-	-	-	-
1b.4.14	Security Staff Cost	-	-	-	-	-	-	3,725	559	4,284	4,284	-	-	-	-	-	-	-	-	-	61,864
1b.4.15	DOC Staff Cost	-	-	-	-	-	-	4,009	601	4,610	4,610	-	-	-	-	-	-	-	-	-	47,185

Table C-2
Prairie Island Nuclear Generating Plant, Unit 2
DECON Decommissioning Cost Estimate with DOE Pickup of Industry Spent Fuel Starting in 2025
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 1b Period-Dependent Costs (continued)																					
1b.4.16	Utility Staff Cost	-	-	-	-	-	-	10,416	1,562	11,978	11,978	-	-	-	-	-	-	-	-	-	174,059
1b.4	Subtotal Period 1b Period-Dependent Costs	35	666	7	2	-	27	23,890	3,577	28,204	27,052	1,152	-	-	327	-	-	-	6,541	11	283,108
1b.0	TOTAL PERIOD 1b COST	3,573	4,264	410	447	169	3,920	33,718	7,809	54,309	51,356	2,592	361	6,324	13,322	588	-	-	608,224	33,522	300,885
PERIOD 1 TOTALS		3,573	5,316	422	451	169	3,966	101,826	17,563	133,285	123,462	9,200	622	6,324	13,887	588	-	-	619,523	33,540	802,305
PERIOD 2a - Large Component Removal																					
Period 2a Direct Decommissioning Activities																					
Nuclear Steam Supply System Removal																					
2a.1.1.1	Reactor Coolant Piping	51	45	6	8	-	150	-	76	336	336	-	-	-	305	-	-	-	34,809	1,414	-
2a.1.1.2	Pressurizer Relief Tank	22	20	4	5	-	100	-	42	193	193	-	-	-	203	-	-	-	23,193	625	-
2a.1.1.3	Reactor Coolant Pumps & Motors	54	63	101	83	-	736	-	249	1,287	1,287	-	-	-	2,332	-	-	-	295,800	2,049	100
2a.1.1.4	Pressurizer	48	68	467	88	-	693	-	274	1,639	1,639	-	-	-	2,196	-	-	-	185,015	2,355	938
2a.1.1.5	Steam Generators	225	2,943	2,093	1,638	1,246	3,570	-	2,383	14,097	14,097	-	-	18,672	11,316	-	-	-	1,668,341	14,819	2,875
2a.1.1.6	CRDMs/ICIs/Service Structure Removal	286	277	211	48	-	763	-	431	2,016	2,016	-	-	-	4,797	-	-	-	177,400	8,104	-
2a.1.1.7	Reactor Vessel Internals	78	4,468	21,874	1,072	-	7,946	277	13,141	48,856	48,856	-	-	-	501	125	673	-	164,987	23,040	1,080
2a.1.1.8	Reactor Vessel	89	5,717	1,754	719	-	1,956	277	5,970	16,483	16,483	-	-	-	5,690	-	-	-	570,074	23,040	1,080
2a.1.1	Totals	855	13,600	26,512	3,662	1,246	15,913	553	22,568	84,908	84,908	-	-	18,672	27,341	125	673	-	3,119,620	75,446	6,073
Removal of Major Equipment																					
2a.1.2	Main Turbine/Generator	-	305	189	55	272	306	-	221	1,348	1,348	-	-	2,131	1,187	-	-	-	206,316	4,667	-
2a.1.3	Main Condensers	-	2,532	121	49	364	451	-	820	4,336	4,336	-	-	3,800	1,587	-	-	-	275,903	39,151	-
Cascading Costs from Clean Building Demolition																					
2a.1.4.1	Reactor	-	728	-	-	-	-	-	109	837	837	-	-	-	-	-	-	-	-	7,589	-
2a.1.4.2	Auxiliary	-	210	-	-	-	-	-	32	242	242	-	-	-	-	-	-	-	-	1,309	-
2a.1.4.3	Radwaste	-	8	-	-	-	-	-	1	9	9	-	-	-	-	-	-	-	-	65	-
2a.1.4	Totals	-	946	-	-	-	-	-	142	1,088	1,088	-	-	-	-	-	-	-	-	8,963	-
Disposal of Plant Systems																					
2a.1.5.1	Admin Bldg Ventilation	-	6	-	-	-	-	-	1	6	-	-	6	-	-	-	-	-	-	90	-
2a.1.5.2	Air Removal	-	25	-	-	-	-	-	4	29	-	-	29	-	-	-	-	-	-	422	-
2a.1.5.3	Auxiliary Feedwater	-	40	-	-	-	-	-	6	46	-	-	46	-	-	-	-	-	-	676	-
2a.1.5.4	Auxiliary Feedwater - RCA	-	36	0	1	15	-	-	12	65	65	-	-	178	-	-	-	-	7,214	486	-
2a.1.5.5	Bleed Steam	-	78	-	-	-	-	-	12	90	-	-	90	-	-	-	-	-	-	1,331	-
2a.1.5.6	Caustic Addition - RCA	-	38	0	1	21	-	-	13	74	74	-	-	240	-	-	-	-	9,761	468	-
2a.1.5.7	Chemical Feed	-	15	-	-	-	-	-	2	17	-	-	17	-	-	-	-	-	-	261	-
2a.1.5.8	Chemical Feed - RCA	-	3	0	0	1	-	-	1	5	5	-	-	16	-	-	-	-	634	31	-
2a.1.5.9	Circulating Water	-	24	-	-	-	-	-	4	28	-	-	28	-	-	-	-	-	-	401	-
2a.1.5.10	Condensate	-	459	-	-	-	-	-	69	527	-	-	527	-	-	-	-	-	-	7,537	-
2a.1.5.11	Condensate Polishing	-	181	-	-	-	-	-	27	209	-	-	209	-	-	-	-	-	-	2,987	-
2a.1.5.12	Condensate Polishing - RCA	-	36	1	3	42	-	-	16	98	98	-	-	483	-	-	-	-	19,616	493	-
2a.1.5.13	Electro-Hydraulic	-	8	-	-	-	-	-	1	10	-	-	10	-	-	-	-	-	-	143	-
2a.1.5.14	External Circulating Water	-	23	-	-	-	-	-	3	26	-	-	26	-	-	-	-	-	-	385	-
2a.1.5.15	External Circulating Water - RCA	-	70	1	4	62	-	-	28	165	165	-	-	721	-	-	-	-	29,284	938	-
2a.1.5.16	Feedwater	-	111	-	-	-	-	-	17	128	-	-	128	-	-	-	-	-	-	1,840	-
2a.1.5.17	Feedwater - RCA	-	236	7	24	359	-	-	117	744	744	-	-	4,147	-	-	-	-	168,414	3,377	-
2a.1.5.18	Gland Seal	-	29	-	-	-	-	-	4	34	-	-	34	-	-	-	-	-	-	504	-
2a.1.5.19	Heater Drain	-	334	-	-	-	-	-	50	384	-	-	384	-	-	-	-	-	-	5,638	-
2a.1.5.20	Hypobromous Acid Feed	-	5	-	-	-	-	-	1	6	-	-	6	-	-	-	-	-	-	86	-
2a.1.5.21	Hypobromous Acid Feed - RCA	-	1	0	0	0	-	-	0	1	1	-	-	2	-	-	-	-	100	12	-
2a.1.5.22	Internal Circ Water & CDSR	-	22	-	-	-	-	-	3	25	-	-	25	-	-	-	-	-	-	366	-
2a.1.5.23	Main Gen/Exciter/Transformer	-	0	-	-	-	-	-	0	0	-	-	0	-	-	-	-	-	-	5	-
2a.1.5.24	Main Steam	-	88	-	-	-	-	-	13	101	-	-	101	-	-	-	-	-	-	1,482	-
2a.1.5.25	Main Steam - RCA	-	364	9	30	447	-	-	163	1,013	1,013	-	-	5,166	-	-	-	-	209,799	5,146	-
2a.1.5.26	Repairable Spare Snubbers	-	6	0	0	1	-	-	2	8	8	-	-	12	-	-	-	-	490	82	-
2a.1.5.27	Steam Exclusion	-	2	-	-	-	-	-	0	2	-	-	2	-	-	-	-	-	-	32	-
2a.1.5.28	Steam Exclusion - RCA	-	4	0	0	2	-	-	1	8	8	-	-	24	-	-	-	-	966	47	-
2a.1.5.29	Steam Generator Blowdown	-	398	20	21	165	179	-	174	957	957	-	-	1,906	631	-	-	-	119,126	5,778	-
2a.1.5.30	Steam Generators	-	5	-	-	-	-	-	1	5	-	-	5	-	-	-	-	-	-	75	-
2a.1.5.31	Turbine & Moisture Separators	-	329	-	-	-	-	-	49	379	-	-	379	-	-	-	-	-	-	5,472	-
2a.1.5.32	Turbine Oil Purification	-	46	-	-	-	-	-	7	53	-	-	53	-	-	-	-	-	-	757	-
2a.1.5.33	Water Treatment	-	394	-	-	-	-	-	59	453	-	-	453	-	-	-	-	-	-	6,677	-
2a.1.5.34	Water Treatment - RCA	-	19	0	1	10	-	-	6	37	37	-	-	115	-	-	-	-	4,652	252	-

Table C-2
Prairie Island Nuclear Generating Plant, Unit 2
DECON Decommissioning Cost Estimate with DOE Pickup of Industry Spent Fuel Starting in 2025
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
2a.1.5	Totals	-	3,437	39	85	1,125	179	-	867	5,733	3,174	-	2,559	13,010	631	-	-	-	570,056	54,280	-
2a.1.6	Scaffolding in support of decommissioning	-	2,833	24	8	97	25	-	733	3,721	3,721	-	-	1,012	89	-	-	-	51,445	26,270	-
2a.1	Subtotal Period 2a Activity Costs	855	23,653	26,885	3,859	3,105	16,875	553	25,350	101,134	98,575	-	2,559	38,625	30,835	125	673	-	4,223,340	208,777	6,073
Period 2a Additional Costs																					
2a.2.1	Remedial Action Surveys	-	-	-	-	-	-	1,560	468	2,027	2,027	-	-	-	-	-	-	-	-	20,388	-
2a.2.2	Retired RPV upper internals package	1	659	785	107	-	1,439	-	1,437	4,427	4,427	-	-	-	2,097	125	-	-	205,890	2,175	87
2a.2	Subtotal Period 2a Additional Costs	1	659	785	107	-	1,439	1,560	1,905	6,454	6,454	-	-	-	2,097	125	-	-	205,890	22,562	87
Period 2a Collateral Costs																					
2a.3.1	Process decommissioning water waste	51	-	33	86	-	135	-	75	381	381	-	-	-	323	-	-	-	19,358	63	-
2a.3.3	Small tool allowance	-	251	-	-	-	-	-	38	289	260	-	29	-	-	-	-	-	-	-	-
2a.3.4	Spent Fuel Capital and Transfer	-	-	-	-	-	-	927	139	1,066	-	1,066	-	-	-	-	-	-	-	-	-
2a.3.5	Retention and Severance	-	-	-	-	-	-	6,105	916	7,021	7,021	-	-	-	-	-	-	-	-	-	-
2a.3.6	Prairie Island Indian Community Payments	-	-	-	-	-	-	1,224	-	1,224	-	1,224	-	-	-	-	-	-	-	-	-
2a.3	Subtotal Period 2a Collateral Costs	51	251	33	86	-	135	8,256	1,168	9,980	7,661	2,290	29	-	323	-	-	-	19,358	63	-
Period 2a Period-Dependent Costs																					
2a.4.1	Decon supplies	68	-	-	-	-	-	-	17	85	85	-	-	-	-	-	-	-	-	-	-
2a.4.2	Insurance	-	-	-	-	-	-	501	50	551	551	-	-	-	-	-	-	-	-	-	-
2a.4.3	Property taxes	-	-	-	-	-	-	2,507	251	2,758	2,758	-	-	-	-	-	-	-	-	-	-
2a.4.4	Health physics supplies	-	1,622	-	-	-	-	-	406	2,028	2,028	-	-	-	-	-	-	-	-	-	-
2a.4.5	Heavy equipment rental	-	2,153	-	-	-	-	-	323	2,477	2,477	-	-	-	-	-	-	-	-	-	-
2a.4.6	Disposal of DAW generated	-	-	89	26	-	331	-	95	541	541	-	-	-	4,063	-	-	-	81,252	133	-
2a.4.7	Plant energy budget	-	-	-	-	-	-	1,411	212	1,623	1,623	-	-	-	-	-	-	-	-	-	-
2a.4.8	NRC Fees	-	-	-	-	-	-	389	39	428	428	-	-	-	-	-	-	-	-	-	-
2a.4.9	Emergency Planning Fees	-	-	-	-	-	-	1,259	126	1,385	-	1,385	-	-	-	-	-	-	-	-	-
2a.4.10	Fixed Overhead	-	-	-	-	-	-	1,214	182	1,396	1,396	-	-	-	-	-	-	-	-	-	-
2a.4.11	Spent Fuel Pool O&M	-	-	-	-	-	-	394	59	453	-	453	-	-	-	-	-	-	-	-	-
2a.4.12	ISFSI Operating Costs	-	-	-	-	-	-	51	8	58	-	58	-	-	-	-	-	-	-	-	-
2a.4.13	Railroad Track Maintenance	-	-	-	-	-	-	265	40	305	305	-	-	-	-	-	-	-	-	-	-
2a.4.14	Security Staff Cost	-	-	-	-	-	-	6,661	999	7,661	7,661	-	-	-	-	-	-	-	-	-	110,166
2a.4.15	DOC Staff Cost	-	-	-	-	-	-	13,492	2,024	15,516	15,516	-	-	-	-	-	-	-	-	-	155,048
2a.4.16	Utility Staff Cost	-	-	-	-	-	-	17,880	2,682	20,562	20,562	-	-	-	-	-	-	-	-	-	288,676
2a.4	Subtotal Period 2a Period-Dependent Costs	68	3,776	89	26	-	331	46,025	7,512	57,825	55,929	1,896	-	-	4,063	-	-	-	81,252	133	553,890
2a.0	TOTAL PERIOD 2a COST	974	28,339	27,792	4,078	3,105	18,780	56,393	35,934	175,394	168,620	4,186	2,588	38,625	37,317	250	673	-	4,529,841	231,534	560,049
PERIOD 2b - Site Decontamination																					
Period 2b Direct Decommissioning Activities																					
Disposal of Plant Systems																					
2b.1.1.1	ADT & Misc Ventilation	-	24	0	1	13	3	-	9	50	50	-	-	153	9	-	-	-	6,814	363	-
2b.1.1.2	Aux Bldg Normal Ventilation	-	67	2	5	60	11	-	29	174	174	-	-	692	39	-	-	-	30,671	1,013	-
2b.1.1.3	Aux Bldg Special Ventilation	-	13	0	0	6	2	-	5	26	26	-	-	70	6	-	-	-	3,243	197	-
2b.1.1.4	Battery Rm Special Ventilation	-	1	-	-	-	-	-	0	2	-	-	2	-	-	-	-	-	-	24	-
2b.1.1.5	Boron Recycle	0	4	0	0	0	3	-	2	9	9	-	-	3	9	-	-	-	709	50	-
2b.1.1.6	Chemical & Volume Control	722	902	59	44	204	560	-	770	3,260	3,260	-	-	2,356	1,977	-	-	-	225,854	23,197	-
2b.1.1.7	Cold Chemical Lab Ventilation	-	1	-	-	-	-	-	0	1	-	-	1	-	-	-	-	-	-	9	-
2b.1.1.8	Component Cooling - RCA	-	617	21	70	1,038	-	-	322	2,068	2,068	-	-	11,996	-	-	-	-	487,169	8,583	-
2b.1.1.9	Containment Cooling	-	31	-	-	-	-	-	5	35	-	-	35	-	-	-	-	-	-	502	-
2b.1.1.10	Containment Cooling - RCA	-	288	5	16	237	-	-	110	656	656	-	-	2,743	-	-	-	-	111,390	3,949	-
2b.1.1.11	Containment Hydrogen Control - RCA	-	35	0	1	12	-	-	11	60	60	-	-	141	-	-	-	-	5,742	494	-
2b.1.1.12	Containment Spray - RCA	-	186	3	8	126	-	-	67	389	389	-	-	1,453	-	-	-	-	59,019	2,617	-
2b.1.1.13	Containment Ventilation	-	224	23	38	408	205	-	177	1,075	1,075	-	-	4,721	722	-	-	-	239,450	3,375	-
2b.1.1.14	Control/Relay/Cmptr Rm Vent	-	30	1	2	23	6	-	13	74	74	-	-	260	20	-	-	-	11,915	454	-
2b.1.1.15	Cooling Water	-	139	-	-	-	-	-	21	160	-	-	160	-	-	-	-	-	-	2,344	-
2b.1.1.16	Cooling Water - RCA	-	456	15	49	730	-	-	232	1,482	1,482	-	-	8,442	-	-	-	-	342,822	6,311	-
2b.1.1.17	Cranes/Hoists/Elevators - RCA	-	3	0	1	9	-	-	2	15	15	-	-	103	-	-	-	-	4,184	48	-
2b.1.1.18	D3 Emergency Diesel	-	9	-	-	-	-	-	1	10	-	-	10	-	-	-	-	-	-	141	-
2b.1.1.19	D4 Emergency Diesel	-	9	-	-	-	-	-	1	10	-	-	10	-	-	-	-	-	-	141	-
2b.1.1.20	D5 Emergency Diesel	-	0	-	-	-	-	-	0	0	-	-	0	-	-	-	-	-	-	5	-
2b.1.1.21	Electrical - Clean	-	1,502	-	-	-	-	-	225	1,727	-	-	1,727	-	-	-	-	-	-	24,276	-
2b.1.1.22	Electrical - Contaminated	-	461	5	13	173	21	-	149	821	821	-	-	1,997	75	-	-	-	86,080	6,503	-
2b.1.1.23	Electrical - Decontaminated	-	2,866	33	109	1,622	-	-	980	5,610	5,610	-	-	18,753	-	-	-	-	761,569	38,423	-

Table C-2
Prairie Island Nuclear Generating Plant, Unit 2
DECON Decommissioning Cost Estimate with DOE Pickup of Industry Spent Fuel Starting in 2025
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Disposal of Plant Systems (continued)																					
2b.1.1.24	Filter Rm Ventilation	-	4	0	0	2	0	-	2	9	9	-	-	24	1	-	-	-	1,020	69	-
2b.1.1.25	Fire Protection & Detection	-	178	-	-	-	-	-	27	205	-	-	205	-	-	-	-	-	-	3,009	-
2b.1.1.26	Fire Protection & Detection - RCA	-	236	3	11	158	-	-	85	492	492	-	-	1,828	-	-	-	-	74,245	3,134	-
2b.1.1.27	Fuel Handling	-	71	1	2	17	14	-	24	130	130	-	-	200	49	-	-	-	11,396	1,101	-
2b.1.1.28	Fuel Oil	-	1	-	-	-	-	-	0	1	-	-	1	-	-	-	-	-	-	9	-
2b.1.1.29	HVAC - Clean	-	132	-	-	-	-	-	20	151	-	-	151	-	-	-	-	-	-	2,373	-
2b.1.1.30	HVAC - Contaminated	-	1,222	26	69	929	115	-	487	2,848	2,848	-	-	10,745	405	-	-	-	463,144	16,579	-
2b.1.1.31	Heating	-	279	-	-	-	-	-	42	321	-	-	321	-	-	-	-	-	-	4,804	-
2b.1.1.32	Heating - RCA	-	323	3	11	165	-	-	107	609	609	-	-	1,907	-	-	-	-	77,458	4,086	-
2b.1.1.33	Hot Lab & Sample Rm Ventilation	-	19	0	1	9	1	-	6	37	37	-	-	107	4	-	-	-	4,632	285	-
2b.1.1.34	Incore Instrumentation	0	29	1	1	5	16	-	13	67	67	-	-	60	58	-	-	-	6,264	458	-
2b.1.1.35	Misc Drains & Vents	-	223	12	9	40	121	-	95	500	500	-	-	458	426	-	-	-	46,850	3,180	-
2b.1.1.36	Misc Lab & Service Areas Vent	-	123	8	6	32	70	-	55	293	293	-	-	370	244	-	-	-	31,186	1,713	-
2b.1.1.37	Miscellaneous Gas	-	63	-	-	-	-	-	9	72	-	-	72	-	-	-	-	-	-	1,073	-
2b.1.1.38	Miscellaneous Gas - RCA	-	129	1	3	52	-	-	41	226	226	-	-	600	-	-	-	-	24,378	1,636	-
2b.1.1.39	Radiation Monitoring	-	6	-	-	-	-	-	1	7	-	-	7	-	-	-	-	-	-	111	-
2b.1.1.40	Radiation Monitoring - RCA	-	62	1	2	27	-	-	20	112	112	-	-	316	-	-	-	-	12,826	782	-
2b.1.1.41	Reactor Coolant	158	227	20	12	20	208	-	195	839	839	-	-	229	730	-	-	-	57,672	5,517	-
2b.1.1.42	Reactor Hot Sampling	135	121	10	5	5	89	-	123	489	489	-	-	54	312	-	-	-	22,919	3,686	-
2b.1.1.43	Reactor Makeup	-	36	-	-	-	-	-	5	41	-	-	41	-	-	-	-	-	-	583	-
2b.1.1.44	Reactor Makeup - RCA	-	4	0	0	2	-	-	1	8	8	-	-	28	-	-	-	-	1,148	47	-
2b.1.1.45	Reactor Vessel	9	17	0	0	2	4	-	10	43	43	-	-	22	14	-	-	-	1,826	385	-
2b.1.1.46	Residual Heat Removal	336	374	84	66	247	924	-	548	2,578	2,578	-	-	2,853	3,244	-	-	-	330,651	7,112	-
2b.1.1.47	Safeguards Chilled Water	-	4	-	-	-	-	-	1	5	-	-	5	-	-	-	-	-	-	75	-
2b.1.1.48	Safety Injection	-	836	40	56	577	329	-	390	2,228	2,228	-	-	6,676	1,161	-	-	-	347,600	12,284	-
2b.1.1.49	Sampling	-	51	3	2	3	27	-	20	105	105	-	-	37	93	-	-	-	7,697	714	-
2b.1.1.50	Service Bldg & New Cmptr Vent	-	0	-	-	-	-	-	0	0	-	-	0	-	-	-	-	-	-	6	-
2b.1.1.51	Shield Bldg Ventilation	-	114	13	19	175	138	-	94	554	554	-	-	2,028	484	-	-	-	114,378	1,743	-
2b.1.1.52	Station & Instrument Air	-	140	-	-	-	-	-	21	161	-	-	161	-	-	-	-	-	-	2,424	-
2b.1.1.53	Station & Instrument Air - RCA	-	288	3	9	141	-	-	95	535	535	-	-	1,625	-	-	-	-	65,986	3,638	-
2b.1.1.54	Turbine Bldg Traps & Drains	-	26	-	-	-	-	-	4	30	-	-	30	-	-	-	-	-	-	462	-
2b.1.1.55	Turbine Bldg Traps & Drains - RCA	-	28	0	1	16	-	-	10	55	55	-	-	180	-	-	-	-	7,321	344	-
2b.1.1.56	Turbine Bldg Ventilation	-	40	-	-	-	-	-	6	46	-	-	46	-	-	-	-	-	-	655	-
2b.1.1.57	Unit Coolers	-	20	-	-	-	-	-	3	23	-	-	23	-	-	-	-	-	-	332	-
2b.1.1.58	Unit Coolers - RCA	-	54	0	1	20	-	-	17	93	93	-	-	232	-	-	-	-	9,413	690	-
2b.1.1.59	Waste Gas Disposal	531	457	40	35	212	381	-	516	2,173	2,173	-	-	2,453	1,358	-	-	-	188,334	14,308	-
2b.1.1.60	Waste Liquid Disposal	1,386	1,733	108	76	316	1,019	-	1,451	6,089	6,089	-	-	3,655	3,594	-	-	-	385,370	44,485	-
2b.1.1.61	Waste Solid Disposal	111	139	11	8	34	112	-	126	541	541	-	-	389	393	-	-	-	41,732	3,481	-
2b.1.1	Totals	3,390	15,678	558	763	7,868	4,377	-	7,798	40,433	37,423	-	3,010	90,963	15,429	-	-	-	4,712,076	270,390	-
2b.1.2	Scaffolding in support of decommissioning	-	3,542	30	10	121	32	-	916	4,651	4,651	-	-	1,265	112	-	-	-	64,307	32,837	-
Decontamination of Site Buildings																					
2b.1.3.1	Reactor	1,150	2,624	139	853	193	11,080	-	4,172	20,210	20,210	-	-	2,230	57,418	-	-	-	3,559,977	50,853	-
2b.1.3.2	Auxiliary	1,223	400	12	80	92	582	-	884	3,272	3,272	-	-	1,060	3,355	-	-	-	332,498	23,808	-
2b.1.3.3	Backwash Waste Receiving Tank	-	27	1	11	-	87	-	30	158	158	-	-	-	507	-	-	-	43,896	299	-
2b.1.3.4	Drum Transfer & Truck Loading Enclosure	17	8	0	2	2	13	-	14	56	56	-	-	19	74	-	-	-	7,118	368	-
2b.1.3.5	LLRW Storage Enclosure	117	51	1	11	3	87	-	95	366	366	-	-	38	502	-	-	-	44,971	2,424	-
2b.1.3.6	Radwaste	52	23	1	5	4	39	-	43	166	166	-	-	42	225	-	-	-	21,136	1,082	-
2b.1.3.7	Resin Disposal	15	11	0	2	7	12	-	15	64	64	-	-	83	69	-	-	-	9,271	383	-
2b.1.3	Totals	2,574	3,145	155	964	300	11,900	-	5,253	24,292	24,292	-	-	3,471	62,151	-	-	-	4,018,868	79,216	-
2b.1.4	Prepare/submit License Termination Plan	-	-	-	-	-	-	206	31	236	236	-	-	-	-	-	-	-	-	-	1,751
2b.1.5	Receive NRC approval of termination plan									a											
2b.1	Subtotal Period 2b Activity Costs	5,965	22,365	744	1,737	8,290	16,309	206	13,998	69,612	66,602	-	3,010	95,700	77,691	-	-	-	8,795,250	382,443	1,751
Period 2b Additional Costs																					
2b.2.1	Remedial Action Surveys	-	-	-	-	-	-	1,930	579	2,509	2,509	-	-	-	-	-	-	-	-	25,228	-
2b.2.2	Operational Equipment	-	-	9	29	312	-	-	52	402	402	-	-	5,855	-	-	-	-	146,375	16	-
2b.2	Subtotal Period 2b Additional Costs	-	-	9	29	312	-	1,930	631	2,911	2,911	-	-	5,855	-	-	-	-	146,375	25,244	-
Period 2b Collateral Costs																					
2b.3.1	Process decommissioning water waste	167	-	112	289	-	453	-	251	1,272	1,272	-	-	-	1,081	-	-	-	64,837	211	-
2b.3.2	Process decommissioning chemical flush waste	3	-	114	431	-	858	-	292	1,700	1,700	-	-	-	1,154	-	-	-	122,948	216	-
2b.3.3	Small tool allowance	-	414	-	-	-	-	-	62	476	476	-	-	-	-	-	-	-	-	-	-
2b.3.4	Spent Fuel Capital and Transfer	-	-	-	-	-	-	924	139	1,062	-	1,062	-	-	-	-	-	-	-	-	-

Table C-2
Prairie Island Nuclear Generating Plant, Unit 2
DECON Decommissioning Cost Estimate with DOE Pickup of Industry Spent Fuel Starting in 2025
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 2b Collateral Costs (continued)																					
2b.3.5	Retention and Severance	-	-	-	-	-	-	4,127	619	4,746	4,746	-	-	-	-	-	-	-	-	-	-
2b.3.6	Prairie Island Indian Community Payments	-	-	-	-	-	-	1,517	-	1,517	-	1,517	-	-	-	-	-	-	-	-	-
2b.3.7	On-site survey and release of 0.437 tons clean metallic waste	-	-	-	-	-	-	1	0	1	1	-	-	-	-	-	-	-	-	-	-
2b.3	Subtotal Period 2b Collateral Costs	170	414	226	721	-	1,311	6,569	1,363	10,774	8,195	2,579	-	-	2,234	-	-	-	187,785	427	-
Period 2b Period-Dependent Costs																					
2b.4.1	Decon supplies	1,135	-	-	-	-	-	-	284	1,419	1,419	-	-	-	-	-	-	-	-	-	-
2b.4.2	Insurance	-	-	-	-	-	-	620	62	682	682	-	-	-	-	-	-	-	-	-	-
2b.4.3	Property taxes	-	-	-	-	-	-	2,983	298	3,281	3,281	-	-	-	-	-	-	-	-	-	-
2b.4.4	Health physics supplies	-	2,580	-	-	-	-	-	645	3,225	3,225	-	-	-	-	-	-	-	-	-	-
2b.4.5	Heavy equipment rental	-	2,740	-	-	-	-	-	411	3,151	3,151	-	-	-	-	-	-	-	-	-	-
2b.4.6	Disposal of DAW generated	-	-	115	34	-	431	-	124	704	704	-	-	-	5,291	-	-	-	105,826	173	-
2b.4.7	Plant energy budget	-	-	-	-	-	-	1,379	207	1,586	1,586	-	-	-	-	-	-	-	-	-	-
2b.4.8	NRC Fees	-	-	-	-	-	-	481	48	529	529	-	-	-	-	-	-	-	-	-	-
2b.4.9	Emergency Planning Fees	-	-	-	-	-	-	1,558	156	1,714	-	1,714	-	-	-	-	-	-	-	-	-
2b.4.10	Fixed Overhead	-	-	-	-	-	-	1,503	225	1,728	1,728	-	-	-	-	-	-	-	-	-	-
2b.4.11	Spent Fuel Pool O&M	-	-	-	-	-	-	487	73	560	-	560	-	-	-	-	-	-	-	-	-
2b.4.12	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	246	37	282	282	-	-	-	-	-	-	-	-	-	-
2b.4.13	ISFSI Operating Costs	-	-	-	-	-	-	63	9	72	-	72	-	-	-	-	-	-	-	-	-
2b.4.14	Railroad Track Maintenance	-	-	-	-	-	-	70	10	80	80	-	-	-	-	-	-	-	-	-	-
2b.4.15	Security Staff Cost	-	-	-	-	-	-	8,243	1,236	9,479	9,479	-	-	-	-	-	-	-	-	-	136,323
2b.4.16	DOC Staff Cost	-	-	-	-	-	-	16,150	2,422	18,572	18,572	-	-	-	-	-	-	-	-	-	184,288
2b.4.17	Utility Staff Cost	-	-	-	-	-	-	21,222	3,183	24,405	24,405	-	-	-	-	-	-	-	-	-	342,069
2b.4	Subtotal Period 2b Period-Dependent Costs	1,135	5,320	115	34	-	431	55,004	9,432	71,472	69,125	2,346	-	-	5,291	-	-	-	105,826	173	662,680
2b.0	TOTAL PERIOD 2b COST	7,270	28,099	1,095	2,520	8,602	18,050	63,708	25,425	154,768	146,833	4,926	3,010	101,555	85,217	-	-	-	9,235,236	408,286	664,431
PERIOD 2c - Spent fuel delay prior to SFP decon																					
Period 2c Direct Decommissioning Activities																					
Period 2c Additional Costs																					
2c.2.1	Security Modifications	-	-	-	-	-	-	4,348	652	5,000	5,000	-	-	-	-	-	-	-	-	-	-
2c.2	Subtotal Period 2c Additional Costs	-	-	-	-	-	-	4,348	652	5,000	5,000	-	-	-	-	-	-	-	-	-	-
Period 2c Collateral Costs																					
2c.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	61,759	9,264	71,023	-	71,023	-	-	-	-	-	-	-	-	-
2c.3.2	Retention and Severance	-	-	-	-	-	-	2,034	305	2,339	2,339	-	-	-	-	-	-	-	-	-	-
2c.3.3	Prairie Island Indian Community Payments	-	-	-	-	-	-	1,630	-	1,630	-	1,630	-	-	-	-	-	-	-	-	-
2c.3	Subtotal Period 2c Collateral Costs	-	-	-	-	-	-	65,423	9,569	74,991	2,339	72,653	-	-	-	-	-	-	-	-	-
Period 2c Period-Dependent Costs																					
2c.4.1	Insurance	-	-	-	-	-	-	666	67	733	733	-	-	-	-	-	-	-	-	-	-
2c.4.2	Property taxes	-	-	-	-	-	-	3,060	306	3,366	3,366	-	-	-	-	-	-	-	-	-	-
2c.4.3	Health physics supplies	-	270	-	-	-	-	-	67	337	337	-	-	-	-	-	-	-	-	-	-
2c.4.4	Disposal of DAW generated	-	-	12	3	-	44	-	13	72	72	-	-	-	538	-	-	-	10,761	18	-
2c.4.5	Plant energy budget	-	-	-	-	-	-	395	59	454	454	-	-	-	-	-	-	-	-	-	-
2c.4.6	NRC Fees	-	-	-	-	-	-	305	31	336	336	-	-	-	-	-	-	-	-	-	-
2c.4.7	Emergency Planning Fees	-	-	-	-	-	-	1,674	167	1,842	-	1,842	-	-	-	-	-	-	-	-	-
2c.4.8	Fixed Overhead	-	-	-	-	-	-	1,615	242	1,857	1,857	-	-	-	-	-	-	-	-	-	-
2c.4.9	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	53	8	61	61	-	-	-	-	-	-	-	-	-	-
2c.4.10	ISFSI Operating Costs	-	-	-	-	-	-	67	10	77	-	77	-	-	-	-	-	-	-	-	-
2c.4.11	Railroad Track Maintenance	-	-	-	-	-	-	75	11	86	86	-	-	-	-	-	-	-	-	-	-
2c.4.12	Security Staff Cost	-	-	-	-	-	-	8,857	1,329	10,185	10,185	-	-	-	-	-	-	-	-	-	146,478
2c.4.13	Utility Staff Cost	-	-	-	-	-	-	6,575	986	7,561	7,561	-	-	-	-	-	-	-	-	-	107,146
2c.4	Subtotal Period 2c Period-Dependent Costs	-	270	12	3	-	44	23,343	3,296	26,968	25,049	1,919	-	-	538	-	-	-	10,761	18	253,623
2c.0	TOTAL PERIOD 2c COST	-	270	12	3	-	44	93,114	13,517	106,959	32,387	74,572	-	-	538	-	-	-	10,761	18	253,623
PERIOD 2d - Decontamination Following Wet Fuel Storage																					
Period 2d Direct Decommissioning Activities																					
2d.1.1	Remove spent fuel racks	328	32	94	32	-	595	-	335	1,416	1,416	-	-	-	2,092	-	-	-	138,298	576	-
Disposal of Plant Systems																					
2d.1.2.1	Electrical - Contaminated - Fuel Pool	-	197	2	6	75	9	-	64	353	353	-	-	864	33	-	-	-	37,250	2,783	-
2d.1.2.2	Electrical - Decontaminated - Fuel Pool	-	1,230	14	47	698	-	-	421	2,410	2,410	-	-	8,069	-	-	-	-	327,668	16,495	-

Table C-2
Prairie Island Nuclear Generating Plant, Unit 2
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Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Disposal of Plant Systems (continued)																					
2d.1.2.3	Fire Protection & Detection - RCA Fuel P	-	36	1	2	25	-	-	13	76	76	-	-	286	-	-	-	-	11,622	476	-
2d.1.2.4	HVAC - Contaminated - Fuel Pool	-	549	12	31	418	52	-	219	1,280	1,280	-	-	4,828	182	-	-	-	208,080	7,448	-
2d.1.2.5	Safeguards Chilled Water - RCA	-	4	0	0	2	-	-	1	8	8	-	-	26	-	-	-	-	1,045	51	-
2d.1.2.6	Spent Fuel Pool Cooling	31	35	3	2	3	30	-	33	137	137	-	-	39	107	-	-	-	8,635	882	-
2d.1.2.7	Spent Fuel Pool Normal Ventilation	-	26	1	2	23	3	-	11	66	66	-	-	265	12	-	-	-	11,532	394	-
2d.1.2	Totals	31	2,077	32	89	1,244	95	-	761	4,328	4,328	-	-	14,376	333	-	-	-	605,832	28,530	-
Decontamination of Site Buildings																					
2d.1.3.1	Fuel Handling of Aux Building	975	1,082	9	32	209	173	-	838	3,319	3,319	-	-	2,417	944	-	-	-	177,818	30,401	-
2d.1.3	Totals	975	1,082	9	32	209	173	-	838	3,319	3,319	-	-	2,417	944	-	-	-	177,818	30,401	-
2d.1.4	Scaffolding in support of decommissioning	-	708	6	2	24	6	-	183	930	930	-	-	253	22	-	-	-	12,861	6,567	-
2d.1	Subtotal Period 2d Activity Costs	1,334	3,900	142	155	1,477	868	-	2,118	9,994	9,994	-	-	17,046	3,391	-	-	-	934,809	66,074	-
Period 2d Additional Costs																					
2d.2.1	License Termination Survey Planning	-	-	-	-	-	-	845	253	1,098	1,098	-	-	-	-	-	-	-	-	-	6,240
2d.2.2	Remedial Action Surveys	-	-	-	-	-	-	1,237	371	1,608	1,608	-	-	-	-	-	-	-	-	16,173	-
2d.2	Subtotal Period 2d Additional Costs	-	-	-	-	-	-	2,082	625	2,706	2,706	-	-	-	-	-	-	-	-	16,173	6,240
Period 2d Collateral Costs																					
2d.3.1	Process decommissioning water waste	39	-	27	70	-	109	-	60	306	306	-	-	-	261	-	-	-	15,666	51	-
2d.3.2	Process decommissioning chemical flush waste	0	-	1	5	-	10	-	3	20	20	-	-	-	13	-	-	-	1,422	2	-
2d.3.3	Small tool allowance	-	79	-	-	-	-	-	12	91	91	-	-	-	-	-	-	-	-	-	-
2d.3.4	Decommissioning Equipment Disposition	-	-	144	55	575	150	-	147	1,071	1,071	-	-	6,000	529	-	-	-	304,968	88	-
2d.3.5	Spent Fuel Capital and Transfer	-	-	-	-	-	-	13,365	2,005	15,370	-	15,370	-	-	-	-	-	-	-	-	-
2d.3.6	Prairie Island Indian Community Payments	-	-	-	-	-	-	974	-	974	-	974	-	-	-	-	-	-	-	-	-
2d.3	Subtotal Period 2d Collateral Costs	39	79	172	130	575	270	14,339	2,227	17,831	1,488	16,344	-	6,000	803	-	-	-	322,056	142	-
Period 2d Period-Dependent Costs																					
2d.4.1	Decon supplies	218	-	-	-	-	-	-	54	272	272	-	-	-	-	-	-	-	-	-	-
2d.4.2	Insurance	-	-	-	-	-	-	399	40	439	439	-	-	-	-	-	-	-	-	-	-
2d.4.3	Property taxes	-	-	-	-	-	-	1,746	175	1,921	1,921	-	-	-	-	-	-	-	-	-	-
2d.4.4	Health physics supplies	-	743	-	-	-	-	-	186	929	929	-	-	-	-	-	-	-	-	-	-
2d.4.5	Heavy equipment rental	-	1,763	-	-	-	-	-	264	2,027	2,027	-	-	-	-	-	-	-	-	-	-
2d.4.6	Disposal of DAW generated	-	-	44	13	-	163	-	47	266	266	-	-	-	2,002	-	-	-	40,031	65	-
2d.4.7	Plant energy budget	-	-	-	-	-	-	473	71	544	544	-	-	-	-	-	-	-	-	-	-
2d.4.8	NRC Fees	-	-	-	-	-	-	257	26	283	283	-	-	-	-	-	-	-	-	-	-
2d.4.9	Emergency Planning Fees	-	-	-	-	-	-	1,003	100	1,103	-	1,103	-	-	-	-	-	-	-	-	-
2d.4.10	Fixed Overhead	-	-	-	-	-	-	967	145	1,112	1,112	-	-	-	-	-	-	-	-	-	-
2d.4.11	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	316	47	363	363	-	-	-	-	-	-	-	-	-	-
2d.4.12	ISFSI Operating Costs	-	-	-	-	-	-	40	6	46	-	46	-	-	-	-	-	-	-	-	-
2d.4.13	Railroad Track Maintenance	-	-	-	-	-	-	45	7	52	52	-	-	-	-	-	-	-	-	-	-
2d.4.14	Security Staff Cost	-	-	-	-	-	-	5,141	771	5,912	5,912	-	-	-	-	-	-	-	-	-	84,454
2d.4.15	DOC Staff Cost	-	-	-	-	-	-	6,087	913	7,000	7,000	-	-	-	-	-	-	-	-	-	70,243
2d.4.16	Utility Staff Cost	-	-	-	-	-	-	7,824	1,174	8,997	8,557	441	-	-	-	-	-	-	-	-	126,681
2d.4	Subtotal Period 2d Period-Dependent Costs	218	2,506	44	13	-	163	24,297	4,026	31,267	29,677	1,590	-	-	2,002	-	-	-	40,031	65	281,377
2d.0	TOTAL PERIOD 2d COST	1,591	6,486	357	298	2,052	1,301	40,718	8,995	61,799	43,865	17,934	-	23,046	6,196	-	-	-	1,296,896	82,455	287,617
PERIOD 2f - License Termination																					
Period 2f Direct Decommissioning Activities																					
2f.1.1	ORISE confirmatory survey	-	-	-	-	-	-	176	53	229	229	-	-	-	-	-	-	-	-	-	-
2f.1.2	Terminate license									a											
2f.1	Subtotal Period 2f Activity Costs	-	-	-	-	-	-	176	53	229	229	-	-	-	-	-	-	-	-	-	-
Period 2f Additional Costs																					
2f.2.1	License Termination Survey	-	-	-	-	-	-	7,406	2,222	9,628	9,628	-	-	-	-	-	-	-	-	102,642	3,120
2f.2	Subtotal Period 2f Additional Costs	-	-	-	-	-	-	7,406	2,222	9,628	9,628	-	-	-	-	-	-	-	-	102,642	3,120
Period 2f Collateral Costs																					
2f.3.1	DOC staff relocation expenses	-	-	-	-	-	-	1,189	178	1,367	1,367	-	-	-	-	-	-	-	-	-	-
2f.3.2	Spent Fuel Capital and Transfer	-	-	-	-	-	-	431	65	496	-	496	-	-	-	-	-	-	-	-	-
2f.3.3	Prairie Island Indian Community Payments	-	-	-	-	-	-	934	-	934	-	934	-	-	-	-	-	-	-	-	-
2f.3	Subtotal Period 2f Collateral Costs	-	-	-	-	-	-	2,553	243	2,796	1,367	1,429	-	-	-	-	-	-	-	-	-

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															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 2f Period-Dependent Costs																					
2f.4.1	Insurance	-	-	-	-	-	-	382	38	420	420	-	-	-	-	-	-	-	-	-	-
2f.4.2	Property taxes	-	-	-	-	-	-	1,626	163	1,789	1,789	-	-	-	-	-	-	-	-	-	-
2f.4.3	Health physics supplies	-	602	-	-	-	-	-	150	752	752	-	-	-	-	-	-	-	-	-	-
2f.4.4	Disposal of DAW generated	-	-	7	2	-	27	-	8	44	44	-	-	-	334	-	-	-	6,685	11	-
2f.4.5	Plant energy budget	-	-	-	-	-	-	227	34	261	261	-	-	-	-	-	-	-	-	-	-
2f.4.6	NRC Fees	-	-	-	-	-	-	272	27	299	299	-	-	-	-	-	-	-	-	-	-
2f.4.7	Emergency Planning Fees	-	-	-	-	-	-	51	5	56	-	56	-	-	-	-	-	-	-	-	-
2f.4.8	Fixed Overhead	-	-	-	-	-	-	926	139	1,065	1,065	-	-	-	-	-	-	-	-	-	-
2f.4.9	ISFSI Operating Costs	-	-	-	-	-	-	39	6	44	-	44	-	-	-	-	-	-	-	-	-
2f.4.10	Railroad Track Maintenance	-	-	-	-	-	-	43	6	50	50	-	-	-	-	-	-	-	-	-	-
2f.4.11	Security Staff Cost	-	-	-	-	-	-	4,924	739	5,663	5,663	-	-	-	-	-	-	-	-	-	80,898
2f.4.12	DOC Staff Cost	-	-	-	-	-	-	4,101	615	4,716	4,716	-	-	-	-	-	-	-	-	-	46,283
2f.4.13	Utility Staff Cost	-	-	-	-	-	-	3,854	578	4,433	4,007	426	-	-	-	-	-	-	-	-	59,507
2f.4	Subtotal Period 2f Period-Dependent Costs	-	602	7	2	-	27	16,445	2,508	19,592	19,065	526	-	-	334	-	-	-	6,685	11	186,687
2f.0	TOTAL PERIOD 2f COST	-	602	7	2	-	27	26,581	5,026	32,245	30,290	1,956	-	-	334	-	-	-	6,685	102,653	189,807
PERIOD 2 TOTALS		9,835	63,795	29,263	6,901	13,758	38,202	280,514	88,898	531,166	421,995	103,573	5,598	163,227	129,603	250	673	-	15,079,420	824,945	1,955,528
PERIOD 3b - Site Restoration																					
Period 3b Direct Decommissioning Activities																					
Demolition of Remaining Site Buildings																					
3b.1.1.1	Reactor	-	4,256	-	-	-	-	-	638	4,895	-	-	4,895	-	-	-	-	-	-	44,679	-
3b.1.1.2	Auxiliary	-	1,897	-	-	-	-	-	285	2,182	-	-	2,182	-	-	-	-	-	-	11,902	-
3b.1.1.3	Condensate Storage Tank Foundation	-	6	-	-	-	-	-	1	7	-	-	7	-	-	-	-	-	-	33	-
3b.1.1.4	Construction Warehouse & Fab Shop	-	118	-	-	-	-	-	18	135	-	-	135	-	-	-	-	-	-	1,405	-
3b.1.1.5	D3/D4 Emergency Generator	-	13	-	-	-	-	-	2	15	-	-	15	-	-	-	-	-	-	84	-
3b.1.1.6	Drum Transfer & Truck Loading Enclosure	-	19	-	-	-	-	-	3	21	-	-	21	-	-	-	-	-	-	221	-
3b.1.1.7	Hydrogen House	-	6	-	-	-	-	-	1	7	-	-	7	-	-	-	-	-	-	47	-
3b.1.1.8	LLRW Storage Enclosure	-	121	-	-	-	-	-	18	139	-	-	139	-	-	-	-	-	-	853	-
3b.1.1.9	Misc Structures 2017	-	1,391	-	-	-	-	-	209	1,599	-	-	1,599	-	-	-	-	-	-	12,939	-
3b.1.1.10	Radwaste	-	165	-	-	-	-	-	25	190	-	-	190	-	-	-	-	-	-	1,400	-
3b.1.1.11	Resin Disposal	-	13	-	-	-	-	-	2	15	-	-	15	-	-	-	-	-	-	120	-
3b.1.1.12	Structures below 3' below grade	-	1,713	-	-	-	-	-	257	1,969	-	-	1,969	-	-	-	-	-	-	9,238	-
3b.1.1.13	Sulfuric Acid Tank Enclosure	-	3	-	-	-	-	-	0	3	-	-	3	-	-	-	-	-	-	35	-
3b.1.1.14	Turbine	-	1,983	-	-	-	-	-	298	2,281	-	-	2,281	-	-	-	-	-	-	22,052	-
3b.1.1.15	Turbine Pedestal	-	349	-	-	-	-	-	52	402	-	-	402	-	-	-	-	-	-	1,857	-
3b.1.1.16	Warehouse #2	-	22	-	-	-	-	-	3	25	-	-	25	-	-	-	-	-	-	213	-
3b.1.1.17	Waste Neutralizing Tank House	-	7	-	-	-	-	-	1	8	-	-	8	-	-	-	-	-	-	56	-
3b.1.1.18	Waste Oil Storage	-	8	-	-	-	-	-	1	10	-	-	10	-	-	-	-	-	-	70	-
3b.1.1.19	Water Treatment	-	303	-	-	-	-	-	46	349	-	-	349	-	-	-	-	-	-	2,690	-
3b.1.1.20	Fuel Handling of Aux Building	-	1,032	-	-	-	-	-	155	1,186	-	-	1,186	-	-	-	-	-	-	8,240	-
3b.1.1	Totals	-	13,424	-	-	-	-	-	2,014	15,438	-	-	15,438	-	-	-	-	-	-	118,134	-
Site Closeout Activities																					
3b.1.2	Remove Rubble	-	1,308	-	-	-	-	-	196	1,505	-	-	1,505	-	-	-	-	-	-	6,495	-
3b.1.3	Grade & landscape site	-	431	-	-	-	-	-	65	495	-	-	495	-	-	-	-	-	-	921	-
3b.1.4	Final report to NRC	-	-	-	-	-	-	78	12	90	90	-	-	-	-	-	-	-	-	-	667
3b.1	Subtotal Period 3b Activity Costs	-	15,163	-	-	-	-	78	2,286	17,528	90	-	17,438	-	-	-	-	-	-	125,549	667
Period 3b Additional Costs																					
3b.2.1	Clean Concrete Disposal	-	3,313	-	-	-	-	8	498	3,818	-	-	3,818	-	-	-	-	-	-	12,824	-
3b.2.2	Underground Services Excavations	-	811	-	-	-	-	520	200	1,531	-	-	1,531	-	-	-	-	-	-	7,407	-
3b.2.3	Intake Structure Cofferdam	-	423	-	-	-	-	-	63	486	-	-	486	-	-	-	-	-	-	3,552	-
3b.2.4	Construction Debris	-	-	-	-	-	-	463	69	532	-	-	532	-	-	-	-	-	-	-	-
3b.2.5	Backfill	-	8,465	-	-	-	-	-	1,270	9,735	-	-	9,735	-	-	-	-	-	-	9,327	-
3b.2	Subtotal Period 3b Additional Costs	-	13,012	-	-	-	-	991	2,100	16,103	-	-	16,103	-	-	-	-	-	-	33,110	-
Period 3b Collateral Costs																					
3b.3.1	Small tool allowance	-	172	-	-	-	-	-	26	198	-	-	198	-	-	-	-	-	-	-	-
3b.3.2	Spent Fuel Capital and Transfer	-	-	-	-	-	-	1,088	163	1,252	-	1,252	-	-	-	-	-	-	-	-	-
3b.3.3	Prairie Island Indian Community Payments	-	-	-	-	-	-	2,651	-	2,651	-	2,651	-	-	-	-	-	-	-	-	-
3b.3	Subtotal Period 3b Collateral Costs	-	172	-	-	-	-	3,739	189	4,100	-	3,902	198	-	-	-	-	-	-	-	-

Table C-2
Prairie Island Nuclear Generating Plant, Unit 2
DECON Decommissioning Cost Estimate with DOE Pickup of Industry Spent Fuel Starting in 2025
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 3b Period-Dependent Costs																					
3b.4.1	Insurance	-	-	-	-	-	-	542	54	596	-	596	-	-	-	-	-	-	-	-	-
3b.4.2	Property taxes	-	-	-	-	-	-	4,333	433	4,767	-	4,767	-	-	-	-	-	-	-	-	-
3b.4.3	Heavy equipment rental	-	6,670	-	-	-	-	-	1,000	7,670	-	-	7,670	-	-	-	-	-	-	-	-
3b.4.4	Plant energy budget	-	-	-	-	-	-	321	48	369	-	-	369	-	-	-	-	-	-	-	-
3b.4.5	NRC ISFSI Fees	-	-	-	-	-	-	236	24	259	-	259	-	-	-	-	-	-	-	-	-
3b.4.6	Emergency Planning Fees	-	-	-	-	-	-	145	14	159	-	159	-	-	-	-	-	-	-	-	-
3b.4.7	Fixed Overhead	-	-	-	-	-	-	990	148	1,138	-	-	1,138	-	-	-	-	-	-	-	-
3b.4.8	ISFSI Operating Costs	-	-	-	-	-	-	109	16	126	-	126	-	-	-	-	-	-	-	-	-
3b.4.9	Railroad Track Maintenance	-	-	-	-	-	-	331	50	380	-	-	380	-	-	-	-	-	-	-	-
3b.4.10	Security Staff Cost	-	-	-	-	-	-	4,245	637	4,882	-	4,882	-	-	-	-	-	-	-	-	57,340
3b.4.11	DOC Staff Cost	-	-	-	-	-	-	10,467	1,570	12,038	-	-	12,038	-	-	-	-	-	-	-	116,885
3b.4.12	Utility Staff Cost	-	-	-	-	-	-	4,813	722	5,535	(0)	1,207	4,329	-	-	-	-	-	-	-	74,431
3b.4	Subtotal Period 3b Period-Dependent Costs	-	6,670	-	-	-	-	26,533	4,718	37,920	(0)	11,996	25,924	-	-	-	-	-	-	-	248,656
3b.0	TOTAL PERIOD 3b COST	-	35,017	-	-	-	-	31,341	9,293	75,652	90	15,899	59,663	-	-	-	-	-	-	158,659	249,323
PERIOD 3c - Fuel Storage Operations/Shipping																					
Period 3c Direct Decommissioning Activities																					
Period 3c Collateral Costs																					
3c.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	5,808	871	6,679	-	6,679	-	-	-	-	-	-	-	-	-
3c.3.2	Prairie Island Indian Community Payments	-	-	-	-	-	-	26,863	-	26,863	-	26,863	-	-	-	-	-	-	-	-	-
3c.3	Subtotal Period 3c Collateral Costs	-	-	-	-	-	-	32,671	871	33,543	-	33,543	-	-	-	-	-	-	-	-	-
Period 3c Period-Dependent Costs																					
3c.4.1	Insurance	-	-	-	-	-	-	5,494	549	6,044	-	6,044	-	-	-	-	-	-	-	-	-
3c.4.2	Property taxes	-	-	-	-	-	-	26,564	2,656	29,221	-	29,221	-	-	-	-	-	-	-	-	-
3c.4.4	NRC ISFSI Fees	-	-	-	-	-	-	3,519	352	3,871	-	3,871	-	-	-	-	-	-	-	-	-
3c.4.5	Emergency Planning Fees	-	-	-	-	-	-	1,471	147	1,618	-	1,618	-	-	-	-	-	-	-	-	-
3c.4.6	Fixed Overhead	-	-	-	-	-	-	3,281	492	3,774	-	3,774	-	-	-	-	-	-	-	-	-
3c.4.7	ISFSI Operating Costs	-	-	-	-	-	-	1,110	167	1,277	-	1,277	-	-	-	-	-	-	-	-	-
3c.4.8	Railroad Track Maintenance	-	-	-	-	-	-	1,240	186	1,426	-	1,426	-	-	-	-	-	-	-	-	-
3c.4.9	Security Staff Cost	-	-	-	-	-	-	43,057	6,459	49,516	-	49,516	-	-	-	-	-	-	-	-	581,545
3c.4.10	Utility Staff Cost	-	-	-	-	-	-	10,635	1,595	12,230	-	12,230	-	-	-	-	-	-	-	-	150,978
3c.4	Subtotal Period 3c Period-Dependent Costs	-	-	-	-	-	-	96,373	12,603	108,976	-	108,976	-	-	-	-	-	-	-	-	732,523
3c.0	TOTAL PERIOD 3c COST	-	-	-	-	-	-	129,044	13,475	142,519	-	142,519	-	-	-	-	-	-	-	-	732,523
PERIOD 3d - GTCC shipping																					
Period 3d Direct Decommissioning Activities																					
Nuclear Steam Supply System Removal																					
3d.1.1.1	Vessel & Internals GTCC Disposal	-	-	1,331	-	-	8,689	-	1,636	11,656	11,656	-	-	-	-	-	-	-	3,746	837,596	-	-
3d.1.1	Totals	-	-	1,331	-	-	8,689	-	1,636	11,656	11,656	-	-	-	-	-	-	-	3,746	837,596	-	-
3d.1	Subtotal Period 3d Activity Costs	-	-	1,331	-	-	8,689	-	1,636	11,656	11,656	-	-	-	-	-	-	-	3,746	837,596	-	-
Period 3d Collateral Costs																					
3d.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	12	2	14	-	14	-	-	-	-	-	-	-	-	-	-
3d.3.2	Prairie Island Indian Community Payments	-	-	-	-	-	-	48	-	48	-	48	-	-	-	-	-	-	-	-	-	-
3d.3	Subtotal Period 3d Collateral Costs	-	-	-	-	-	-	60	2	62	-	62	-	-	-	-	-	-	-	-	-	-
Period 3d Period-Dependent Costs																					
3d.4.1	Insurance	-	-	-	-	-	-	10	1	11	11	-	-	-	-	-	-	-	-	-	-	-
3d.4.2	Property taxes	-	-	-	-	-	-	39	4	43	43	-	-	-	-	-	-	-	-	-	-	-
3d.4.4	NRC ISFSI Fees	-	-	-	-	-	-	4	0	5	-	5	-	-	-	-	-	-	-	-	-	-
3d.4.5	Emergency Planning Fees	-	-	-	-	-	-	3	0	3	-	3	-	-	-	-	-	-	-	-	-	-
3d.4.6	Fixed Overhead	-	-	-	-	-	-	6	1	7	7	-	-	-	-	-	-	-	-	-	-	-
3d.4.7	ISFSI Operating Costs	-	-	-	-	-	-	2	0	2	-	2	-	-	-	-	-	-	-	-	-	-
3d.4.8	Railroad Track Maintenance	-	-	-	-	-	-	2	0	3	3	-	-	-	-	-	-	-	-	-	-	-
3d.4.9	Security Staff Cost	-	-	-	-	-	-	77	12	88	88	-	-	-	-	-	-	-	-	-	-	1,037
3d.4.10	Utility Staff Cost	-	-	-	-	-	-	19	3	22	22	-	-	-	-	-	-	-	-	-	-	269
3d.4	Subtotal Period 3d Period-Dependent Costs	-	-	-	-	-	-	162	21	183	173	10	-	-	-	-	-	-	-	-	-	1,306
3d.0	TOTAL PERIOD 3d COST	-	-	1,331	-	-	8,689	222	1,659	11,901	11,829	72	-	-	-	-	-	-	3,746	837,596	-	1,306

Table C-2
Prairie Island Nuclear Generating Plant, Unit 2
DECON Decommissioning Cost Estimate with DOE Pickup of Industry Spent Fuel Starting in 2025
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
PERIOD 3e - ISFSI Decontamination																					
Period 3e Direct Decommissioning Activities																					
Period 3e Additional Costs																					
3e.2.1	License Termination ISFSI	-	37	2	211	-	2,157	682	772	3,861	3,861	-	-	-	7,458	-	-	-	1,071,985	3,403	888
3e.2	Subtotal Period 3e Additional Costs	-	37	2	211	-	2,157	682	772	3,861	3,861	-	-	-	7,458	-	-	-	1,071,985	3,403	888
Period 3e Period-Dependent Costs																					
3e.4.1	Insurance	-	-	-	-	-	-	96	24	121	121	-	-	-	-	-	-	-	-	-	-
3e.4.2	Property taxes	-	-	-	-	-	-	26	6	32	32	-	-	-	-	-	-	-	-	-	-
3e.4.4	Fixed Overhead	-	-	-	-	-	-	51	13	63	63	-	-	-	-	-	-	-	-	-	-
3e.4.5	Railroad Track Maintenance	-	-	-	-	-	-	19	5	24	24	-	-	-	-	-	-	-	-	-	-
3e.4.6	Security Staff Cost	-	-	-	-	-	-	154	38	192	192	-	-	-	-	-	-	-	-	-	2,500
3e.4.7	Utility Staff Cost	-	-	-	-	-	-	130	33	163	163	-	-	-	-	-	-	-	-	-	1,896
3e.4	Subtotal Period 3e Period-Dependent Costs	-	-	-	-	-	-	476	119	595	595	-	-	-	-	-	-	-	-	-	4,396
3e.0	TOTAL PERIOD 3e COST	-	37	2	211	-	2,157	1,158	891	4,456	4,456	-	-	-	7,458	-	-	-	1,071,985	3,403	5,284
PERIOD 3f - ISFSI Site Restoration																					
Period 3f Direct Decommissioning Activities																					
Period 3f Additional Costs																					
3f.2.1	Demolition and Site Restoration of ISFSI	-	399	-	-	-	-	87	73	558	-	-	558	-	-	-	-	-	-	1,900	160
3f.2	Subtotal Period 3f Additional Costs	-	399	-	-	-	-	87	73	558	-	-	558	-	-	-	-	-	-	1,900	160
Period 3f Collateral Costs																					
3f.3.1	Small tool allowance	-	3	-	-	-	-	-	0	3	-	-	3	-	-	-	-	-	-	-	-
3f.3	Subtotal Period 3f Collateral Costs	-	3	-	-	-	-	-	0	3	-	-	3	-	-	-	-	-	-	-	-
Period 3f Period-Dependent Costs																					
3f.4.2	Property taxes	-	-	-	-	-	-	13	1	14	-	-	14	-	-	-	-	-	-	-	-
3f.4.3	Heavy equipment rental	-	62	-	-	-	-	-	9	71	-	-	71	-	-	-	-	-	-	-	-
3f.4.4	Plant energy budget	-	-	-	-	-	-	13	2	15	-	-	15	-	-	-	-	-	-	-	-
3f.4.5	Fixed Overhead	-	-	-	-	-	-	25	4	29	-	-	29	-	-	-	-	-	-	-	-
3f.4.6	Railroad Track Maintenance	-	-	-	-	-	-	10	1	11	-	-	11	-	-	-	-	-	-	-	-
3f.4.7	Security Staff Cost	-	-	-	-	-	-	78	12	89	-	-	89	-	-	-	-	-	-	-	1,260
3f.4.8	Utility Staff Cost	-	-	-	-	-	-	52	8	60	-	-	60	-	-	-	-	-	-	-	782
3f.4	Subtotal Period 3f Period-Dependent Costs	-	62	-	-	-	-	190	37	289	-	-	289	-	-	-	-	-	-	-	2,042
3f.0	TOTAL PERIOD 3f COST	-	463	-	-	-	-	277	110	851	-	-	851	-	-	-	-	-	-	1,900	2,202
PERIOD 3 TOTALS		-	35,517	1,333	211	-	10,846	162,042	25,429	235,377	16,375	158,489	60,514	-	7,458	-	-	3,746	1,909,581	163,962	990,638
TOTAL COST TO DECOMMISSION		**13,408**	**104,627**	**31,018**	**7,562**	**13,927**	**53,014**	**544,382**	**131,890**	**899,828**	**561,832**	**271,262**	**66,733**	**169,551**	**150,948**	**839**	**673**	**3,746**	**17,608,520**	**1,022,448**	**3,748,471**

TOTAL COST TO DECOMMISSION WITH 17.17% CONTINGENCY:	**$899,828**	**thousands of 2017 dollars**
TOTAL NRC LICENSE TERMINATION COST IS 62.44% OR:	**$561,832**	**thousands of 2017 dollars**
SPENT FUEL MANAGEMENT COST IS 30.15% OR:	**$271,262**	**thousands of 2017 dollars**
NON-NUCLEAR DEMOLITION COST IS 7.42% OR:	**$66,733**	**thousands of 2017 dollars**
TOTAL LOW-LEVEL RADIOACTIVE WASTE VOLUME BURIED (EXCLUDING GTCC):	**152,460**	**cubic feet**
TOTAL GREATER THAN CLASS C RADWASTE VOLUME GENERATED:	**3,746**	**cubic feet**
TOTAL SCRAP METAL REMOVED:	**41,515**	**tons**
TOTAL CRAFT LABOR REQUIREMENTS:	**1,022,448**	**man-hours**

End Notes:
n/a - indicates that this activity not charged as decommissioning expense
a - indicates that this activity performed by decommissioning staff
0 - indicates that this value is less than 0.5 but is non-zero
A cell containing " - " indicates a zero value

APPENDIX D

DETAILED COST ANALYSIS

SCENARIO 2: DECON with 60 Year DFS

Page

Prairie Island Nuclear Generating Plant, Unit 1 .....D-2

Prairie Island Nuclear Generating Plant, Unit 2 .....D-10

Table D-1
Prairie Island Nuclear Generating Plant, Unit 1
DECON Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
PERIOD 1a - Shutdown through Transition																					
Period 1a Direct Decommissioning Activities																					
1a.1.1	Prepare preliminary decommissioning cost	-	-	-	-	-	-	153	23	175	175	-	-	-	-	-	-	-	-	-	1,300
1a.1.2	Notification of Cessation of Operations									a											
1a.1.3	Remove fuel & source material									n/a											
1a.1.4	Notification of Permanent Defueling									a											
1a.1.5	Deactivate plant systems & process waste									a											
1a.1.6	Prepare and submit PSDAR	-	-	-	-	-	-	235	35	270	270	-	-	-	-	-	-	-	-	-	2,000
1a.1.7	Review plant dwgs & specs.	-	-	-	-	-	-	540	81	621	621	-	-	-	-	-	-	-	-	-	4,600
1a.1.8	Perform detailed rad survey									a											
1a.1.9	Estimate by-product inventory	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1a.1.10	End product description	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1a.1.11	Detailed by-product inventory	-	-	-	-	-	-	153	23	175	175	-	-	-	-	-	-	-	-	-	1,300
1a.1.12	Define major work sequence	-	-	-	-	-	-	880	132	1,012	1,012	-	-	-	-	-	-	-	-	-	7,500
1a.1.13	Perform SER and EA	-	-	-	-	-	-	364	55	418	418	-	-	-	-	-	-	-	-	-	3,100
1a.1.14	Prepare/submit Defueled Technical Specifications	-	-	-	-	-	-	880	132	1,012	1,012	-	-	-	-	-	-	-	-	-	7,500
1a.1.15	Perform Site-Specific Cost Study	-	-	-	-	-	-	587	88	675	675	-	-	-	-	-	-	-	-	-	5,000
1a.1.16	Prepare/submit Irradiated Fuel Management Plan	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
Activity Specifications																					
1a.1.17.1	Plant & temporary facilities	-	-	-	-	-	-	578	87	664	598	-	66	-	-	-	-	-	-	-	4,920
1a.1.17.2	Plant systems	-	-	-	-	-	-	489	73	562	506	-	56	-	-	-	-	-	-	-	4,167
1a.1.17.3	NSSS Decontamination Flush	-	-	-	-	-	-	59	9	67	67	-	-	-	-	-	-	-	-	-	500
1a.1.17.4	Reactor internals	-	-	-	-	-	-	833	125	958	958	-	-	-	-	-	-	-	-	-	7,100
1a.1.17.5	Reactor vessel	-	-	-	-	-	-	763	114	877	877	-	-	-	-	-	-	-	-	-	6,500
1a.1.17.6	Biological shield	-	-	-	-	-	-	59	9	67	67	-	-	-	-	-	-	-	-	-	500
1a.1.17.7	Steam generators	-	-	-	-	-	-	366	55	421	421	-	-	-	-	-	-	-	-	-	3,120
1a.1.17.8	Reinforced concrete	-	-	-	-	-	-	188	28	216	108	-	108	-	-	-	-	-	-	-	1,600
1a.1.17.9	Main Turbine	-	-	-	-	-	-	47	7	54	-	-	54	-	-	-	-	-	-	-	400
1a.1.17.10	Main Condensers	-	-	-	-	-	-	47	7	54	-	-	54	-	-	-	-	-	-	-	400
1a.1.17.11	Plant structures & buildings	-	-	-	-	-	-	366	55	421	211	-	211	-	-	-	-	-	-	-	3,120
1a.1.17.12	Waste management	-	-	-	-	-	-	540	81	621	621	-	-	-	-	-	-	-	-	-	4,600
1a.1.17.13	Facility & site closeout	-	-	-	-	-	-	106	16	121	61	-	61	-	-	-	-	-	-	-	900
1a.1.17	Total	-	-	-	-	-	-	4,440	666	5,106	4,496	-	610	-	-	-	-	-	-	-	37,827
Planning & Site Preparations																					
1a.1.18	Prepare dismantling sequence	-	-	-	-	-	-	282	42	324	324	-	-	-	-	-	-	-	-	-	2,400
1a.1.19	Plant prep. & temp. svces	-	-	-	-	-	-	3,300	495	3,795	3,795	-	-	-	-	-	-	-	-	-	-
1a.1.20	Design water clean-up system	-	-	-	-	-	-	164	25	189	189	-	-	-	-	-	-	-	-	-	1,400
1a.1.21	Rigging/Cont. Cntrl Envlps/tooling/etc.	-	-	-	-	-	-	2,300	345	2,645	2,645	-	-	-	-	-	-	-	-	-	-
1a.1.22	Procure casks/liners & containers	-	-	-	-	-	-	144	22	166	166	-	-	-	-	-	-	-	-	-	1,230
1a.1	Subtotal Period 1a Activity Costs	-	-	-	-	-	-	14,774	2,216	16,990	16,380	-	610	-	-	-	-	-	-	-	78,157
Period 1a Additional Costs																					
1a.2.1	Spent Fuel Pool Isolation	-	-	-	-	-	-	11,691	1,754	13,445	13,445	-	-	-	-	-	-	-	-	-	-
1a.2	Subtotal Period 1a Additional Costs	-	-	-	-	-	-	11,691	1,754	13,445	13,445	-	-	-	-	-	-	-	-	-	-
Period 1a Collateral Costs																					
1a.3.1	Prairie Island Indian Community Payments	-	-	-	-	-	-	2,003	-	2,003	-	2,003	-	-	-	-	-	-	-	-	-
1a.3	Subtotal Period 1a Collateral Costs	-	-	-	-	-	-	2,003	-	2,003	-	2,003	-	-	-	-	-	-	-	-	-
Period 1a Period-Dependent Costs																					
1a.4.1	Insurance	-	-	-	-	-	-	1,730	173	1,903	1,903	-	-	-	-	-	-	-	-	-	-
1a.4.2	Property taxes	-	-	-	-	-	-	2,682	268	2,950	2,950	-	-	-	-	-	-	-	-	-	-
1a.4.3	Health physics supplies	-	515	-	-	-	-	-	129	644	644	-	-	-	-	-	-	-	-	-	-
1a.4.4	Heavy equipment rental	-	567	-	-	-	-	-	85	652	652	-	-	-	-	-	-	-	-	-	-
1a.4.5	Disposal of DAW generated	-	-	13	4	-	50	-	14	81	81	-	-	-	610	-	-	-	12,190	20	-
1a.4.6	Plant energy budget	-	-	-	-	-	-	1,515	227	1,742	1,742	-	-	-	-	-	-	-	-	-	-
1a.4.7	NRC Fees	-	-	-	-	-	-	1,110	111	1,221	1,221	-	-	-	-	-	-	-	-	-	-
1a.4.8	Emergency Planning Fees	-	-	-	-	-	-	1,604	160	1,765	-	1,765	-	-	-	-	-	-	-	-	-
1a.4.9	Fixed Overhead	-	-	-	-	-	-	1,470	220	1,690	1,690	-	-	-	-	-	-	-	-	-	-
1a.4.10	Spent Fuel Pool O&M	-	-	-	-	-	-	401	60	461	-	461	-	-	-	-	-	-	-	-	-
1a.4.11	ISFSI Operating Costs	-	-	-	-	-	-	52	8	59	-	59	-	-	-	-	-	-	-	-	-
1a.4.12	Railroad Track Maintenance	-	-	-	-	-	-	58	9	66	66	-	-	-	-	-	-	-	-	-	-
1a.4.13	Security Staff Cost	-	-	-	-	-	-	7,390	1,108	8,498	8,498	-	-	-	-	-	-	-	-	-	122,720
1a.4.14	Utility Staff Cost	-	-	-	-	-	-	25,791	3,869	29,660	29,660	-	-	-	-	-	-	-	-	-	422,240
1a.4	Subtotal Period 1a Period-Dependent Costs	-	1,083	13	4	-	50	43,802	6,442	51,394	49,108	2,286	-	-	610	-	-	-	12,190	20	544,960

Table D-1
Prairie Island Nuclear Generating Plant, Unit 1
DECON Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
1a.0	TOTAL PERIOD 1a COST	-	1,083	13	4	-	50	72,271	10,412	83,832	78,933	4,289	610	-	610	-	-	-	12,190	20	623,117
PERIOD 1b - Decommissioning Preparations																					
Period 1b Direct Decommissioning Activities																					
Detailed Work Procedures																					
1b.1.1.1	Plant systems	-	-	-	-	-	-	556	83	639	575	-	64	-	-	-	-	-	-	-	4,733
1b.1.1.2	NSSS Decontamination Flush	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1b.1.1.3	Reactor internals	-	-	-	-	-	-	293	44	337	337	-	-	-	-	-	-	-	-	-	2,500
1b.1.1.4	Remaining buildings	-	-	-	-	-	-	158	24	182	46	-	137	-	-	-	-	-	-	-	1,350
1b.1.1.5	CRD cooling assembly	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1b.1.1.6	CRD housings & ICI tubes	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1b.1.1.7	Incore instrumentation	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1b.1.1.8	Reactor vessel	-	-	-	-	-	-	426	64	490	490	-	-	-	-	-	-	-	-	-	3,630
1b.1.1.9	Facility closeout	-	-	-	-	-	-	141	21	162	81	-	81	-	-	-	-	-	-	-	1,200
1b.1.1.10	Missile shields	-	-	-	-	-	-	53	8	61	61	-	-	-	-	-	-	-	-	-	450
1b.1.1.11	Biological shield	-	-	-	-	-	-	141	21	162	162	-	-	-	-	-	-	-	-	-	1,200
1b.1.1.12	Steam generators	-	-	-	-	-	-	540	81	621	621	-	-	-	-	-	-	-	-	-	4,600
1b.1.1.13	Reinforced concrete	-	-	-	-	-	-	117	18	135	67	-	67	-	-	-	-	-	-	-	1,000
1b.1.1.14	Main Turbine	-	-	-	-	-	-	183	27	211	-	-	211	-	-	-	-	-	-	-	1,560
1b.1.1.15	Main Condensers	-	-	-	-	-	-	183	27	211	-	-	211	-	-	-	-	-	-	-	1,560
1b.1.1.16	Auxiliary building	-	-	-	-	-	-	320	48	369	332	-	37	-	-	-	-	-	-	-	2,730
1b.1.1.17	Reactor building	-	-	-	-	-	-	320	48	369	332	-	37	-	-	-	-	-	-	-	2,730
1b.1.1	Total	-	-	-	-	-	-	3,902	585	4,487	3,643	-	844	-	-	-	-	-	-	-	33,243
1b.1.2	Decon primary loop	552	-	-	-	-	-	-	276	828	828	-	-	-	-	-	-	-	-	1,067	-
1b.1	Subtotal Period 1b Activity Costs	552	-	-	-	-	-	3,902	861	5,315	4,471	-	844	-	-	-	-	-	-	1,067	33,243
Period 1b Additional Costs																					
1b.2.1	Site Characterization	-	-	-	-	-	-	3,700	1,110	4,810	4,810	-	-	-	-	-	-	-	-	21,020	8,332
1b.2.2	Mixed/Hazardous Waste	-	-	318	75	164	-	-	68	624	624	-	-	6,133	-	-	-	-	351,986	2,361	-
1b.2.3	Asbestos Abatement	-	2,364	2	110	-	1,359	-	947	4,782	4,782	-	-	-	12,843	-	-	-	166,959	20,907	-
1b.2	Subtotal Period 1b Additional Costs	-	2,364	320	185	164	1,359	3,700	2,125	10,216	10,216	-	-	6,133	12,843	-	-	-	518,945	44,288	8,332
Period 1b Collateral Costs																					
1b.3.1	Decon equipment	973	-	-	-	-	-	-	146	1,119	1,119	-	-	-	-	-	-	-	-	-	-
1b.3.2	DOC staff relocation expenses	-	-	-	-	-	-	1,189	178	1,367	1,367	-	-	-	-	-	-	-	-	-	-
1b.3.3	Process decommissioning water waste	24	-	16	41	-	64	-	36	180	180	-	-	-	152	-	-	-	9,121	30	-
1b.3.4	Process decommissioning chemical flush waste	2	-	58	220	-	2,471	-	657	3,408	3,408	-	-	-	-	588	-	-	62,689	110	-
1b.3.5	Small tool allowance	-	34	-	-	-	-	-	5	39	39	-	-	-	-	-	-	-	-	-	-
1b.3.6	Pipe cutting equipment	-	1,200	-	-	-	-	-	180	1,380	1,380	-	-	-	-	-	-	-	-	-	-
1b.3.7	Decon rig	1,987	-	-	-	-	-	-	298	2,285	2,285	-	-	-	-	-	-	-	-	-	-
1b.3.8	Spent Fuel Capital and Transfer	-	-	-	-	-	-	159	24	183	-	183	-	-	-	-	-	-	-	-	-
1b.3.9	Retention and Severance	-	-	-	-	-	-	1,088	163	1,251	1,251	-	-	-	-	-	-	-	-	-	-
1b.3.10	Prairie Island Indian Community Payments	-	-	-	-	-	-	630	-	630	-	630	-	-	-	-	-	-	-	-	-
1b.3	Subtotal Period 1b Collateral Costs	2,986	1,234	74	261	-	2,534	3,065	1,687	11,841	11,028	813	-	-	152	588	-	-	71,810	140	-
Period 1b Period-Dependent Costs																					
1b.4.1	Decon supplies	35	-	-	-	-	-	-	9	44	44	-	-	-	-	-	-	-	-	-	-
1b.4.2	Insurance	-	-	-	-	-	-	872	87	959	959	-	-	-	-	-	-	-	-	-	-
1b.4.3	Property taxes	-	-	-	-	-	-	1,352	135	1,487	1,487	-	-	-	-	-	-	-	-	-	-
1b.4.4	Health physics supplies	-	402	-	-	-	-	-	101	503	503	-	-	-	-	-	-	-	-	-	-
1b.4.5	Heavy equipment rental	-	286	-	-	-	-	-	43	329	329	-	-	-	-	-	-	-	-	-	-
1b.4.6	Disposal of DAW generated	-	-	8	2	-	29	-	8	48	48	-	-	-	360	-	-	-	7,197	12	-
1b.4.7	Plant energy budget	-	-	-	-	-	-	1,527	229	1,756	1,756	-	-	-	-	-	-	-	-	-	-
1b.4.8	NRC Fees	-	-	-	-	-	-	323	32	355	355	-	-	-	-	-	-	-	-	-	-
1b.4.9	Emergency Planning Fees	-	-	-	-	-	-	809	81	890	-	890	-	-	-	-	-	-	-	-	-
1b.4.10	Fixed Overhead	-	-	-	-	-	-	741	111	852	852	-	-	-	-	-	-	-	-	-	-
1b.4.11	Spent Fuel Pool O&M	-	-	-	-	-	-	202	30	233	-	233	-	-	-	-	-	-	-	-	-
1b.4.12	ISFSI Operating Costs	-	-	-	-	-	-	26	4	30	-	30	-	-	-	-	-	-	-	-	-
1b.4.13	Railroad Track Maintenance	-	-	-	-	-	-	29	4	33	33	-	-	-	-	-	-	-	-	-	-
1b.4.14	Security Staff Cost	-	-	-	-	-	-	3,725	559	4,284	4,284	-	-	-	-	-	-	-	-	-	61,864
1b.4.15	DOC Staff Cost	-	-	-	-	-	-	5,656	848	6,504	6,504	-	-	-	-	-	-	-	-	-	63,961
1b.4.16	Utility Staff Cost	-	-	-	-	-	-	13,074	1,961	15,035	15,035	-	-	-	-	-	-	-	-	-	213,904
1b.4	Subtotal Period 1b Period-Dependent Costs	35	688	8	2	-	29	28,336	4,243	33,341	32,189	1,152	-	-	360	-	-	-	7,197	12	339,730
1b.0	TOTAL PERIOD 1b COST	3,573	4,286	402	447	164	3,923	39,002	8,917	60,713	57,904	1,965	844	6,133	13,355	588	-	-	597,952	45,506	381,305

Table D-1
Prairie Island Nuclear Generating Plant, Unit 1
DECON Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
PERIOD 1 TOTALS		3,573	5,368	415	451	164	3,972	111,274	19,329	144,546	136,838	6,254	1,454	6,133	13,964	588	-	-	610,142	45,526	1,004,421
PERIOD 2a - Large Component Removal																					
Period 2a Direct Decommissioning Activities																					
Nuclear Steam Supply System Removal																					
2a.1.1.1	Reactor Coolant Piping	51	45	6	8	-	150	-	76	336	336	-	-	-	305	-	-	-	34,809	1,414	-
2a.1.1.2	Pressurizer Relief Tank	22	20	4	5	-	100	-	42	193	193	-	-	-	203	-	-	-	23,193	625	-
2a.1.1.3	Reactor Coolant Pumps & Motors	54	63	101	83	-	736	-	249	1,287	1,287	-	-	-	2,332	-	-	-	295,800	2,049	100
2a.1.1.4	Pressurizer	48	68	467	88	-	693	-	274	1,639	1,639	-	-	-	2,196	-	-	-	185,015	2,355	938
2a.1.1.5	Steam Generators	225	2,943	2,093	1,638	1,246	3,570	-	2,383	14,097	14,097	-	-	18,672	11,316	-	-	-	1,668,341	14,819	2,875
2a.1.1.6	CRDMs/ICIs/Service Structure Removal	286	277	211	48	-	763	-	431	2,016	2,016	-	-	-	4,797	-	-	-	177,400	8,104	-
2a.1.1.7	Reactor Vessel Internals	78	4,468	21,874	1,072	-	7,946	277	13,141	48,856	48,856	-	-	-	501	125	673	-	164,987	23,040	1,080
2a.1.1.8	Reactor Vessel	89	5,717	1,754	719	-	1,956	277	5,970	16,483	16,483	-	-	-	5,690	-	-	-	570,074	23,040	1,080
2a.1.1	Totals	855	13,600	26,512	3,662	1,246	15,913	553	22,568	84,908	84,908	-	-	18,672	27,341	125	673	-	3,119,620	75,446	6,073
Removal of Major Equipment																					
2a.1.2	Main Turbine/Generator	-	305	189	55	272	306	-	221	1,348	1,348	-	-	2,131	1,187	-	-	-	206,316	4,667	-
2a.1.3	Main Condensers	-	2,532	121	49	364	451	-	820	4,336	4,336	-	-	3,800	1,587	-	-	-	275,903	39,151	-
Cascading Costs from Clean Building Demolition																					
2a.1.4.1	Reactor	-	728	-	-	-	-	-	109	837	837	-	-	-	-	-	-	-	-	7,589	-
2a.1.4	Totals	-	728	-	-	-	-	-	109	837	837	-	-	-	-	-	-	-	-	7,589	-
Disposal of Plant Systems																					
2a.1.5.1	Air Removal	-	27	-	-	-	-	-	4	31	-	-	31	-	-	-	-	-	-	452	-
2a.1.5.2	Auxiliary Feedwater	-	40	-	-	-	-	-	6	46	-	-	46	-	-	-	-	-	-	670	-
2a.1.5.3	Auxiliary Feedwater - RCA	-	45	0	1	19	-	-	14	79	79	-	-	215	-	-	-	-	8,722	601	-
2a.1.5.4	Bleed Steam	-	78	-	-	-	-	-	12	90	-	-	90	-	-	-	-	-	-	1,335	-
2a.1.5.5	Caustic Addition - RCA	-	36	0	1	20	-	-	12	71	71	-	-	233	-	-	-	-	9,453	444	-
2a.1.5.6	Chemical Feed	-	17	-	-	-	-	-	3	20	-	-	20	-	-	-	-	-	-	304	-
2a.1.5.7	Chemical Feed - RCA	-	1	0	0	1	-	-	0	2	2	-	-	6	-	-	-	-	243	12	-
2a.1.5.8	Circulating Water	-	37	-	-	-	-	-	6	42	-	-	42	-	-	-	-	-	-	619	-
2a.1.5.9	Condensate	-	414	-	-	-	-	-	62	476	-	-	476	-	-	-	-	-	-	6,837	-
2a.1.5.10	Condensate Polishing	-	205	-	-	-	-	-	31	236	-	-	236	-	-	-	-	-	-	3,420	-
2a.1.5.11	Condensate Polishing - RCA	-	176	4	12	180	-	-	73	444	444	-	-	2,078	-	-	-	-	84,395	2,329	-
2a.1.5.12	Electro-hydraulic	-	8	-	-	-	-	-	1	9	-	-	9	-	-	-	-	-	-	127	-
2a.1.5.13	Feedwater	-	133	-	-	-	-	-	20	153	-	-	153	-	-	-	-	-	-	2,215	-
2a.1.5.14	Feedwater - RCA	-	186	6	19	278	-	-	91	579	579	-	-	3,208	-	-	-	-	130,294	2,651	-
2a.1.5.15	Gland Seal	-	29	-	-	-	-	-	4	34	-	-	34	-	-	-	-	-	-	505	-
2a.1.5.16	Heater Drain	-	349	-	-	-	-	-	52	401	-	-	401	-	-	-	-	-	-	5,881	-
2a.1.5.17	Internal Circ Water & CDSR	-	23	-	-	-	-	-	3	27	-	-	27	-	-	-	-	-	-	389	-
2a.1.5.18	Main Gen/Exciter/Transformer	-	0	-	-	-	-	-	0	0	-	-	0	-	-	-	-	-	-	5	-
2a.1.5.19	Main Steam	-	101	-	-	-	-	-	15	116	-	-	116	-	-	-	-	-	-	1,690	-
2a.1.5.20	Main Steam - RCA	-	350	9	29	436	-	-	158	983	983	-	-	5,044	-	-	-	-	204,825	4,956	-
2a.1.5.21	Steam Generator Blowdown	-	459	21	22	176	195	-	195	1,067	1,067	-	-	2,031	686	-	-	-	127,773	6,667	-
2a.1.5.22	Steam Generators	-	5	-	-	-	-	-	1	5	-	-	5	-	-	-	-	-	-	75	-
2a.1.5.23	Turbine & Moisture Separators	-	337	-	-	-	-	-	51	388	-	-	388	-	-	-	-	-	-	5,609	-
2a.1.5.24	Turbine Oil Purification	-	61	-	-	-	-	-	9	71	-	-	71	-	-	-	-	-	-	1,003	-
2a.1.5	Totals	-	3,117	40	85	1,108	195	-	825	5,370	3,226	-	2,145	12,815	686	-	-	-	565,705	48,794	-
2a.1.6	Scaffolding in support of decommissioning	-	854	3	1	13	3	-	217	1,092	1,092	-	-	138	12	-	-	-	7,016	6,368	-
2a.1	Subtotal Period 2a Activity Costs	855	21,136	26,865	3,852	3,004	16,868	553	24,759	97,891	95,747	-	2,145	37,556	30,812	125	673	-	4,174,560	182,015	6,073
Period 2a Additional Costs																					
2a.2.1	Remedial Action Surveys	-	-	-	-	-	-	2,126	638	2,764	2,764	-	-	-	-	-	-	-	-	27,791	-
2a.2.2	Retired RPV upper internals package	1	659	785	107	-	1,439	-	1,437	4,427	4,427	-	-	-	2,097	125	-	-	205,890	2,175	87
2a.2	Subtotal Period 2a Additional Costs	1	659	785	107	-	1,439	2,126	2,075	7,191	7,191	-	-	-	2,097	125	-	-	205,890	29,966	87
Period 2a Collateral Costs																					
2a.3.1	Process decommissioning water waste	47	-	31	81	-	126	-	70	356	356	-	-	-	302	-	-	-	18,119	59	-
2a.3.3	Small tool allowance	-	223	-	-	-	-	-	33	257	231	-	26	-	-	-	-	-	-	-	-
2a.3.4	Spent Fuel Capital and Transfer	-	-	-	-	-	-	1,476	221	1,698	-	1,698	-	-	-	-	-	-	-	-	-
2a.3.5	Retention and Severance	-	-	-	-	-	-	12,156	1,823	13,980	13,980	-	-	-	-	-	-	-	-	-	-
2a.3.6	Prairie Island Indian Community Payments	-	-	-	-	-	-	1,670	-	1,670	-	1,670	-	-	-	-	-	-	-	-	-
2a.3	Subtotal Period 2a Collateral Costs	47	223	31	81	-	126	15,302	2,149	17,960	14,567	3,367	26	-	302	-	-	-	18,119	59	-

Table D-1
Prairie Island Nuclear Generating Plant, Unit 1
DECON Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 2a Period-Dependent Costs																					
2a.4.1	Decon supplies	93	-	-	-	-	-	-	23	116	116	-	-	-	-	-	-	-	-	-	-
2a.4.2	Insurance	-	-	-	-	-	-	683	68	751	751	-	-	-	-	-	-	-	-	-	-
2a.4.3	Property taxes	-	-	-	-	-	-	3,542	354	3,896	3,896	-	-	-	-	-	-	-	-	-	-
2a.4.4	Health physics supplies	-	1,717	-	-	-	-	-	429	2,146	2,146	-	-	-	-	-	-	-	-	-	-
2a.4.5	Heavy equipment rental	-	2,935	-	-	-	-	-	440	3,376	3,376	-	-	-	-	-	-	-	-	-	-
2a.4.6	Disposal of DAW generated	-	-	79	23	-	295	-	85	482	482	-	-	-	3,623	-	-	-	72,452	118	-
2a.4.7	Plant energy budget	-	-	-	-	-	-	1,924	289	2,212	2,212	-	-	-	-	-	-	-	-	-	-
2a.4.8	NRC Fees	-	-	-	-	-	-	774	77	851	851	-	-	-	-	-	-	-	-	-	-
2a.4.9	Emergency Planning Fees	-	-	-	-	-	-	1,717	172	1,888	-	1,888	-	-	-	-	-	-	-	-	-
2a.4.10	Fixed Overhead	-	-	-	-	-	-	1,655	248	1,904	1,904	-	-	-	-	-	-	-	-	-	-
2a.4.11	Spent Fuel Pool O&M	-	-	-	-	-	-	537	80	617	-	617	-	-	-	-	-	-	-	-	-
2a.4.12	ISFSI Operating Costs	-	-	-	-	-	-	69	10	79	-	79	-	-	-	-	-	-	-	-	-
2a.4.13	Railroad Track Maintenance	-	-	-	-	-	-	286	43	328	328	-	-	-	-	-	-	-	-	-	-
2a.4.14	Security Staff Cost	-	-	-	-	-	-	9,811	1,472	11,283	11,283	-	-	-	-	-	-	-	-	-	162,878
2a.4.15	DOC Staff Cost	-	-	-	-	-	-	18,392	2,759	21,150	21,150	-	-	-	-	-	-	-	-	-	211,351
2a.4.16	Utility Staff Cost	-	-	-	-	-	-	24,265	3,640	27,904	27,904	-	-	-	-	-	-	-	-	-	392,305
2a.4	Subtotal Period 2a Period-Dependent Costs	93	4,652	79	23	-	295	63,653	10,190	78,986	76,401	2,585	-	-	3,623	-	-	-	72,452	118	766,534
2a.0	TOTAL PERIOD 2a COST	995	26,670	27,760	4,062	3,004	18,729	81,635	39,172	202,027	193,905	5,952	2,170	37,556	36,834	250	673	-	4,471,020	212,158	772,694
PERIOD 2b - Site Decontamination																					
Period 2b Direct Decommissioning Activities																					
Disposal of Plant Systems																					
2b.1.1.1	Aux Bldg Normal Ventilation	-	2	0	0	0	-	-	1	3	3	-	-	3	-	-	-	-	140	29	-
2b.1.1.2	Battery Rm Special Ventilation	-	0	-	-	-	-	-	0	0	-	-	0	-	-	-	-	-	-	6	-
2b.1.1.3	Buildings Maintenance	-	4	-	-	-	-	-	1	5	-	-	5	-	-	-	-	-	-	65	-
2b.1.1.4	Chemical & Volume Control	1,077	1,331	83	69	389	802	-	1,149	4,901	4,901	-	-	4,498	2,846	-	-	-	369,246	34,533	-
2b.1.1.5	Component Cooling - RCA	-	821	22	72	1,075	-	-	379	2,369	2,369	-	-	12,427	-	-	-	-	504,675	11,242	-
2b.1.1.6	Containment Cooling	-	65	-	-	-	-	-	10	74	-	-	74	-	-	-	-	-	-	1,086	-
2b.1.1.7	Containment Cooling - RCA	-	290	6	20	294	-	-	120	730	730	-	-	3,400	-	-	-	-	138,090	3,971	-
2b.1.1.8	Containment Hydrogen Control - RCA	-	29	0	1	9	-	-	9	48	48	-	-	105	-	-	-	-	4,278	401	-
2b.1.1.9	Containment Spray - RCA	-	90	2	5	75	-	-	35	206	206	-	-	868	-	-	-	-	35,249	1,217	-
2b.1.1.10	Containment Ventilation	-	243	24	40	428	209	-	186	1,130	1,130	-	-	4,951	737	-	-	-	249,786	3,668	-
2b.1.1.11	Cooling Water	-	142	-	-	-	-	-	21	163	-	-	163	-	-	-	-	-	-	2,396	-
2b.1.1.12	Cooling Water - RCA	-	629	14	45	668	-	-	266	1,622	1,622	-	-	7,728	-	-	-	-	313,832	8,594	-
2b.1.1.13	D1 Emergency Diesel	-	44	-	-	-	-	-	7	50	-	-	50	-	-	-	-	-	-	730	-
2b.1.1.14	D2 Emergency Diesel	-	31	-	-	-	-	-	5	36	-	-	36	-	-	-	-	-	-	522	-
2b.1.1.15	Diesel Rooms Ventilation	-	8	-	-	-	-	-	1	10	-	-	10	-	-	-	-	-	-	135	-
2b.1.1.16	Electrical - Clean	-	1,669	-	-	-	-	-	250	1,919	-	-	1,919	-	-	-	-	-	-	26,981	-
2b.1.1.17	Electrical - Contaminated	-	592	6	16	219	27	-	191	1,051	1,051	-	-	2,527	95	-	-	-	108,935	8,377	-
2b.1.1.18	Electrical - Decontaminated	-	3,674	41	137	2,037	-	-	1,249	7,138	7,138	-	-	23,551	-	-	-	-	956,401	49,378	-
2b.1.1.19	Fuel Handling	-	116	6	9	79	62	-	58	329	329	-	-	908	218	-	-	-	51,280	1,784	-
2b.1.1.20	Fuel Oil	-	106	-	-	-	-	-	16	122	-	-	122	-	-	-	-	-	-	1,697	-
2b.1.1.21	HVAC - Clean	-	105	-	-	-	-	-	16	121	-	-	121	-	-	-	-	-	-	1,891	-
2b.1.1.22	HVAC - Contaminated	-	371	8	21	282	35	-	148	864	864	-	-	3,261	123	-	-	-	140,573	5,032	-
2b.1.1.23	Incore Instrumentation	0	27	1	1	5	16	-	12	64	64	-	-	60	57	-	-	-	6,177	425	-
2b.1.1.24	Misc Drains & Vents	-	222	14	10	34	146	-	100	527	527	-	-	390	514	-	-	-	49,900	3,091	-
2b.1.1.25	Reactor Coolant	148	298	21	14	30	221	-	213	945	945	-	-	344	777	-	-	-	65,413	6,470	-
2b.1.1.26	Reactor Hot Sampling	144	131	11	6	6	98	-	132	527	527	-	-	66	342	-	-	-	25,347	3,946	-
2b.1.1.27	Reactor Makeup	-	64	-	-	-	-	-	10	73	-	-	73	-	-	-	-	-	-	1,042	-
2b.1.1.28	Reactor Vessel	9	20	1	0	2	4	-	11	47	47	-	-	26	14	-	-	-	2,011	425	-
2b.1.1.29	Residual Heat Removal	344	399	85	66	250	926	-	559	2,630	2,630	-	-	2,895	3,252	-	-	-	332,849	7,621	-
2b.1.1.30	Safeguards Chilled Water	-	15	-	-	-	-	-	2	18	-	-	18	-	-	-	-	-	-	259	-
2b.1.1.31	Safety Injection	-	853	40	57	587	327	-	396	2,261	2,261	-	-	6,788	1,156	-	-	-	351,793	12,561	-
2b.1.1.32	Sampling	-	58	4	2	5	31	-	23	122	122	-	-	59	107	-	-	-	9,505	811	-
2b.1.1.33	Shield Bldg Ventilation	-	133	14	20	186	139	-	100	593	593	-	-	2,152	491	-	-	-	119,838	2,030	-
2b.1.1.34	Station & Instrument Air	-	17	-	-	-	-	-	3	20	-	-	20	-	-	-	-	-	-	300	-
2b.1.1.35	Station & Instrument Air - RCA	-	79	1	2	29	-	-	24	135	135	-	-	332	-	-	-	-	13,496	1,053	-
2b.1.1.36	Turbine Bldg Traps & Drains	-	44	-	-	-	-	-	7	50	-	-	50	-	-	-	-	-	-	767	-
2b.1.1.37	Unit Coolers	-	37	-	-	-	-	-	6	42	-	-	42	-	-	-	-	-	-	611	-
2b.1.1.38	Unit Coolers - RCA	-	53	0	1	20	-	-	16	91	91	-	-	230	-	-	-	-	9,348	683	-
2b.1.1	Totals	1,724	12,813	403	614	6,710	3,044	-	5,730	31,037	28,333	-	2,704	77,571	10,728	-	-	-	3,858,165	205,829	-
2b.1.2	Scaffolding in support of decommissioning	-	1,067	4	1	17	4	-	271	1,364	1,364	-	-	173	15	-	-	-	8,770	7,960	-

Table D-1
Prairie Island Nuclear Generating Plant, Unit 1
DECON Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Decontamination of Site Buildings																					
2b.1.3.1	Reactor	1,150	2,623	139	852	193	11,079	-	4,171	20,208	20,208	-	-	2,230	57,414	-	-	-	3,559,624	50,842	-
2b.1.3.2	Backwash Waste Receiving Tank	-	27	1	11	-	87	-	30	158	158	-	-	-	507	-	-	-	43,896	299	-
2b.1.3	Totals	1,150	2,650	141	864	193	11,166	-	4,202	20,366	20,366	-	-	2,230	57,921	-	-	-	3,603,520	51,140	-
2b.1.4	Prepare/submit License Termination Plan	-	-	-	-	-	-	481	72	553	553	-	-	-	-	-	-	-	-	-	4,096
2b.1.5	Receive NRC approval of termination plan									a											
2b.1	Subtotal Period 2b Activity Costs	2,874	16,530	547	1,479	6,919	14,215	481	10,275	53,320	50,616	-	2,704	79,974	68,664	-	-	-	7,470,455	264,930	4,096
Period 2b Additional Costs																					
2b.2.1	Remedial Action Surveys	-	-	-	-	-	-	1,943	583	2,526	2,526	-	-	-	-	-	-	-	-	25,399	-
2b.2.2	Operational Equipment	-	-	9	29	312	-	-	52	402	402	-	-	5,855	-	-	-	-	146,375	16	-
2b.2	Subtotal Period 2b Additional Costs	-	-	9	29	312	-	1,943	635	2,928	2,928	-	-	5,855	-	-	-	-	146,375	25,415	-
Period 2b Collateral Costs																					
2b.3.1	Process decommissioning water waste	105	-	70	182	-	285	-	158	800	800	-	-	-	680	-	-	-	40,799	133	-
2b.3.2	Process decommissioning chemical flush waste	3	-	87	327	-	651	-	222	1,289	1,289	-	-	-	875	-	-	-	93,252	164	-
2b.3.3	Small tool allowance	-	289	-	-	-	-	-	43	332	332	-	-	-	-	-	-	-	-	-	-
2b.3.4	Spent Fuel Capital and Transfer	-	-	-	-	-	-	407	61	468	-	468	-	-	-	-	-	-	-	-	-
2b.3.5	Retention and Severance	-	-	-	-	-	-	6,994	1,049	8,043	8,043	-	-	-	-	-	-	-	-	-	-
2b.3.6	Prairie Island Indian Community Payments	-	-	-	-	-	-	1,525	-	1,525	-	1,525	-	-	-	-	-	-	-	-	-
2b.3	Subtotal Period 2b Collateral Costs	107	289	157	509	-	936	8,926	1,533	12,457	10,463	1,993	-	-	1,555	-	-	-	134,051	296	-
Period 2b Period-Dependent Costs																					
2b.4.1	Decon supplies	482	-	-	-	-	-	-	121	603	603	-	-	-	-	-	-	-	-	-	-
2b.4.2	Insurance	-	-	-	-	-	-	624	62	687	687	-	-	-	-	-	-	-	-	-	-
2b.4.3	Property taxes	-	-	-	-	-	-	3,099	310	3,409	3,409	-	-	-	-	-	-	-	-	-	-
2b.4.4	Health physics supplies	-	1,969	-	-	-	-	-	492	2,461	2,461	-	-	-	-	-	-	-	-	-	-
2b.4.5	Heavy equipment rental	-	2,759	-	-	-	-	-	414	3,173	3,173	-	-	-	-	-	-	-	-	-	-
2b.4.6	Disposal of DAW generated	-	-	78	23	-	293	-	85	479	479	-	-	-	3,600	-	-	-	71,996	117	-
2b.4.7	Plant energy budget	-	-	-	-	-	-	1,388	208	1,596	1,596	-	-	-	-	-	-	-	-	-	-
2b.4.8	NRC Fees	-	-	-	-	-	-	707	71	778	778	-	-	-	-	-	-	-	-	-	-
2b.4.9	Emergency Planning Fees	-	-	-	-	-	-	1,569	157	1,726	-	1,726	-	-	-	-	-	-	-	-	-
2b.4.10	Fixed Overhead	-	-	-	-	-	-	1,513	227	1,740	1,740	-	-	-	-	-	-	-	-	-	-
2b.4.11	Spent Fuel Pool O&M	-	-	-	-	-	-	490	74	564	-	564	-	-	-	-	-	-	-	-	-
2b.4.12	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	247	37	284	284	-	-	-	-	-	-	-	-	-	-
2b.4.13	ISFSI Operating Costs	-	-	-	-	-	-	63	9	73	-	73	-	-	-	-	-	-	-	-	-
2b.4.14	Railroad Track Maintenance	-	-	-	-	-	-	70	11	81	81	-	-	-	-	-	-	-	-	-	-
2b.4.15	Security Staff Cost	-	-	-	-	-	-	8,299	1,245	9,544	9,544	-	-	-	-	-	-	-	-	-	137,246
2b.4.16	DOC Staff Cost	-	-	-	-	-	-	11,450	1,718	13,168	13,168	-	-	-	-	-	-	-	-	-	137,246
2b.4.17	Utility Staff Cost	-	-	-	-	-	-	15,293	2,294	17,586	17,586	-	-	-	-	-	-	-	-	-	255,430
2b.4	Subtotal Period 2b Period-Dependent Costs	482	4,728	78	23	-	293	44,813	7,533	57,951	55,588	2,362	-	-	3,600	-	-	-	71,996	117	529,921
2b.0	TOTAL PERIOD 2b COST	3,464	21,546	792	2,040	7,231	15,444	56,163	19,976	126,656	119,596	4,356	2,704	85,829	73,819	-	-	-	7,822,876	290,758	534,017
PERIOD 2c - Spent fuel delay prior to SFP decon																					
Period 2c Direct Decommissioning Activities																					
Period 2c Additional Costs																					
2c.2.1	Security Modifications	-	-	-	-	-	-	4,348	652	5,000	5,000	-	-	-	-	-	-	-	-	-	-
2c.2	Subtotal Period 2c Additional Costs	-	-	-	-	-	-	4,348	652	5,000	5,000	-	-	-	-	-	-	-	-	-	-
Period 2c Collateral Costs																					
2c.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	71,928	10,789	82,717	-	82,717	-	-	-	-	-	-	-	-	-
2c.3.2	Retention and Severance	-	-	-	-	-	-	4,478	672	5,149	5,149	-	-	-	-	-	-	-	-	-	-
2c.3.3	Prairie Island Indian Community Payments	-	-	-	-	-	-	2,702	-	2,702	-	2,702	-	-	-	-	-	-	-	-	-
2c.3	Subtotal Period 2c Collateral Costs	-	-	-	-	-	-	79,108	11,461	90,569	5,149	85,420	-	-	-	-	-	-	-	-	-
Period 2c Period-Dependent Costs																					
2c.4.1	Insurance	-	-	-	-	-	-	1,104	110	1,215	1,215	-	-	-	-	-	-	-	-	-	-
2c.4.2	Property taxes	-	-	-	-	-	-	5,154	515	5,669	5,669	-	-	-	-	-	-	-	-	-	-
2c.4.3	Health physics supplies	-	390	-	-	-	-	-	98	488	488	-	-	-	-	-	-	-	-	-	-
2c.4.4	Disposal of DAW generated	-	-	18	5	-	66	-	19	108	108	-	-	-	809	-	-	-	16,171	26	-
2c.4.5	Plant energy budget	-	-	-	-	-	-	655	98	753	753	-	-	-	-	-	-	-	-	-	-
2c.4.6	NRC Fees	-	-	-	-	-	-	555	55	610	610	-	-	-	-	-	-	-	-	-	-
2c.4.7	Emergency Planning Fees	-	-	-	-	-	-	2,776	278	3,053	-	3,053	-	-	-	-	-	-	-	-	-

Table D-1
Prairie Island Nuclear Generating Plant, Unit 1
DECON Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Period 2c Period-Dependent Costs (continued)																					
2c.4.8	Fixed Overhead	-	-	-	-	-	-	2,676	401	3,078	3,078	-	-	-	-	-	-	-	-	-	-
2c.4.9	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	87	13	101	101	-	-	-	-	-	-	-	-	-	-
2c.4.10	ISFSI Operating Costs	-	-	-	-	-	-	112	17	128	-	128	-	-	-	-	-	-	-	-	-
2c.4.11	Railroad Track Maintenance	-	-	-	-	-	-	125	19	143	143	-	-	-	-	-	-	-	-	-	-
2c.4.12	Security Staff Cost	-	-	-	-	-	-	14,681	2,202	16,883	16,883	-	-	-	-	-	-	-	-	-	242,796
2c.4.13	Utility Staff Cost	-	-	-	-	-	-	2,064	310	2,374	2,374	-	-	-	-	-	-	-	-	-	33,722
2c.4	Subtotal Period 2c Period-Dependent Costs	-	390	18	5	-	66	29,988	4,135	34,602	31,421	3,181	-	-	809	-	-	-	16,171	26	276,518
2c.0	TOTAL PERIOD 2c COST	-	390	18	5	-	66	113,444	16,248	130,171	41,570	88,601	-	-	809	-	-	-	16,171	26	276,518
PERIOD 2d - Decontamination Following Wet Fuel Storage																					
Period 2d Direct Decommissioning Activities																					
2d.1.1	Remove spent fuel racks	328	32	94	32	-	595	-	335	1,416	1,416	-	-	-	2,092	-	-	-	138,298	576	-
Disposal of Plant Systems																					
2d.1.2.1	Electrical - Contaminated - Fuel Pool	-	147	2	4	53	7	-	47	259	259	-	-	615	23	-	-	-	26,508	2,077	-
2d.1.2.2	Electrical - Decontaminated - Fuel Pool	-	918	10	34	510	-	-	312	1,785	1,785	-	-	5,893	-	-	-	-	239,327	12,340	-
2d.1.2.3	HVAC - Contaminated - Fuel Pool	-	159	3	9	121	15	-	63	370	370	-	-	1,398	53	-	-	-	60,246	2,157	-
2d.1.2.4	Safeguards Chilled Water - RCA	-	82	1	3	43	-	-	27	155	155	-	-	495	-	-	-	-	20,100	1,019	-
2d.1.2.5	Spent Fuel Pool Cooling	293	342	34	25	70	377	-	344	1,484	1,484	-	-	806	1,325	-	-	-	120,439	7,613	-
2d.1.2.6	Station & Instrument Air - RCA Fuel Pool	-	20	0	0	7	-	-	6	34	34	-	-	83	-	-	-	-	3,374	263	-
2d.1.2	Totals	293	1,668	50	75	804	399	-	800	4,088	4,088	-	-	9,290	1,401	-	-	-	469,994	25,468	-
2d.1.4	Scaffolding in support of decommissioning	-	213	1	0	3	1	-	54	273	273	-	-	35	3	-	-	-	1,754	1,592	-
2d.1	Subtotal Period 2d Activity Costs	621	1,913	145	107	807	994	-	1,189	5,777	5,777	-	-	9,325	3,496	-	-	-	610,046	27,637	-
Period 2d Additional Costs																					
2d.2.1	License Termination Survey Planning	-	-	-	-	-	-	845	253	1,098	1,098	-	-	-	-	-	-	-	-	-	6,240
2d.2.2	Remedial Action Surveys	-	-	-	-	-	-	1,237	371	1,608	1,608	-	-	-	-	-	-	-	-	16,173	-
2d.2	Subtotal Period 2d Additional Costs	-	-	-	-	-	-	2,082	625	2,706	2,706	-	-	-	-	-	-	-	-	16,173	6,240
Period 2d Collateral Costs																					
2d.3.1	Process decommissioning water waste	27	-	18	48	-	75	-	41	209	209	-	-	-	179	-	-	-	10,724	35	-
2d.3.2	Process decommissioning chemical flush waste	1	-	32	121	-	241	-	82	478	478	-	-	-	324	-	-	-	34,576	61	-
2d.3.3	Small tool allowance	-	35	-	-	-	-	-	5	41	41	-	-	-	-	-	-	-	-	-	-
2d.3.4	Decommissioning Equipment Disposition	-	-	144	55	575	150	-	147	1,071	1,071	-	-	6,000	529	-	-	-	304,968	88	-
2d.3.5	Spent Fuel Capital and Transfer	-	-	-	-	-	-	13,144	1,972	15,115	-	15,115	-	-	-	-	-	-	-	-	-
2d.3.6	Prairie Island Indian Community Payments	-	-	-	-	-	-	971	-	971	-	971	-	-	-	-	-	-	-	-	-
2d.3	Subtotal Period 2d Collateral Costs	27	35	194	224	575	467	14,114	2,247	17,884	1,798	16,086	-	6,000	1,032	-	-	-	350,268	184	-
Period 2d Period-Dependent Costs																					
2d.4.1	Decon supplies	54	-	-	-	-	-	-	14	68	68	-	-	-	-	-	-	-	-	-	-
2d.4.2	Insurance	-	-	-	-	-	-	398	40	437	437	-	-	-	-	-	-	-	-	-	-
2d.4.3	Property taxes	-	-	-	-	-	-	1,740	174	1,914	1,914	-	-	-	-	-	-	-	-	-	-
2d.4.4	Health physics supplies	-	559	-	-	-	-	-	140	699	699	-	-	-	-	-	-	-	-	-	-
2d.4.5	Heavy equipment rental	-	1,757	-	-	-	-	-	264	2,020	2,020	-	-	-	-	-	-	-	-	-	-
2d.4.6	Disposal of DAW generated	-	-	18	5	-	67	-	19	110	110	-	-	-	829	-	-	-	16,581	27	-
2d.4.7	Plant energy budget	-	-	-	-	-	-	471	71	542	542	-	-	-	-	-	-	-	-	-	-
2d.4.8	NRC Fees	-	-	-	-	-	-	381	38	419	419	-	-	-	-	-	-	-	-	-	-
2d.4.9	Emergency Planning Fees	-	-	-	-	-	-	999	100	1,099	-	1,099	-	-	-	-	-	-	-	-	-
2d.4.10	Fixed Overhead	-	-	-	-	-	-	963	144	1,108	1,108	-	-	-	-	-	-	-	-	-	-
2d.4.11	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	315	47	362	362	-	-	-	-	-	-	-	-	-	-
2d.4.12	ISFSI Operating Costs	-	-	-	-	-	-	40	6	46	-	46	-	-	-	-	-	-	-	-	-
2d.4.13	Railroad Track Maintenance	-	-	-	-	-	-	45	7	52	52	-	-	-	-	-	-	-	-	-	-
2d.4.14	Security Staff Cost	-	-	-	-	-	-	5,123	768	5,891	5,891	-	-	-	-	-	-	-	-	-	84,157
2d.4.15	DOC Staff Cost	-	-	-	-	-	-	6,065	910	6,975	6,975	-	-	-	-	-	-	-	-	-	69,996
2d.4.16	Utility Staff Cost	-	-	-	-	-	-	7,796	1,169	8,966	8,527	439	-	-	-	-	-	-	-	-	126,236
2d.4	Subtotal Period 2d Period-Dependent Costs	54	2,316	18	5	-	67	24,337	3,911	30,708	29,123	1,584	-	-	829	-	-	-	16,581	27	280,390
2d.0	TOTAL PERIOD 2d COST	703	4,264	357	337	1,382	1,528	40,533	7,971	57,075	39,405	17,670	-	15,325	5,357	-	-	-	976,895	44,021	286,630

Table D-1
Prairie Island Nuclear Generating Plant, Unit 1
DECON Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
PERIOD 2f - License Termination																					
Period 2f Direct Decommissioning Activities																					
2f.1.1	ORISE confirmatory survey	-	-	-	-	-	-	176	53	229	229	-	-	-	-	-	-	-	-	-	-
2f.1.2	Terminate license									a											
2f.1	Subtotal Period 2f Activity Costs	-	-	-	-	-	-	176	53	229	229	-	-	-	-	-	-	-	-	-	-
Period 2f Additional Costs																					
2f.2.1	License Termination Survey	-	-	-	-	-	-	3,217	965	4,182	4,182	-	-	-	-	-	-	-	-	40,172	3,120
2f.2	Subtotal Period 2f Additional Costs	-	-	-	-	-	-	3,217	965	4,182	4,182	-	-	-	-	-	-	-	-	40,172	3,120
Period 2f Collateral Costs																					
2f.3.1	DOC staff relocation expenses	-	-	-	-	-	-	1,189	178	1,367	1,367	-	-	-	-	-	-	-	-	-	-
2f.3.2	Prairie Island Indian Community Payments	-	-	-	-	-	-	934	-	934	-	934	-	-	-	-	-	-	-	-	-
2f.3	Subtotal Period 2f Collateral Costs	-	-	-	-	-	-	2,122	178	2,300	1,367	934	-	-	-	-	-	-	-	-	-
Period 2f Period-Dependent Costs																					
2f.4.1	Insurance	-	-	-	-	-	-	382	38	420	420	-	-	-	-	-	-	-	-	-	-
2f.4.2	Property taxes	-	-	-	-	-	-	1,626	163	1,789	1,789	-	-	-	-	-	-	-	-	-	-
2f.4.3	Health physics supplies	-	420	-	-	-	-	-	105	524	524	-	-	-	-	-	-	-	-	-	-
2f.4.4	Disposal of DAW generated	-	-	7	2	-	27	-	8	44	44	-	-	-	334	-	-	-	6,685	11	-
2f.4.5	Plant energy budget	-	-	-	-	-	-	227	34	261	261	-	-	-	-	-	-	-	-	-	-
2f.4.6	NRC Fees	-	-	-	-	-	-	417	42	459	459	-	-	-	-	-	-	-	-	-	-
2f.4.7	Emergency Planning Fees	-	-	-	-	-	-	51	5	56	-	56	-	-	-	-	-	-	-	-	-
2f.4.8	Fixed Overhead	-	-	-	-	-	-	926	139	1,065	1,065	-	-	-	-	-	-	-	-	-	-
2f.4.9	ISFSI Operating Costs	-	-	-	-	-	-	39	6	44	-	44	-	-	-	-	-	-	-	-	-
2f.4.10	Railroad Track Maintenance	-	-	-	-	-	-	43	6	50	50	-	-	-	-	-	-	-	-	-	-
2f.4.11	Security Staff Cost	-	-	-	-	-	-	4,924	739	5,663	5,663	-	-	-	-	-	-	-	-	-	80,898
2f.4.12	DOC Staff Cost	-	-	-	-	-	-	4,101	615	4,716	4,716	-	-	-	-	-	-	-	-	-	46,283
2f.4.13	Utility Staff Cost	-	-	-	-	-	-	3,854	578	4,433	4,007	426	-	-	-	-	-	-	-	-	59,507
2f.4	Subtotal Period 2f Period-Dependent Costs	-	420	7	2	-	27	16,591	2,477	19,524	18,998	526	-	-	334	-	-	-	6,685	11	186,687
2f.0	TOTAL PERIOD 2f COST	-	420	7	2	-	27	22,106	3,674	26,236	24,776	1,460	-	-	334	-	-	-	6,685	40,183	189,807
PERIOD 2 TOTALS		5,161	53,290	28,935	6,446	11,617	35,794	313,880	87,041	542,165	419,252	118,038	4,875	138,709	117,153	250	673	-	13,293,650	587,146	2,059,666
PERIOD 3b - Site Restoration																					
Period 3b Direct Decommissioning Activities																					
Demolition of Remaining Site Buildings																					
3b.1.1.1	Reactor	-	4,255	-	-	-	-	-	638	4,894	-	-	4,894	-	-	-	-	-	-	44,669	-
3b.1.1.2	Condensate Storage Tank Foundation	-	3	-	-	-	-	-	0	4	-	-	4	-	-	-	-	-	-	16	-
3b.1.1.3	Structures below 3' below grade	-	1,581	-	-	-	-	-	237	1,818	-	-	1,818	-	-	-	-	-	-	8,411	-
3b.1.1.4	Turbine	-	1,983	-	-	-	-	-	297	2,280	-	-	2,280	-	-	-	-	-	-	22,040	-
3b.1.1.5	Turbine Pedestal	-	349	-	-	-	-	-	52	402	-	-	402	-	-	-	-	-	-	1,857	-
3b.1.1	Totals	-	8,171	-	-	-	-	-	1,226	9,397	-	-	9,397	-	-	-	-	-	-	76,993	-
Site Closeout Activities																					
3b.1.2	Grade & landscape site	-	431	-	-	-	-	-	65	495	-	-	495	-	-	-	-	-	-	921	-
3b.1.3	Final report to NRC	-	-	-	-	-	-	183	27	211	211	-	-	-	-	-	-	-	-	-	1,560
3b.1	Subtotal Period 3b Activity Costs	-	8,602	-	-	-	-	183	1,318	10,102	211	-	9,892	-	-	-	-	-	-	77,914	1,560
Period 3b Additional Costs																					
3b.2.1	Clean Concrete Disposal	-	2,213	-	-	-	-	3	332	2,549	-	-	2,549	-	-	-	-	-	-	8,386	-
3b.2.2	Underground Services Excavations	-	811	-	-	-	-	520	200	1,531	-	-	1,531	-	-	-	-	-	-	7,407	-
3b.2.3	Intake Structure Cofferdam	-	596	-	-	-	-	-	89	686	-	-	686	-	-	-	-	-	-	5,168	-
3b.2.4	Construction Debris	-	-	-	-	-	-	10	2	12	-	-	12	-	-	-	-	-	-	-	-
3b.2.5	Backfill	-	2,751	-	-	-	-	-	413	3,164	-	-	3,164	-	-	-	-	-	-	2,904	-
3b.2	Subtotal Period 3b Additional Costs	-	6,371	-	-	-	-	534	1,036	7,941	-	-	7,941	-	-	-	-	-	-	23,865	-
Period 3b Collateral Costs																					
3b.3.1	Small tool allowance	-	110	-	-	-	-	-	16	126	-	-	126	-	-	-	-	-	-	-	-
3b.3.2	Prairie Island Indian Community Payments	-	-	-	-	-	-	2,651	-	2,651	-	2,651	-	-	-	-	-	-	-	-	-
3b.3	Subtotal Period 3b Collateral Costs	-	110	-	-	-	-	2,651	16	2,777	-	2,651	126	-	-	-	-	-	-	-	-

Table D-1
Prairie Island Nuclear Generating Plant, Unit 1
DECON Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Period 3b Period-Dependent Costs																					
3b.4.1	Insurance	-	-	-	-	-	-	542	54	596	-	596	-	-	-	-	-	-	-	-	-
3b.4.2	Property taxes	-	-	-	-	-	-	4,334	433	4,767	-	4,767	-	-	-	-	-	-	-	-	-
3b.4.3	Heavy equipment rental	-	6,670	-	-	-	-	-	1,000	7,670	-	-	7,670	-	-	-	-	-	-	-	-
3b.4.4	Plant energy budget	-	-	-	-	-	-	321	48	369	-	-	369	-	-	-	-	-	-	-	-
3b.4.5	NRC ISFSI Fees	-	-	-	-	-	-	236	24	259	-	259	-	-	-	-	-	-	-	-	-
3b.4.6	Emergency Planning Fees	-	-	-	-	-	-	145	14	159	-	159	-	-	-	-	-	-	-	-	-
3b.4.7	Fixed Overhead	-	-	-	-	-	-	990	148	1,138	-	-	1,138	-	-	-	-	-	-	-	-
3b.4.8	ISFSI Operating Costs	-	-	-	-	-	-	109	16	126	-	126	-	-	-	-	-	-	-	-	-
3b.4.9	Railroad Track Maintenance	-	-	-	-	-	-	331	50	380	-	-	380	-	-	-	-	-	-	-	-
3b.4.10	Security Staff Cost	-	-	-	-	-	-	4,245	637	4,882	-	4,882	-	-	-	-	-	-	-	-	57,340
3b.4.11	DOC Staff Cost	-	-	-	-	-	-	10,467	1,570	12,038	-	-	12,038	-	-	-	-	-	-	-	116,885
3b.4.12	Utility Staff Cost	-	-	-	-	-	-	4,813	722	5,535	(0)	1,207	4,329	-	-	-	-	-	-	-	74,431
3b.4	Subtotal Period 3b Period-Dependent Costs	-	6,670	-	-	-	-	26,534	4,718	37,921	(0)	11,997	25,924	-	-	-	-	-	-	-	248,656
3b.0	TOTAL PERIOD 3b COST	-	21,752	-	-	-	-	29,901	7,088	58,741	211	14,648	43,882	-	-	-	-	-	-	101,779	250,216
PERIOD 3c - Fuel Storage Operations/Shipping																					
Period 3c Direct Decommissioning Activities																					
Period 3c Collateral Costs																					
3c.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	16,797	2,520	19,316	-	19,316	-	-	-	-	-	-	-	-	-
3c.3.2	Prairie Island Indian Community Payments	-	-	-	-	-	-	43,116	-	43,116	-	43,116	-	-	-	-	-	-	-	-	-
3c.3	Subtotal Period 3c Collateral Costs	-	-	-	-	-	-	59,913	2,520	62,433	-	62,433	-	-	-	-	-	-	-	-	-
Period 3c Period-Dependent Costs																					
3c.4.1	Insurance	-	-	-	-	-	-	8,818	882	9,700	-	9,700	-	-	-	-	-	-	-	-	-
3c.4.2	Property taxes	-	-	-	-	-	-	39,829	3,983	43,812	-	43,812	-	-	-	-	-	-	-	-	-
3c.4.4	NRC ISFSI Fees	-	-	-	-	-	-	5,648	565	6,213	-	6,213	-	-	-	-	-	-	-	-	-
3c.4.5	Emergency Planning Fees	-	-	-	-	-	-	2,360	236	2,596	-	2,596	-	-	-	-	-	-	-	-	-
3c.4.6	Fixed Overhead	-	-	-	-	-	-	5,267	790	6,057	-	6,057	-	-	-	-	-	-	-	-	-
3c.4.7	ISFSI Operating Costs	-	-	-	-	-	-	1,782	267	2,049	-	2,049	-	-	-	-	-	-	-	-	-
3c.4.8	Railroad Track Maintenance	-	-	-	-	-	-	1,991	299	2,289	-	2,289	-	-	-	-	-	-	-	-	-
3c.4.9	Security Staff Cost	-	-	-	-	-	-	69,105	10,366	79,471	-	79,471	-	-	-	-	-	-	-	-	933,362
3c.4.10	Utility Staff Cost	-	-	-	-	-	-	17,069	2,560	19,629	-	19,629	-	-	-	-	-	-	-	-	242,315
3c.4	Subtotal Period 3c Period-Dependent Costs	-	-	-	-	-	-	151,870	19,948	171,817	-	171,817	-	-	-	-	-	-	-	-	1,175,677
3c.0	TOTAL PERIOD 3c COST	-	-	-	-	-	-	211,783	22,467	234,250	-	234,250	-	-	-	-	-	-	-	-	1,175,677
PERIOD 3d - GTCC shipping																					
Period 3d Direct Decommissioning Activities																					
Nuclear Steam Supply System Removal																					
3d.1.1.1	Vessel & Internals GTCC Disposal	-	-	1,331	-	-	8,689	-	1,636	11,656	11,656	-	-	-	-	-	-	3,746	837,596	-	-
3d.1.1	Totals	-	-	1,331	-	-	8,689	-	1,636	11,656	11,656	-	-	-	-	-	-	3,746	837,596	-	-
3d.1	Subtotal Period 3d Activity Costs	-	-	1,331	-	-	8,689	-	1,636	11,656	11,656	-	-	-	-	-	-	3,746	837,596	-	-
Period 3d Collateral Costs																					
3d.3.1	Prairie Island Indian Community Payments	-	-	-	-	-	-	48	-	48	-	48	-	-	-	-	-	-	-	-	-
3d.3	Subtotal Period 3d Collateral Costs	-	-	-	-	-	-	48	-	48	-	48	-	-	-	-	-	-	-	-	-
Period 3d Period-Dependent Costs																					
3d.4.1	Insurance	-	-	-	-	-	-	10	1	11	11	-	-	-	-	-	-	-	-	-	-
3d.4.2	Property taxes	-	-	-	-	-	-	39	4	43	43	-	-	-	-	-	-	-	-	-	-
3d.4.4	NRC ISFSI Fees	-	-	-	-	-	-	4	0	5	-	5	-	-	-	-	-	-	-	-	-
3d.4.5	Emergency Planning Fees	-	-	-	-	-	-	3	0	3	-	3	-	-	-	-	-	-	-	-	-
3d.4.6	Fixed Overhead	-	-	-	-	-	-	6	1	7	7	-	-	-	-	-	-	-	-	-	-
3d.4.7	ISFSI Operating Costs	-	-	-	-	-	-	2	0	2	-	2	-	-	-	-	-	-	-	-	-
3d.4.8	Railroad Track Maintenance	-	-	-	-	-	-	2	0	3	-	3	-	-	-	-	-	-	-	-	-
3d.4.9	Security Staff Cost	-	-	-	-	-	-	77	12	88	88	-	-	-	-	-	-	-	-	-	1,037
3d.4.10	Utility Staff Cost	-	-	-	-	-	-	19	3	22	22	-	-	-	-	-	-	-	-	-	269
3d.4	Subtotal Period 3d Period-Dependent Costs	-	-	-	-	-	-	162	21	183	171	12	-	-	-	-	-	-	-	-	1,306
3d.0	TOTAL PERIOD 3d COST	-	-	1,331	-	-	8,689	210	1,658	11,887	11,827	60	-	-	-	-	-	3,746	837,596	-	1,306

Table D-1
Prairie Island Nuclear Generating Plant, Unit 1
DECON Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
PERIOD 3e - ISFSI Decontamination																					
Period 3e Direct Decommissioning Activities																					
Period 3e Additional Costs																					
3e.2.1	License Termination ISFSI	-	37	2	211	-	2,157	710	779	3,896	3,896	-	-	-	7,458	-	-	-	1,071,985	3,670	888
3e.2	Subtotal Period 3e Additional Costs	-	37	2	211	-	2,157	710	779	3,896	3,896	-	-	-	7,458	-	-	-	1,071,985	3,670	888
Period 3e Period-Dependent Costs																					
3e.4.1	Insurance	-	-	-	-	-	-	96	24	121	121	-	-	-	-	-	-	-	-	-	-
3e.4.2	Property taxes	-	-	-	-	-	-	26	6	32	32	-	-	-	-	-	-	-	-	-	-
3e.4.4	Fixed Overhead	-	-	-	-	-	-	51	13	63	63	-	-	-	-	-	-	-	-	-	-
3e.4.5	Railroad Track Maintenance	-	-	-	-	-	-	19	5	24	24	-	-	-	-	-	-	-	-	-	-
3e.4.6	Security Staff Cost	-	-	-	-	-	-	154	38	192	192	-	-	-	-	-	-	-	-	-	2,500
3e.4.7	Utility Staff Cost	-	-	-	-	-	-	130	33	163	163	-	-	-	-	-	-	-	-	-	1,896
3e.4	Subtotal Period 3e Period-Dependent Costs	-	-	-	-	-	-	476	119	595	595	-	-	-	-	-	-	-	-	-	4,396
3e.0	TOTAL PERIOD 3e COST	-	37	2	211	-	2,157	1,186	898	4,491	4,491	-	-	-	7,458	-	-	-	1,071,985	3,670	5,284
PERIOD 3f - ISFSI Site Restoration																					
Period 3f Direct Decommissioning Activities																					
Period 3f Additional Costs																					
3f.2.1	Demolition and Site Restoration of ISFSI	-	495	-	-	-	-	87	87	669	-	-	669	-	-	-	-	-	-	2,308	160
3f.2	Subtotal Period 3f Additional Costs	-	495	-	-	-	-	87	87	669	-	-	669	-	-	-	-	-	-	2,308	160
Period 3f Collateral Costs																					
3f.3.1	Small tool allowance	-	4	-	-	-	-	-	1	4	-	-	4	-	-	-	-	-	-	-	-
3f.3	Subtotal Period 3f Collateral Costs	-	4	-	-	-	-	-	1	4	-	-	4	-	-	-	-	-	-	-	-
Period 3f Period-Dependent Costs																					
3f.4.2	Property taxes	-	-	-	-	-	-	13	1	14	-	-	14	-	-	-	-	-	-	-	-
3f.4.3	Heavy equipment rental	-	62	-	-	-	-	-	9	71	-	-	71	-	-	-	-	-	-	-	-
3f.4.4	Plant energy budget	-	-	-	-	-	-	13	2	15	-	-	15	-	-	-	-	-	-	-	-
3f.4.5	Fixed Overhead	-	-	-	-	-	-	25	4	29	-	-	29	-	-	-	-	-	-	-	-
3f.4.6	Railroad Track Maintenance	-	-	-	-	-	-	10	1	11	-	-	11	-	-	-	-	-	-	-	-
3f.4.7	Security Staff Cost	-	-	-	-	-	-	78	12	89	-	-	89	-	-	-	-	-	-	-	1,260
3f.4.8	Utility Staff Cost	-	-	-	-	-	-	52	8	60	-	-	60	-	-	-	-	-	-	-	782
3f.4	Subtotal Period 3f Period-Dependent Costs	-	62	-	-	-	-	190	37	289	-	-	289	-	-	-	-	-	-	-	2,042
3f.0	TOTAL PERIOD 3f COST	-	560	-	-	-	-	277	125	962	-	-	962	-	-	-	-	-	-	2,308	2,202
PERIOD 3 TOTALS		-	22,349	1,333	211	-	10,846	243,357	32,235	310,331	16,528	248,958	44,844	-	7,458	-	-	3,746	1,909,581	107,756	1,434,684
TOTAL COST TO DECOMMISSION		**8,734**	**81,007**	**30,683**	**7,109**	**11,781**	**50,612**	**668,511**	**138,605**	**997,041**	**572,618**	**373,251**	**51,173**	**144,842**	**138,575**	**839**	**673**	**3,746**	**15,813,370**	**740,428**	**4,498,771**

TOTAL COST TO DECOMMISSION WITH 16.15% CONTINGENCY:	**$997,041**	**thousands of 2017 dollars**
TOTAL NRC LICENSE TERMINATION COST IS 57.43% OR:	**$572,618**	**thousands of 2017 dollars**
SPENT FUEL MANAGEMENT COST IS 37.44% OR:	**$373,250**	**thousands of 2017 dollars**
NON-NUCLEAR DEMOLITION COST IS 5.13% OR:	**$51,173**	**thousands of 2017 dollars**
TOTAL LOW-LEVEL RADIOACTIVE WASTE VOLUME BURIED (EXCLUDING GTCC):	**91,286**	**cubic feet**
TOTAL GREATER THAN CLASS C RADWASTE VOLUME GENERATED:	**3,746**	**cubic feet**
TOTAL SCRAP METAL REMOVED:	**32,925**	**tons**
TOTAL CRAFT LABOR REQUIREMENTS:	**740,428**	**man-hours**

End Notes:
n/a - indicates that this activity not charged as decommissioning expense
a - indicates that this activity performed by decommissioning staff
0 - indicates that this value is less than 0.5 but is non-zero
A cell containing " - " indicates a zero value

Table D-2
Prairie Island Nuclear Generating Plant, Unit 2
DECON Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
PERIOD 1a - Shutdown through Transition																					
Period 1a Direct Decommissioning Activities																					
1a.1.1	Prepare preliminary decommissioning cost	-	-	-	-	-	-	65	10	75	75	-	-	-	-	-	-	-	-	-	556
1a.1.2	Notification of Cessation of Operations									a											
1a.1.3	Remove fuel & source material									n/a											
1a.1.4	Notification of Permanent Defueling									a											
1a.1.5	Deactivate plant systems & process waste									a											
1a.1.6	Prepare and submit PSDAR	-	-	-	-	-	-	100	15	115	115	-	-	-	-	-	-	-	-	-	855
1a.1.7	Review plant dwgs & specs.	-	-	-	-	-	-	231	35	266	266	-	-	-	-	-	-	-	-	-	1,967
1a.1.8	Perform detailed rad survey									a											
1a.1.9	Estimate by-product inventory	-	-	-	-	-	-	50	8	58	58	-	-	-	-	-	-	-	-	-	428
1a.1.10	End product description	-	-	-	-	-	-	50	8	58	58	-	-	-	-	-	-	-	-	-	428
1a.1.11	Detailed by-product inventory	-	-	-	-	-	-	65	10	75	75	-	-	-	-	-	-	-	-	-	556
1a.1.12	Define major work sequence	-	-	-	-	-	-	376	56	433	433	-	-	-	-	-	-	-	-	-	3,207
1a.1.13	Perform SER and EA	-	-	-	-	-	-	156	23	179	179	-	-	-	-	-	-	-	-	-	1,326
1a.1.14	Prepare/submit Defueled Technical Specifications	-	-	-	-	-	-	376	56	433	433	-	-	-	-	-	-	-	-	-	3,207
1a.1.15	Perform Site-Specific Cost Study	-	-	-	-	-	-	251	38	289	289	-	-	-	-	-	-	-	-	-	2,138
1a.1.16	Prepare/submit Irradiated Fuel Management Plan	-	-	-	-	-	-	50	8	58	58	-	-	-	-	-	-	-	-	-	428
Activity Specifications																					
1a.1.17.1	Plant & temporary facilities	-	-	-	-	-	-	247	37	284	256	-	28	-	-	-	-	-	-	-	2,104
1a.1.17.2	Plant systems	-	-	-	-	-	-	209	31	241	216	-	24	-	-	-	-	-	-	-	1,782
1a.1.17.3	NSSS Decontamination Flush	-	-	-	-	-	-	25	4	29	29	-	-	-	-	-	-	-	-	-	214
1a.1.17.4	Reactor internals	-	-	-	-	-	-	356	53	410	410	-	-	-	-	-	-	-	-	-	3,036
1a.1.17.5	Reactor vessel	-	-	-	-	-	-	326	49	375	375	-	-	-	-	-	-	-	-	-	2,779
1a.1.17.6	Biological shield	-	-	-	-	-	-	25	4	29	29	-	-	-	-	-	-	-	-	-	214
1a.1.17.7	Steam generators	-	-	-	-	-	-	157	23	180	180	-	-	-	-	-	-	-	-	-	1,334
1a.1.17.8	Reinforced concrete	-	-	-	-	-	-	80	12	92	46	-	46	-	-	-	-	-	-	-	684
1a.1.17.9	Main Turbine	-	-	-	-	-	-	20	3	23	-	-	23	-	-	-	-	-	-	-	171
1a.1.17.10	Main Condensers	-	-	-	-	-	-	20	3	23	-	-	23	-	-	-	-	-	-	-	171
1a.1.17.11	Plant structures & buildings	-	-	-	-	-	-	157	23	180	90	-	90	-	-	-	-	-	-	-	1,334
1a.1.17.12	Waste management	-	-	-	-	-	-	231	35	266	266	-	-	-	-	-	-	-	-	-	1,967
1a.1.17.13	Facility & site closeout	-	-	-	-	-	-	45	7	52	26	-	26	-	-	-	-	-	-	-	385
1a.1.17	Total	-	-	-	-	-	-	1,899	285	2,183	1,923	-	261	-	-	-	-	-	-	-	16,175
Planning & Site Preparations																					
1a.1.18	Prepare dismantling sequence	-	-	-	-	-	-	120	18	139	139	-	-	-	-	-	-	-	-	-	1,026
1a.1.19	Plant prep. & temp. svces	-	-	-	-	-	-	3,300	495	3,795	3,795	-	-	-	-	-	-	-	-	-	-
1a.1.20	Design water clean-up system	-	-	-	-	-	-	70	11	81	81	-	-	-	-	-	-	-	-	-	599
1a.1.21	Rigging/Cont. Cntrl Envlps/tooling/etc.	-	-	-	-	-	-	2,300	345	2,645	2,645	-	-	-	-	-	-	-	-	-	-
1a.1.22	Procure casks/liners & containers	-	-	-	-	-	-	62	9	71	71	-	-	-	-	-	-	-	-	-	526
1a.1	Subtotal Period 1a Activity Costs	-	-	-	-	-	-	9,523	1,428	10,951	10,690	-	261	-	-	-	-	-	-	-	33,420
Period 1a Additional Costs																					
1a.2.1	Spent Fuel Pool Isolation	-	-	-	-	-	-	7,794	1,169	8,963	8,963	-	-	-	-	-	-	-	-	-	-
1a.2	Subtotal Period 1a Additional Costs	-	-	-	-	-	-	7,794	1,169	8,963	8,963	-	-	-	-	-	-	-	-	-	-
Period 1a Collateral Costs																					
1a.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	1,227	184	1,411	-	1,411	-	-	-	-	-	-	-	-	-
1a.3.2	Retention and Severance	-	-	-	-	-	-	8,394	1,259	9,653	9,653	-	-	-	-	-	-	-	-	-	-
1a.3.3	Prairie Island Indian Community Payments	-	-	-	-	-	-	2,281	-	2,281	-	2,281	-	-	-	-	-	-	-	-	-
1a.3	Subtotal Period 1a Collateral Costs	-	-	-	-	-	-	11,902	1,443	13,345	9,653	3,692	-	-	-	-	-	-	-	-	-
Period 1a Period-Dependent Costs																					
1a.4.1	Insurance	-	-	-	-	-	-	1,730	173	1,903	1,903	-	-	-	-	-	-	-	-	-	-
1a.4.2	Property taxes	-	-	-	-	-	-	2,682	268	2,950	2,950	-	-	-	-	-	-	-	-	-	-
1a.4.3	Health physics supplies	-	485	-	-	-	-	-	121	606	606	-	-	-	-	-	-	-	-	-	-
1a.4.4	Heavy equipment rental	-	567	-	-	-	-	-	85	652	652	-	-	-	-	-	-	-	-	-	-
1a.4.5	Disposal of DAW generated	-	-	12	4	-	46	-	13	75	75	-	-	-	565	-	-	-	11,299	18	-
1a.4.6	Plant energy budget	-	-	-	-	-	-	1,515	227	1,742	1,742	-	-	-	-	-	-	-	-	-	-
1a.4.7	NRC Fees	-	-	-	-	-	-	778	78	855	855	-	-	-	-	-	-	-	-	-	-
1a.4.8	Emergency Planning Fees	-	-	-	-	-	-	1,604	160	1,765	-	1,765	-	-	-	-	-	-	-	-	-
1a.4.9	Fixed Overhead	-	-	-	-	-	-	1,470	220	1,690	1,690	-	-	-	-	-	-	-	-	-	-
1a.4.10	Spent Fuel Pool O&M	-	-	-	-	-	-	401	60	461	-	461	-	-	-	-	-	-	-	-	-
1a.4.11	ISFSI Operating Costs	-	-	-	-	-	-	52	8	59	-	59	-	-	-	-	-	-	-	-	-
1a.4.12	Railroad Track Maintenance	-	-	-	-	-	-	58	9	66	66	-	-	-	-	-	-	-	-	-	-
1a.4.13	Security Staff Cost	-	-	-	-	-	-	7,390	1,108	8,498	8,498	-	-	-	-	-	-	-	-	-	122,720

Table D-2
Prairie Island Nuclear Generating Plant, Unit 2
DECON Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 1a Period-Dependent Costs (continued)																					
1a.4.14	Utility Staff Cost	-	-	-	-	-	-	20,662	3,099	23,761	23,761	-	-	-	-	-	-	-	-	-	345,280
1a.4	Subtotal Period 1a Period-Dependent Costs	-	1,052	12	4	-	46	38,340	5,631	45,085	42,800	2,286	-	-	565	-	-	-	11,299	18	468,000
1a.0	TOTAL PERIOD 1a COST	-	1,052	12	4	-	46	67,559	9,672	78,345	72,107	5,977	261	-	565	-	-	-	11,299	18	501,420
PERIOD 1b - Decommissioning Preparations																					
Period 1b Direct Decommissioning Activities																					
Detailed Work Procedures																					
1b.1.1.1	Plant systems	-	-	-	-	-	-	238	36	273	246	-	27	-	-	-	-	-	-	-	2,024
1b.1.1.2	NSSS Decontamination Flush	-	-	-	-	-	-	50	8	58	58	-	-	-	-	-	-	-	-	-	428
1b.1.1.3	Reactor internals	-	-	-	-	-	-	125	19	144	144	-	-	-	-	-	-	-	-	-	1,069
1b.1.1.4	Remaining buildings	-	-	-	-	-	-	68	10	78	19	-	58	-	-	-	-	-	-	-	577
1b.1.1.5	CRD cooling assembly	-	-	-	-	-	-	50	8	58	58	-	-	-	-	-	-	-	-	-	428
1b.1.1.6	CRD housings & ICI tubes	-	-	-	-	-	-	50	8	58	58	-	-	-	-	-	-	-	-	-	428
1b.1.1.7	Incore instrumentation	-	-	-	-	-	-	50	8	58	58	-	-	-	-	-	-	-	-	-	428
1b.1.1.8	Reactor vessel	-	-	-	-	-	-	182	27	210	210	-	-	-	-	-	-	-	-	-	1,552
1b.1.1.9	Facility closeout	-	-	-	-	-	-	60	9	69	35	-	35	-	-	-	-	-	-	-	513
1b.1.1.10	Missile shields	-	-	-	-	-	-	23	3	26	26	-	-	-	-	-	-	-	-	-	192
1b.1.1.11	Biological shield	-	-	-	-	-	-	60	9	69	69	-	-	-	-	-	-	-	-	-	513
1b.1.1.12	Steam generators	-	-	-	-	-	-	231	35	266	266	-	-	-	-	-	-	-	-	-	1,967
1b.1.1.13	Reinforced concrete	-	-	-	-	-	-	50	8	58	29	-	29	-	-	-	-	-	-	-	428
1b.1.1.14	Main Turbine	-	-	-	-	-	-	78	12	90	-	-	90	-	-	-	-	-	-	-	667
1b.1.1.15	Main Condensers	-	-	-	-	-	-	78	12	90	-	-	90	-	-	-	-	-	-	-	667
1b.1.1.16	Auxiliary building	-	-	-	-	-	-	137	21	158	142	-	16	-	-	-	-	-	-	-	1,167
1b.1.1.17	Reactor building	-	-	-	-	-	-	137	21	158	142	-	16	-	-	-	-	-	-	-	1,167
1b.1.1	Total	-	-	-	-	-	-	1,669	250	1,919	1,558	-	361	-	-	-	-	-	-	-	14,215
1b.1.2	Decon primary loop	552	-	-	-	-	-	-	276	828	828	-	-	-	-	-	-	-	-	1,067	-
1b.1	Subtotal Period 1b Activity Costs	552	-	-	-	-	-	1,669	526	2,747	2,386	-	361	-	-	-	-	-	-	1,067	14,215
Period 1b Additional Costs																					
1b.2.1	Site Characterization	-	-	-	-	-	-	1,582	475	2,057	2,057	-	-	-	-	-	-	-	-	8,988	3,563
1b.2.2	Mixed/Hazardous Waste	-	-	326	75	169	-	-	69	639	639	-	-	6,324	-	-	-	-	362,914	2,410	-
1b.2.3	Asbestos Abatement	-	2,364	2	110	-	1,359	-	947	4,782	4,782	-	-	-	12,843	-	-	-	166,959	20,907	-
1b.2	Subtotal Period 1b Additional Costs	-	2,364	328	185	169	1,359	1,582	1,491	7,478	7,478	-	-	6,324	12,843	-	-	-	529,873	32,305	3,563
Period 1b Collateral Costs																					
1b.3.1	Decon equipment	973	-	-	-	-	-	-	146	1,119	1,119	-	-	-	-	-	-	-	-	-	-
1b.3.2	DOC staff relocation expenses	-	-	-	-	-	-	1,189	178	1,367	1,367	-	-	-	-	-	-	-	-	-	-
1b.3.3	Process decommissioning water waste	24	-	16	41	-	64	-	36	180	180	-	-	-	152	-	-	-	9,121	30	-
1b.3.4	Process decommissioning chemical flush waste	2	-	58	220	-	2,471	-	657	3,408	3,408	-	-	-	-	588	-	-	62,689	110	-
1b.3.5	Small tool allowance	-	34	-	-	-	-	-	5	39	39	-	-	-	-	-	-	-	-	-	-
1b.3.6	Pipe cutting equipment	-	1,200	-	-	-	-	-	180	1,380	1,380	-	-	-	-	-	-	-	-	-	-
1b.3.7	Decon rig	1,987	-	-	-	-	-	-	298	2,285	2,285	-	-	-	-	-	-	-	-	-	-
1b.3.8	Spent Fuel Capital and Transfer	-	-	-	-	-	-	370	56	426	-	426	-	-	-	-	-	-	-	-	-
1b.3.9	Retention and Severance	-	-	-	-	-	-	4,055	608	4,664	4,664	-	-	-	-	-	-	-	-	-	-
1b.3.10	Prairie Island Indian Community Payments	-	-	-	-	-	-	629	-	629	-	629	-	-	-	-	-	-	-	-	-
1b.3	Subtotal Period 1b Collateral Costs	2,986	1,234	74	261	-	2,534	6,243	2,164	15,495	14,441	1,055	-	-	152	588	-	-	71,810	140	-
Period 1b Period-Dependent Costs																					
1b.4.1	Decon supplies	35	-	-	-	-	-	-	9	44	44	-	-	-	-	-	-	-	-	-	-
1b.4.2	Insurance	-	-	-	-	-	-	872	87	959	959	-	-	-	-	-	-	-	-	-	-
1b.4.3	Property taxes	-	-	-	-	-	-	1,319	132	1,451	1,451	-	-	-	-	-	-	-	-	-	-
1b.4.4	Health physics supplies	-	380	-	-	-	-	-	95	475	475	-	-	-	-	-	-	-	-	-	-
1b.4.5	Heavy equipment rental	-	286	-	-	-	-	-	43	329	329	-	-	-	-	-	-	-	-	-	-
1b.4.6	Disposal of DAW generated	-	-	7	2	-	27	-	8	44	44	-	-	-	327	-	-	-	6,541	11	-
1b.4.7	Plant energy budget	-	-	-	-	-	-	1,527	229	1,756	1,756	-	-	-	-	-	-	-	-	-	-
1b.4.8	NRC Fees	-	-	-	-	-	-	214	21	236	236	-	-	-	-	-	-	-	-	-	-
1b.4.9	Emergency Planning Fees	-	-	-	-	-	-	809	81	890	-	890	-	-	-	-	-	-	-	-	-
1b.4.10	Fixed Overhead	-	-	-	-	-	-	741	111	852	852	-	-	-	-	-	-	-	-	-	-
1b.4.11	Spent Fuel Pool O&M	-	-	-	-	-	-	202	30	233	-	233	-	-	-	-	-	-	-	-	-
1b.4.12	ISFSI Operating Costs	-	-	-	-	-	-	26	4	30	-	30	-	-	-	-	-	-	-	-	-
1b.4.13	Railroad Track Maintenance	-	-	-	-	-	-	29	4	33	33	-	-	-	-	-	-	-	-	-	-
1b.4.14	Security Staff Cost	-	-	-	-	-	-	3,725	559	4,284	4,284	-	-	-	-	-	-	-	-	-	61,864
1b.4.15	DOC Staff Cost	-	-	-	-	-	-	4,009	601	4,610	4,610	-	-	-	-	-	-	-	-	-	47,185

Table D-2
Prairie Island Nuclear Generating Plant, Unit 2
DECON Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 1b Period-Dependent Costs (continued)																					
1b.4.16	Utility Staff Cost	-	-	-	-	-	-	10,416	1,562	11,978	11,978	-	-	-	-	-	-	-	-	-	174,059
1b.4	Subtotal Period 1b Period-Dependent Costs	35	666	7	2	-	27	23,890	3,577	28,204	27,052	1,152	-	-	327	-	-	-	6,541	11	283,108
1b.0	TOTAL PERIOD 1b COST	3,573	4,264	410	447	169	3,920	33,383	7,759	53,923	51,356	2,207	361	6,324	13,322	588	-	-	608,224	33,522	300,885
PERIOD 1 TOTALS		3,573	5,316	422	451	169	3,966	100,942	17,430	132,268	123,462	8,184	622	6,324	13,887	588	-	-	619,523	33,540	802,305
PERIOD 2a - Large Component Removal																					
Period 2a Direct Decommissioning Activities																					
Nuclear Steam Supply System Removal																					
2a.1.1.1	Reactor Coolant Piping	51	45	6	8	-	150	-	76	336	336	-	-	-	305	-	-	-	34,809	1,414	-
2a.1.1.2	Pressurizer Relief Tank	22	20	4	5	-	100	-	42	193	193	-	-	-	203	-	-	-	23,193	625	-
2a.1.1.3	Reactor Coolant Pumps & Motors	54	63	101	83	-	736	-	249	1,287	1,287	-	-	-	2,332	-	-	-	295,800	2,049	100
2a.1.1.4	Pressurizer	48	68	467	88	-	693	-	274	1,639	1,639	-	-	-	2,196	-	-	-	185,015	2,355	938
2a.1.1.5	Steam Generators	225	2,943	2,093	1,638	1,246	3,570	-	2,383	14,097	14,097	-	-	18,672	11,316	-	-	-	1,668,341	14,819	2,875
2a.1.1.6	CRDMs/ICIs/Service Structure Removal	286	277	211	48	-	763	-	431	2,016	2,016	-	-	-	4,797	-	-	-	177,400	8,104	-
2a.1.1.7	Reactor Vessel Internals	78	4,468	21,874	1,072	-	7,946	277	13,141	48,856	48,856	-	-	-	501	125	673	-	164,987	23,040	1,080
2a.1.1.8	Reactor Vessel	89	5,717	1,754	719	-	1,956	277	5,970	16,483	16,483	-	-	-	5,690	-	-	-	570,074	23,040	1,080
2a.1.1	Totals	855	13,600	26,512	3,662	1,246	15,913	553	22,568	84,908	84,908	-	-	18,672	27,341	125	673	-	3,119,620	75,446	6,073
Removal of Major Equipment																					
2a.1.2	Main Turbine/Generator	-	305	189	55	272	306	-	221	1,348	1,348	-	-	2,131	1,187	-	-	-	206,316	4,667	-
2a.1.3	Main Condensers	-	2,532	121	49	364	451	-	820	4,336	4,336	-	-	3,800	1,587	-	-	-	275,903	39,151	-
Cascading Costs from Clean Building Demolition																					
2a.1.4.1	Reactor	-	728	-	-	-	-	-	109	837	837	-	-	-	-	-	-	-	-	7,589	-
2a.1.4.2	Auxiliary	-	210	-	-	-	-	-	32	242	242	-	-	-	-	-	-	-	-	1,309	-
2a.1.4.3	Radwaste	-	8	-	-	-	-	-	1	9	9	-	-	-	-	-	-	-	-	65	-
2a.1.4	Totals	-	946	-	-	-	-	-	142	1,088	1,088	-	-	-	-	-	-	-	-	8,963	-
Disposal of Plant Systems																					
2a.1.5.1	Admin Bldg Ventilation	-	6	-	-	-	-	-	1	6	-	-	6	-	-	-	-	-	-	90	-
2a.1.5.2	Air Removal	-	25	-	-	-	-	-	4	29	-	-	29	-	-	-	-	-	-	422	-
2a.1.5.3	Auxiliary Feedwater	-	40	-	-	-	-	-	6	46	-	-	46	-	-	-	-	-	-	676	-
2a.1.5.4	Auxiliary Feedwater - RCA	-	36	0	1	15	-	-	12	65	65	-	-	178	-	-	-	-	7,214	486	-
2a.1.5.5	Bleed Steam	-	78	-	-	-	-	-	12	90	-	-	90	-	-	-	-	-	-	1,331	-
2a.1.5.6	Caustic Addition - RCA	-	38	0	1	21	-	-	13	74	74	-	-	240	-	-	-	-	9,761	468	-
2a.1.5.7	Chemical Feed	-	15	-	-	-	-	-	2	17	-	-	17	-	-	-	-	-	-	261	-
2a.1.5.8	Chemical Feed - RCA	-	3	0	0	1	-	-	1	5	5	-	-	16	-	-	-	-	634	31	-
2a.1.5.9	Circulating Water	-	24	-	-	-	-	-	4	28	-	-	28	-	-	-	-	-	-	401	-
2a.1.5.10	Condensate	-	459	-	-	-	-	-	69	527	-	-	527	-	-	-	-	-	-	7,537	-
2a.1.5.11	Condensate Polishing	-	181	-	-	-	-	-	27	209	-	-	209	-	-	-	-	-	-	2,987	-
2a.1.5.12	Condensate Polishing - RCA	-	36	1	3	42	-	-	16	98	98	-	-	483	-	-	-	-	19,616	493	-
2a.1.5.13	Electro-Hydraulic	-	8	-	-	-	-	-	1	10	-	-	10	-	-	-	-	-	-	143	-
2a.1.5.14	External Circulating Water	-	23	-	-	-	-	-	3	26	-	-	26	-	-	-	-	-	-	385	-
2a.1.5.15	External Circulating Water - RCA	-	70	1	4	62	-	-	28	165	165	-	-	721	-	-	-	-	29,284	938	-
2a.1.5.16	Feedwater	-	111	-	-	-	-	-	17	128	-	-	128	-	-	-	-	-	-	1,840	-
2a.1.5.17	Feedwater - RCA	-	236	7	24	359	-	-	117	744	744	-	-	4,147	-	-	-	-	168,414	3,377	-
2a.1.5.18	Gland Seal	-	29	-	-	-	-	-	4	34	-	-	34	-	-	-	-	-	-	504	-
2a.1.5.19	Heater Drain	-	334	-	-	-	-	-	50	384	-	-	384	-	-	-	-	-	-	5,638	-
2a.1.5.20	Hypobromous Acid Feed	-	5	-	-	-	-	-	1	6	-	-	6	-	-	-	-	-	-	86	-
2a.1.5.21	Hypobromous Acid Feed - RCA	-	1	0	0	0	-	-	0	1	1	-	-	2	-	-	-	-	100	12	-
2a.1.5.22	Internal Circ Water & CDSR	-	22	-	-	-	-	-	3	25	-	-	25	-	-	-	-	-	-	366	-
2a.1.5.23	Main Gen/Exciter/Transformer	-	0	-	-	-	-	-	0	0	-	-	0	-	-	-	-	-	-	5	-
2a.1.5.24	Main Steam	-	88	-	-	-	-	-	13	101	-	-	101	-	-	-	-	-	-	1,482	-
2a.1.5.25	Main Steam - RCA	-	364	9	30	447	-	-	163	1,013	1,013	-	-	5,166	-	-	-	-	209,799	5,146	-
2a.1.5.26	Repairable Spare Snubbers	-	6	0	0	1	-	-	2	8	8	-	-	12	-	-	-	-	490	82	-
2a.1.5.27	Steam Exclusion	-	2	-	-	-	-	-	0	2	-	-	2	-	-	-	-	-	-	32	-
2a.1.5.28	Steam Exclusion - RCA	-	4	0	0	2	-	-	1	8	8	-	-	24	-	-	-	-	966	47	-
2a.1.5.29	Steam Generator Blowdown	-	398	20	21	165	179	-	174	957	957	-	-	1,906	631	-	-	-	119,126	5,778	-
2a.1.5.30	Steam Generators	-	5	-	-	-	-	-	1	5	-	-	5	-	-	-	-	-	-	75	-
2a.1.5.31	Turbine & Moisture Separators	-	329	-	-	-	-	-	49	379	-	-	379	-	-	-	-	-	-	5,472	-
2a.1.5.32	Turbine Oil Purification	-	46	-	-	-	-	-	7	53	-	-	53	-	-	-	-	-	-	757	-
2a.1.5.33	Water Treatment	-	394	-	-	-	-	-	59	453	-	-	453	-	-	-	-	-	-	6,677	-
2a.1.5.34	Water Treatment - RCA	-	19	0	1	10	-	-	6	37	37	-	-	115	-	-	-	-	4,652	252	-

Table D-2
Prairie Island Nuclear Generating Plant, Unit 2
DECON Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
2a.1.5	Totals	-	3,437	39	85	1,125	179	-	867	5,733	3,174	-	2,559	13,010	631	-	-	-	570,056	54,280	-
2a.1.6	Scaffolding in support of decommissioning	-	2,833	24	8	97	25	-	733	3,721	3,721	-	-	1,012	89	-	-	-	51,445	26,270	-
2a.1	Subtotal Period 2a Activity Costs	855	23,653	26,885	3,859	3,105	16,875	553	25,350	101,134	98,575	-	2,559	38,625	30,835	125	673	-	4,223,340	208,777	6,073
Period 2a Additional Costs																					
2a.2.1	Remedial Action Surveys	-	-	-	-	-	-	1,560	468	2,027	2,027	-	-	-	-	-	-	-	-	20,388	-
2a.2.2	Retired RPV upper internals package	1	659	785	107	-	1,439	-	1,437	4,427	4,427	-	-	-	2,097	125	-	-	205,890	2,175	87
2a.2	Subtotal Period 2a Additional Costs	1	659	785	107	-	1,439	1,560	1,905	6,454	6,454	-	-	-	2,097	125	-	-	205,890	22,562	87
Period 2a Collateral Costs																					
2a.3.1	Process decommissioning water waste	51	-	33	86	-	135	-	75	381	381	-	-	-	323	-	-	-	19,358	63	-
2a.3.3	Small tool allowance	-	251	-	-	-	-	-	38	289	260	-	29	-	-	-	-	-	-	-	-
2a.3.4	Spent Fuel Capital and Transfer	-	-	-	-	-	-	326	49	375	-	375	-	-	-	-	-	-	-	-	-
2a.3.5	Retention and Severance	-	-	-	-	-	-	6,105	916	7,021	7,021	-	-	-	-	-	-	-	-	-	-
2a.3.6	Prairie Island Indian Community Payments	-	-	-	-	-	-	1,224	-	1,224	-	1,224	-	-	-	-	-	-	-	-	-
2a.3	Subtotal Period 2a Collateral Costs	51	251	33	86	-	135	7,655	1,078	9,289	7,661	1,599	29	-	323	-	-	-	19,358	63	-
Period 2a Period-Dependent Costs																					
2a.4.1	Decon supplies	68	-	-	-	-	-	-	17	85	85	-	-	-	-	-	-	-	-	-	-
2a.4.2	Insurance	-	-	-	-	-	-	501	50	551	551	-	-	-	-	-	-	-	-	-	-
2a.4.3	Property taxes	-	-	-	-	-	-	2,507	251	2,758	2,758	-	-	-	-	-	-	-	-	-	-
2a.4.4	Health physics supplies	-	1,622	-	-	-	-	-	406	2,028	2,028	-	-	-	-	-	-	-	-	-	-
2a.4.5	Heavy equipment rental	-	2,153	-	-	-	-	-	323	2,477	2,477	-	-	-	-	-	-	-	-	-	-
2a.4.6	Disposal of DAW generated	-	-	89	26	-	331	-	95	541	541	-	-	-	4,063	-	-	-	81,252	133	-
2a.4.7	Plant energy budget	-	-	-	-	-	-	1,411	212	1,623	1,623	-	-	-	-	-	-	-	-	-	-
2a.4.8	NRC Fees	-	-	-	-	-	-	389	39	428	428	-	-	-	-	-	-	-	-	-	-
2a.4.9	Emergency Planning Fees	-	-	-	-	-	-	1,259	126	1,385	-	1,385	-	-	-	-	-	-	-	-	-
2a.4.10	Fixed Overhead	-	-	-	-	-	-	1,214	182	1,396	1,396	-	-	-	-	-	-	-	-	-	-
2a.4.11	Spent Fuel Pool O&M	-	-	-	-	-	-	394	59	453	-	453	-	-	-	-	-	-	-	-	-
2a.4.12	ISFSI Operating Costs	-	-	-	-	-	-	51	8	58	-	58	-	-	-	-	-	-	-	-	-
2a.4.13	Railroad Track Maintenance	-	-	-	-	-	-	265	40	305	305	-	-	-	-	-	-	-	-	-	-
2a.4.14	Security Staff Cost	-	-	-	-	-	-	6,661	999	7,661	7,661	-	-	-	-	-	-	-	-	-	110,166
2a.4.15	DOC Staff Cost	-	-	-	-	-	-	13,492	2,024	15,516	15,516	-	-	-	-	-	-	-	-	-	155,048
2a.4.16	Utility Staff Cost	-	-	-	-	-	-	17,880	2,682	20,562	20,562	-	-	-	-	-	-	-	-	-	288,676
2a.4	Subtotal Period 2a Period-Dependent Costs	68	3,776	89	26	-	331	46,025	7,512	57,825	55,929	1,896	-	-	4,063	-	-	-	81,252	133	553,890
2a.0	TOTAL PERIOD 2a COST	974	28,339	27,792	4,078	3,105	18,780	55,792	35,844	174,703	168,620	3,495	2,588	38,625	37,317	250	673	-	4,529,841	231,534	560,049
PERIOD 2b - Site Decontamination																					
Period 2b Direct Decommissioning Activities																					
Disposal of Plant Systems																					
2b.1.1.1	ADT & Misc Ventilation	-	24	0	1	13	3	-	9	50	50	-	-	153	9	-	-	-	6,814	363	-
2b.1.1.2	Aux Bldg Normal Ventilation	-	67	2	5	60	11	-	29	174	174	-	-	692	39	-	-	-	30,671	1,013	-
2b.1.1.3	Aux Bldg Special Ventilation	-	13	0	0	6	2	-	5	26	26	-	-	70	6	-	-	-	3,243	197	-
2b.1.1.4	Battery Rm Special Ventilation	-	1	-	-	-	-	-	0	2	-	-	2	-	-	-	-	-	-	24	-
2b.1.1.5	Boron Recycle	0	4	0	0	0	3	-	2	9	9	-	-	3	9	-	-	-	709	50	-
2b.1.1.6	Chemical & Volume Control	722	902	59	44	204	560	-	770	3,260	3,260	-	-	2,356	1,977	-	-	-	225,854	23,197	-
2b.1.1.7	Cold Chemical Lab Ventilation	-	1	-	-	-	-	-	0	1	-	-	1	-	-	-	-	-	-	9	-
2b.1.1.8	Component Cooling - RCA	-	617	21	70	1,038	-	-	322	2,068	2,068	-	-	11,996	-	-	-	-	487,169	8,583	-
2b.1.1.9	Containment Cooling	-	31	-	-	-	-	-	5	35	-	-	35	-	-	-	-	-	-	502	-
2b.1.1.10	Containment Cooling - RCA	-	288	5	16	237	-	-	110	656	656	-	-	2,743	-	-	-	-	111,390	3,949	-
2b.1.1.11	Containment Hydrogen Control - RCA	-	35	0	1	12	-	-	11	60	60	-	-	141	-	-	-	-	5,742	494	-
2b.1.1.12	Containment Spray - RCA	-	186	3	8	126	-	-	67	389	389	-	-	1,453	-	-	-	-	59,019	2,617	-
2b.1.1.13	Containment Ventilation	-	224	23	38	408	205	-	177	1,075	1,075	-	-	4,721	722	-	-	-	239,450	3,375	-
2b.1.1.14	Control/Relay/Cmptr Rm Vent	-	30	1	2	23	6	-	13	74	74	-	-	260	20	-	-	-	11,915	454	-
2b.1.1.15	Cooling Water	-	139	-	-	-	-	-	21	160	-	-	160	-	-	-	-	-	-	2,344	-
2b.1.1.16	Cooling Water - RCA	-	456	15	49	730	-	-	232	1,482	1,482	-	-	8,442	-	-	-	-	342,822	6,311	-
2b.1.1.17	Cranes/Hoists/Elevators - RCA	-	3	0	1	9	-	-	2	15	15	-	-	103	-	-	-	-	4,184	48	-
2b.1.1.18	D3 Emergency Diesel	-	9	-	-	-	-	-	1	10	-	-	10	-	-	-	-	-	-	141	-
2b.1.1.19	D4 Emergency Diesel	-	9	-	-	-	-	-	1	10	-	-	10	-	-	-	-	-	-	141	-
2b.1.1.20	D5 Emergency Diesel	-	0	-	-	-	-	-	0	0	-	-	0	-	-	-	-	-	-	5	-
2b.1.1.21	Electrical - Clean	-	1,502	-	-	-	-	-	225	1,727	-	-	1,727	-	-	-	-	-	-	24,276	-
2b.1.1.22	Electrical - Contaminated	-	461	5	13	173	21	-	149	821	821	-	-	1,997	75	-	-	-	86,080	6,503	-
2b.1.1.23	Electrical - Decontaminated	-	2,866	33	109	1,622	-	-	980	5,610	5,610	-	-	18,753	-	-	-	-	761,569	38,423	-

Table D-2
Prairie Island Nuclear Generating Plant, Unit 2
DECON Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Disposal of Plant Systems (continued)																					
2b.1.1.24	Filter Rm Ventilation	-	4	0	0	2	0	-	2	9	9	-	-	24	1	-	-	-	1,020	69	-
2b.1.1.25	Fire Protection & Detection	-	178	-	-	-	-	-	27	205	-	-	205	-	-	-	-	-	-	3,009	-
2b.1.1.26	Fire Protection & Detection - RCA	-	236	3	11	158	-	-	85	492	492	-	-	1,828	-	-	-	-	74,245	3,134	-
2b.1.1.27	Fuel Handling	-	71	1	2	17	14	-	24	130	130	-	-	200	49	-	-	-	11,396	1,101	-
2b.1.1.28	Fuel Oil	-	1	-	-	-	-	-	0	1	-	-	1	-	-	-	-	-	-	9	-
2b.1.1.29	HVAC - Clean	-	132	-	-	-	-	-	20	151	-	-	151	-	-	-	-	-	-	2,373	-
2b.1.1.30	HVAC - Contaminated	-	1,222	26	69	929	115	-	487	2,848	2,848	-	-	10,745	405	-	-	-	463,144	16,579	-
2b.1.1.31	Heating	-	279	-	-	-	-	-	42	321	-	-	321	-	-	-	-	-	-	4,804	-
2b.1.1.32	Heating - RCA	-	323	3	11	165	-	-	107	609	609	-	-	1,907	-	-	-	-	77,458	4,086	-
2b.1.1.33	Hot Lab & Sample Rm Ventilation	-	19	0	1	9	1	-	6	37	37	-	-	107	4	-	-	-	4,632	285	-
2b.1.1.34	Incore Instrumentation	0	29	1	1	5	16	-	13	67	67	-	-	60	58	-	-	-	6,264	458	-
2b.1.1.35	Misc Drains & Vents	-	223	12	9	40	121	-	95	500	500	-	-	458	426	-	-	-	46,850	3,180	-
2b.1.1.36	Misc Lab & Service Areas Vent	-	123	8	6	32	70	-	55	293	293	-	-	370	244	-	-	-	31,186	1,713	-
2b.1.1.37	Miscellaneous Gas	-	63	-	-	-	-	-	9	72	-	-	72	-	-	-	-	-	-	1,073	-
2b.1.1.38	Miscellaneous Gas - RCA	-	129	1	3	52	-	-	41	226	226	-	-	600	-	-	-	-	24,378	1,636	-
2b.1.1.39	Radiation Monitoring	-	6	-	-	-	-	-	1	7	-	-	7	-	-	-	-	-	-	111	-
2b.1.1.40	Radiation Monitoring - RCA	-	62	1	2	27	-	-	20	112	112	-	-	316	-	-	-	-	12,826	782	-
2b.1.1.41	Reactor Coolant	158	227	20	12	20	208	-	195	839	839	-	-	229	730	-	-	-	57,672	5,517	-
2b.1.1.42	Reactor Hot Sampling	135	121	10	5	5	89	-	123	489	489	-	-	54	312	-	-	-	22,919	3,686	-
2b.1.1.43	Reactor Makeup	-	36	-	-	-	-	-	5	41	-	-	41	-	-	-	-	-	-	583	-
2b.1.1.44	Reactor Makeup - RCA	-	4	0	0	2	-	-	1	8	8	-	-	28	-	-	-	-	1,148	47	-
2b.1.1.45	Reactor Vessel	9	17	0	0	2	4	-	10	43	43	-	-	22	14	-	-	-	1,826	385	-
2b.1.1.46	Residual Heat Removal	336	374	84	66	247	924	-	548	2,578	2,578	-	-	2,853	3,244	-	-	-	330,651	7,112	-
2b.1.1.47	Safeguards Chilled Water	-	4	-	-	-	-	-	1	5	-	-	5	-	-	-	-	-	-	75	-
2b.1.1.48	Safety Injection	-	836	40	56	577	329	-	390	2,228	2,228	-	-	6,676	1,161	-	-	-	347,600	12,284	-
2b.1.1.49	Sampling	-	51	3	2	3	27	-	20	105	105	-	-	37	93	-	-	-	7,697	714	-
2b.1.1.50	Service Bldg & New Cmptr Vent	-	0	-	-	-	-	-	0	0	-	-	0	-	-	-	-	-	-	6	-
2b.1.1.51	Shield Bldg Ventilation	-	114	13	19	175	138	-	94	554	554	-	-	2,028	484	-	-	-	114,378	1,743	-
2b.1.1.52	Station & Instrument Air	-	140	-	-	-	-	-	21	161	-	-	161	-	-	-	-	-	-	2,424	-
2b.1.1.53	Station & Instrument Air - RCA	-	288	3	9	141	-	-	95	535	535	-	-	1,625	-	-	-	-	65,986	3,638	-
2b.1.1.54	Turbine Bldg Traps & Drains	-	26	-	-	-	-	-	4	30	-	-	30	-	-	-	-	-	-	462	-
2b.1.1.55	Turbine Bldg Traps & Drains - RCA	-	28	0	1	16	-	-	10	55	55	-	-	180	-	-	-	-	7,321	344	-
2b.1.1.56	Turbine Bldg Ventilation	-	40	-	-	-	-	-	6	46	-	-	46	-	-	-	-	-	-	655	-
2b.1.1.57	Unit Coolers	-	20	-	-	-	-	-	3	23	-	-	23	-	-	-	-	-	-	332	-
2b.1.1.58	Unit Coolers - RCA	-	54	0	1	20	-	-	17	93	93	-	-	232	-	-	-	-	9,413	690	-
2b.1.1.59	Waste Gas Disposal	531	457	40	35	212	381	-	516	2,173	2,173	-	-	2,453	1,358	-	-	-	188,334	14,308	-
2b.1.1.60	Waste Liquid Disposal	1,386	1,733	108	76	316	1,019	-	1,451	6,089	6,089	-	-	3,655	3,594	-	-	-	385,370	44,485	-
2b.1.1.61	Waste Solid Disposal	111	139	11	8	34	112	-	126	541	541	-	-	389	393	-	-	-	41,732	3,481	-
2b.1.1	Totals	3,390	15,678	558	763	7,868	4,377	-	7,798	40,433	37,423	-	3,010	90,963	15,429	-	-	-	4,712,076	270,390	-
2b.1.2	Scaffolding in support of decommissioning	-	3,542	30	10	121	32	-	916	4,651	4,651	-	-	1,265	112	-	-	-	64,307	32,837	-
Decontamination of Site Buildings																					
2b.1.3.1	Reactor	1,150	2,624	139	853	193	11,080	-	4,172	20,210	20,210	-	-	2,230	57,418	-	-	-	3,559,977	50,853	-
2b.1.3.2	Auxiliary	1,223	400	12	80	92	582	-	884	3,272	3,272	-	-	1,060	3,355	-	-	-	332,498	23,808	-
2b.1.3.3	Backwash Waste Receiving Tank	-	27	1	11	-	87	-	30	158	158	-	-	-	507	-	-	-	43,896	299	-
2b.1.3.4	Drum Transfer & Truck Loading Enclosure	17	8	0	2	2	13	-	14	56	56	-	-	19	74	-	-	-	7,118	368	-
2b.1.3.5	LLRW Storage Enclosure	117	51	1	11	3	87	-	95	366	366	-	-	38	502	-	-	-	44,971	2,424	-
2b.1.3.6	Radwaste	52	23	1	5	4	39	-	43	166	166	-	-	42	225	-	-	-	21,136	1,082	-
2b.1.3.7	Resin Disposal	15	11	0	2	7	12	-	15	64	64	-	-	83	69	-	-	-	9,271	383	-
2b.1.3	Totals	2,574	3,145	155	964	300	11,900	-	5,253	24,292	24,292	-	-	3,471	62,151	-	-	-	4,018,868	79,216	-
2b.1.4	Prepare/submit License Termination Plan	-	-	-	-	-	-	206	31	236	236	-	-	-	-	-	-	-	-	-	1,751
2b.1.5	Receive NRC approval of termination plan									a											
2b.1	Subtotal Period 2b Activity Costs	5,965	22,365	744	1,737	8,290	16,309	206	13,998	69,612	66,602	-	3,010	95,700	77,691	-	-	-	8,795,250	382,443	1,751
Period 2b Additional Costs																					
2b.2.1	Remedial Action Surveys	-	-	-	-	-	-	1,930	579	2,509	2,509	-	-	-	-	-	-	-	-	25,228	-
2b.2.2	Operational Equipment	-	-	9	29	312	-	-	52	402	402	-	-	5,855	-	-	-	-	146,375	16	-
2b.2	Subtotal Period 2b Additional Costs	-	-	9	29	312	-	1,930	631	2,911	2,911	-	-	5,855	-	-	-	-	146,375	25,244	-
Period 2b Collateral Costs																					
2b.3.1	Process decommissioning water waste	167	-	112	289	-	453	-	251	1,272	1,272	-	-	-	1,081	-	-	-	64,837	211	-
2b.3.2	Process decommissioning chemical flush waste	3	-	114	431	-	858	-	292	1,700	1,700	-	-	-	1,154	-	-	-	122,948	216	-
2b.3.3	Small tool allowance	-	414	-	-	-	-	-	62	476	476	-	-	-	-	-	-	-	-	-	-
2b.3.4	Spent Fuel Capital and Transfer	-	-	-	-	-	-	5,437	815	6,252	-	6,252	-	-	-	-	-	-	-	-	-

Table D-2
Prairie Island Nuclear Generating Plant, Unit 2
DECON Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 2b Collateral Costs (continued)																					
2b.3.5	Retention and Severance	-	-	-	-	-	-	4,127	619	4,746	4,746	-	-	-	-	-	-	-	-	-	-
2b.3.6	Prairie Island Indian Community Payments	-	-	-	-	-	-	1,517	-	1,517	-	1,517	-	-	-	-	-	-	-	-	-
2b.3.7	On-site survey and release of 0.437 tons clean metallic waste	-	-	-	-	-	-	1	0	1	1	-	-	-	-	-	-	-	-	-	-
2b.3	Subtotal Period 2b Collateral Costs	170	414	226	721	-	1,311	11,082	2,040	15,964	8,195	7,769	-	-	2,234	-	-	-	187,785	427	-
Period 2b Period-Dependent Costs																					
2b.4.1	Decon supplies	1,135	-	-	-	-	-	-	284	1,419	1,419	-	-	-	-	-	-	-	-	-	-
2b.4.2	Insurance	-	-	-	-	-	-	620	62	682	682	-	-	-	-	-	-	-	-	-	-
2b.4.3	Property taxes	-	-	-	-	-	-	2,983	298	3,281	3,281	-	-	-	-	-	-	-	-	-	-
2b.4.4	Health physics supplies	-	2,580	-	-	-	-	-	645	3,225	3,225	-	-	-	-	-	-	-	-	-	-
2b.4.5	Heavy equipment rental	-	2,740	-	-	-	-	-	411	3,151	3,151	-	-	-	-	-	-	-	-	-	-
2b.4.6	Disposal of DAW generated	-	-	115	34	-	431	-	124	704	704	-	-	-	5,291	-	-	-	105,826	173	-
2b.4.7	Plant energy budget	-	-	-	-	-	-	1,379	207	1,586	1,586	-	-	-	-	-	-	-	-	-	-
2b.4.8	NRC Fees	-	-	-	-	-	-	481	48	529	529	-	-	-	-	-	-	-	-	-	-
2b.4.9	Emergency Planning Fees	-	-	-	-	-	-	1,558	156	1,714	-	1,714	-	-	-	-	-	-	-	-	-
2b.4.10	Fixed Overhead	-	-	-	-	-	-	1,503	225	1,728	1,728	-	-	-	-	-	-	-	-	-	-
2b.4.11	Spent Fuel Pool O&M	-	-	-	-	-	-	487	73	560	-	560	-	-	-	-	-	-	-	-	-
2b.4.12	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	246	37	282	282	-	-	-	-	-	-	-	-	-	-
2b.4.13	ISFSI Operating Costs	-	-	-	-	-	-	63	9	72	-	72	-	-	-	-	-	-	-	-	-
2b.4.14	Railroad Track Maintenance	-	-	-	-	-	-	70	10	80	80	-	-	-	-	-	-	-	-	-	-
2b.4.15	Security Staff Cost	-	-	-	-	-	-	8,243	1,236	9,479	9,479	-	-	-	-	-	-	-	-	-	136,323
2b.4.16	DOC Staff Cost	-	-	-	-	-	-	16,150	2,422	18,572	18,572	-	-	-	-	-	-	-	-	-	184,288
2b.4.17	Utility Staff Cost	-	-	-	-	-	-	21,222	3,183	24,405	24,405	-	-	-	-	-	-	-	-	-	342,069
2b.4	Subtotal Period 2b Period-Dependent Costs	1,135	5,320	115	34	-	431	55,004	9,432	71,472	69,125	2,346	-	-	5,291	-	-	-	105,826	173	662,680
2b.0	TOTAL PERIOD 2b COST	7,270	28,099	1,095	2,520	8,602	18,050	68,221	26,102	159,958	146,833	10,115	3,010	101,555	85,217	-	-	-	9,235,236	408,286	664,431
PERIOD 2c - Spent fuel delay prior to SFP decon																					
Period 2c Direct Decommissioning Activities																					
Period 2c Additional Costs																					
2c.2.1	Security Modifications	-	-	-	-	-	-	4,348	652	5,000	5,000	-	-	-	-	-	-	-	-	-	-
2c.2	Subtotal Period 2c Additional Costs	-	-	-	-	-	-	4,348	652	5,000	5,000	-	-	-	-	-	-	-	-	-	-
Period 2c Collateral Costs																					
2c.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	66,610	9,992	76,602	-	76,602	-	-	-	-	-	-	-	-	-
2c.3.2	Retention and Severance	-	-	-	-	-	-	2,034	305	2,339	2,339	-	-	-	-	-	-	-	-	-	-
2c.3.3	Prairie Island Indian Community Payments	-	-	-	-	-	-	1,630	-	1,630	-	1,630	-	-	-	-	-	-	-	-	-
2c.3	Subtotal Period 2c Collateral Costs	-	-	-	-	-	-	70,274	10,297	80,571	2,339	78,232	-	-	-	-	-	-	-	-	-
Period 2c Period-Dependent Costs																					
2c.4.1	Insurance	-	-	-	-	-	-	666	67	733	733	-	-	-	-	-	-	-	-	-	-
2c.4.2	Property taxes	-	-	-	-	-	-	3,060	306	3,366	3,366	-	-	-	-	-	-	-	-	-	-
2c.4.3	Health physics supplies	-	270	-	-	-	-	-	67	337	337	-	-	-	-	-	-	-	-	-	-
2c.4.4	Disposal of DAW generated	-	-	12	3	-	44	-	13	72	72	-	-	-	538	-	-	-	10,761	18	-
2c.4.5	Plant energy budget	-	-	-	-	-	-	395	59	454	454	-	-	-	-	-	-	-	-	-	-
2c.4.6	NRC Fees	-	-	-	-	-	-	305	31	336	336	-	-	-	-	-	-	-	-	-	-
2c.4.7	Emergency Planning Fees	-	-	-	-	-	-	1,674	167	1,842	-	1,842	-	-	-	-	-	-	-	-	-
2c.4.8	Fixed Overhead	-	-	-	-	-	-	1,615	242	1,857	1,857	-	-	-	-	-	-	-	-	-	-
2c.4.9	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	53	8	61	61	-	-	-	-	-	-	-	-	-	-
2c.4.10	ISFSI Operating Costs	-	-	-	-	-	-	67	10	77	-	77	-	-	-	-	-	-	-	-	-
2c.4.11	Railroad Track Maintenance	-	-	-	-	-	-	75	11	86	86	-	-	-	-	-	-	-	-	-	-
2c.4.12	Security Staff Cost	-	-	-	-	-	-	8,857	1,329	10,185	10,185	-	-	-	-	-	-	-	-	-	146,478
2c.4.13	Utility Staff Cost	-	-	-	-	-	-	6,575	986	7,561	7,561	-	-	-	-	-	-	-	-	-	107,146
2c.4	Subtotal Period 2c Period-Dependent Costs	-	270	12	3	-	44	23,343	3,296	26,968	25,049	1,919	-	-	538	-	-	-	10,761	18	253,623
2c.0	TOTAL PERIOD 2c COST	-	270	12	3	-	44	97,965	14,245	112,539	32,387	80,151	-	-	538	-	-	-	10,761	18	253,623
PERIOD 2d - Decontamination Following Wet Fuel Storage																					
Period 2d Direct Decommissioning Activities																					
2d.1.1	Remove spent fuel racks	328	32	94	32	-	595	-	335	1,416	1,416	-	-	-	2,092	-	-	-	138,298	576	-
Disposal of Plant Systems																					
2d.1.2.1	Electrical - Contaminated - Fuel Pool	-	197	2	6	75	9	-	64	353	353	-	-	864	33	-	-	-	37,250	2,783	-
2d.1.2.2	Electrical - Decontaminated - Fuel Pool	-	1,230	14	47	698	-	-	421	2,410	2,410	-	-	8,069	-	-	-	-	327,668	16,495	-

Table D-2
Prairie Island Nuclear Generating Plant, Unit 2
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(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Disposal of Plant Systems (continued)																					
2d.1.2.3	Fire Protection & Detection - RCA Fuel P	-	36	1	2	25	-	-	13	76	76	-	-	286	-	-	-	-	11,622	476	-
2d.1.2.4	HVAC - Contaminated - Fuel Pool	-	549	12	31	418	52	-	219	1,280	1,280	-	-	4,828	182	-	-	-	208,080	7,448	-
2d.1.2.5	Safeguards Chilled Water - RCA	-	4	0	0	2	-	-	1	8	8	-	-	26	-	-	-	-	1,045	51	-
2d.1.2.6	Spent Fuel Pool Cooling	31	35	3	2	3	30	-	33	137	137	-	-	39	107	-	-	-	8,635	882	-
2d.1.2.7	Spent Fuel Pool Normal Ventilation	-	26	1	2	23	3	-	11	66	66	-	-	265	12	-	-	-	11,532	394	-
2d.1.2	Totals	31	2,077	32	89	1,244	95	-	761	4,328	4,328	-	-	14,376	333	-	-	-	605,832	28,530	-
Decontamination of Site Buildings																					
2d.1.3.1	Fuel Handling of Aux Building	975	1,082	9	32	209	173	-	838	3,319	3,319	-	-	2,417	944	-	-	-	177,818	30,401	-
2d.1.3	Totals	975	1,082	9	32	209	173	-	838	3,319	3,319	-	-	2,417	944	-	-	-	177,818	30,401	-
2d.1.4	Scaffolding in support of decommissioning	-	708	6	2	24	6	-	183	930	930	-	-	253	22	-	-	-	12,861	6,567	-
2d.1	Subtotal Period 2d Activity Costs	1,334	3,900	142	155	1,477	868	-	2,118	9,994	9,994	-	-	17,046	3,391	-	-	-	934,809	66,074	-
Period 2d Additional Costs																					
2d.2.1	License Termination Survey Planning	-	-	-	-	-	-	845	253	1,098	1,098	-	-	-	-	-	-	-	-	-	6,240
2d.2.2	Remedial Action Surveys	-	-	-	-	-	-	1,237	371	1,608	1,608	-	-	-	-	-	-	-	-	16,173	-
2d.2	Subtotal Period 2d Additional Costs	-	-	-	-	-	-	2,082	625	2,706	2,706	-	-	-	-	-	-	-	-	16,173	6,240
Period 2d Collateral Costs																					
2d.3.1	Process decommissioning water waste	39	-	27	70	-	109	-	60	306	306	-	-	-	261	-	-	-	15,670	51	-
2d.3.2	Process decommissioning chemical flush waste	0	-	1	5	-	10	-	3	20	20	-	-	-	13	-	-	-	1,422	2	-
2d.3.3	Small tool allowance	-	79	-	-	-	-	-	12	91	91	-	-	-	-	-	-	-	-	-	-
2d.3.4	Decommissioning Equipment Disposition	-	-	144	55	575	150	-	147	1,071	1,071	-	-	6,000	529	-	-	-	304,968	88	-
2d.3.5	Spent Fuel Capital and Transfer	-	-	-	-	-	-	13,144	1,972	15,115	-	15,115	-	-	-	-	-	-	-	-	-
2d.3.6	Prairie Island Indian Community Payments	-	-	-	-	-	-	971	-	971	-	971	-	-	-	-	-	-	-	-	-
2d.3	Subtotal Period 2d Collateral Costs	39	79	172	130	575	270	14,114	2,194	17,573	1,488	16,086	-	6,000	804	-	-	-	322,060	142	-
Period 2d Period-Dependent Costs																					
2d.4.1	Decon supplies	218	-	-	-	-	-	-	54	272	272	-	-	-	-	-	-	-	-	-	-
2d.4.2	Insurance	-	-	-	-	-	-	398	40	437	437	-	-	-	-	-	-	-	-	-	-
2d.4.3	Property taxes	-	-	-	-	-	-	1,740	174	1,914	1,914	-	-	-	-	-	-	-	-	-	-
2d.4.4	Health physics supplies	-	742	-	-	-	-	-	186	928	928	-	-	-	-	-	-	-	-	-	-
2d.4.5	Heavy equipment rental	-	1,757	-	-	-	-	-	264	2,020	2,020	-	-	-	-	-	-	-	-	-	-
2d.4.6	Disposal of DAW generated	-	-	44	13	-	163	-	47	266	266	-	-	-	2,000	-	-	-	40,003	65	-
2d.4.7	Plant energy budget	-	-	-	-	-	-	471	71	542	542	-	-	-	-	-	-	-	-	-	-
2d.4.8	NRC Fees	-	-	-	-	-	-	256	26	282	282	-	-	-	-	-	-	-	-	-	-
2d.4.9	Emergency Planning Fees	-	-	-	-	-	-	999	100	1,099	-	1,099	-	-	-	-	-	-	-	-	-
2d.4.10	Fixed Overhead	-	-	-	-	-	-	963	144	1,108	1,108	-	-	-	-	-	-	-	-	-	-
2d.4.11	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	315	47	362	362	-	-	-	-	-	-	-	-	-	-
2d.4.12	ISFSI Operating Costs	-	-	-	-	-	-	40	6	46	-	46	-	-	-	-	-	-	-	-	-
2d.4.13	Railroad Track Maintenance	-	-	-	-	-	-	45	7	52	52	-	-	-	-	-	-	-	-	-	-
2d.4.14	Security Staff Cost	-	-	-	-	-	-	5,123	768	5,891	5,891	-	-	-	-	-	-	-	-	-	84,157
2d.4.15	DOC Staff Cost	-	-	-	-	-	-	6,065	910	6,975	6,975	-	-	-	-	-	-	-	-	-	69,996
2d.4.16	Utility Staff Cost	-	-	-	-	-	-	7,796	1,169	8,966	8,527	439	-	-	-	-	-	-	-	-	126,236
2d.4	Subtotal Period 2d Period-Dependent Costs	218	2,499	44	13	-	163	24,212	4,013	31,160	29,576	1,584	-	-	2,000	-	-	-	40,003	65	280,390
2d.0	TOTAL PERIOD 2d COST	1,591	6,478	357	298	2,052	1,301	40,408	8,949	61,434	43,764	17,670	-	23,046	6,195	-	-	-	1,296,872	82,455	286,630
PERIOD 2f - License Termination																					
Period 2f Direct Decommissioning Activities																					
2f.1.1	ORISE confirmatory survey	-	-	-	-	-	-	176	53	229	229	-	-	-	-	-	-	-	-	-	-
2f.1.2	Terminate license									a											
2f.1	Subtotal Period 2f Activity Costs	-	-	-	-	-	-	176	53	229	229	-	-	-	-	-	-	-	-	-	-
Period 2f Additional Costs																					
2f.2.1	License Termination Survey	-	-	-	-	-	-	7,406	2,222	9,628	9,628	-	-	-	-	-	-	-	-	102,642	3,120
2f.2	Subtotal Period 2f Additional Costs	-	-	-	-	-	-	7,406	2,222	9,628	9,628	-	-	-	-	-	-	-	-	102,642	3,120
Period 2f Collateral Costs																					
2f.3.1	DOC staff relocation expenses	-	-	-	-	-	-	1,189	178	1,367	1,367	-	-	-	-	-	-	-	-	-	-
2f.3.2	Prairie Island Indian Community Payments	-	-	-	-	-	-	934	-	934	-	934	-	-	-	-	-	-	-	-	-
2f.3	Subtotal Period 2f Collateral Costs	-	-	-	-	-	-	2,122	178	2,300	1,367	934	-	-	-	-	-	-	-	-	-

Table D-2
Prairie Island Nuclear Generating Plant, Unit 2
DECON Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 2f Period-Dependent Costs																					
2f.4.1	Insurance	-	-	-	-	-	-	382	38	420	420	-	-	-	-	-	-	-	-	-	-
2f.4.2	Property taxes	-	-	-	-	-	-	1,626	163	1,789	1,789	-	-	-	-	-	-	-	-	-	-
2f.4.3	Health physics supplies	-	602	-	-	-	-	-	150	752	752	-	-	-	-	-	-	-	-	-	-
2f.4.4	Disposal of DAW generated	-	-	7	2	-	27	-	8	44	44	-	-	-	334	-	-	-	6,685	11	-
2f.4.5	Plant energy budget	-	-	-	-	-	-	227	34	261	261	-	-	-	-	-	-	-	-	-	-
2f.4.6	NRC Fees	-	-	-	-	-	-	272	27	299	299	-	-	-	-	-	-	-	-	-	-
2f.4.7	Emergency Planning Fees	-	-	-	-	-	-	51	5	56	-	56	-	-	-	-	-	-	-	-	-
2f.4.8	Fixed Overhead	-	-	-	-	-	-	926	139	1,065	1,065	-	-	-	-	-	-	-	-	-	-
2f.4.9	ISFSI Operating Costs	-	-	-	-	-	-	39	6	44	-	44	-	-	-	-	-	-	-	-	-
2f.4.10	Railroad Track Maintenance	-	-	-	-	-	-	43	6	50	50	-	-	-	-	-	-	-	-	-	-
2f.4.11	Security Staff Cost	-	-	-	-	-	-	4,924	739	5,663	5,663	-	-	-	-	-	-	-	-	-	80,898
2f.4.12	DOC Staff Cost	-	-	-	-	-	-	4,101	615	4,716	4,716	-	-	-	-	-	-	-	-	-	46,283
2f.4.13	Utility Staff Cost	-	-	-	-	-	-	3,854	578	4,433	4,007	426	-	-	-	-	-	-	-	-	59,507
2f.4	Subtotal Period 2f Period-Dependent Costs	-	602	7	2	-	27	16,445	2,508	19,592	19,066	526	-	-	334	-	-	-	6,685	11	186,687
2f.0	TOTAL PERIOD 2f COST	-	602	7	2	-	27	26,150	4,962	31,750	30,290	1,460	-	-	334	-	-	-	6,685	102,653	189,807
PERIOD 2 TOTALS		9,835	63,787	29,263	6,901	13,758	38,202	288,537	90,101	540,384	421,894	112,892	5,598	163,227	129,602	250	673	-	15,079,400	824,945	1,954,541
PERIOD 3b - Site Restoration																					
Period 3b Direct Decommissioning Activities																					
Demolition of Remaining Site Buildings																					
3b.1.1.1	Reactor	-	4,256	-	-	-	-	-	638	4,895	-	-	4,895	-	-	-	-	-	-	44,679	-
3b.1.1.2	Auxiliary	-	1,897	-	-	-	-	-	285	2,182	-	-	2,182	-	-	-	-	-	-	11,902	-
3b.1.1.3	Condensate Storage Tank Foundation	-	6	-	-	-	-	-	1	7	-	-	7	-	-	-	-	-	-	33	-
3b.1.1.4	Construction Warehouse & Fab Shop	-	118	-	-	-	-	-	18	135	-	-	135	-	-	-	-	-	-	1,405	-
3b.1.1.5	D3/D4 Emergency Generator	-	13	-	-	-	-	-	2	15	-	-	15	-	-	-	-	-	-	84	-
3b.1.1.6	Drum Transfer & Truck Loading Enclosure	-	19	-	-	-	-	-	3	21	-	-	21	-	-	-	-	-	-	221	-
3b.1.1.7	Hydrogen House	-	6	-	-	-	-	-	1	7	-	-	7	-	-	-	-	-	-	47	-
3b.1.1.8	LLRW Storage Enclosure	-	121	-	-	-	-	-	18	139	-	-	139	-	-	-	-	-	-	853	-
3b.1.1.9	Misc Structures 2017	-	1,391	-	-	-	-	-	209	1,599	-	-	1,599	-	-	-	-	-	-	12,939	-
3b.1.1.10	Radwaste	-	165	-	-	-	-	-	25	190	-	-	190	-	-	-	-	-	-	1,400	-
3b.1.1.11	Resin Disposal	-	13	-	-	-	-	-	2	15	-	-	15	-	-	-	-	-	-	120	-
3b.1.1.12	Structures below 3' below grade	-	1,713	-	-	-	-	-	257	1,969	-	-	1,969	-	-	-	-	-	-	9,238	-
3b.1.1.13	Sulfuric Acid Tank Enclosure	-	3	-	-	-	-	-	0	3	-	-	3	-	-	-	-	-	-	35	-
3b.1.1.14	Turbine	-	1,983	-	-	-	-	-	298	2,281	-	-	2,281	-	-	-	-	-	-	22,052	-
3b.1.1.15	Turbine Pedestal	-	349	-	-	-	-	-	52	402	-	-	402	-	-	-	-	-	-	1,857	-
3b.1.1.16	Warehouse #2	-	22	-	-	-	-	-	3	25	-	-	25	-	-	-	-	-	-	213	-
3b.1.1.17	Waste Neutralizing Tank House	-	7	-	-	-	-	-	1	8	-	-	8	-	-	-	-	-	-	56	-
3b.1.1.18	Waste Oil Storage	-	8	-	-	-	-	-	1	10	-	-	10	-	-	-	-	-	-	70	-
3b.1.1.19	Water Treatment	-	303	-	-	-	-	-	46	349	-	-	349	-	-	-	-	-	-	2,690	-
3b.1.1.20	Fuel Handling of Aux Building	-	1,032	-	-	-	-	-	155	1,186	-	-	1,186	-	-	-	-	-	-	8,240	-
3b.1.1	Totals	-	13,424	-	-	-	-	-	2,014	15,438	-	-	15,438	-	-	-	-	-	-	118,134	-
Site Closeout Activities																					
3b.1.2	Remove Rubble	-	1,308	-	-	-	-	-	196	1,505	-	-	1,505	-	-	-	-	-	-	6,495	-
3b.1.3	Grade & landscape site	-	431	-	-	-	-	-	65	495	-	-	495	-	-	-	-	-	-	921	-
3b.1.4	Final report to NRC	-	-	-	-	-	-	78	12	90	90	-	-	-	-	-	-	-	-	-	667
3b.1	Subtotal Period 3b Activity Costs	-	15,163	-	-	-	-	78	2,286	17,528	90	-	17,438	-	-	-	-	-	-	125,549	667
Period 3b Additional Costs																					
3b.2.1	Clean Concrete Disposal	-	3,313	-	-	-	-	8	498	3,818	-	-	3,818	-	-	-	-	-	-	12,824	-
3b.2.2	Underground Services Excavations	-	811	-	-	-	-	520	200	1,531	-	-	1,531	-	-	-	-	-	-	7,407	-
3b.2.3	Intake Structure Cofferdam	-	423	-	-	-	-	-	63	486	-	-	486	-	-	-	-	-	-	3,552	-
3b.2.4	Construction Debris	-	-	-	-	-	-	463	69	532	-	-	532	-	-	-	-	-	-	-	-
3b.2.5	Backfill	-	8,465	-	-	-	-	-	1,270	9,735	-	-	9,735	-	-	-	-	-	-	9,327	-
3b.2	Subtotal Period 3b Additional Costs	-	13,012	-	-	-	-	991	2,100	16,103	-	-	16,103	-	-	-	-	-	-	33,110	-
Period 3b Collateral Costs																					
3b.3.1	Small tool allowance	-	172	-	-	-	-	-	26	198	-	-	198	-	-	-	-	-	-	-	-
3b.3.2	Prairie Island Indian Community Payments	-	-	-	-	-	-	2,651	-	2,651	-	2,651	-	-	-	-	-	-	-	-	-
3b.3	Subtotal Period 3b Collateral Costs	-	172	-	-	-	-	2,651	26	2,848	-	2,651	198	-	-	-	-	-	-	-	-

Table D-2
Prairie Island Nuclear Generating Plant, Unit 2
DECON Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Period 3b Period-Dependent Costs																					
3b.4.1	Insurance	-	-	-	-	-	-	542	54	596	-	596	-	-	-	-	-	-	-	-	-
3b.4.2	Property taxes	-	-	-	-	-	-	4,334	433	4,767	-	4,767	-	-	-	-	-	-	-	-	-
3b.4.3	Heavy equipment rental	-	6,670	-	-	-	-	-	1,000	7,670	-	-	7,670	-	-	-	-	-	-	-	-
3b.4.4	Plant energy budget	-	-	-	-	-	-	321	48	369	-	-	369	-	-	-	-	-	-	-	-
3b.4.5	NRC ISFSI Fees	-	-	-	-	-	-	236	24	259	-	259	-	-	-	-	-	-	-	-	-
3b.4.6	Emergency Planning Fees	-	-	-	-	-	-	145	14	159	-	159	-	-	-	-	-	-	-	-	-
3b.4.7	Fixed Overhead	-	-	-	-	-	-	990	148	1,138	-	-	1,138	-	-	-	-	-	-	-	-
3b.4.8	ISFSI Operating Costs	-	-	-	-	-	-	109	16	126	-	126	-	-	-	-	-	-	-	-	-
3b.4.9	Railroad Track Maintenance	-	-	-	-	-	-	331	50	380	-	-	380	-	-	-	-	-	-	-	-
3b.4.10	Security Staff Cost	-	-	-	-	-	-	4,245	637	4,882	-	4,882	-	-	-	-	-	-	-	-	57,340
3b.4.11	DOC Staff Cost	-	-	-	-	-	-	10,467	1,570	12,038	-	-	12,038	-	-	-	-	-	-	-	116,885
3b.4.12	Utility Staff Cost	-	-	-	-	-	-	4,813	722	5,535	(0)	1,207	4,329	-	-	-	-	-	-	-	74,431
3b.4	Subtotal Period 3b Period-Dependent Costs	-	6,670	-	-	-	-	26,534	4,718	37,921	(0)	11,997	25,924	-	-	-	-	-	-	-	248,656
3b.0	TOTAL PERIOD 3b COST	-	35,017	-	-	-	-	30,253	9,130	74,401	90	14,648	59,663	-	-	-	-	-	-	158,659	249,323
PERIOD 3c - Fuel Storage Operations/Shipping																					
Period 3c Direct Decommissioning Activities																					
Period 3c Collateral Costs																					
3c.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	16,797	2,520	19,316	-	19,316	-	-	-	-	-	-	-	-	-
3c.3.2	Prairie Island Indian Community Payments	-	-	-	-	-	-	43,116	-	43,116	-	43,116	-	-	-	-	-	-	-	-	-
3c.3	Subtotal Period 3c Collateral Costs	-	-	-	-	-	-	59,913	2,520	62,433	-	62,433	-	-	-	-	-	-	-	-	-
Period 3c Period-Dependent Costs																					
3c.4.1	Insurance	-	-	-	-	-	-	8,818	882	9,700	-	9,700	-	-	-	-	-	-	-	-	-
3c.4.2	Property taxes	-	-	-	-	-	-	39,829	3,983	43,812	-	43,812	-	-	-	-	-	-	-	-	-
3c.4.4	NRC ISFSI Fees	-	-	-	-	-	-	5,648	565	6,213	-	6,213	-	-	-	-	-	-	-	-	-
3c.4.5	Emergency Planning Fees	-	-	-	-	-	-	2,360	236	2,596	-	2,596	-	-	-	-	-	-	-	-	-
3c.4.6	Fixed Overhead	-	-	-	-	-	-	5,267	790	6,057	-	6,057	-	-	-	-	-	-	-	-	-
3c.4.7	ISFSI Operating Costs	-	-	-	-	-	-	1,782	267	2,049	-	2,049	-	-	-	-	-	-	-	-	-
3c.4.8	Railroad Track Maintenance	-	-	-	-	-	-	1,991	299	2,289	-	2,289	-	-	-	-	-	-	-	-	-
3c.4.9	Security Staff Cost	-	-	-	-	-	-	69,105	10,366	79,471	-	79,471	-	-	-	-	-	-	-	-	933,362
3c.4.10	Utility Staff Cost	-	-	-	-	-	-	17,069	2,560	19,629	-	19,629	-	-	-	-	-	-	-	-	242,315
3c.4	Subtotal Period 3c Period-Dependent Costs	-	-	-	-	-	-	151,870	19,948	171,817	-	171,817	-	-	-	-	-	-	-	-	1,175,677
3c.0	TOTAL PERIOD 3c COST	-	-	-	-	-	-	211,783	22,467	234,250	-	234,250	-	-	-	-	-	-	-	-	1,175,677
PERIOD 3d - GTCC shipping																					
Period 3d Direct Decommissioning Activities																					
Nuclear Steam Supply System Removal																					
3d.1.1.1	Vessel & Internals GTCC Disposal	-	-	1,331	-	-	8,689	-	1,636	11,656	11,656	-	-	-	-	-	-	-	3,746	837,596	-	-
3d.1.1	Totals	-	-	1,331	-	-	8,689	-	1,636	11,656	11,656	-	-	-	-	-	-	-	3,746	837,596	-	-
3d.1	Subtotal Period 3d Activity Costs	-	-	1,331	-	-	8,689	-	1,636	11,656	11,656	-	-	-	-	-	-	-	3,746	837,596	-	-
Period 3d Collateral Costs																					
3d.3.1	Prairie Island Indian Community Payments	-	-	-	-	-	-	48	-	48	-	48	-	-	-	-	-	-	-	-	-	-
3d.3	Subtotal Period 3d Collateral Costs	-	-	-	-	-	-	48	-	48	-	48	-	-	-	-	-	-	-	-	-	-
Period 3d Period-Dependent Costs																					
3d.4.1	Insurance	-	-	-	-	-	-	10	1	11	11	-	-	-	-	-	-	-	-	-	-	-
3d.4.2	Property taxes	-	-	-	-	-	-	39	4	43	43	-	-	-	-	-	-	-	-	-	-	-
3d.4.4	NRC ISFSI Fees	-	-	-	-	-	-	4	0	5	-	5	-	-	-	-	-	-	-	-	-	-
3d.4.5	Emergency Planning Fees	-	-	-	-	-	-	3	0	3	-	3	-	-	-	-	-	-	-	-	-	-
3d.4.6	Fixed Overhead	-	-	-	-	-	-	6	1	7	7	-	-	-	-	-	-	-	-	-	-	-
3d.4.7	ISFSI Operating Costs	-	-	-	-	-	-	2	0	2	-	2	-	-	-	-	-	-	-	-	-	-
3d.4.8	Railroad Track Maintenance	-	-	-	-	-	-	2	0	3	-	3	-	-	-	-	-	-	-	-	-	-
3d.4.9	Security Staff Cost	-	-	-	-	-	-	77	12	88	88	-	-	-	-	-	-	-	-	-	-	1,037
3d.4.10	Utility Staff Cost	-	-	-	-	-	-	19	3	22	22	-	-	-	-	-	-	-	-	-	-	269
3d.4	Subtotal Period 3d Period-Dependent Costs	-	-	-	-	-	-	162	21	183	171	12	-	-	-	-	-	-	-	-	-	1,306
3d.0	TOTAL PERIOD 3d COST	-	-	1,331	-	-	8,689	210	1,658	11,887	11,827	60	-	-	-	-	-	-	3,746	837,596	-	1,306

Table D-2
Prairie Island Nuclear Generating Plant, Unit 2
DECON Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
PERIOD 3e - ISFSI Decontamination																					
Period 3e Direct Decommissioning Activities																					
Period 3e Additional Costs																					
3e.2.1	License Termination ISFSI	-	37	2	211	-	2,157	710	779	3,896	3,896	-	-	-	7,458	-	-	-	1,071,985	3,670	888
3e.2	Subtotal Period 3e Additional Costs	-	37	2	211	-	2,157	710	779	3,896	3,896	-	-	-	7,458	-	-	-	1,071,985	3,670	888
Period 3e Period-Dependent Costs																					
3e.4.1	Insurance	-	-	-	-	-	-	96	24	121	121	-	-	-	-	-	-	-	-	-	-
3e.4.2	Property taxes	-	-	-	-	-	-	26	6	32	32	-	-	-	-	-	-	-	-	-	-
3e.4.4	Fixed Overhead	-	-	-	-	-	-	51	13	63	63	-	-	-	-	-	-	-	-	-	-
3e.4.5	Railroad Track Maintenance	-	-	-	-	-	-	19	5	24	24	-	-	-	-	-	-	-	-	-	-
3e.4.6	Security Staff Cost	-	-	-	-	-	-	154	38	192	192	-	-	-	-	-	-	-	-	-	2,500
3e.4.7	Utility Staff Cost	-	-	-	-	-	-	130	33	163	163	-	-	-	-	-	-	-	-	-	1,896
3e.4	Subtotal Period 3e Period-Dependent Costs	-	-	-	-	-	-	476	119	595	595	-	-	-	-	-	-	-	-	-	4,396
3e.0	TOTAL PERIOD 3e COST	-	37	2	211	-	2,157	1,186	898	4,491	4,491	-	-	-	7,458	-	-	-	1,071,985	3,670	5,284
PERIOD 3f - ISFSI Site Restoration																					
Period 3f Direct Decommissioning Activities																					
Period 3f Additional Costs																					
3f.2.1	Demolition and Site Restoration of ISFSI	-	495	-	-	-	-	87	87	669	-	-	669	-	-	-	-	-	-	2,308	160
3f.2	Subtotal Period 3f Additional Costs	-	495	-	-	-	-	87	87	669	-	-	669	-	-	-	-	-	-	2,308	160
Period 3f Collateral Costs																					
3f.3.1	Small tool allowance	-	4	-	-	-	-	-	1	4	-	-	4	-	-	-	-	-	-	-	-
3f.3	Subtotal Period 3f Collateral Costs	-	4	-	-	-	-	-	1	4	-	-	4	-	-	-	-	-	-	-	-
Period 3f Period-Dependent Costs																					
3f.4.2	Property taxes	-	-	-	-	-	-	13	1	14	-	-	14	-	-	-	-	-	-	-	-
3f.4.3	Heavy equipment rental	-	62	-	-	-	-	-	9	71	-	-	71	-	-	-	-	-	-	-	-
3f.4.4	Plant energy budget	-	-	-	-	-	-	13	2	15	-	-	15	-	-	-	-	-	-	-	-
3f.4.5	Fixed Overhead	-	-	-	-	-	-	25	4	29	-	-	29	-	-	-	-	-	-	-	-
3f.4.6	Railroad Track Maintenance	-	-	-	-	-	-	10	1	11	-	-	11	-	-	-	-	-	-	-	-
3f.4.7	Security Staff Cost	-	-	-	-	-	-	78	12	89	-	-	89	-	-	-	-	-	-	-	1,260
3f.4.8	Utility Staff Cost	-	-	-	-	-	-	52	8	60	-	-	60	-	-	-	-	-	-	-	782
3f.4	Subtotal Period 3f Period-Dependent Costs	-	62	-	-	-	-	190	37	289	-	-	289	-	-	-	-	-	-	-	2,042
3f.0	TOTAL PERIOD 3f COST	-	560	-	-	-	-	277	125	962	-	-	962	-	-	-	-	-	-	2,308	2,202
PERIOD 3 TOTALS		-	35,614	1,333	211	-	10,846	243,709	34,278	325,991	16,408	248,958	60,625	-	7,458	-	-	3,746	1,909,581	164,637	1,433,792
TOTAL COST TO DECOMMISSION		**13,408**	**104,717**	**31,018**	**7,562**	**13,927**	**53,014**	**633,188**	**141,809**	**998,643**	**561,764**	**370,034**	**66,845**	**169,551**	**150,947**	**839**	**673**	**3,746**	**17,608,500**	**1,023,123**	**4,190,637**

TOTAL COST TO DECOMMISSION WITH 16.55% CONTINGENCY:	**$998,643**	**thousands of 2017 dollars**
TOTAL NRC LICENSE TERMINATION COST IS 56.25% OR:	**$561,764**	**thousands of 2017 dollars**
SPENT FUEL MANAGEMENT COST IS 37.05% OR:	**$370,034**	**thousands of 2017 dollars**
NON-NUCLEAR DEMOLITION COST IS 6.69% OR:	**$66,845**	**thousands of 2017 dollars**
TOTAL LOW-LEVEL RADIOACTIVE WASTE VOLUME BURIED (EXCLUDING GTCC):	**152,458**	**cubic feet**
TOTAL GREATER THAN CLASS C RADWASTE VOLUME GENERATED:	**3,746**	**cubic feet**
TOTAL SCRAP METAL REMOVED:	**41,515**	**tons**
TOTAL CRAFT LABOR REQUIREMENTS:	**1,023,123**	**man-hours**

End Notes:
n/a - indicates that this activity not charged as decommissioning expense
a - indicates that this activity performed by decommissioning staff
0 - indicates that this value is less than 0.5 but is non-zero
A cell containing " - " indicates a zero value

APPENDIX E

DETAILED COST ANALYSIS

SCENARIO 3: DECON with 100 Year DFS

Page

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Prairie Island Nuclear Generating Plant, Unit 2 ..... E-10

Table E-1
Prairie Island Nuclear Generating Plant, Unit 1
DECON Decommissioning Cost Estimate with 100 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
PERIOD 1a - Shutdown through Transition																					
Period 1a Direct Decommissioning Activities																					
1a.1.1	Prepare preliminary decommissioning cost	-	-	-	-	-	-	153	23	175	175	-	-	-	-	-	-	-	-	-	1,300
1a.1.2	Notification of Cessation of Operations									a											
1a.1.3	Remove fuel & source material									n/a											
1a.1.4	Notification of Permanent Defueling									a											
1a.1.5	Deactivate plant systems & process waste									a											
1a.1.6	Prepare and submit PSDAR	-	-	-	-	-	-	235	35	270	270	-	-	-	-	-	-	-	-	-	2,000
1a.1.7	Review plant dwgs & specs.	-	-	-	-	-	-	540	81	621	621	-	-	-	-	-	-	-	-	-	4,600
1a.1.8	Perform detailed rad survey									a											
1a.1.9	Estimate by-product inventory	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1a.1.10	End product description	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1a.1.11	Detailed by-product inventory	-	-	-	-	-	-	153	23	175	175	-	-	-	-	-	-	-	-	-	1,300
1a.1.12	Define major work sequence	-	-	-	-	-	-	880	132	1,012	1,012	-	-	-	-	-	-	-	-	-	7,500
1a.1.13	Perform SER and EA	-	-	-	-	-	-	364	55	418	418	-	-	-	-	-	-	-	-	-	3,100
1a.1.14	Prepare/submit Defueled Technical Specifications	-	-	-	-	-	-	880	132	1,012	1,012	-	-	-	-	-	-	-	-	-	7,500
1a.1.15	Perform Site-Specific Cost Study	-	-	-	-	-	-	587	88	675	675	-	-	-	-	-	-	-	-	-	5,000
1a.1.16	Prepare/submit Irradiated Fuel Management Plan	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
Activity Specifications																					
1a.1.17.1	Plant & temporary facilities	-	-	-	-	-	-	578	87	664	598	-	66	-	-	-	-	-	-	-	4,920
1a.1.17.2	Plant systems	-	-	-	-	-	-	489	73	562	506	-	56	-	-	-	-	-	-	-	4,167
1a.1.17.3	NSSS Decontamination Flush	-	-	-	-	-	-	59	9	67	67	-	-	-	-	-	-	-	-	-	500
1a.1.17.4	Reactor internals	-	-	-	-	-	-	833	125	958	958	-	-	-	-	-	-	-	-	-	7,100
1a.1.17.5	Reactor vessel	-	-	-	-	-	-	763	114	877	877	-	-	-	-	-	-	-	-	-	6,500
1a.1.17.6	Biological shield	-	-	-	-	-	-	59	9	67	67	-	-	-	-	-	-	-	-	-	500
1a.1.17.7	Steam generators	-	-	-	-	-	-	366	55	421	421	-	-	-	-	-	-	-	-	-	3,120
1a.1.17.8	Reinforced concrete	-	-	-	-	-	-	188	28	216	108	-	108	-	-	-	-	-	-	-	1,600
1a.1.17.9	Main Turbine	-	-	-	-	-	-	47	7	54	-	-	54	-	-	-	-	-	-	-	400
1a.1.17.10	Main Condensers	-	-	-	-	-	-	47	7	54	-	-	54	-	-	-	-	-	-	-	400
1a.1.17.11	Plant structures & buildings	-	-	-	-	-	-	366	55	421	211	-	211	-	-	-	-	-	-	-	3,120
1a.1.17.12	Waste management	-	-	-	-	-	-	540	81	621	621	-	-	-	-	-	-	-	-	-	4,600
1a.1.17.13	Facility & site closeout	-	-	-	-	-	-	106	16	121	61	-	61	-	-	-	-	-	-	-	900
1a.1.17	Total	-	-	-	-	-	-	4,440	666	5,106	4,496	-	610	-	-	-	-	-	-	-	37,827
Planning & Site Preparations																					
1a.1.18	Prepare dismantling sequence	-	-	-	-	-	-	282	42	324	324	-	-	-	-	-	-	-	-	-	2,400
1a.1.19	Plant prep. & temp. svces	-	-	-	-	-	-	3,300	495	3,795	3,795	-	-	-	-	-	-	-	-	-	-
1a.1.20	Design water clean-up system	-	-	-	-	-	-	164	25	189	189	-	-	-	-	-	-	-	-	-	1,400
1a.1.21	Rigging/Cont. Cntrl Envlps/tooling/etc.	-	-	-	-	-	-	2,300	345	2,645	2,645	-	-	-	-	-	-	-	-	-	-
1a.1.22	Procure casks/liners & containers	-	-	-	-	-	-	144	22	166	166	-	-	-	-	-	-	-	-	-	1,230
1a.1	Subtotal Period 1a Activity Costs	-	-	-	-	-	-	14,774	2,216	16,990	16,380	-	610	-	-	-	-	-	-	-	78,157
Period 1a Additional Costs																					
1a.2.1	Spent Fuel Pool Isolation	-	-	-	-	-	-	11,691	1,754	13,445	13,445	-	-	-	-	-	-	-	-	-	-
1a.2	Subtotal Period 1a Additional Costs	-	-	-	-	-	-	11,691	1,754	13,445	13,445	-	-	-	-	-	-	-	-	-	-
Period 1a Collateral Costs																					
1a.3.1	Prairie Island Indian Community Payments	-	-	-	-	-	-	2,003	-	2,003	-	2,003	-	-	-	-	-	-	-	-	-
1a.3	Subtotal Period 1a Collateral Costs	-	-	-	-	-	-	2,003	-	2,003	-	2,003	-	-	-	-	-	-	-	-	-
Period 1a Period-Dependent Costs																					
1a.4.1	Insurance	-	-	-	-	-	-	1,730	173	1,903	1,903	-	-	-	-	-	-	-	-	-	-
1a.4.2	Property taxes	-	-	-	-	-	-	2,040	204	2,244	2,244	-	-	-	-	-	-	-	-	-	-
1a.4.3	Health physics supplies	-	515	-	-	-	-	-	129	644	644	-	-	-	-	-	-	-	-	-	-
1a.4.4	Heavy equipment rental	-	567	-	-	-	-	-	85	652	652	-	-	-	-	-	-	-	-	-	-
1a.4.5	Disposal of DAW generated	-	-	13	4	-	50	-	14	81	81	-	-	-	610	-	-	-	12,190	20	-
1a.4.6	Plant energy budget	-	-	-	-	-	-	1,515	227	1,742	1,742	-	-	-	-	-	-	-	-	-	-
1a.4.7	NRC Fees	-	-	-	-	-	-	1,110	111	1,221	1,221	-	-	-	-	-	-	-	-	-	-
1a.4.8	Emergency Planning Fees	-	-	-	-	-	-	1,604	160	1,765	-	1,765	-	-	-	-	-	-	-	-	-
1a.4.9	Fixed Overhead	-	-	-	-	-	-	1,470	220	1,690	1,690	-	-	-	-	-	-	-	-	-	-
1a.4.10	Spent Fuel Pool O&M	-	-	-	-	-	-	401	60	461	-	461	-	-	-	-	-	-	-	-	-
1a.4.11	ISFSI Operating Costs	-	-	-	-	-	-	52	8	59	-	59	-	-	-	-	-	-	-	-	-
1a.4.12	Railroad Track Maintenance	-	-	-	-	-	-	58	9	66	66	-	-	-	-	-	-	-	-	-	-
1a.4.13	Security Staff Cost	-	-	-	-	-	-	7,390	1,108	8,498	8,498	-	-	-	-	-	-	-	-	-	122,720
1a.4.14	Utility Staff Cost	-	-	-	-	-	-	25,791	3,869	29,660	29,660	-	-	-	-	-	-	-	-	-	422,240
1a.4	Subtotal Period 1a Period-Dependent Costs	-	1,083	13	4	-	50	43,160	6,378	50,687	48,402	2,286	-	-	610	-	-	-	12,190	20	544,960

Table E-1
Prairie Island Nuclear Generating Plant, Unit 1
DECON Decommissioning Cost Estimate with 100 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
1a.0	TOTAL PERIOD 1a COST	-	1,083	13	4	-	50	71,629	10,348	83,126	78,227	4,289	610	-	610	-	-	-	12,190	20	623,117
PERIOD 1b - Decommissioning Preparations																					
Period 1b Direct Decommissioning Activities																					
Detailed Work Procedures																					
1b.1.1.1	Plant systems	-	-	-	-	-	-	556	83	639	575	-	64	-	-	-	-	-	-	-	4,733
1b.1.1.2	NSSS Decontamination Flush	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1b.1.1.3	Reactor internals	-	-	-	-	-	-	293	44	337	337	-	-	-	-	-	-	-	-	-	2,500
1b.1.1.4	Remaining buildings	-	-	-	-	-	-	158	24	182	46	-	137	-	-	-	-	-	-	-	1,350
1b.1.1.5	CRD cooling assembly	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1b.1.1.6	CRD housings & ICI tubes	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1b.1.1.7	Incore instrumentation	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1b.1.1.8	Reactor vessel	-	-	-	-	-	-	426	64	490	490	-	-	-	-	-	-	-	-	-	3,630
1b.1.1.9	Facility closeout	-	-	-	-	-	-	141	21	162	81	-	81	-	-	-	-	-	-	-	1,200
1b.1.1.10	Missile shields	-	-	-	-	-	-	53	8	61	61	-	-	-	-	-	-	-	-	-	450
1b.1.1.11	Biological shield	-	-	-	-	-	-	141	21	162	162	-	-	-	-	-	-	-	-	-	1,200
1b.1.1.12	Steam generators	-	-	-	-	-	-	540	81	621	621	-	-	-	-	-	-	-	-	-	4,600
1b.1.1.13	Reinforced concrete	-	-	-	-	-	-	117	18	135	67	-	67	-	-	-	-	-	-	-	1,000
1b.1.1.14	Main Turbine	-	-	-	-	-	-	183	27	211	-	-	211	-	-	-	-	-	-	-	1,560
1b.1.1.15	Main Condensers	-	-	-	-	-	-	183	27	211	-	-	211	-	-	-	-	-	-	-	1,560
1b.1.1.16	Auxiliary building	-	-	-	-	-	-	320	48	369	332	-	37	-	-	-	-	-	-	-	2,730
1b.1.1.17	Reactor building	-	-	-	-	-	-	320	48	369	332	-	37	-	-	-	-	-	-	-	2,730
1b.1.1	Total	-	-	-	-	-	-	3,902	585	4,487	3,643	-	844	-	-	-	-	-	-	-	33,243
1b.1.2	Decon primary loop	552	-	-	-	-	-	-	276	828	828	-	-	-	-	-	-	-	-	1,067	-
1b.1	Subtotal Period 1b Activity Costs	552	-	-	-	-	-	3,902	861	5,315	4,471	-	844	-	-	-	-	-	-	1,067	33,243
Period 1b Additional Costs																					
1b.2.1	Site Characterization	-	-	-	-	-	-	3,700	1,110	4,810	4,810	-	-	-	-	-	-	-	-	21,020	8,332
1b.2.2	Mixed/Hazardous Waste	-	-	318	75	164	-	-	68	624	624	-	-	6,133	-	-	-	-	351,986	2,361	-
1b.2.3	Asbestos Abatement	-	2,364	2	110	-	1,359	-	947	4,782	4,782	-	-	-	12,843	-	-	-	166,959	20,907	-
1b.2	Subtotal Period 1b Additional Costs	-	2,364	320	185	164	1,359	3,700	2,125	10,216	10,216	-	-	6,133	12,843	-	-	-	518,945	44,288	8,332
Period 1b Collateral Costs																					
1b.3.1	Decon equipment	973	-	-	-	-	-	-	146	1,119	1,119	-	-	-	-	-	-	-	-	-	-
1b.3.2	DOC staff relocation expenses	-	-	-	-	-	-	1,189	178	1,367	1,367	-	-	-	-	-	-	-	-	-	-
1b.3.3	Process decommissioning water waste	24	-	16	41	-	64	-	36	180	180	-	-	-	152	-	-	-	9,121	30	-
1b.3.4	Process decommissioning chemical flush waste	2	-	58	220	-	2,471	-	657	3,408	3,408	-	-	-	-	588	-	-	62,689	110	-
1b.3.5	Small tool allowance	-	34	-	-	-	-	-	5	39	39	-	-	-	-	-	-	-	-	-	-
1b.3.6	Pipe cutting equipment	-	1,200	-	-	-	-	-	180	1,380	1,380	-	-	-	-	-	-	-	-	-	-
1b.3.7	Decon rig	1,987	-	-	-	-	-	-	298	2,285	2,285	-	-	-	-	-	-	-	-	-	-
1b.3.8	Spent Fuel Capital and Transfer	-	-	-	-	-	-	159	24	183	-	183	-	-	-	-	-	-	-	-	-
1b.3.9	Retention and Severance	-	-	-	-	-	-	1,088	163	1,251	1,251	-	-	-	-	-	-	-	-	-	-
1b.3.10	Prairie Island Indian Community Payments	-	-	-	-	-	-	630	-	630	-	630	-	-	-	-	-	-	-	-	-
1b.3	Subtotal Period 1b Collateral Costs	2,986	1,234	74	261	-	2,534	3,065	1,687	11,841	11,028	813	-	-	152	588	-	-	71,810	140	-
Period 1b Period-Dependent Costs																					
1b.4.1	Decon supplies	35	-	-	-	-	-	-	9	44	44	-	-	-	-	-	-	-	-	-	-
1b.4.2	Insurance	-	-	-	-	-	-	872	87	959	959	-	-	-	-	-	-	-	-	-	-
1b.4.3	Property taxes	-	-	-	-	-	-	1,352	135	1,487	1,487	-	-	-	-	-	-	-	-	-	-
1b.4.4	Health physics supplies	-	402	-	-	-	-	-	101	503	503	-	-	-	-	-	-	-	-	-	-
1b.4.5	Heavy equipment rental	-	286	-	-	-	-	-	43	329	329	-	-	-	-	-	-	-	-	-	-
1b.4.6	Disposal of DAW generated	-	-	8	2	-	29	-	8	48	48	-	-	-	360	-	-	-	7,197	12	-
1b.4.7	Plant energy budget	-	-	-	-	-	-	1,527	229	1,756	1,756	-	-	-	-	-	-	-	-	-	-
1b.4.8	NRC Fees	-	-	-	-	-	-	323	32	355	355	-	-	-	-	-	-	-	-	-	-
1b.4.9	Emergency Planning Fees	-	-	-	-	-	-	809	81	890	-	890	-	-	-	-	-	-	-	-	-
1b.4.10	Fixed Overhead	-	-	-	-	-	-	741	111	852	852	-	-	-	-	-	-	-	-	-	-
1b.4.11	Spent Fuel Pool O&M	-	-	-	-	-	-	202	30	233	-	233	-	-	-	-	-	-	-	-	-
1b.4.12	ISFSI Operating Costs	-	-	-	-	-	-	26	4	30	-	30	-	-	-	-	-	-	-	-	-
1b.4.13	Railroad Track Maintenance	-	-	-	-	-	-	29	4	33	33	-	-	-	-	-	-	-	-	-	-
1b.4.14	Security Staff Cost	-	-	-	-	-	-	3,725	559	4,284	4,284	-	-	-	-	-	-	-	-	-	61,864
1b.4.15	DOC Staff Cost	-	-	-	-	-	-	5,656	848	6,504	6,504	-	-	-	-	-	-	-	-	-	63,961
1b.4.16	Utility Staff Cost	-	-	-	-	-	-	13,074	1,961	15,035	15,035	-	-	-	-	-	-	-	-	-	213,904
1b.4	Subtotal Period 1b Period-Dependent Costs	35	688	8	2	-	29	28,336	4,243	33,341	32,189	1,152	-	-	360	-	-	-	7,197	12	339,730
1b.0	TOTAL PERIOD 1b COST	3,573	4,286	402	447	164	3,923	39,002	8,917	60,713	57,904	1,965	844	6,133	13,355	588	-	-	597,952	45,506	381,305

Table E-1
Prairie Island Nuclear Generating Plant, Unit 1
DECON Decommissioning Cost Estimate with 100 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
PERIOD 1 TOTALS		3,573	5,368	415	451	164	3,972	110,631	19,264	143,839	136,131	6,254	1,454	6,133	13,964	588	-	-	610,142	45,526	1,004,421
PERIOD 2a - Large Component Removal																					
Period 2a Direct Decommissioning Activities																					
Nuclear Steam Supply System Removal																					
2a.1.1.1	Reactor Coolant Piping	51	45	6	8	-	150	-	76	336	336	-	-	-	305	-	-	-	34,809	1,414	-
2a.1.1.2	Pressurizer Relief Tank	22	20	4	5	-	100	-	42	193	193	-	-	-	203	-	-	-	23,193	625	-
2a.1.1.3	Reactor Coolant Pumps & Motors	54	63	101	83	-	736	-	249	1,287	1,287	-	-	-	2,332	-	-	-	295,800	2,049	100
2a.1.1.4	Pressurizer	48	68	467	88	-	693	-	274	1,639	1,639	-	-	-	2,196	-	-	-	185,015	2,355	938
2a.1.1.5	Steam Generators	225	2,943	2,093	1,638	1,246	3,570	-	2,383	14,097	14,097	-	-	18,672	11,316	-	-	-	1,668,341	14,819	2,875
2a.1.1.6	CRDMs/ICIs/Service Structure Removal	286	277	211	48	-	763	-	431	2,016	2,016	-	-	-	4,797	-	-	-	177,400	8,104	-
2a.1.1.7	Reactor Vessel Internals	78	4,468	21,874	1,072	-	7,946	277	13,141	48,856	48,856	-	-	-	501	125	673	-	164,987	23,040	1,080
2a.1.1.8	Reactor Vessel	89	5,717	1,754	719	-	1,956	277	5,970	16,483	16,483	-	-	-	5,690	-	-	-	570,074	23,040	1,080
2a.1.1	Totals	855	13,600	26,512	3,662	1,246	15,913	553	22,568	84,908	84,908	-	-	18,672	27,341	125	673	-	3,119,620	75,446	6,073
Removal of Major Equipment																					
2a.1.2	Main Turbine/Generator	-	305	189	55	272	306	-	221	1,348	1,348	-	-	2,131	1,187	-	-	-	206,316	4,667	-
2a.1.3	Main Condensers	-	2,532	121	49	364	451	-	820	4,336	4,336	-	-	3,800	1,587	-	-	-	275,903	39,151	-
Cascading Costs from Clean Building Demolition																					
2a.1.4.1	Reactor	-	728	-	-	-	-	-	109	837	837	-	-	-	-	-	-	-	-	7,589	-
2a.1.4	Totals	-	728	-	-	-	-	-	109	837	837	-	-	-	-	-	-	-	-	7,589	-
Disposal of Plant Systems																					
2a.1.5.1	Air Removal	-	27	-	-	-	-	-	4	31	-	-	31	-	-	-	-	-	-	452	-
2a.1.5.2	Auxiliary Feedwater	-	40	-	-	-	-	-	6	46	-	-	46	-	-	-	-	-	-	670	-
2a.1.5.3	Auxiliary Feedwater - RCA	-	45	0	1	19	-	-	14	79	79	-	-	215	-	-	-	-	8,722	601	-
2a.1.5.4	Bleed Steam	-	78	-	-	-	-	-	12	90	-	-	90	-	-	-	-	-	-	1,335	-
2a.1.5.5	Caustic Addition - RCA	-	36	0	1	20	-	-	12	71	71	-	-	233	-	-	-	-	9,453	444	-
2a.1.5.6	Chemical Feed	-	17	-	-	-	-	-	3	20	-	-	20	-	-	-	-	-	-	304	-
2a.1.5.7	Chemical Feed - RCA	-	1	0	0	1	-	-	0	2	2	-	-	6	-	-	-	-	243	12	-
2a.1.5.8	Circulating Water	-	37	-	-	-	-	-	6	42	-	-	42	-	-	-	-	-	-	619	-
2a.1.5.9	Condensate	-	414	-	-	-	-	-	62	476	-	-	476	-	-	-	-	-	-	6,837	-
2a.1.5.10	Condensate Polishing	-	205	-	-	-	-	-	31	236	-	-	236	-	-	-	-	-	-	3,420	-
2a.1.5.11	Condensate Polishing - RCA	-	176	4	12	180	-	-	73	444	444	-	-	2,078	-	-	-	-	84,395	2,329	-
2a.1.5.12	Electro-hydraulic	-	8	-	-	-	-	-	1	9	-	-	9	-	-	-	-	-	-	127	-
2a.1.5.13	Feedwater	-	133	-	-	-	-	-	20	153	-	-	153	-	-	-	-	-	-	2,215	-
2a.1.5.14	Feedwater - RCA	-	186	6	19	278	-	-	91	579	579	-	-	3,208	-	-	-	-	130,294	2,651	-
2a.1.5.15	Gland Seal	-	29	-	-	-	-	-	4	34	-	-	34	-	-	-	-	-	-	505	-
2a.1.5.16	Heater Drain	-	349	-	-	-	-	-	52	401	-	-	401	-	-	-	-	-	-	5,881	-
2a.1.5.17	Internal Circ Water & CDSR	-	23	-	-	-	-	-	3	27	-	-	27	-	-	-	-	-	-	389	-
2a.1.5.18	Main Gen/Exciter/Transformer	-	0	-	-	-	-	-	0	0	-	-	0	-	-	-	-	-	-	5	-
2a.1.5.19	Main Steam	-	101	-	-	-	-	-	15	116	-	-	116	-	-	-	-	-	-	1,690	-
2a.1.5.20	Main Steam - RCA	-	350	9	29	436	-	-	158	983	983	-	-	5,044	-	-	-	-	204,825	4,956	-
2a.1.5.21	Steam Generator Blowdown	-	459	21	22	176	195	-	195	1,067	1,067	-	-	2,031	686	-	-	-	127,773	6,667	-
2a.1.5.22	Steam Generators	-	5	-	-	-	-	-	1	5	-	-	5	-	-	-	-	-	-	75	-
2a.1.5.23	Turbine & Moisture Separators	-	337	-	-	-	-	-	51	388	-	-	388	-	-	-	-	-	-	5,609	-
2a.1.5.24	Turbine Oil Purification	-	61	-	-	-	-	-	9	71	-	-	71	-	-	-	-	-	-	1,003	-
2a.1.5	Totals	-	3,117	40	85	1,108	195	-	825	5,370	3,226	-	2,145	12,815	686	-	-	-	565,705	48,794	-
2a.1.6	Scaffolding in support of decommissioning	-	854	3	1	13	3	-	217	1,092	1,092	-	-	138	12	-	-	-	7,016	6,368	-
2a.1	Subtotal Period 2a Activity Costs	855	21,136	26,865	3,852	3,004	16,868	553	24,759	97,891	95,747	-	2,145	37,556	30,812	125	673	-	4,174,560	182,015	6,073
Period 2a Additional Costs																					
2a.2.1	Remedial Action Surveys	-	-	-	-	-	-	2,126	638	2,764	2,764	-	-	-	-	-	-	-	-	27,791	-
2a.2.2	Retired RPV upper internals package	1	659	785	107	-	1,439	-	1,437	4,427	4,427	-	-	-	2,097	125	-	-	205,890	2,175	87
2a.2	Subtotal Period 2a Additional Costs	1	659	785	107	-	1,439	2,126	2,075	7,191	7,191	-	-	-	2,097	125	-	-	205,890	29,966	87
Period 2a Collateral Costs																					
2a.3.1	Process decommissioning water waste	47	-	31	81	-	126	-	70	356	356	-	-	-	302	-	-	-	18,119	59	-
2a.3.3	Small tool allowance	-	223	-	-	-	-	-	33	257	231	-	26	-	-	-	-	-	-	-	-
2a.3.4	Spent Fuel Capital and Transfer	-	-	-	-	-	-	1,476	221	1,698	-	1,698	-	-	-	-	-	-	-	-	-
2a.3.5	Retention and Severance	-	-	-	-	-	-	12,156	1,823	13,980	13,980	-	-	-	-	-	-	-	-	-	-
2a.3.6	Prairie Island Indian Community Payments	-	-	-	-	-	-	1,670	-	1,670	-	1,670	-	-	-	-	-	-	-	-	-
2a.3	Subtotal Period 2a Collateral Costs	47	223	31	81	-	126	15,302	2,149	17,960	14,567	3,367	26	-	302	-	-	-	18,119	59	-

Table E-1
Prairie Island Nuclear Generating Plant, Unit 1
DECON Decommissioning Cost Estimate with 100 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 2a Period-Dependent Costs																					
2a.4.1	Decon supplies	93	-	-	-	-	-	-	23	116	116	-	-	-	-	-	-	-	-	-	-
2a.4.2	Insurance	-	-	-	-	-	-	683	68	751	751	-	-	-	-	-	-	-	-	-	-
2a.4.3	Property taxes	-	-	-	-	-	-	3,542	354	3,896	3,896	-	-	-	-	-	-	-	-	-	-
2a.4.4	Health physics supplies	-	1,717	-	-	-	-	-	429	2,146	2,146	-	-	-	-	-	-	-	-	-	-
2a.4.5	Heavy equipment rental	-	2,935	-	-	-	-	-	440	3,376	3,376	-	-	-	-	-	-	-	-	-	-
2a.4.6	Disposal of DAW generated	-	-	79	23	-	295	-	85	482	482	-	-	-	3,623	-	-	-	72,452	118	-
2a.4.7	Plant energy budget	-	-	-	-	-	-	1,924	289	2,212	2,212	-	-	-	-	-	-	-	-	-	-
2a.4.8	NRC Fees	-	-	-	-	-	-	774	77	851	851	-	-	-	-	-	-	-	-	-	-
2a.4.9	Emergency Planning Fees	-	-	-	-	-	-	1,717	172	1,888	-	1,888	-	-	-	-	-	-	-	-	-
2a.4.10	Fixed Overhead	-	-	-	-	-	-	1,655	248	1,904	1,904	-	-	-	-	-	-	-	-	-	-
2a.4.11	Spent Fuel Pool O&M	-	-	-	-	-	-	537	80	617	-	617	-	-	-	-	-	-	-	-	-
2a.4.12	ISFSI Operating Costs	-	-	-	-	-	-	69	10	79	-	79	-	-	-	-	-	-	-	-	-
2a.4.13	Railroad Track Maintenance	-	-	-	-	-	-	286	43	328	328	-	-	-	-	-	-	-	-	-	-
2a.4.14	Security Staff Cost	-	-	-	-	-	-	9,811	1,472	11,283	11,283	-	-	-	-	-	-	-	-	-	162,878
2a.4.15	DOC Staff Cost	-	-	-	-	-	-	18,392	2,759	21,150	21,150	-	-	-	-	-	-	-	-	-	211,351
2a.4.16	Utility Staff Cost	-	-	-	-	-	-	24,265	3,640	27,904	27,904	-	-	-	-	-	-	-	-	-	392,305
2a.4	Subtotal Period 2a Period-Dependent Costs	93	4,652	79	23	-	295	63,653	10,190	78,986	76,401	2,585	-	-	3,623	-	-	-	72,452	118	766,534
2a.0	TOTAL PERIOD 2a COST	995	26,670	27,760	4,062	3,004	18,729	81,635	39,172	202,027	193,905	5,952	2,170	37,556	36,834	250	673	-	4,471,020	212,158	772,694
PERIOD 2b - Site Decontamination																					
Period 2b Direct Decommissioning Activities																					
Disposal of Plant Systems																					
2b.1.1.1	Aux Bldg Normal Ventilation	-	2	0	0	0	-	-	1	3	3	-	-	3	-	-	-	-	140	29	-
2b.1.1.2	Battery Rm Special Ventilation	-	0	-	-	-	-	-	0	0	-	-	0	-	-	-	-	-	-	6	-
2b.1.1.3	Buildings Maintenance	-	4	-	-	-	-	-	1	5	-	-	5	-	-	-	-	-	-	65	-
2b.1.1.4	Chemical & Volume Control	1,077	1,331	83	69	389	802	-	1,149	4,901	4,901	-	-	4,498	2,846	-	-	-	369,246	34,533	-
2b.1.1.5	Component Cooling - RCA	-	821	22	72	1,075	-	-	379	2,369	2,369	-	-	12,427	-	-	-	-	504,675	11,242	-
2b.1.1.6	Containment Cooling	-	65	-	-	-	-	-	10	74	-	-	74	-	-	-	-	-	-	1,086	-
2b.1.1.7	Containment Cooling - RCA	-	290	6	20	294	-	-	120	730	730	-	-	3,400	-	-	-	-	138,090	3,971	-
2b.1.1.8	Containment Hydrogen Control - RCA	-	29	0	1	9	-	-	9	48	48	-	-	105	-	-	-	-	4,278	401	-
2b.1.1.9	Containment Spray - RCA	-	90	2	5	75	-	-	35	206	206	-	-	868	-	-	-	-	35,249	1,217	-
2b.1.1.10	Containment Ventilation	-	243	24	40	428	209	-	186	1,130	1,130	-	-	4,951	737	-	-	-	249,786	3,668	-
2b.1.1.11	Cooling Water	-	142	-	-	-	-	-	21	163	-	-	163	-	-	-	-	-	-	2,396	-
2b.1.1.12	Cooling Water - RCA	-	629	14	45	668	-	-	266	1,622	1,622	-	-	7,728	-	-	-	-	313,832	8,594	-
2b.1.1.13	D1 Emergency Diesel	-	44	-	-	-	-	-	7	50	-	-	50	-	-	-	-	-	-	730	-
2b.1.1.14	D2 Emergency Diesel	-	31	-	-	-	-	-	5	36	-	-	36	-	-	-	-	-	-	522	-
2b.1.1.15	Diesel Rooms Ventilation	-	8	-	-	-	-	-	1	10	-	-	10	-	-	-	-	-	-	135	-
2b.1.1.16	Electrical - Clean	-	1,669	-	-	-	-	-	250	1,919	-	-	1,919	-	-	-	-	-	-	26,981	-
2b.1.1.17	Electrical - Contaminated	-	592	6	16	219	27	-	191	1,051	1,051	-	-	2,527	95	-	-	-	108,935	8,377	-
2b.1.1.18	Electrical - Decontaminated	-	3,674	41	137	2,037	-	-	1,249	7,138	7,138	-	-	23,551	-	-	-	-	956,401	49,378	-
2b.1.1.19	Fuel Handling	-	116	6	9	79	62	-	58	329	329	-	-	908	218	-	-	-	51,280	1,784	-
2b.1.1.20	Fuel Oil	-	106	-	-	-	-	-	16	122	-	-	122	-	-	-	-	-	-	1,697	-
2b.1.1.21	HVAC - Clean	-	105	-	-	-	-	-	16	121	-	-	121	-	-	-	-	-	-	1,891	-
2b.1.1.22	HVAC - Contaminated	-	371	8	21	282	35	-	148	864	864	-	-	3,261	123	-	-	-	140,573	5,032	-
2b.1.1.23	Incore Instrumentation	0	27	1	1	5	16	-	12	64	64	-	-	60	57	-	-	-	6,177	425	-
2b.1.1.24	Misc Drains & Vents	-	222	14	10	34	146	-	100	527	527	-	-	390	514	-	-	-	49,900	3,091	-
2b.1.1.25	Reactor Coolant	148	298	21	14	30	221	-	213	945	945	-	-	344	777	-	-	-	65,413	6,470	-
2b.1.1.26	Reactor Hot Sampling	144	131	11	6	6	98	-	132	527	527	-	-	66	342	-	-	-	25,347	3,946	-
2b.1.1.27	Reactor Makeup	-	64	-	-	-	-	-	10	73	-	-	73	-	-	-	-	-	-	1,042	-
2b.1.1.28	Reactor Vessel	9	20	1	0	2	4	-	11	47	47	-	-	26	14	-	-	-	2,011	425	-
2b.1.1.29	Residual Heat Removal	344	399	85	66	250	926	-	559	2,630	2,630	-	-	2,895	3,252	-	-	-	332,849	7,621	-
2b.1.1.30	Safeguards Chilled Water	-	15	-	-	-	-	-	2	18	-	-	18	-	-	-	-	-	-	259	-
2b.1.1.31	Safety Injection	-	853	40	57	587	327	-	396	2,261	2,261	-	-	6,788	1,156	-	-	-	351,793	12,561	-
2b.1.1.32	Sampling	-	58	4	2	5	31	-	23	122	122	-	-	59	107	-	-	-	9,505	811	-
2b.1.1.33	Shield Bldg Ventilation	-	133	14	20	186	139	-	100	593	593	-	-	2,152	491	-	-	-	119,838	2,030	-
2b.1.1.34	Station & Instrument Air	-	17	-	-	-	-	-	3	20	-	-	20	-	-	-	-	-	-	300	-
2b.1.1.35	Station & Instrument Air - RCA	-	79	1	2	29	-	-	24	135	135	-	-	332	-	-	-	-	13,496	1,053	-
2b.1.1.36	Turbine Bldg Traps & Drains	-	44	-	-	-	-	-	7	50	-	-	50	-	-	-	-	-	-	767	-
2b.1.1.37	Unit Coolers	-	37	-	-	-	-	-	6	42	-	-	42	-	-	-	-	-	-	611	-
2b.1.1.38	Unit Coolers - RCA	-	53	0	1	20	-	-	16	91	91	-	-	230	-	-	-	-	9,348	683	-
2b.1.1	Totals	1,724	12,813	403	614	6,710	3,044	-	5,730	31,037	28,333	-	2,704	77,571	10,728	-	-	-	3,858,165	205,829	-
2b.1.2	Scaffolding in support of decommissioning	-	1,067	4	1	17	4	-	271	1,364	1,364	-	-	173	15	-	-	-	8,770	7,960	-

Xcel Energy

Table E-1
Prairie Island Nuclear Generating Plant, Unit 1
DECON Decommissioning Cost Estimate with 100 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Decontamination of Site Buildings																					
2b.1.3.1	Reactor	1,150	2,623	139	852	193	11,079	-	4,171	20,208	20,208	-	-	2,230	57,414	-	-	-	3,559,624	50,842	-
2b.1.3.2	Backwash Waste Receiving Tank	-	27	1	11	-	87	-	30	158	158	-	-	-	507	-	-	-	43,896	299	-
2b.1.3	Totals	1,150	2,650	141	864	193	11,166	-	4,202	20,366	20,366	-	-	2,230	57,921	-	-	-	3,603,520	51,140	-
2b.1.4	Prepare/submit License Termination Plan	-	-	-	-	-	-	481	72	553	553	-	-	-	-	-	-	-	-	-	4,096
2b.1.5	Receive NRC approval of termination plan									a											
2b.1	Subtotal Period 2b Activity Costs	2,874	16,530	547	1,479	6,919	14,215	481	10,275	53,320	50,616	-	2,704	79,974	68,664	-	-	-	7,470,455	264,930	4,096
Period 2b Additional Costs																					
2b.2.1	Remedial Action Surveys	-	-	-	-	-	-	1,943	583	2,526	2,526	-	-	-	-	-	-	-	-	25,399	-
2b.2.2	Operational Equipment	-	-	9	29	312	-	-	52	402	402	-	-	5,855	-	-	-	-	146,375	16	-
2b.2	Subtotal Period 2b Additional Costs	-	-	9	29	312	-	1,943	635	2,928	2,928	-	-	5,855	-	-	-	-	146,375	25,415	-
Period 2b Collateral Costs																					
2b.3.1	Process decommissioning water waste	105	-	70	182	-	285	-	158	800	800	-	-	-	680	-	-	-	40,799	133	-
2b.3.2	Process decommissioning chemical flush waste	3	-	87	327	-	651	-	222	1,289	1,289	-	-	-	875	-	-	-	93,252	164	-
2b.3.3	Small tool allowance	-	289	-	-	-	-	-	43	332	332	-	-	-	-	-	-	-	-	-	-
2b.3.4	Spent Fuel Capital and Transfer	-	-	-	-	-	-	4,321	648	4,969	-	4,969	-	-	-	-	-	-	-	-	-
2b.3.5	Retention and Severance	-	-	-	-	-	-	6,994	1,049	8,043	8,043	-	-	-	-	-	-	-	-	-	-
2b.3.6	Prairie Island Indian Community Payments	-	-	-	-	-	-	1,525	-	1,525	-	1,525	-	-	-	-	-	-	-	-	-
2b.3	Subtotal Period 2b Collateral Costs	107	289	157	509	-	936	12,841	2,120	16,958	10,463	6,495	-	-	1,555	-	-	-	134,051	296	-
Period 2b Period-Dependent Costs																					
2b.4.1	Decon supplies	482	-	-	-	-	-	-	121	603	603	-	-	-	-	-	-	-	-	-	-
2b.4.2	Insurance	-	-	-	-	-	-	624	62	687	687	-	-	-	-	-	-	-	-	-	-
2b.4.3	Property taxes	-	-	-	-	-	-	3,099	310	3,409	3,409	-	-	-	-	-	-	-	-	-	-
2b.4.4	Health physics supplies	-	1,969	-	-	-	-	-	492	2,461	2,461	-	-	-	-	-	-	-	-	-	-
2b.4.5	Heavy equipment rental	-	2,759	-	-	-	-	-	414	3,173	3,173	-	-	-	-	-	-	-	-	-	-
2b.4.6	Disposal of DAW generated	-	-	78	23	-	293	-	85	479	479	-	-	-	3,600	-	-	-	71,996	117	-
2b.4.7	Plant energy budget	-	-	-	-	-	-	1,388	208	1,596	1,596	-	-	-	-	-	-	-	-	-	-
2b.4.8	NRC Fees	-	-	-	-	-	-	707	71	778	778	-	-	-	-	-	-	-	-	-	-
2b.4.9	Emergency Planning Fees	-	-	-	-	-	-	1,569	157	1,726	-	1,726	-	-	-	-	-	-	-	-	-
2b.4.10	Fixed Overhead	-	-	-	-	-	-	1,513	227	1,740	1,740	-	-	-	-	-	-	-	-	-	-
2b.4.11	Spent Fuel Pool O&M	-	-	-	-	-	-	490	74	564	-	564	-	-	-	-	-	-	-	-	-
2b.4.12	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	247	37	284	284	-	-	-	-	-	-	-	-	-	-
2b.4.13	ISFSI Operating Costs	-	-	-	-	-	-	63	9	73	-	73	-	-	-	-	-	-	-	-	-
2b.4.14	Railroad Track Maintenance	-	-	-	-	-	-	70	11	81	81	-	-	-	-	-	-	-	-	-	-
2b.4.15	Security Staff Cost	-	-	-	-	-	-	8,299	1,245	9,544	9,544	-	-	-	-	-	-	-	-	-	137,246
2b.4.16	DOC Staff Cost	-	-	-	-	-	-	11,450	1,718	13,168	13,168	-	-	-	-	-	-	-	-	-	137,246
2b.4.17	Utility Staff Cost	-	-	-	-	-	-	15,293	2,294	17,586	17,586	-	-	-	-	-	-	-	-	-	255,430
2b.4	Subtotal Period 2b Period-Dependent Costs	482	4,728	78	23	-	293	44,813	7,533	57,951	55,588	2,362	-	-	3,600	-	-	-	71,996	117	529,921
2b.0	TOTAL PERIOD 2b COST	3,464	21,546	792	2,040	7,231	15,444	60,078	20,563	131,157	119,596	8,857	2,704	85,829	73,819	-	-	-	7,822,876	290,758	534,017
PERIOD 2c - Spent fuel delay prior to SFP decon																					
Period 2c Direct Decommissioning Activities																					
Period 2c Additional Costs																					
2c.2.1	Security Modifications	-	-	-	-	-	-	4,348	652	5,000	5,000	-	-	-	-	-	-	-	-	-	-
2c.2	Subtotal Period 2c Additional Costs	-	-	-	-	-	-	4,348	652	5,000	5,000	-	-	-	-	-	-	-	-	-	-
Period 2c Collateral Costs																					
2c.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	72,993	10,949	83,941	-	83,941	-	-	-	-	-	-	-	-	-
2c.3.2	Retention and Severance	-	-	-	-	-	-	4,478	672	5,149	5,149	-	-	-	-	-	-	-	-	-	-
2c.3.3	Prairie Island Indian Community Payments	-	-	-	-	-	-	2,702	-	2,702	-	2,702	-	-	-	-	-	-	-	-	-
2c.3	Subtotal Period 2c Collateral Costs	-	-	-	-	-	-	80,172	11,621	91,793	5,149	86,643	-	-	-	-	-	-	-	-	-
Period 2c Period-Dependent Costs																					
2c.4.1	Insurance	-	-	-	-	-	-	1,104	110	1,215	1,215	-	-	-	-	-	-	-	-	-	-
2c.4.2	Property taxes	-	-	-	-	-	-	5,154	515	5,669	5,669	-	-	-	-	-	-	-	-	-	-
2c.4.3	Health physics supplies	-	390	-	-	-	-	-	98	488	488	-	-	-	-	-	-	-	-	-	-
2c.4.4	Disposal of DAW generated	-	-	18	5	-	66	-	19	108	108	-	-	-	809	-	-	-	16,171	26	-
2c.4.5	Plant energy budget	-	-	-	-	-	-	655	98	753	753	-	-	-	-	-	-	-	-	-	-
2c.4.6	NRC Fees	-	-	-	-	-	-	555	55	610	610	-	-	-	-	-	-	-	-	-	-
2c.4.7	Emergency Planning Fees	-	-	-	-	-	-	2,776	278	3,053	-	3,053	-	-	-	-	-	-	-	-	-

Table E-1
Prairie Island Nuclear Generating Plant, Unit 1
DECON Decommissioning Cost Estimate with 100 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Period 2c Period-Dependent Costs (continued)																					
2c.4.8	Fixed Overhead	-	-	-	-	-	-	2,676	401	3,078	3,078	-	-	-	-	-	-	-	-	-	-
2c.4.9	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	87	13	101	101	-	-	-	-	-	-	-	-	-	-
2c.4.10	ISFSI Operating Costs	-	-	-	-	-	-	112	17	128	-	128	-	-	-	-	-	-	-	-	-
2c.4.11	Railroad Track Maintenance	-	-	-	-	-	-	125	19	143	143	-	-	-	-	-	-	-	-	-	-
2c.4.12	Security Staff Cost	-	-	-	-	-	-	14,681	2,202	16,883	16,883	-	-	-	-	-	-	-	-	-	242,796
2c.4.13	Utility Staff Cost	-	-	-	-	-	-	2,064	310	2,374	2,374	-	-	-	-	-	-	-	-	-	33,722
2c.4	Subtotal Period 2c Period-Dependent Costs	-	390	18	5	-	66	29,988	4,135	34,602	31,421	3,181	-	-	809	-	-	-	16,171	26	276,518
2c.0	TOTAL PERIOD 2c COST	-	390	18	5	-	66	114,508	16,408	131,395	41,570	89,825	-	-	809	-	-	-	16,171	26	276,518
PERIOD 2d - Decontamination Following Wet Fuel Storage																					
Period 2d Direct Decommissioning Activities																					
2d.1.1	Remove spent fuel racks	328	32	94	32	-	595	-	335	1,416	1,416	-	-	-	2,092	-	-	-	138,298	576	-
Disposal of Plant Systems																					
2d.1.2.1	Electrical - Contaminated - Fuel Pool	-	147	2	4	53	7	-	47	259	259	-	-	615	23	-	-	-	26,508	2,077	-
2d.1.2.2	Electrical - Decontaminated - Fuel Pool	-	918	10	34	510	-	-	312	1,785	1,785	-	-	5,893	-	-	-	-	239,327	12,340	-
2d.1.2.3	HVAC - Contaminated - Fuel Pool	-	159	3	9	121	15	-	63	370	370	-	-	1,398	53	-	-	-	60,246	2,157	-
2d.1.2.4	Safeguards Chilled Water - RCA	-	82	1	3	43	-	-	27	155	155	-	-	495	-	-	-	-	20,100	1,019	-
2d.1.2.5	Spent Fuel Pool Cooling	293	342	34	25	70	377	-	344	1,484	1,484	-	-	806	1,325	-	-	-	120,439	7,613	-
2d.1.2.6	Station & Instrument Air - RCA Fuel Pool	-	20	0	0	7	-	-	6	34	34	-	-	83	-	-	-	-	3,374	263	-
2d.1.2	Totals	293	1,668	50	75	804	399	-	800	4,088	4,088	-	-	9,290	1,401	-	-	-	469,994	25,468	-
2d.1.4	Scaffolding in support of decommissioning	-	213	1	0	3	1	-	54	273	273	-	-	35	3	-	-	-	1,754	1,592	-
2d.1	Subtotal Period 2d Activity Costs	621	1,913	145	107	807	994	-	1,189	5,777	5,777	-	-	9,325	3,496	-	-	-	610,046	27,637	-
Period 2d Additional Costs																					
2d.2.1	License Termination Survey Planning	-	-	-	-	-	-	845	253	1,098	1,098	-	-	-	-	-	-	-	-	-	6,240
2d.2.2	Remedial Action Surveys	-	-	-	-	-	-	1,237	371	1,608	1,608	-	-	-	-	-	-	-	-	16,173	-
2d.2	Subtotal Period 2d Additional Costs	-	-	-	-	-	-	2,082	625	2,706	2,706	-	-	-	-	-	-	-	-	16,173	6,240
Period 2d Collateral Costs																					
2d.3.1	Process decommissioning water waste	27	-	18	48	-	75	-	41	209	209	-	-	-	179	-	-	-	10,724	35	-
2d.3.2	Process decommissioning chemical flush waste	1	-	32	121	-	241	-	82	478	478	-	-	-	324	-	-	-	34,576	61	-
2d.3.3	Small tool allowance	-	35	-	-	-	-	-	5	41	41	-	-	-	-	-	-	-	-	-	-
2d.3.4	Decommissioning Equipment Disposition	-	-	144	55	575	150	-	147	1,071	1,071	-	-	6,000	529	-	-	-	304,968	88	-
2d.3.5	Spent Fuel Capital and Transfer	-	-	-	-	-	-	12,947	1,942	14,889	-	14,889	-	-	-	-	-	-	-	-	-
2d.3.6	Prairie Island Indian Community Payments	-	-	-	-	-	-	971	-	971	-	971	-	-	-	-	-	-	-	-	-
2d.3	Subtotal Period 2d Collateral Costs	27	35	194	224	575	467	13,917	2,217	17,658	1,798	15,859	-	6,000	1,032	-	-	-	350,268	184	-
Period 2d Period-Dependent Costs																					
2d.4.1	Decon supplies	54	-	-	-	-	-	-	14	68	68	-	-	-	-	-	-	-	-	-	-
2d.4.2	Insurance	-	-	-	-	-	-	398	40	437	437	-	-	-	-	-	-	-	-	-	-
2d.4.3	Property taxes	-	-	-	-	-	-	1,740	174	1,914	1,914	-	-	-	-	-	-	-	-	-	-
2d.4.4	Health physics supplies	-	559	-	-	-	-	-	140	699	699	-	-	-	-	-	-	-	-	-	-
2d.4.5	Heavy equipment rental	-	1,757	-	-	-	-	-	264	2,020	2,020	-	-	-	-	-	-	-	-	-	-
2d.4.6	Disposal of DAW generated	-	-	18	5	-	67	-	19	110	110	-	-	-	829	-	-	-	16,581	27	-
2d.4.7	Plant energy budget	-	-	-	-	-	-	471	71	542	542	-	-	-	-	-	-	-	-	-	-
2d.4.8	NRC Fees	-	-	-	-	-	-	381	38	419	419	-	-	-	-	-	-	-	-	-	-
2d.4.9	Emergency Planning Fees	-	-	-	-	-	-	999	100	1,099	-	1,099	-	-	-	-	-	-	-	-	-
2d.4.10	Fixed Overhead	-	-	-	-	-	-	963	144	1,108	1,108	-	-	-	-	-	-	-	-	-	-
2d.4.11	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	315	47	362	362	-	-	-	-	-	-	-	-	-	-
2d.4.12	ISFSI Operating Costs	-	-	-	-	-	-	40	6	46	-	46	-	-	-	-	-	-	-	-	-
2d.4.13	Railroad Track Maintenance	-	-	-	-	-	-	45	7	52	52	-	-	-	-	-	-	-	-	-	-
2d.4.14	Security Staff Cost	-	-	-	-	-	-	5,123	768	5,891	5,891	-	-	-	-	-	-	-	-	-	84,157
2d.4.15	DOC Staff Cost	-	-	-	-	-	-	6,065	910	6,975	6,975	-	-	-	-	-	-	-	-	-	69,996
2d.4.16	Utility Staff Cost	-	-	-	-	-	-	7,796	1,169	8,966	8,123	843	-	-	-	-	-	-	-	-	126,236
2d.4	Subtotal Period 2d Period-Dependent Costs	54	2,316	18	5	-	67	24,337	3,911	30,708	28,720	1,988	-	-	829	-	-	-	16,581	27	280,390
2d.0	TOTAL PERIOD 2d COST	703	4,264	357	337	1,382	1,528	40,336	7,942	56,849	39,002	17,847	-	15,325	5,357	-	-	-	976,895	44,021	286,630
PERIOD 2f - License Termination																					
Period 2f Direct Decommissioning Activities																					
2f.1.1	ORISE confirmatory survey	-	-	-	-	-	-	176	53	229	229	-	-	-	-	-	-	-	-	-	-
2f.1.2	Terminate license									a											
2f.1	Subtotal Period 2f Activity Costs	-	-	-	-	-	-	176	53	229	229	-	-	-	-	-	-	-	-	-	-

Table E-1
Prairie Island Nuclear Generating Plant, Unit 1
DECON Decommissioning Cost Estimate with 100 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Period 2f Additional Costs																					
2f.2.1	License Termination Survey	-	-	-	-	-	-	3,217	965	4,182	4,182	-	-	-	-	-	-	-	-	40,172	3,120
2f.2	Subtotal Period 2f Additional Costs	-	-	-	-	-	-	3,217	965	4,182	4,182	-	-	-	-	-	-	-	-	40,172	3,120
Period 2f Collateral Costs																					
2f.3.1	DOC staff relocation expenses	-	-	-	-	-	-	1,189	178	1,367	1,367	-	-	-	-	-	-	-	-	-	-
2f.3.2	Prairie Island Indian Community Payments	-	-	-	-	-	-	934	-	934	-	934	-	-	-	-	-	-	-	-	-
2f.3	Subtotal Period 2f Collateral Costs	-	-	-	-	-	-	2,122	178	2,300	1,367	934	-	-	-	-	-	-	-	-	-
Period 2f Period-Dependent Costs																					
2f.4.1	Insurance	-	-	-	-	-	-	382	38	420	420	-	-	-	-	-	-	-	-	-	-
2f.4.2	Property taxes	-	-	-	-	-	-	1,626	163	1,789	1,789	-	-	-	-	-	-	-	-	-	-
2f.4.3	Health physics supplies	-	420	-	-	-	-	-	105	524	524	-	-	-	-	-	-	-	-	-	-
2f.4.4	Disposal of DAW generated	-	-	7	2	-	27	-	8	44	44	-	-	-	334	-	-	-	6,685	11	-
2f.4.5	Plant energy budget	-	-	-	-	-	-	227	34	261	261	-	-	-	-	-	-	-	-	-	-
2f.4.6	NRC Fees	-	-	-	-	-	-	417	42	459	459	-	-	-	-	-	-	-	-	-	-
2f.4.7	Emergency Planning Fees	-	-	-	-	-	-	51	5	56	-	56	-	-	-	-	-	-	-	-	-
2f.4.8	Fixed Overhead	-	-	-	-	-	-	926	139	1,065	1,065	-	-	-	-	-	-	-	-	-	-
2f.4.9	ISFSI Operating Costs	-	-	-	-	-	-	39	6	44	-	44	-	-	-	-	-	-	-	-	-
2f.4.10	Railroad Track Maintenance	-	-	-	-	-	-	43	6	50	50	-	-	-	-	-	-	-	-	-	-
2f.4.11	Security Staff Cost	-	-	-	-	-	-	4,924	739	5,663	5,663	-	-	-	-	-	-	-	-	-	80,898
2f.4.12	DOC Staff Cost	-	-	-	-	-	-	4,101	615	4,716	4,716	-	-	-	-	-	-	-	-	-	46,283
2f.4.13	Utility Staff Cost	-	-	-	-	-	-	3,854	578	4,433	3,626	807	-	-	-	-	-	-	-	-	59,507
2f.4	Subtotal Period 2f Period-Dependent Costs	-	420	7	2	-	27	16,591	2,477	19,524	18,617	907	-	-	334	-	-	-	6,685	11	186,687
2f.0	TOTAL PERIOD 2f COST	-	420	7	2	-	27	22,106	3,674	26,236	24,395	1,841	-	-	334	-	-	-	6,685	40,183	189,807
PERIOD 2 TOTALS		5,161	53,290	28,935	6,446	11,617	35,794	318,662	87,758	547,664	418,467	124,322	4,875	138,709	117,153	250	673	-	13,293,650	587,146	2,059,666
PERIOD 3b - Site Restoration																					
Period 3b Direct Decommissioning Activities																					
Demolition of Remaining Site Buildings																					
3b.1.1.1	Reactor	-	4,255	-	-	-	-	-	638	4,894	-	-	4,894	-	-	-	-	-	-	44,669	-
3b.1.1.2	Condensate Storage Tank Foundation	-	3	-	-	-	-	-	0	4	-	-	4	-	-	-	-	-	-	16	-
3b.1.1.3	Structures below 3' below grade	-	1,581	-	-	-	-	-	237	1,818	-	-	1,818	-	-	-	-	-	-	8,411	-
3b.1.1.4	Turbine	-	1,983	-	-	-	-	-	297	2,280	-	-	2,280	-	-	-	-	-	-	22,040	-
3b.1.1.5	Turbine Pedestal	-	349	-	-	-	-	-	52	402	-	-	402	-	-	-	-	-	-	1,857	-
3b.1.1	Totals	-	8,171	-	-	-	-	-	1,226	9,397	-	-	9,397	-	-	-	-	-	-	76,993	-
Site Closeout Activities																					
3b.1.2	Grade & landscape site	-	431	-	-	-	-	-	65	495	-	-	495	-	-	-	-	-	-	921	-
3b.1.3	Final report to NRC	-	-	-	-	-	-	183	27	211	211	-	-	-	-	-	-	-	-	-	1,560
3b.1	Subtotal Period 3b Activity Costs	-	8,602	-	-	-	-	183	1,318	10,102	211	-	9,892	-	-	-	-	-	-	77,914	1,560
Period 3b Additional Costs																					
3b.2.1	Clean Concrete Disposal	-	2,213	-	-	-	-	3	332	2,549	-	-	2,549	-	-	-	-	-	-	8,386	-
3b.2.2	Underground Services Excavations	-	811	-	-	-	-	520	200	1,531	-	-	1,531	-	-	-	-	-	-	7,407	-
3b.2.3	Intake Structure Cofferdam	-	596	-	-	-	-	-	89	686	-	-	686	-	-	-	-	-	-	5,168	-
3b.2.4	Construction Debris	-	-	-	-	-	-	10	2	12	-	-	12	-	-	-	-	-	-	-	-
3b.2.5	Backfill	-	2,751	-	-	-	-	-	413	3,164	-	-	3,164	-	-	-	-	-	-	2,904	-
3b.2	Subtotal Period 3b Additional Costs	-	6,371	-	-	-	-	534	1,036	7,941	-	-	7,941	-	-	-	-	-	-	23,865	-
Period 3b Collateral Costs																					
3b.3.1	Small tool allowance	-	110	-	-	-	-	-	16	126	-	-	126	-	-	-	-	-	-	-	-
3b.3.2	Prairie Island Indian Community Payments	-	-	-	-	-	-	2,651	-	2,651	-	2,651	-	-	-	-	-	-	-	-	-
3b.3	Subtotal Period 3b Collateral Costs	-	110	-	-	-	-	2,651	16	2,777	-	2,651	126	-	-	-	-	-	-	-	-
Period 3b Period-Dependent Costs																					
3b.4.1	Insurance	-	-	-	-	-	-	542	54	596	-	596	-	-	-	-	-	-	-	-	-
3b.4.2	Property taxes	-	-	-	-	-	-	4,334	433	4,767	-	4,767	-	-	-	-	-	-	-	-	-
3b.4.3	Heavy equipment rental	-	6,670	-	-	-	-	-	1,000	7,670	-	-	7,670	-	-	-	-	-	-	-	-
3b.4.4	Plant energy budget	-	-	-	-	-	-	321	48	369	-	-	369	-	-	-	-	-	-	-	-
3b.4.5	NRC ISFSI Fees	-	-	-	-	-	-	236	24	259	-	259	-	-	-	-	-	-	-	-	-
3b.4.6	Emergency Planning Fees	-	-	-	-	-	-	145	14	159	-	159	-	-	-	-	-	-	-	-	-
3b.4.7	Fixed Overhead	-	-	-	-	-	-	990	148	1,138	-	-	1,138	-	-	-	-	-	-	-	-
3b.4.8	ISFSI Operating Costs	-	-	-	-	-	-	109	16	126	-	126	-	-	-	-	-	-	-	-	-

Table E-1
Prairie Island Nuclear Generating Plant, Unit 1
DECON Decommissioning Cost Estimate with 100 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Period 3b Period-Dependent Costs (continued)																					
3b.4.9	Railroad Track Maintenance	-	-	-	-	-	-	331	50	380	-	-	380	-	-	-	-	-	-	-	-
3b.4.10	Security Staff Cost	-	-	-	-	-	-	4,245	637	4,882	-	4,882	-	-	-	-	-	-	-	-	57,340
3b.4.11	DOC Staff Cost	-	-	-	-	-	-	10,467	1,570	12,038	-	-	12,038	-	-	-	-	-	-	-	116,885
3b.4.12	Utility Staff Cost	-	-	-	-	-	-	4,964	745	5,709	(0)	2,283	3,425	-	-	-	-	-	-	-	76,637
3b.4	Subtotal Period 3b Period-Dependent Costs	-	6,670	-	-	-	-	26,684	4,740	38,094	(0)	13,074	25,021	-	-	-	-	-	-	-	250,861
3b.0	TOTAL PERIOD 3b COST	-	21,752	-	-	-	-	30,052	7,110	58,914	211	15,724	42,979	-	-	-	-	-	-	101,779	252,421
PERIOD 3c - Fuel Storage Operations																					
Period 3c Direct Decommissioning Activities																					
Period 3c Additional Costs																					
3c.2.1	ISFSI Disposition of Original Casks	-	-	-	128	-	1,548	-	406	2,082	-	2,082	-	-	4,906	-	-	-	576,566	-	-
3c.2	Subtotal Period 3c Additional Costs	-	-	-	128	-	1,548	-	406	2,082	-	2,082	-	-	4,906	-	-	-	576,566	-	-
Period 3c Collateral Costs																					
3c.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	264,850	39,728	304,578	-	304,578	-	-	-	-	-	-	-	-	-
3c.3.2	Prairie Island Indian Community Payments	-	-	-	-	-	-	61,914	-	61,914	-	61,914	-	-	-	-	-	-	-	-	-
3c.3	Subtotal Period 3c Collateral Costs	-	-	-	-	-	-	326,765	39,728	366,492	-	366,492	-	-	-	-	-	-	-	-	-
Period 3c Period-Dependent Costs																					
3c.4.1	Insurance	-	-	-	-	-	-	12,663	1,266	13,929	-	13,929	-	-	-	-	-	-	-	-	-
3c.4.2	Property taxes	-	-	-	-	-	-	55,169	5,517	60,685	-	60,685	-	-	-	-	-	-	-	-	-
3c.4.3	Plant energy budget	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3c.4.4	NRC ISFSI Fees	-	-	-	-	-	-	8,111	811	8,922	-	8,922	-	-	-	-	-	-	-	-	-
3c.4.5	Emergency Planning Fees	-	-	-	-	-	-	3,389	339	3,728	-	3,728	-	-	-	-	-	-	-	-	-
3c.4.6	Fixed Overhead	-	-	-	-	-	-	7,563	1,134	8,697	-	8,697	-	-	-	-	-	-	-	-	-
3c.4.7	ISFSI Operating Costs	-	-	-	-	-	-	2,559	384	2,942	-	2,942	-	-	-	-	-	-	-	-	-
3c.4.8	Railroad Track Maintenance	-	-	-	-	-	-	2,858	429	3,287	-	3,287	-	-	-	-	-	-	-	-	-
3c.4.9	Security Staff Cost	-	-	-	-	-	-	99,234	14,885	114,119	-	114,119	-	-	-	-	-	-	-	-	1,340,295
3c.4.10	DOC Staff Cost	-	-	-	-	-	-	4,779	717	5,495	-	5,495	-	-	-	-	-	-	-	-	51,550
3c.4.11	Utility Staff Cost	-	-	-	-	-	-	46,446	6,967	53,413	-	53,413	-	-	-	-	-	-	-	-	683,035
3c.4	Subtotal Period 3c Period-Dependent Costs	-	-	-	-	-	-	242,770	32,449	275,219	-	275,219	-	-	-	-	-	-	-	-	2,074,880
3c.0	TOTAL PERIOD 3c COST	-	-	-	128	-	1,548	569,535	72,583	643,794	-	643,794	-	-	4,906	-	-	-	576,566	-	2,074,880
PERIOD 3d - Spent Fuel/GTCC shipping																					
Period 3d Direct Decommissioning Activities																					
Nuclear Steam Supply System Removal																					
3d.1.1.1	Vessel & Internals GTCC Disposal	-	-	1,331	-	-	8,689	-	1,636	11,656	11,656	-	-	-	-	-	-	3,746	837,596	-	-
3d.1.1	Totals	-	-	1,331	-	-	8,689	-	1,636	11,656	11,656	-	-	-	-	-	-	3,746	837,596	-	-
3d.1	Subtotal Period 3d Activity Costs	-	-	1,331	-	-	8,689	-	1,636	11,656	11,656	-	-	-	-	-	-	3,746	837,596	-	-
Period 3d Collateral Costs																					
3d.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	126,070	18,910	144,980	-	144,980	-	-	-	-	-	-	-	-	-
3d.3.2	Prairie Island Indian Community Payments	-	-	-	-	-	-	31,250	-	31,250	-	31,250	-	-	-	-	-	-	-	-	-
3d.3	Subtotal Period 3d Collateral Costs	-	-	-	-	-	-	157,320	18,910	176,230	-	176,230	-	-	-	-	-	-	-	-	-
Period 3d Period-Dependent Costs																					
3d.4.1	Insurance	-	-	-	-	-	-	6,390	639	7,029	-	7,029	-	-	-	-	-	-	-	-	-
3d.4.2	Property taxes	-	-	-	-	-	-	24,558	2,456	27,013	-	27,013	-	-	-	-	-	-	-	-	-
3d.4.4	NRC ISFSI Fees	-	-	-	-	-	-	2,782	278	3,060	-	3,060	-	-	-	-	-	-	-	-	-
3d.4.5	Emergency Planning Fees	-	-	-	-	-	-	1,710	171	1,881	-	1,881	-	-	-	-	-	-	-	-	-
3d.4.6	Fixed Overhead	-	-	-	-	-	-	3,816	572	4,389	-	4,389	-	-	-	-	-	-	-	-	-
3d.4.7	ISFSI Operating Costs	-	-	-	-	-	-	1,291	194	1,485	-	1,485	-	-	-	-	-	-	-	-	-
3d.4.8	Railroad Track Maintenance	-	-	-	-	-	-	1,443	216	1,659	-	1,659	-	-	-	-	-	-	-	-	-
Period 3d Period-Dependent Costs (continued)																					
3d.4.9	Security Staff Cost	-	-	-	-	-	-	48,076	7,211	55,287	-	55,287	-	-	-	-	-	-	-	-	676,370
3d.4.10	Utility Staff Cost	-	-	-	-	-	-	12,369	1,855	14,225	-	14,225	-	-	-	-	-	-	-	-	175,596
3d.4	Subtotal Period 3d Period-Dependent Costs	-	-	-	-	-	-	102,435	13,593	116,029	-	116,029	-	-	-	-	-	-	-	-	851,967
3d.0	TOTAL PERIOD 3d COST	-	-	1,331	-	-	8,689	259,755	34,140	303,915	11,656	292,259	-	-	-	-	-	3,746	837,596	-	851,967

Table E-1
Prairie Island Nuclear Generating Plant, Unit 1
DECON Decommissioning Cost Estimate with 100 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
PERIOD 3e - ISFSI Decontamination																					
Period 3e Direct Decommissioning Activities																					
Period 3e Additional Costs																					
3e.2.1	License Termination ISFSI	15	1	-	-	-	-	970	247	1,233	1,233	-	-	-	-	-	-	-	-	5,604	972
3e.2	Subtotal Period 3e Additional Costs	15	1	-	-	-	-	970	247	1,233	1,233	-	-	-	-	-	-	-	-	5,604	972
Period 3e Period-Dependent Costs																					
3e.4.1	Insurance	-	-	-	-	-	-	96	24	121	121	-	-	-	-	-	-	-	-	-	-
3e.4.4	Fixed Overhead	-	-	-	-	-	-	51	13	63	63	-	-	-	-	-	-	-	-	-	-
3e.4.5	Railroad Track Maintenance	-	-	-	-	-	-	19	5	24	24	-	-	-	-	-	-	-	-	-	-
3e.4.6	Security Staff Cost	-	-	-	-	-	-	154	38	192	192	-	-	-	-	-	-	-	-	-	2,500
3e.4.7	Utility Staff Cost	-	-	-	-	-	-	130	33	163	163	-	-	-	-	-	-	-	-	-	1,896
3e.4	Subtotal Period 3e Period-Dependent Costs	-	-	-	-	-	-	450	113	563	563	-	-	-	-	-	-	-	-	-	4,396
3e.0	TOTAL PERIOD 3e COST	15	1	-	-	-	-	1,420	359	1,795	1,795	-	-	-	-	-	-	-	-	5,604	5,368
PERIOD 3f - ISFSI Site Restoration																					
Period 3f Direct Decommissioning Activities																					
Period 3f Additional Costs																					
3f.2.1	Demolition and Site Restoration of ISFSI	-	946	-	-	-	-	154	165	1,265	-	-	1,265	-	-	-	-	-	-	4,922	160
3f.2	Subtotal Period 3f Additional Costs	-	946	-	-	-	-	154	165	1,265	-	-	1,265	-	-	-	-	-	-	4,922	160
Period 3f Collateral Costs																					
3f.3.1	Small tool allowance	-	7	-	-	-	-	-	1	8	-	-	8	-	-	-	-	-	-	-	-
3f.3	Subtotal Period 3f Collateral Costs	-	7	-	-	-	-	-	1	8	-	-	8	-	-	-	-	-	-	-	-
Period 3f Period-Dependent Costs																					
3f.4.3	Heavy equipment rental	-	62	-	-	-	-	-	9	71	-	-	71	-	-	-	-	-	-	-	-
3f.4.4	Plant energy budget	-	-	-	-	-	-	13	2	15	-	-	15	-	-	-	-	-	-	-	-
3f.4.5	Fixed Overhead	-	-	-	-	-	-	25	4	29	-	-	29	-	-	-	-	-	-	-	-
3f.4.6	Railroad Track Maintenance	-	-	-	-	-	-	10	1	11	-	-	11	-	-	-	-	-	-	-	-
3f.4.7	Security Staff Cost	-	-	-	-	-	-	78	12	89	-	-	89	-	-	-	-	-	-	-	1,260
3f.4.8	Utility Staff Cost	-	-	-	-	-	-	52	8	60	-	-	60	-	-	-	-	-	-	-	782
3f.4	Subtotal Period 3f Period-Dependent Costs	-	62	-	-	-	-	177	36	275	-	-	275	-	-	-	-	-	-	-	2,042
3f.0	TOTAL PERIOD 3f COST	-	1,014	-	-	-	-	331	202	1,547	-	-	1,547	-	-	-	-	-	-	4,922	2,202
PERIOD 3 TOTALS		15	22,767	1,331	128	-	10,236	861,093	114,394	1,009,965	13,662	951,777	44,526	-	4,906	-	-	3,746	1,414,161	112,304	3,186,837
TOTAL COST TO DECOMMISSION		**8,749**	**81,426**	**30,681**	**7,026**	**11,781**	**50,002**	**1,290,387**	**221,416**	**1,701,468**	**568,261**	**1,082,353**	**50,855**	**144,842**	**136,023**	**839**	**673**	**3,746**	**15,317,950**	**744,976**	**6,250,924**

TOTAL COST TO DECOMMISSION WITH 14.96% CONTINGENCY:	**$1,701,468**	**thousands of 2017 dollars**
TOTAL NRC LICENSE TERMINATION COST IS 33.4% OR:	**$568,261**	**thousands of 2017 dollars**
SPENT FUEL MANAGEMENT COST IS 63.61% OR:	**$1,082,353**	**thousands of 2017 dollars**
NON-NUCLEAR DEMOLITION COST IS 2.99% OR:	**$50,855**	**thousands of 2017 dollars**
TOTAL LOW-LEVEL RADIOACTIVE WASTE VOLUME BURIED (EXCLUDING GTCC):	**137,535**	**cubic feet**
TOTAL GREATER THAN CLASS C RADWASTE VOLUME GENERATED:	**3,746**	**cubic feet**
TOTAL SCRAP METAL REMOVED:	**32,925**	**tons**
TOTAL CRAFT LABOR REQUIREMENTS:	**744,976**	**man-hours**

End Notes:
n/a - indicates that this activity not charged as decommissioning expense
a - indicates that this activity performed by decommissioning staff
0 - indicates that this value is less than 0.5 but is non-zero
A cell containing " - " indicates a zero value

Table E-2
Prairie Island Nuclear Generating Plant, Unit 2
DECON Decommissioning Cost Estimate with 100 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
PERIOD 1a - Shutdown through Transition																					
Period 1a Direct Decommissioning Activities																					
1a.1.1	Prepare preliminary decommissioning cost	-	-	-	-	-	-	65	10	75	75	-	-	-	-	-	-	-	-	-	556
1a.1.2	Notification of Cessation of Operations									a											
1a.1.3	Remove fuel & source material									n/a											
1a.1.4	Notification of Permanent Defueling									a											
1a.1.5	Deactivate plant systems & process waste									a											
1a.1.6	Prepare and submit PSDAR	-	-	-	-	-	-	100	15	115	115	-	-	-	-	-	-	-	-	-	855
1a.1.7	Review plant dwgs & specs.	-	-	-	-	-	-	231	35	266	266	-	-	-	-	-	-	-	-	-	1,967
1a.1.8	Perform detailed rad survey									a											
1a.1.9	Estimate by-product inventory	-	-	-	-	-	-	50	8	58	58	-	-	-	-	-	-	-	-	-	428
1a.1.10	End product description	-	-	-	-	-	-	50	8	58	58	-	-	-	-	-	-	-	-	-	428
1a.1.11	Detailed by-product inventory	-	-	-	-	-	-	65	10	75	75	-	-	-	-	-	-	-	-	-	556
1a.1.12	Define major work sequence	-	-	-	-	-	-	376	56	433	433	-	-	-	-	-	-	-	-	-	3,207
1a.1.13	Perform SER and EA	-	-	-	-	-	-	156	23	179	179	-	-	-	-	-	-	-	-	-	1,326
1a.1.14	Prepare/submit Defueled Technical Specifications	-	-	-	-	-	-	376	56	433	433	-	-	-	-	-	-	-	-	-	3,207
1a.1.15	Perform Site-Specific Cost Study	-	-	-	-	-	-	251	38	289	289	-	-	-	-	-	-	-	-	-	2,138
1a.1.16	Prepare/submit Irradiated Fuel Management Plan	-	-	-	-	-	-	50	8	58	58	-	-	-	-	-	-	-	-	-	428
Activity Specifications																					
1a.1.17.1	Plant & temporary facilities	-	-	-	-	-	-	247	37	284	256	-	28	-	-	-	-	-	-	-	2,104
1a.1.17.2	Plant systems	-	-	-	-	-	-	209	31	241	216	-	24	-	-	-	-	-	-	-	1,782
1a.1.17.3	NSSS Decontamination Flush	-	-	-	-	-	-	25	4	29	29	-	-	-	-	-	-	-	-	-	214
1a.1.17.4	Reactor internals	-	-	-	-	-	-	356	53	410	410	-	-	-	-	-	-	-	-	-	3,036
1a.1.17.5	Reactor vessel	-	-	-	-	-	-	326	49	375	375	-	-	-	-	-	-	-	-	-	2,779
1a.1.17.6	Biological shield	-	-	-	-	-	-	25	4	29	29	-	-	-	-	-	-	-	-	-	214
1a.1.17.7	Steam generators	-	-	-	-	-	-	157	23	180	180	-	-	-	-	-	-	-	-	-	1,334
1a.1.17.8	Reinforced concrete	-	-	-	-	-	-	80	12	92	46	-	46	-	-	-	-	-	-	-	684
1a.1.17.9	Main Turbine	-	-	-	-	-	-	20	3	23	-	-	23	-	-	-	-	-	-	-	171
1a.1.17.10	Main Condensers	-	-	-	-	-	-	20	3	23	-	-	23	-	-	-	-	-	-	-	171
1a.1.17.11	Plant structures & buildings	-	-	-	-	-	-	157	23	180	90	-	90	-	-	-	-	-	-	-	1,334
1a.1.17.12	Waste management	-	-	-	-	-	-	231	35	266	266	-	-	-	-	-	-	-	-	-	1,967
1a.1.17.13	Facility & site closeout	-	-	-	-	-	-	45	7	52	26	-	26	-	-	-	-	-	-	-	385
1a.1.17	Total	-	-	-	-	-	-	1,899	285	2,183	1,923	-	261	-	-	-	-	-	-	-	16,175
Planning & Site Preparations																					
1a.1.18	Prepare dismantling sequence	-	-	-	-	-	-	120	18	139	139	-	-	-	-	-	-	-	-	-	1,026
1a.1.19	Plant prep. & temp. svces	-	-	-	-	-	-	3,300	495	3,795	3,795	-	-	-	-	-	-	-	-	-	-
1a.1.20	Design water clean-up system	-	-	-	-	-	-	70	11	81	81	-	-	-	-	-	-	-	-	-	599
1a.1.21	Rigging/Cont. Cntrl Envlps/tooling/etc.	-	-	-	-	-	-	2,300	345	2,645	2,645	-	-	-	-	-	-	-	-	-	-
1a.1.22	Procure casks/liners & containers	-	-	-	-	-	-	62	9	71	71	-	-	-	-	-	-	-	-	-	526
1a.1	Subtotal Period 1a Activity Costs	-	-	-	-	-	-	9,523	1,428	10,951	10,690	-	261	-	-	-	-	-	-	-	33,420
Period 1a Additional Costs																					
1a.2.1	Spent Fuel Pool Isolation	-	-	-	-	-	-	7,794	1,169	8,963	8,963	-	-	-	-	-	-	-	-	-	-
1a.2	Subtotal Period 1a Additional Costs	-	-	-	-	-	-	7,794	1,169	8,963	8,963	-	-	-	-	-	-	-	-	-	-
Period 1a Collateral Costs																					
1a.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	1,227	184	1,411	-	1,411	-	-	-	-	-	-	-	-	-
1a.3.2	Retention and Severance	-	-	-	-	-	-	8,394	1,259	9,653	9,653	-	-	-	-	-	-	-	-	-	-
1a.3.3	Prairie Island Indian Community Payments	-	-	-	-	-	-	2,281	-	2,281	-	2,281	-	-	-	-	-	-	-	-	-
1a.3	Subtotal Period 1a Collateral Costs	-	-	-	-	-	-	11,902	1,443	13,345	9,653	3,692	-	-	-	-	-	-	-	-	-
Period 1a Period-Dependent Costs																					
1a.4.1	Insurance	-	-	-	-	-	-	1,730	173	1,903	1,903	-	-	-	-	-	-	-	-	-	-
1a.4.2	Property taxes	-	-	-	-	-	-	2,682	268	2,950	2,950	-	-	-	-	-	-	-	-	-	-
1a.4.3	Health physics supplies	-	485	-	-	-	-	-	121	606	606	-	-	-	-	-	-	-	-	-	-
1a.4.4	Heavy equipment rental	-	567	-	-	-	-	-	85	652	652	-	-	-	-	-	-	-	-	-	-
1a.4.5	Disposal of DAW generated	-	-	12	4	-	46	-	13	75	75	-	-	-	565	-	-	-	11,299	18	-
1a.4.6	Plant energy budget	-	-	-	-	-	-	1,515	227	1,742	1,742	-	-	-	-	-	-	-	-	-	-
1a.4.7	NRC Fees	-	-	-	-	-	-	778	78	855	855	-	-	-	-	-	-	-	-	-	-
1a.4.8	Emergency Planning Fees	-	-	-	-	-	-	1,604	160	1,765	-	1,765	-	-	-	-	-	-	-	-	-
1a.4.9	Fixed Overhead	-	-	-	-	-	-	1,470	220	1,690	1,690	-	-	-	-	-	-	-	-	-	-
1a.4.10	Spent Fuel Pool O&M	-	-	-	-	-	-	401	60	461	-	461	-	-	-	-	-	-	-	-	-
1a.4.11	ISFSI Operating Costs	-	-	-	-	-	-	52	8	59	-	59	-	-	-	-	-	-	-	-	-
1a.4.12	Railroad Track Maintenance	-	-	-	-	-	-	58	9	66	66	-	-	-	-	-	-	-	-	-	-
1a.4.13	Security Staff Cost	-	-	-	-	-	-	7,390	1,108	8,498	8,498	-	-	-	-	-	-	-	-	-	122,720
1a.4.14	Utility Staff Cost	-	-	-	-	-	-	20,662	3,099	23,761	23,761	-	-	-	-	-	-	-	-	-	345,280

Table E-2
Prairie Island Nuclear Generating Plant, Unit 2
DECON Decommissioning Cost Estimate with 100 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
1a.4	Subtotal Period 1a Period-Dependent Costs	-	1,052	12	4	-	46	38,340	5,631	45,085	42,800	2,286	-	-	565	-	-	-	11,299	18	468,000
1a.0	TOTAL PERIOD 1a COST	-	1,052	12	4	-	46	67,559	9,672	78,345	72,107	5,977	261	-	565	-	-	-	11,299	18	501,420
PERIOD 1b - Decommissioning Preparations																					
Period 1b Direct Decommissioning Activities																					
Detailed Work Procedures																					
1b.1.1.1	Plant systems	-	-	-	-	-	-	238	36	273	246	-	27	-	-	-	-	-	-	-	2,024
1b.1.1.2	NSSS Decontamination Flush	-	-	-	-	-	-	50	8	58	58	-	-	-	-	-	-	-	-	-	428
1b.1.1.3	Reactor internals	-	-	-	-	-	-	125	19	144	144	-	-	-	-	-	-	-	-	-	1,069
1b.1.1.4	Remaining buildings	-	-	-	-	-	-	68	10	78	19	-	58	-	-	-	-	-	-	-	577
1b.1.1.5	CRD cooling assembly	-	-	-	-	-	-	50	8	58	58	-	-	-	-	-	-	-	-	-	428
1b.1.1.6	CRD housings & ICI tubes	-	-	-	-	-	-	50	8	58	58	-	-	-	-	-	-	-	-	-	428
1b.1.1.7	Incore instrumentation	-	-	-	-	-	-	50	8	58	58	-	-	-	-	-	-	-	-	-	428
1b.1.1.8	Reactor vessel	-	-	-	-	-	-	182	27	210	210	-	-	-	-	-	-	-	-	-	1,552
1b.1.1.9	Facility closeout	-	-	-	-	-	-	60	9	69	35	-	35	-	-	-	-	-	-	-	513
1b.1.1.10	Missile shields	-	-	-	-	-	-	23	3	26	26	-	-	-	-	-	-	-	-	-	192
1b.1.1.11	Biological shield	-	-	-	-	-	-	60	9	69	69	-	-	-	-	-	-	-	-	-	513
1b.1.1.12	Steam generators	-	-	-	-	-	-	231	35	266	266	-	-	-	-	-	-	-	-	-	1,967
1b.1.1.13	Reinforced concrete	-	-	-	-	-	-	50	8	58	29	-	29	-	-	-	-	-	-	-	428
1b.1.1.14	Main Turbine	-	-	-	-	-	-	78	12	90	-	-	90	-	-	-	-	-	-	-	667
1b.1.1.15	Main Condensers	-	-	-	-	-	-	78	12	90	-	-	90	-	-	-	-	-	-	-	667
1b.1.1.16	Auxiliary building	-	-	-	-	-	-	137	21	158	142	-	16	-	-	-	-	-	-	-	1,167
1b.1.1.17	Reactor building	-	-	-	-	-	-	137	21	158	142	-	16	-	-	-	-	-	-	-	1,167
1b.1.1	Total	-	-	-	-	-	-	1,669	250	1,919	1,558	-	361	-	-	-	-	-	-	-	14,215
1b.1.2	Decon primary loop	552	-	-	-	-	-	-	276	828	828	-	-	-	-	-	-	-	-	1,067	-
1b.1	Subtotal Period 1b Activity Costs	552	-	-	-	-	-	1,669	526	2,747	2,386	-	361	-	-	-	-	-	-	1,067	14,215
Period 1b Additional Costs																					
1b.2.1	Site Characterization	-	-	-	-	-	-	1,582	475	2,057	2,057	-	-	-	-	-	-	-	-	8,988	3,563
1b.2.2	Mixed/Hazardous Waste	-	-	326	75	169	-	-	69	639	639	-	-	6,324	-	-	-	-	362,914	2,410	-
1b.2.3	Asbestos Abatement	-	2,364	2	110	-	1,359	-	947	4,782	4,782	-	-	-	12,843	-	-	-	166,959	20,907	-
1b.2	Subtotal Period 1b Additional Costs	-	2,364	328	185	169	1,359	1,582	1,491	7,478	7,478	-	-	6,324	12,843	-	-	-	529,873	32,305	3,563
Period 1b Collateral Costs																					
1b.3.1	Decon equipment	973	-	-	-	-	-	-	146	1,119	1,119	-	-	-	-	-	-	-	-	-	-
1b.3.2	DOC staff relocation expenses	-	-	-	-	-	-	1,189	178	1,367	1,367	-	-	-	-	-	-	-	-	-	-
1b.3.3	Process decommissioning water waste	24	-	16	41	-	64	-	36	180	180	-	-	-	152	-	-	-	9,121	30	-
1b.3.4	Process decommissioning chemical flush waste	2	-	58	220	-	2,471	-	657	3,408	3,408	-	-	-	-	588	-	-	62,689	110	-
1b.3.5	Small tool allowance	-	34	-	-	-	-	-	5	39	39	-	-	-	-	-	-	-	-	-	-
1b.3.6	Pipe cutting equipment	-	1,200	-	-	-	-	-	180	1,380	1,380	-	-	-	-	-	-	-	-	-	-
1b.3.7	Decon rig	1,987	-	-	-	-	-	-	298	2,285	2,285	-	-	-	-	-	-	-	-	-	-
1b.3.8	Spent Fuel Capital and Transfer	-	-	-	-	-	-	370	56	426	-	426	-	-	-	-	-	-	-	-	-
1b.3.9	Retention and Severance	-	-	-	-	-	-	4,055	608	4,664	4,664	-	-	-	-	-	-	-	-	-	-
1b.3.10	Prairie Island Indian Community Payments	-	-	-	-	-	-	629	-	629	-	629	-	-	-	-	-	-	-	-	-
1b.3	Subtotal Period 1b Collateral Costs	2,986	1,234	74	261	-	2,534	6,243	2,164	15,495	14,441	1,055	-	-	152	588	-	-	71,810	140	-
Period 1b Period-Dependent Costs																					
1b.4.1	Decon supplies	35	-	-	-	-	-	-	9	44	44	-	-	-	-	-	-	-	-	-	-
1b.4.2	Insurance	-	-	-	-	-	-	872	87	959	959	-	-	-	-	-	-	-	-	-	-
1b.4.3	Property taxes	-	-	-	-	-	-	1,319	132	1,451	1,451	-	-	-	-	-	-	-	-	-	-
1b.4.4	Health physics supplies	-	380	-	-	-	-	-	95	475	475	-	-	-	-	-	-	-	-	-	-
1b.4.5	Heavy equipment rental	-	286	-	-	-	-	-	43	329	329	-	-	-	-	-	-	-	-	-	-
1b.4.6	Disposal of DAW generated	-	-	7	2	-	27	-	8	44	44	-	-	-	327	-	-	-	6,541	11	-
1b.4.7	Plant energy budget	-	-	-	-	-	-	1,527	229	1,756	1,756	-	-	-	-	-	-	-	-	-	-
1b.4.8	NRC Fees	-	-	-	-	-	-	214	21	236	236	-	-	-	-	-	-	-	-	-	-
1b.4.9	Emergency Planning Fees	-	-	-	-	-	-	809	81	890	-	890	-	-	-	-	-	-	-	-	-
1b.4.10	Fixed Overhead	-	-	-	-	-	-	741	111	852	852	-	-	-	-	-	-	-	-	-	-
1b.4.11	Spent Fuel Pool O&M	-	-	-	-	-	-	202	30	233	-	233	-	-	-	-	-	-	-	-	-
1b.4.12	ISFSI Operating Costs	-	-	-	-	-	-	26	4	30	-	30	-	-	-	-	-	-	-	-	-
1b.4.13	Railroad Track Maintenance	-	-	-	-	-	-	29	4	33	33	-	-	-	-	-	-	-	-	-	-
1b.4.14	Security Staff Cost	-	-	-	-	-	-	3,725	559	4,284	4,284	-	-	-	-	-	-	-	-	-	61,864
1b.4.15	DOC Staff Cost	-	-	-	-	-	-	4,009	601	4,610	4,610	-	-	-	-	-	-	-	-	-	47,185
1b.4.16	Utility Staff Cost	-	-	-	-	-	-	10,416	1,562	11,978	11,978	-	-	-	-	-	-	-	-	-	174,059
1b.4	Subtotal Period 1b Period-Dependent Costs	35	666	7	2	-	27	23,890	3,577	28,204	27,052	1,152	-	-	327	-	-	-	6,541	11	283,108

Table E-2
Prairie Island Nuclear Generating Plant, Unit 2
DECON Decommissioning Cost Estimate with 100 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
1b.0	TOTAL PERIOD 1b COST	3,573	4,264	410	447	169	3,920	33,383	7,759	53,923	51,356	2,207	361	6,324	13,322	588	-	-	608,224	33,522	300,885
PERIOD 1 TOTALS		3,573	5,316	422	451	169	3,966	100,942	17,430	132,268	123,462	8,184	622	6,324	13,887	588	-	-	619,523	33,540	802,305
PERIOD 2a - Large Component Removal																					
Period 2a Direct Decommissioning Activities																					
Nuclear Steam Supply System Removal																					
2a.1.1.1	Reactor Coolant Piping	51	45	6	8	-	150	-	76	336	336	-	-	-	305	-	-	-	34,809	1,414	-
2a.1.1.2	Pressurizer Relief Tank	22	20	4	5	-	100	-	42	193	193	-	-	-	203	-	-	-	23,193	625	-
2a.1.1.3	Reactor Coolant Pumps & Motors	54	63	101	83	-	736	-	249	1,287	1,287	-	-	-	2,332	-	-	-	295,800	2,049	100
2a.1.1.4	Pressurizer	48	68	467	88	-	693	-	274	1,639	1,639	-	-	-	2,196	-	-	-	185,015	2,355	938
2a.1.1.5	Steam Generators	225	2,943	2,093	1,638	1,246	3,570	-	2,383	14,097	14,097	-	-	18,672	11,316	-	-	-	1,668,341	14,819	2,875
2a.1.1.6	CRDMs/ICIs/Service Structure Removal	286	277	211	48	-	763	-	431	2,016	2,016	-	-	-	4,797	-	-	-	177,400	8,104	-
2a.1.1.7	Reactor Vessel Internals	78	4,468	21,874	1,072	-	7,946	277	13,141	48,856	48,856	-	-	-	501	125	673	-	164,987	23,040	1,080
2a.1.1.8	Reactor Vessel	89	5,717	1,754	719	-	1,956	277	5,970	16,483	16,483	-	-	-	5,690	-	-	-	570,074	23,040	1,080
2a.1.1	Totals	855	13,600	26,512	3,662	1,246	15,913	553	22,568	84,908	84,908	-	-	18,672	27,341	125	673	-	3,119,620	75,446	6,073
Removal of Major Equipment																					
2a.1.2	Main Turbine/Generator	-	305	189	55	272	306	-	221	1,348	1,348	-	-	2,131	1,187	-	-	-	206,316	4,667	-
2a.1.3	Main Condensers	-	2,532	121	49	364	451	-	820	4,336	4,336	-	-	3,800	1,587	-	-	-	275,903	39,151	-
Cascading Costs from Clean Building Demolition																					
2a.1.4.1	Reactor	-	728	-	-	-	-	-	109	837	837	-	-	-	-	-	-	-	-	7,589	-
2a.1.4.2	Auxiliary	-	210	-	-	-	-	-	32	242	242	-	-	-	-	-	-	-	-	1,309	-
2a.1.4.3	Radwaste	-	8	-	-	-	-	-	1	9	9	-	-	-	-	-	-	-	-	65	-
2a.1.4	Totals	-	946	-	-	-	-	-	142	1,088	1,088	-	-	-	-	-	-	-	-	8,963	-
Disposal of Plant Systems																					
2a.1.5.1	Admin Bldg Ventilation	-	6	-	-	-	-	-	1	6	-	-	6	-	-	-	-	-	-	90	-
2a.1.5.2	Air Removal	-	25	-	-	-	-	-	4	29	-	-	29	-	-	-	-	-	-	422	-
2a.1.5.3	Auxiliary Feedwater	-	40	-	-	-	-	-	6	46	-	-	46	-	-	-	-	-	-	676	-
2a.1.5.4	Auxiliary Feedwater - RCA	-	36	0	1	15	-	-	12	65	65	-	-	178	-	-	-	-	7,214	486	-
2a.1.5.5	Bleed Steam	-	78	-	-	-	-	-	12	90	-	-	90	-	-	-	-	-	-	1,331	-
2a.1.5.6	Caustic Addition - RCA	-	38	0	1	21	-	-	13	74	74	-	-	240	-	-	-	-	9,761	468	-
2a.1.5.7	Chemical Feed	-	15	-	-	-	-	-	2	17	-	-	17	-	-	-	-	-	-	261	-
2a.1.5.8	Chemical Feed - RCA	-	3	0	0	1	-	-	1	5	5	-	-	16	-	-	-	-	634	31	-
2a.1.5.9	Circulating Water	-	24	-	-	-	-	-	4	28	-	-	28	-	-	-	-	-	-	401	-
2a.1.5.10	Condensate	-	459	-	-	-	-	-	69	527	-	-	527	-	-	-	-	-	-	7,537	-
2a.1.5.11	Condensate Polishing	-	181	-	-	-	-	-	27	209	-	-	209	-	-	-	-	-	-	2,987	-
2a.1.5.12	Condensate Polishing - RCA	-	36	1	3	42	-	-	16	98	98	-	-	483	-	-	-	-	19,616	493	-
2a.1.5.13	Electro-Hydraulic	-	8	-	-	-	-	-	1	10	-	-	10	-	-	-	-	-	-	143	-
2a.1.5.14	External Circulating Water	-	23	-	-	-	-	-	3	26	-	-	26	-	-	-	-	-	-	385	-
2a.1.5.15	External Circulating Water - RCA	-	70	1	4	62	-	-	28	165	165	-	-	721	-	-	-	-	29,284	938	-
2a.1.5.16	Feedwater	-	111	-	-	-	-	-	17	128	-	-	128	-	-	-	-	-	-	1,840	-
2a.1.5.17	Feedwater - RCA	-	236	7	24	359	-	-	117	744	744	-	-	4,147	-	-	-	-	168,414	3,377	-
2a.1.5.18	Gland Seal	-	29	-	-	-	-	-	4	34	-	-	34	-	-	-	-	-	-	504	-
2a.1.5.19	Heater Drain	-	334	-	-	-	-	-	50	384	-	-	384	-	-	-	-	-	-	5,638	-
2a.1.5.20	Hypobromous Acid Feed	-	5	-	-	-	-	-	1	6	-	-	6	-	-	-	-	-	-	86	-
2a.1.5.21	Hypobromous Acid Feed - RCA	-	1	0	0	0	-	-	0	1	1	-	-	2	-	-	-	-	100	12	-
2a.1.5.22	Internal Circ Water & CDSR	-	22	-	-	-	-	-	3	25	-	-	25	-	-	-	-	-	-	366	-
2a.1.5.23	Main Gen/Exciter/Transformer	-	0	-	-	-	-	-	0	0	-	-	0	-	-	-	-	-	-	5	-
2a.1.5.24	Main Steam	-	88	-	-	-	-	-	13	101	-	-	101	-	-	-	-	-	-	1,482	-
2a.1.5.25	Main Steam - RCA	-	364	9	30	447	-	-	163	1,013	1,013	-	-	5,166	-	-	-	-	209,799	5,146	-
2a.1.5.26	Repairable Spare Snubbers	-	6	0	0	1	-	-	2	8	8	-	-	12	-	-	-	-	490	82	-
2a.1.5.27	Steam Exclusion	-	2	-	-	-	-	-	0	2	-	-	2	-	-	-	-	-	-	32	-
2a.1.5.28	Steam Exclusion - RCA	-	4	0	0	2	-	-	1	8	8	-	-	24	-	-	-	-	966	47	-
2a.1.5.29	Steam Generator Blowdown	-	398	20	21	165	179	-	174	957	957	-	-	1,906	631	-	-	-	119,126	5,778	-
2a.1.5.30	Steam Generators	-	5	-	-	-	-	-	1	5	-	-	5	-	-	-	-	-	-	75	-
2a.1.5.31	Turbine & Moisture Separators	-	329	-	-	-	-	-	49	379	-	-	379	-	-	-	-	-	-	5,472	-
2a.1.5.32	Turbine Oil Purification	-	46	-	-	-	-	-	7	53	-	-	53	-	-	-	-	-	-	757	-
2a.1.5.33	Water Treatment	-	394	-	-	-	-	-	59	453	-	-	453	-	-	-	-	-	-	6,677	-
2a.1.5.34	Water Treatment - RCA	-	19	0	1	10	-	-	6	37	37	-	-	115	-	-	-	-	4,652	252	-
2a.1.5	Totals	-	3,437	39	85	1,125	179	-	867	5,733	3,174	-	2,559	13,010	631	-	-	-	570,056	54,280	-
2a.1.6	Scaffolding in support of decommissioning	-	2,833	24	8	97	25	-	733	3,721	3,721	-	-	1,012	89	-	-	-	51,445	26,270	-
2a.1	Subtotal Period 2a Activity Costs	855	23,653	26,885	3,859	3,105	16,875	553	25,350	101,134	98,575	-	2,559	38,625	30,835	125	673	-	4,223,340	208,777	6,073

Table E-2
Prairie Island Nuclear Generating Plant, Unit 2
DECON Decommissioning Cost Estimate with 100 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 2a Additional Costs																					
2a.2.1	Remedial Action Surveys	-	-	-	-	-	-	1,560	468	2,027	2,027	-	-	-	-	-	-	-	-	20,388	-
2a.2.2	Retired RPV upper internals package	1	659	785	107	-	1,439	-	1,437	4,427	4,427	-	-	-	2,097	125	-	-	205,890	2,175	87
2a.2	Subtotal Period 2a Additional Costs	1	659	785	107	-	1,439	1,560	1,905	6,454	6,454	-	-	-	2,097	125	-	-	205,890	22,562	87
Period 2a Collateral Costs																					
2a.3.1	Process decommissioning water waste	51	-	33	86	-	135	-	75	381	381	-	-	-	323	-	-	-	19,358	63	-
2a.3.3	Small tool allowance	-	251	-	-	-	-	-	38	289	260	-	29	-	-	-	-	-	-	-	-
2a.3.4	Spent Fuel Capital and Transfer	-	-	-	-	-	-	2,138	321	2,459	-	2,459	-	-	-	-	-	-	-	-	-
2a.3.5	Retention and Severance	-	-	-	-	-	-	6,105	916	7,021	7,021	-	-	-	-	-	-	-	-	-	-
2a.3.6	Prairie Island Indian Community Payments	-	-	-	-	-	-	1,224	-	1,224	-	1,224	-	-	-	-	-	-	-	-	-
2a.3	Subtotal Period 2a Collateral Costs	51	251	33	86	-	135	9,467	1,349	11,373	7,661	3,682	29	-	323	-	-	-	19,358	63	-
Period 2a Period-Dependent Costs																					
2a.4.1	Decon supplies	68	-	-	-	-	-	-	17	85	85	-	-	-	-	-	-	-	-	-	-
2a.4.2	Insurance	-	-	-	-	-	-	501	50	551	551	-	-	-	-	-	-	-	-	-	-
2a.4.3	Property taxes	-	-	-	-	-	-	2,507	251	2,758	2,758	-	-	-	-	-	-	-	-	-	-
2a.4.4	Health physics supplies	-	1,622	-	-	-	-	-	406	2,028	2,028	-	-	-	-	-	-	-	-	-	-
2a.4.5	Heavy equipment rental	-	2,153	-	-	-	-	-	323	2,477	2,477	-	-	-	-	-	-	-	-	-	-
2a.4.6	Disposal of DAW generated	-	-	89	26	-	331	-	95	541	541	-	-	-	4,063	-	-	-	81,252	133	-
2a.4.7	Plant energy budget	-	-	-	-	-	-	1,411	212	1,623	1,623	-	-	-	-	-	-	-	-	-	-
2a.4.8	NRC Fees	-	-	-	-	-	-	389	39	428	428	-	-	-	-	-	-	-	-	-	-
2a.4.9	Emergency Planning Fees	-	-	-	-	-	-	1,259	126	1,385	-	1,385	-	-	-	-	-	-	-	-	-
2a.4.10	Fixed Overhead	-	-	-	-	-	-	1,214	182	1,396	1,396	-	-	-	-	-	-	-	-	-	-
2a.4.11	Spent Fuel Pool O&M	-	-	-	-	-	-	394	59	453	-	453	-	-	-	-	-	-	-	-	-
2a.4.12	ISFSI Operating Costs	-	-	-	-	-	-	51	8	58	-	58	-	-	-	-	-	-	-	-	-
2a.4.13	Railroad Track Maintenance	-	-	-	-	-	-	265	40	305	305	-	-	-	-	-	-	-	-	-	-
2a.4.14	Security Staff Cost	-	-	-	-	-	-	6,661	999	7,661	7,661	-	-	-	-	-	-	-	-	-	110,166
2a.4.15	DOC Staff Cost	-	-	-	-	-	-	13,492	2,024	15,516	15,516	-	-	-	-	-	-	-	-	-	155,048
2a.4.16	Utility Staff Cost	-	-	-	-	-	-	17,880	2,682	20,562	20,562	-	-	-	-	-	-	-	-	-	288,676
2a.4	Subtotal Period 2a Period-Dependent Costs	68	3,776	89	26	-	331	46,025	7,512	57,825	55,929	1,896	-	-	4,063	-	-	-	81,252	133	553,890
2a.0	TOTAL PERIOD 2a COST	974	28,339	27,792	4,078	3,105	18,780	57,604	36,116	176,787	168,620	5,579	2,588	38,625	37,317	250	673	-	4,529,841	231,534	560,049
PERIOD 2b - Site Decontamination																					
Period 2b Direct Decommissioning Activities																					
Disposal of Plant Systems																					
2b.1.1.1	ADT & Misc Ventilation	-	24	0	1	13	3	-	9	50	50	-	-	153	9	-	-	-	6,814	363	-
2b.1.1.2	Aux Bldg Normal Ventilation	-	67	2	5	60	11	-	29	174	174	-	-	692	39	-	-	-	30,671	1,013	-
2b.1.1.3	Aux Bldg Special Ventilation	-	13	0	0	6	2	-	5	26	26	-	-	70	6	-	-	-	3,243	197	-
2b.1.1.4	Battery Rm Special Ventilation	-	1	-	-	-	-	-	0	2	-	-	2	-	-	-	-	-	-	24	-
2b.1.1.5	Boron Recycle	0	4	0	0	0	3	-	2	9	9	-	-	3	9	-	-	-	709	50	-
2b.1.1.6	Chemical & Volume Control	722	902	59	44	204	560	-	770	3,260	3,260	-	-	2,356	1,977	-	-	-	225,854	23,197	-
2b.1.1.7	Cold Chemical Lab Ventilation	-	1	-	-	-	-	-	0	1	-	-	1	-	-	-	-	-	-	9	-
2b.1.1.8	Component Cooling - RCA	-	617	21	70	1,038	-	-	322	2,068	2,068	-	-	11,996	-	-	-	-	487,169	8,583	-
2b.1.1.9	Containment Cooling	-	31	-	-	-	-	-	5	35	-	-	35	-	-	-	-	-	-	502	-
2b.1.1.10	Containment Cooling - RCA	-	288	5	16	237	-	-	110	656	656	-	-	2,743	-	-	-	-	111,390	3,949	-
2b.1.1.11	Containment Hydrogen Control - RCA	-	35	0	1	12	-	-	11	60	60	-	-	141	-	-	-	-	5,742	494	-
2b.1.1.12	Containment Spray - RCA	-	186	3	8	126	-	-	67	389	389	-	-	1,453	-	-	-	-	59,019	2,617	-
2b.1.1.13	Containment Ventilation	-	224	23	38	408	205	-	177	1,075	1,075	-	-	4,721	722	-	-	-	239,450	3,375	-
2b.1.1.14	Control/Relay/Cmptr Rm Vent	-	30	1	2	23	6	-	13	74	74	-	-	260	20	-	-	-	11,915	454	-
2b.1.1.15	Cooling Water	-	139	-	-	-	-	-	21	160	-	-	160	-	-	-	-	-	-	2,344	-
2b.1.1.16	Cooling Water - RCA	-	456	15	49	730	-	-	232	1,482	1,482	-	-	8,442	-	-	-	-	342,822	6,311	-
2b.1.1.17	Cranes/Hoists/Elevators - RCA	-	3	0	1	9	-	-	2	15	15	-	-	103	-	-	-	-	4,184	48	-
2b.1.1.18	D3 Emergency Diesel	-	9	-	-	-	-	-	1	10	-	-	10	-	-	-	-	-	-	141	-
2b.1.1.19	D4 Emergency Diesel	-	9	-	-	-	-	-	1	10	-	-	10	-	-	-	-	-	-	141	-
2b.1.1.20	D5 Emergency Diesel	-	0	-	-	-	-	-	0	0	-	-	0	-	-	-	-	-	-	5	-
2b.1.1.21	Electrical - Clean	-	1,502	-	-	-	-	-	225	1,727	-	-	1,727	-	-	-	-	-	-	24,276	-
2b.1.1.22	Electrical - Contaminated	-	461	5	13	173	21	-	149	821	821	-	-	1,997	75	-	-	-	86,080	6,503	-
2b.1.1.23	Electrical - Decontaminated	-	2,866	33	109	1,622	-	-	980	5,610	5,610	-	-	18,753	-	-	-	-	761,569	38,423	-
2b.1.1.24	Filter Rm Ventilation	-	4	0	0	2	0	-	2	9	9	-	-	24	1	-	-	-	1,020	69	-
2b.1.1.25	Fire Protection & Detection	-	178	-	-	-	-	-	27	205	-	-	205	-	-	-	-	-	-	3,009	-
2b.1.1.26	Fire Protection & Detection - RCA	-	236	3	11	158	-	-	85	492	492	-	-	1,828	-	-	-	-	74,245	3,134	-
2b.1.1.27	Fuel Handling	-	71	1	2	17	14	-	24	130	130	-	-	200	49	-	-	-	11,396	1,101	-
2b.1.1.28	Fuel Oil	-	1	-	-	-	-	-	0	1	-	-	1	-	-	-	-	-	-	9	-
2b.1.1.29	HVAC - Clean	-	132	-	-	-	-	-	20	151	-	-	151	-	-	-	-	-	-	2,373	-
2b.1.1.30	HVAC - Contaminated	-	1,222	26	69	929	115	-	487	2,848	2,848	-	-	10,745	405	-	-	-	463,144	16,579	-

Table E-2
Prairie Island Nuclear Generating Plant, Unit 2
DECON Decommissioning Cost Estimate with 100 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Disposal of Plant Systems (continued)																					
2b.1.1.31	Heating	-	279	-	-	-	-	-	42	321	-	-	321	-	-	-	-	-	-	4,804	-
2b.1.1.32	Heating - RCA	-	323	3	11	165	-	-	107	609	609	-	-	1,907	-	-	-	-	77,458	4,086	-
2b.1.1.33	Hot Lab & Sample Rm Ventilation	-	19	0	1	9	1	-	6	37	37	-	-	107	4	-	-	-	4,632	285	-
2b.1.1.34	Incore Instrumentation	0	29	1	1	5	16	-	13	67	67	-	-	60	58	-	-	-	6,264	458	-
2b.1.1.35	Misc Drains & Vents	-	223	12	9	40	121	-	95	500	500	-	-	458	426	-	-	-	46,850	3,180	-
2b.1.1.36	Misc Lab & Service Areas Vent	-	123	8	6	32	70	-	55	293	293	-	-	370	244	-	-	-	31,186	1,713	-
2b.1.1.37	Miscellaneous Gas	-	63	-	-	-	-	-	9	72	-	-	72	-	-	-	-	-	-	1,073	-
2b.1.1.38	Miscellaneous Gas - RCA	-	129	1	3	52	-	-	41	226	226	-	-	600	-	-	-	-	24,378	1,636	-
2b.1.1.39	Radiation Monitoring	-	6	-	-	-	-	-	1	7	-	-	7	-	-	-	-	-	-	111	-
2b.1.1.40	Radiation Monitoring - RCA	-	62	1	2	27	-	-	20	112	112	-	-	316	-	-	-	-	12,826	782	-
2b.1.1.41	Reactor Coolant	158	227	20	12	20	208	-	195	839	839	-	-	229	730	-	-	-	57,672	5,517	-
2b.1.1.42	Reactor Hot Sampling	135	121	10	5	5	89	-	123	489	489	-	-	54	312	-	-	-	22,919	3,686	-
2b.1.1.43	Reactor Makeup	-	36	-	-	-	-	-	5	41	-	-	41	-	-	-	-	-	-	583	-
2b.1.1.44	Reactor Makeup - RCA	-	4	0	0	2	-	-	1	8	8	-	-	28	-	-	-	-	1,148	47	-
2b.1.1.45	Reactor Vessel	9	17	0	0	2	4	-	10	43	43	-	-	22	14	-	-	-	1,826	385	-
2b.1.1.46	Residual Heat Removal	336	374	84	66	247	924	-	548	2,578	2,578	-	-	2,853	3,244	-	-	-	330,651	7,112	-
2b.1.1.47	Safeguards Chilled Water	-	4	-	-	-	-	-	1	5	-	-	5	-	-	-	-	-	-	75	-
2b.1.1.48	Safety Injection	-	836	40	56	577	329	-	390	2,228	2,228	-	-	6,676	1,161	-	-	-	347,600	12,284	-
2b.1.1.49	Sampling	-	51	3	2	3	27	-	20	105	105	-	-	37	93	-	-	-	7,697	714	-
2b.1.1.50	Service Bldg & New Cmptr Vent	-	0	-	-	-	-	-	0	0	-	-	0	-	-	-	-	-	-	6	-
2b.1.1.51	Shield Bldg Ventilation	-	114	13	19	175	138	-	94	554	554	-	-	2,028	484	-	-	-	114,378	1,743	-
2b.1.1.52	Station & Instrument Air	-	140	-	-	-	-	-	21	161	-	-	161	-	-	-	-	-	-	2,424	-
2b.1.1.53	Station & Instrument Air - RCA	-	288	3	9	141	-	-	95	535	535	-	-	1,625	-	-	-	-	65,986	3,638	-
2b.1.1.54	Turbine Bldg Traps & Drains	-	26	-	-	-	-	-	4	30	-	-	30	-	-	-	-	-	-	462	-
2b.1.1.55	Turbine Bldg Traps & Drains - RCA	-	28	0	1	16	-	-	10	55	55	-	-	180	-	-	-	-	7,321	344	-
2b.1.1.56	Turbine Bldg Ventilation	-	40	-	-	-	-	-	6	46	-	-	46	-	-	-	-	-	-	655	-
2b.1.1.57	Unit Coolers	-	20	-	-	-	-	-	3	23	-	-	23	-	-	-	-	-	-	332	-
2b.1.1.58	Unit Coolers - RCA	-	54	0	1	20	-	-	17	93	93	-	-	232	-	-	-	-	9,413	690	-
2b.1.1.59	Waste Gas Disposal	531	457	40	35	212	381	-	516	2,173	2,173	-	-	2,453	1,358	-	-	-	188,334	14,308	-
2b.1.1.60	Waste Liquid Disposal	1,386	1,733	108	76	316	1,019	-	1,451	6,089	6,089	-	-	3,655	3,594	-	-	-	385,370	44,485	-
2b.1.1.61	Waste Solid Disposal	111	139	11	8	34	112	-	126	541	541	-	-	389	393	-	-	-	41,732	3,481	-
2b.1.1	Totals	3,390	15,678	558	763	7,868	4,377	-	7,798	40,433	37,423	-	3,010	90,963	15,429	-	-	-	4,712,076	270,390	-
2b.1.2	Scaffolding in support of decommissioning	-	3,542	30	10	121	32	-	916	4,651	4,651	-	-	1,265	112	-	-	-	64,307	32,837	-
Decontamination of Site Buildings																					
2b.1.3.1	Reactor	1,150	2,624	139	853	193	11,080	-	4,172	20,210	20,210	-	-	2,230	57,418	-	-	-	3,559,977	50,853	-
2b.1.3.2	Auxiliary	1,223	400	12	80	92	582	-	884	3,272	3,272	-	-	1,060	3,355	-	-	-	332,498	23,808	-
2b.1.3.3	Backwash Waste Receiving Tank	-	27	1	11	-	87	-	30	158	158	-	-	-	507	-	-	-	43,896	299	-
2b.1.3.4	Drum Transfer & Truck Loading Enclosure	17	8	0	2	2	13	-	14	56	56	-	-	19	74	-	-	-	7,118	368	-
2b.1.3.5	LLRW Storage Enclosure	117	51	1	11	3	87	-	95	366	366	-	-	38	502	-	-	-	44,971	2,424	-
2b.1.3.6	Radwaste	52	23	1	5	4	39	-	43	166	166	-	-	42	225	-	-	-	21,136	1,082	-
2b.1.3.7	Resin Disposal	15	11	0	2	7	12	-	15	64	64	-	-	83	69	-	-	-	9,271	383	-
2b.1.3	Totals	2,574	3,145	155	964	300	11,900	-	5,253	24,292	24,292	-	-	3,471	62,151	-	-	-	4,018,868	79,216	-
2b.1.4	Prepare/submit License Termination Plan	-	-	-	-	-	-	206	31	236	236	-	-	-	-	-	-	-	-	-	1,751
2b.1.5	Receive NRC approval of termination plan									a											
2b.1	Subtotal Period 2b Activity Costs	5,965	22,365	744	1,737	8,290	16,309	206	13,998	69,612	66,602	-	3,010	95,700	77,691	-	-	-	8,795,250	382,443	1,751
Period 2b Additional Costs																					
2b.2.1	Remedial Action Surveys	-	-	-	-	-	-	1,930	579	2,509	2,509	-	-	-	-	-	-	-	-	25,228	-
2b.2.2	Operational Equipment	-	-	9	29	312	-	-	52	402	402	-	-	5,855	-	-	-	-	146,375	16	-
2b.2	Subtotal Period 2b Additional Costs	-	-	9	29	312	-	1,930	631	2,911	2,911	-	-	5,855	-	-	-	-	146,375	25,244	-
Period 2b Collateral Costs																					
2b.3.1	Process decommissioning water waste	167	-	112	289	-	453	-	251	1,272	1,272	-	-	-	1,081	-	-	-	64,837	211	-
2b.3.2	Process decommissioning chemical flush waste	3	-	114	431	-	858	-	292	1,700	1,700	-	-	-	1,154	-	-	-	122,948	216	-
2b.3.3	Small tool allowance	-	414	-	-	-	-	-	62	476	476	-	-	-	-	-	-	-	-	-	-
2b.3.4	Spent Fuel Capital and Transfer	-	-	-	-	-	-	9,529	1,429	10,958	-	10,958	-	-	-	-	-	-	-	-	-
2b.3.5	Retention and Severance	-	-	-	-	-	-	4,127	619	4,746	4,746	-	-	-	-	-	-	-	-	-	-
2b.3.6	Prairie Island Indian Community Payments	-	-	-	-	-	-	1,517	-	1,517	-	1,517	-	-	-	-	-	-	-	-	-
2b.3.7	On-site survey and release of 0.437 tons clean metallic waste	-	-	-	-	-	-	1	0	1	1	-	-	-	-	-	-	-	-	-	-
2b.3	Subtotal Period 2b Collateral Costs	170	414	226	721	-	1,311	15,174	2,654	20,670	8,195	12,475	-	-	2,234	-	-	-	187,785	427	-

Table E-2
Prairie Island Nuclear Generating Plant, Unit 2
DECON Decommissioning Cost Estimate with 100 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Period 2b Period-Dependent Costs																					
2b.4.1	Decon supplies	1,135	-	-	-	-	-	-	284	1,419	1,419	-	-	-	-	-	-	-	-	-	-
2b.4.2	Insurance	-	-	-	-	-	-	620	62	682	682	-	-	-	-	-	-	-	-	-	-
2b.4.3	Property taxes	-	-	-	-	-	-	2,983	298	3,281	3,281	-	-	-	-	-	-	-	-	-	-
2b.4.4	Health physics supplies	-	2,580	-	-	-	-	-	645	3,225	3,225	-	-	-	-	-	-	-	-	-	-
2b.4.5	Heavy equipment rental	-	2,740	-	-	-	-	-	411	3,151	3,151	-	-	-	-	-	-	-	-	-	-
2b.4.6	Disposal of DAW generated	-	-	115	34	-	431	-	124	704	704	-	-	-	5,291	-	-	-	105,826	173	-
2b.4.7	Plant energy budget	-	-	-	-	-	-	1,379	207	1,586	1,586	-	-	-	-	-	-	-	-	-	-
2b.4.8	NRC Fees	-	-	-	-	-	-	481	48	529	529	-	-	-	-	-	-	-	-	-	-
2b.4.9	Emergency Planning Fees	-	-	-	-	-	-	1,558	156	1,714	-	1,714	-	-	-	-	-	-	-	-	-
2b.4.10	Fixed Overhead	-	-	-	-	-	-	1,503	225	1,728	1,728	-	-	-	-	-	-	-	-	-	-
2b.4.11	Spent Fuel Pool O&M	-	-	-	-	-	-	487	73	560	-	560	-	-	-	-	-	-	-	-	-
2b.4.12	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	246	37	282	282	-	-	-	-	-	-	-	-	-	-
2b.4.13	ISFSI Operating Costs	-	-	-	-	-	-	63	9	72	-	72	-	-	-	-	-	-	-	-	-
2b.4.14	Railroad Track Maintenance	-	-	-	-	-	-	70	10	80	80	-	-	-	-	-	-	-	-	-	-
2b.4.15	Security Staff Cost	-	-	-	-	-	-	8,243	1,236	9,479	9,479	-	-	-	-	-	-	-	-	-	136,323
2b.4.16	DOC Staff Cost	-	-	-	-	-	-	16,150	2,422	18,572	18,572	-	-	-	-	-	-	-	-	-	184,288
2b.4.17	Utility Staff Cost	-	-	-	-	-	-	21,222	3,183	24,405	24,405	-	-	-	-	-	-	-	-	-	342,069
2b.4	Subtotal Period 2b Period-Dependent Costs	1,135	5,320	115	34	-	431	55,004	9,432	71,472	69,125	2,346	-	-	5,291	-	-	-	105,826	173	662,680
2b.0	TOTAL PERIOD 2b COST	7,270	28,099	1,095	2,520	8,602	18,050	72,314	26,716	164,664	146,833	14,822	3,010	101,555	85,217	-	-	-	9,235,236	408,286	664,431
PERIOD 2c - Spent fuel delay prior to SFP decon																					
Period 2c Direct Decommissioning Activities																					
Period 2c Additional Costs																					
2c.2.1	Security Modifications	-	-	-	-	-	-	4,348	652	5,000	5,000	-	-	-	-	-	-	-	-	-	-
2c.2	Subtotal Period 2c Additional Costs	-	-	-	-	-	-	4,348	652	5,000	5,000	-	-	-	-	-	-	-	-	-	-
Period 2c Collateral Costs																					
2c.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	65,685	9,853	75,538	-	75,538	-	-	-	-	-	-	-	-	-
2c.3.2	Retention and Severance	-	-	-	-	-	-	2,034	305	2,339	2,339	-	-	-	-	-	-	-	-	-	-
2c.3.3	Prairie Island Indian Community Payments	-	-	-	-	-	-	1,630	-	1,630	-	1,630	-	-	-	-	-	-	-	-	-
2c.3	Subtotal Period 2c Collateral Costs	-	-	-	-	-	-	69,349	10,158	79,507	2,339	77,168	-	-	-	-	-	-	-	-	-
Period 2c Period-Dependent Costs																					
2c.4.1	Insurance	-	-	-	-	-	-	666	67	733	733	-	-	-	-	-	-	-	-	-	-
2c.4.2	Property taxes	-	-	-	-	-	-	3,060	306	3,366	3,366	-	-	-	-	-	-	-	-	-	-
2c.4.3	Health physics supplies	-	270	-	-	-	-	-	67	337	337	-	-	-	-	-	-	-	-	-	-
2c.4.4	Disposal of DAW generated	-	-	12	3	-	44	-	13	72	72	-	-	-	538	-	-	-	10,761	18	-
2c.4.5	Plant energy budget	-	-	-	-	-	-	395	59	454	454	-	-	-	-	-	-	-	-	-	-
2c.4.6	NRC Fees	-	-	-	-	-	-	305	31	336	336	-	-	-	-	-	-	-	-	-	-
2c.4.7	Emergency Planning Fees	-	-	-	-	-	-	1,674	167	1,842	-	1,842	-	-	-	-	-	-	-	-	-
2c.4.8	Fixed Overhead	-	-	-	-	-	-	1,615	242	1,857	1,857	-	-	-	-	-	-	-	-	-	-
2c.4.9	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	53	8	61	61	-	-	-	-	-	-	-	-	-	-
2c.4.10	ISFSI Operating Costs	-	-	-	-	-	-	67	10	77	-	77	-	-	-	-	-	-	-	-	-
2c.4.11	Railroad Track Maintenance	-	-	-	-	-	-	75	11	86	86	-	-	-	-	-	-	-	-	-	-
2c.4.12	Security Staff Cost	-	-	-	-	-	-	8,857	1,329	10,185	10,185	-	-	-	-	-	-	-	-	-	146,478
2c.4.13	Utility Staff Cost	-	-	-	-	-	-	6,575	986	7,561	7,561	-	-	-	-	-	-	-	-	-	107,146
2c.4	Subtotal Period 2c Period-Dependent Costs	-	270	12	3	-	44	23,343	3,296	26,968	25,049	1,919	-	-	538	-	-	-	10,761	18	253,623
2c.0	TOTAL PERIOD 2c COST	-	270	12	3	-	44	97,040	14,106	111,475	32,387	79,087	-	-	538	-	-	-	10,761	18	253,623
PERIOD 2d - Decontamination Following Wet Fuel Storage																					
Period 2d Direct Decommissioning Activities																					
2d.1.1	Remove spent fuel racks	328	32	94	32	-	595	-	335	1,416	1,416	-	-	-	2,092	-	-	-	138,298	576	-
Disposal of Plant Systems																					
2d.1.2.1	Electrical - Contaminated - Fuel Pool	-	197	2	6	75	9	-	64	353	353	-	-	864	33	-	-	-	37,250	2,783	-
2d.1.2.2	Electrical - Decontaminated - Fuel Pool	-	1,230	14	47	698	-	-	421	2,410	2,410	-	-	8,069	-	-	-	-	327,668	16,495	-
2d.1.2.3	Fire Protection & Detection - RCA Fuel P	-	36	1	2	25	-	-	13	76	76	-	-	286	-	-	-	-	11,622	476	-
2d.1.2.4	HVAC - Contaminated - Fuel Pool	-	549	12	31	418	52	-	219	1,280	1,280	-	-	4,828	182	-	-	-	208,080	7,448	-
2d.1.2.5	Safeguards Chilled Water - RCA	-	4	0	0	2	-	-	1	8	8	-	-	26	-	-	-	-	1,045	51	-
2d.1.2.6	Spent Fuel Pool Cooling	31	35	3	2	3	30	-	33	137	137	-	-	39	107	-	-	-	8,635	882	-
2d.1.2.7	Spent Fuel Pool Normal Ventilation	-	26	1	2	23	3	-	11	66	66	-	-	265	12	-	-	-	11,532	394	-
2d.1.2	Totals	31	2,077	32	89	1,244	95	-	761	4,328	4,328	-	-	14,376	333	-	-	-	605,832	28,530	-

Table E-2
Prairie Island Nuclear Generating Plant, Unit 2
DECON Decommissioning Cost Estimate with 100 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Decontamination of Site Buildings																					
2d.1.3.1	Fuel Handling of Aux Building	975	1,082	9	32	209	173	-	838	3,319	3,319	-	-	2,417	944	-	-	-	177,818	30,401	-
2d.1.3	Totals	975	1,082	9	32	209	173	-	838	3,319	3,319	-	-	2,417	944	-	-	-	177,818	30,401	-
2d.1.4	Scaffolding in support of decommissioning	-	708	6	2	24	6	-	183	930	930	-	-	253	22	-	-	-	12,861	6,567	-
2d.1	Subtotal Period 2d Activity Costs	1,334	3,900	142	155	1,477	868	-	2,118	9,994	9,994	-	-	17,046	3,391	-	-	-	934,809	66,074	-
Period 2d Additional Costs																					
2d.2.1	License Termination Survey Planning	-	-	-	-	-	-	845	253	1,098	1,098	-	-	-	-	-	-	-	-	-	6,240
2d.2.2	Remedial Action Surveys	-	-	-	-	-	-	1,237	371	1,608	1,608	-	-	-	-	-	-	-	-	16,173	-
2d.2	Subtotal Period 2d Additional Costs	-	-	-	-	-	-	2,082	625	2,706	2,706	-	-	-	-	-	-	-	-	16,173	6,240
Period 2d Collateral Costs																					
2d.3.1	Process decommissioning water waste	39	-	27	70	-	109	-	60	306	306	-	-	-	261	-	-	-	15,670	51	-
2d.3.2	Process decommissioning chemical flush waste	0	-	1	5	-	10	-	3	20	20	-	-	-	13	-	-	-	1,422	2	-
2d.3.3	Small tool allowance	-	79	-	-	-	-	-	12	91	91	-	-	-	-	-	-	-	-	-	-
2d.3.4	Decommissioning Equipment Disposition	-	-	144	55	575	150	-	147	1,071	1,071	-	-	6,000	529	-	-	-	304,968	88	-
2d.3.5	Spent Fuel Capital and Transfer	-	-	-	-	-	-	12,947	1,942	14,889	-	14,889	-	-	-	-	-	-	-	-	-
2d.3.6	Prairie Island Indian Community Payments	-	-	-	-	-	-	971	-	971	-	971	-	-	-	-	-	-	-	-	-
2d.3	Subtotal Period 2d Collateral Costs	39	79	172	130	575	270	13,917	2,164	17,347	1,488	15,859	-	6,000	804	-	-	-	322,060	142	-
Period 2d Period-Dependent Costs																					
2d.4.1	Decon supplies	218	-	-	-	-	-	-	54	272	272	-	-	-	-	-	-	-	-	-	-
2d.4.2	Insurance	-	-	-	-	-	-	398	40	437	437	-	-	-	-	-	-	-	-	-	-
2d.4.3	Property taxes	-	-	-	-	-	-	1,740	174	1,914	1,914	-	-	-	-	-	-	-	-	-	-
2d.4.4	Health physics supplies	-	742	-	-	-	-	-	186	928	928	-	-	-	-	-	-	-	-	-	-
2d.4.5	Heavy equipment rental	-	1,757	-	-	-	-	-	264	2,020	2,020	-	-	-	-	-	-	-	-	-	-
2d.4.6	Disposal of DAW generated	-	-	44	13	-	163	-	47	266	266	-	-	-	2,000	-	-	-	40,003	65	-
2d.4.7	Plant energy budget	-	-	-	-	-	-	471	71	542	542	-	-	-	-	-	-	-	-	-	-
2d.4.8	NRC Fees	-	-	-	-	-	-	256	26	282	282	-	-	-	-	-	-	-	-	-	-
2d.4.9	Emergency Planning Fees	-	-	-	-	-	-	999	100	1,099	-	1,099	-	-	-	-	-	-	-	-	-
2d.4.10	Fixed Overhead	-	-	-	-	-	-	963	144	1,108	1,108	-	-	-	-	-	-	-	-	-	-
2d.4.11	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	315	47	362	362	-	-	-	-	-	-	-	-	-	-
2d.4.12	ISFSI Operating Costs	-	-	-	-	-	-	40	6	46	-	46	-	-	-	-	-	-	-	-	-
2d.4.13	Railroad Track Maintenance	-	-	-	-	-	-	45	7	52	52	-	-	-	-	-	-	-	-	-	-
2d.4.14	Security Staff Cost	-	-	-	-	-	-	5,123	768	5,891	5,891	-	-	-	-	-	-	-	-	-	84,157
2d.4.15	DOC Staff Cost	-	-	-	-	-	-	6,065	910	6,975	6,975	-	-	-	-	-	-	-	-	-	69,996
2d.4.16	Utility Staff Cost	-	-	-	-	-	-	7,796	1,169	8,966	8,123	843	-	-	-	-	-	-	-	-	126,236
2d.4	Subtotal Period 2d Period-Dependent Costs	218	2,499	44	13	-	163	24,212	4,013	31,160	29,173	1,988	-	-	2,000	-	-	-	40,003	65	280,390
2d.0	TOTAL PERIOD 2d COST	1,591	6,478	357	298	2,052	1,301	40,212	8,919	61,208	43,361	17,847	-	23,046	6,195	-	-	-	1,296,872	82,455	286,630
PERIOD 2f - License Termination																					
Period 2f Direct Decommissioning Activities																					
2f.1.1	ORISE confirmatory survey	-	-	-	-	-	-	176	53	229	229	-	-	-	-	-	-	-	-	-	-
2f.1.2	Terminate license									a											
2f.1	Subtotal Period 2f Activity Costs	-	-	-	-	-	-	176	53	229	229	-	-	-	-	-	-	-	-	-	-
Period 2f Additional Costs																					
2f.2.1	License Termination Survey	-	-	-	-	-	-	7,406	2,222	9,628	9,628	-	-	-	-	-	-	-	-	102,642	3,120
2f.2	Subtotal Period 2f Additional Costs	-	-	-	-	-	-	7,406	2,222	9,628	9,628	-	-	-	-	-	-	-	-	102,642	3,120
Period 2f Collateral Costs																					
2f.3.1	DOC staff relocation expenses	-	-	-	-	-	-	1,189	178	1,367	1,367	-	-	-	-	-	-	-	-	-	-
2f.3.2	Prairie Island Indian Community Payments	-	-	-	-	-	-	934	-	934	-	934	-	-	-	-	-	-	-	-	-
2f.3	Subtotal Period 2f Collateral Costs	-	-	-	-	-	-	2,122	178	2,300	1,367	934	-	-	-	-	-	-	-	-	-
Period 2f Period-Dependent Costs																					
2f.4.1	Insurance	-	-	-	-	-	-	382	38	420	420	-	-	-	-	-	-	-	-	-	-
2f.4.2	Property taxes	-	-	-	-	-	-	1,626	163	1,789	1,789	-	-	-	-	-	-	-	-	-	-
2f.4.3	Health physics supplies	-	602	-	-	-	-	-	150	752	752	-	-	-	-	-	-	-	-	-	-
2f.4.4	Disposal of DAW generated	-	-	7	2	-	27	-	8	44	44	-	-	-	334	-	-	-	6,685	11	-
2f.4.5	Plant energy budget	-	-	-	-	-	-	227	34	261	261	-	-	-	-	-	-	-	-	-	-
2f.4.6	NRC Fees	-	-	-	-	-	-	272	27	299	299	-	-	-	-	-	-	-	-	-	-
2f.4.7	Emergency Planning Fees	-	-	-	-	-	-	51	5	56	-	56	-	-	-	-	-	-	-	-	-
2f.4.8	Fixed Overhead	-	-	-	-	-	-	926	139	1,065	1,065	-	-	-	-	-	-	-	-	-	-
2f.4.9	ISFSI Operating Costs	-	-	-	-	-	-	39	6	44	-	44	-	-	-	-	-	-	-	-	-

Table E-2
Prairie Island Nuclear Generating Plant, Unit 2
DECON Decommissioning Cost Estimate with 100 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 2f Period-Dependent Costs (continued)																					
2f.4.10	Railroad Track Maintenance	-	-	-	-	-	-	43	6	50	50	-	-	-	-	-	-	-	-	-	-
2f.4.11	Security Staff Cost	-	-	-	-	-	-	4,924	739	5,663	5,663	-	-	-	-	-	-	-	-	-	80,898
2f.4.12	DOC Staff Cost	-	-	-	-	-	-	4,101	615	4,716	4,716	-	-	-	-	-	-	-	-	-	46,283
2f.4.13	Utility Staff Cost	-	-	-	-	-	-	3,854	578	4,433	3,626	807	-	-	-	-	-	-	-	-	59,507
2f.4	Subtotal Period 2f Period-Dependent Costs	-	602	7	2	-	27	16,445	2,508	19,592	18,684	907	-	-	334	-	-	-	6,685	11	186,687
2f.0	TOTAL PERIOD 2f COST	-	602	7	2	-	27	26,150	4,962	31,750	29,909	1,841	-	-	334	-	-	-	6,685	102,653	189,807
PERIOD 2 TOTALS		9,835	63,787	29,263	6,901	13,758	38,202	293,319	90,819	545,884	421,110	119,176	5,598	163,227	129,602	250	673	-	15,079,400	824,945	1,954,541
PERIOD 3b - Site Restoration																					
Period 3b Direct Decommissioning Activities																					
Demolition of Remaining Site Buildings																					
3b.1.1.1	Reactor	-	4,256	-	-	-	-	-	638	4,895	-	-	4,895	-	-	-	-	-	-	44,679	-
3b.1.1.2	Auxiliary	-	1,897	-	-	-	-	-	285	2,182	-	-	2,182	-	-	-	-	-	-	11,902	-
3b.1.1.3	Condensate Storage Tank Foundation	-	6	-	-	-	-	-	1	7	-	-	7	-	-	-	-	-	-	33	-
3b.1.1.4	Construction Warehouse & Fab Shop	-	118	-	-	-	-	-	18	135	-	-	135	-	-	-	-	-	-	1,405	-
3b.1.1.5	D3/D4 Emergency Generator	-	13	-	-	-	-	-	2	15	-	-	15	-	-	-	-	-	-	84	-
3b.1.1.6	Drum Transfer & Truck Loading Enclosure	-	19	-	-	-	-	-	3	21	-	-	21	-	-	-	-	-	-	221	-
3b.1.1.7	Hydrogen House	-	6	-	-	-	-	-	1	7	-	-	7	-	-	-	-	-	-	47	-
3b.1.1.8	LLRW Storage Enclosure	-	121	-	-	-	-	-	18	139	-	-	139	-	-	-	-	-	-	853	-
3b.1.1.9	Misc Structures 2017	-	1,391	-	-	-	-	-	209	1,599	-	-	1,599	-	-	-	-	-	-	12,939	-
3b.1.1.10	Radwaste	-	165	-	-	-	-	-	25	190	-	-	190	-	-	-	-	-	-	1,400	-
3b.1.1.11	Resin Disposal	-	13	-	-	-	-	-	2	15	-	-	15	-	-	-	-	-	-	120	-
3b.1.1.12	Structures below 3' below grade	-	1,713	-	-	-	-	-	257	1,969	-	-	1,969	-	-	-	-	-	-	9,238	-
3b.1.1.13	Sulfuric Acid Tank Enclosure	-	3	-	-	-	-	-	0	3	-	-	3	-	-	-	-	-	-	35	-
3b.1.1.14	Turbine	-	1,983	-	-	-	-	-	298	2,281	-	-	2,281	-	-	-	-	-	-	22,052	-
3b.1.1.15	Turbine Pedestal	-	349	-	-	-	-	-	52	402	-	-	402	-	-	-	-	-	-	1,857	-
3b.1.1.16	Warehouse #2	-	22	-	-	-	-	-	3	25	-	-	25	-	-	-	-	-	-	213	-
3b.1.1.17	Waste Neutralizing Tank House	-	7	-	-	-	-	-	1	8	-	-	8	-	-	-	-	-	-	56	-
3b.1.1.18	Waste Oil Storage	-	8	-	-	-	-	-	1	10	-	-	10	-	-	-	-	-	-	70	-
3b.1.1.19	Water Treatment	-	303	-	-	-	-	-	46	349	-	-	349	-	-	-	-	-	-	2,690	-
3b.1.1.20	Fuel Handling of Aux Building	-	1,032	-	-	-	-	-	155	1,186	-	-	1,186	-	-	-	-	-	-	8,240	-
3b.1.1	Totals	-	13,424	-	-	-	-	-	2,014	15,438	-	-	15,438	-	-	-	-	-	-	118,134	-
Site Closeout Activities																					
3b.1.2	Remove Rubble	-	1,308	-	-	-	-	-	196	1,505	-	-	1,505	-	-	-	-	-	-	6,495	-
3b.1.3	Grade & landscape site	-	431	-	-	-	-	-	65	495	-	-	495	-	-	-	-	-	-	921	-
3b.1.4	Final report to NRC	-	-	-	-	-	-	78	12	90	90	-	-	-	-	-	-	-	-	-	667
3b.1	Subtotal Period 3b Activity Costs	-	15,163	-	-	-	-	78	2,286	17,528	90	-	17,438	-	-	-	-	-	-	125,549	667
Period 3b Additional Costs																					
3b.2.1	Clean Concrete Disposal	-	3,313	-	-	-	-	8	498	3,818	-	-	3,818	-	-	-	-	-	-	12,824	-
3b.2.2	Underground Services Excavations	-	811	-	-	-	-	520	200	1,531	-	-	1,531	-	-	-	-	-	-	7,407	-
3b.2.3	Intake Structure Cofferdam	-	423	-	-	-	-	-	63	486	-	-	486	-	-	-	-	-	-	3,552	-
3b.2.4	Construction Debris	-	-	-	-	-	-	463	69	532	-	-	532	-	-	-	-	-	-	-	-
3b.2.5	Backfill	-	8,465	-	-	-	-	-	1,270	9,735	-	-	9,735	-	-	-	-	-	-	9,327	-
3b.2	Subtotal Period 3b Additional Costs	-	13,012	-	-	-	-	991	2,100	16,103	-	-	16,103	-	-	-	-	-	-	33,110	-
Period 3b Collateral Costs																					
3b.3.1	Small tool allowance	-	172	-	-	-	-	-	26	198	-	-	198	-	-	-	-	-	-	-	-
3b.3.2	Prairie Island Indian Community Payments	-	-	-	-	-	-	2,651	-	2,651	-	2,651	-	-	-	-	-	-	-	-	-
3b.3	Subtotal Period 3b Collateral Costs	-	172	-	-	-	-	2,651	26	2,848	-	2,651	198	-	-	-	-	-	-	-	-
Period 3b Period-Dependent Costs																					
3b.4.1	Insurance	-	-	-	-	-	-	542	54	596	-	596	-	-	-	-	-	-	-	-	-
3b.4.2	Property taxes	-	-	-	-	-	-	4,334	433	4,767	-	4,767	-	-	-	-	-	-	-	-	-
3b.4.3	Heavy equipment rental	-	6,670	-	-	-	-	-	1,000	7,670	-	-	7,670	-	-	-	-	-	-	-	-
3b.4.4	Plant energy budget	-	-	-	-	-	-	321	48	369	-	-	369	-	-	-	-	-	-	-	-
3b.4.5	NRC ISFSI Fees	-	-	-	-	-	-	236	24	259	-	259	-	-	-	-	-	-	-	-	-
3b.4.6	Emergency Planning Fees	-	-	-	-	-	-	145	14	159	-	159	-	-	-	-	-	-	-	-	-
3b.4.7	Fixed Overhead	-	-	-	-	-	-	990	148	1,138	-	-	1,138	-	-	-	-	-	-	-	-
3b.4.8	ISFSI Operating Costs	-	-	-	-	-	-	109	16	126	-	126	-	-	-	-	-	-	-	-	-
3b.4.9	Railroad Track Maintenance	-	-	-	-	-	-	331	50	380	-	-	380	-	-	-	-	-	-	-	-
3b.4.10	Security Staff Cost	-	-	-	-	-	-	4,245	637	4,882	-	4,882	-	-	-	-	-	-	-	-	57,340
3b.4.11	DOC Staff Cost	-	-	-	-	-	-	10,467	1,570	12,038	-	-	12,038	-	-	-	-	-	-	-	116,885

Table E-2
Prairie Island Nuclear Generating Plant, Unit 2
DECON Decommissioning Cost Estimate with 100 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Period 3b Period-Dependent Costs (continued)																					
3b.4.12	Utility Staff Cost	-	-	-	-	-	-	4,964	745	5,709	(0)	2,283	3,425	-	-	-	-	-	-	-	76,637
3b.4	Subtotal Period 3b Period-Dependent Costs	-	6,670	-	-	-	-	26,684	4,740	38,094	(0)	13,074	25,021	-	-	-	-	-	-	-	250,861
3b.0	TOTAL PERIOD 3b COST	-	35,017	-	-	-	-	30,404	9,153	74,574	90	15,724	58,760	-	-	-	-	-	-	158,659	251,528
PERIOD 3c - Fuel Storage Operations																					
Period 3c Direct Decommissioning Activities																					
Period 3c Additional Costs																					
3c.2.1	ISFSI Disposition of Original Casks	-	-	-	128	-	1,548	-	406	2,082	-	2,082	-	-	4,906	-	-	-	576,566	-	-
3c.2	Subtotal Period 3c Additional Costs	-	-	-	128	-	1,548	-	406	2,082	-	2,082	-	-	4,906	-	-	-	576,566	-	-
Period 3c Collateral Costs																					
3c.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	264,850	39,728	304,578	-	304,578	-	-	-	-	-	-	-	-	-
3c.3.2	Prairie Island Indian Community Payments	-	-	-	-	-	-	61,914	-	61,914	-	61,914	-	-	-	-	-	-	-	-	-
3c.3	Subtotal Period 3c Collateral Costs	-	-	-	-	-	-	326,765	39,728	366,492	-	366,492	-	-	-	-	-	-	-	-	-
Period 3c Period-Dependent Costs																					
3c.4.1	Insurance	-	-	-	-	-	-	12,663	1,266	13,929	-	13,929	-	-	-	-	-	-	-	-	-
3c.4.2	Property taxes	-	-	-	-	-	-	55,169	5,517	60,685	-	60,685	-	-	-	-	-	-	-	-	-
3c.4.4	NRC ISFSI Fees	-	-	-	-	-	-	8,111	811	8,922	-	8,922	-	-	-	-	-	-	-	-	-
3c.4.5	Emergency Planning Fees	-	-	-	-	-	-	3,389	339	3,728	-	3,728	-	-	-	-	-	-	-	-	-
3c.4.6	Fixed Overhead	-	-	-	-	-	-	7,563	1,134	8,697	-	8,697	-	-	-	-	-	-	-	-	-
3c.4.7	ISFSI Operating Costs	-	-	-	-	-	-	2,559	384	2,942	-	2,942	-	-	-	-	-	-	-	-	-
3c.4.8	Railroad Track Maintenance	-	-	-	-	-	-	2,858	429	3,287	-	3,287	-	-	-	-	-	-	-	-	-
3c.4.9	Security Staff Cost	-	-	-	-	-	-	99,234	14,885	114,119	-	114,119	-	-	-	-	-	-	-	-	1,340,295
3c.4.10	DOC Staff Cost	-	-	-	-	-	-	4,779	717	5,495	-	5,495	-	-	-	-	-	-	-	-	51,550
3c.4.11	Utility Staff Cost	-	-	-	-	-	-	46,446	6,967	53,413	-	53,413	-	-	-	-	-	-	-	-	683,035
3c.4	Subtotal Period 3c Period-Dependent Costs	-	-	-	-	-	-	242,770	32,449	275,219	-	275,219	-	-	-	-	-	-	-	-	2,074,880
3c.0	TOTAL PERIOD 3c COST	-	-	-	128	-	1,548	569,535	72,583	643,794	-	643,794	-	-	4,906	-	-	-	576,566	-	2,074,880
PERIOD 3d - Spent Fuel/GTCC shipping																					
Period 3d Direct Decommissioning Activities																					
Nuclear Steam Supply System Removal																					
3d.1.1.1	Vessel & Internals GTCC Disposal	-	-	1,331	-	-	8,689	-	1,636	11,656	11,656	-	-	-	-	-	-	3,746	837,596	-	-
3d.1.1	Totals	-	-	1,331	-	-	8,689	-	1,636	11,656	11,656	-	-	-	-	-	-	3,746	837,596	-	-
3d.1	Subtotal Period 3d Activity Costs	-	-	1,331	-	-	8,689	-	1,636	11,656	11,656	-	-	-	-	-	-	3,746	837,596	-	-
Period 3d Collateral Costs																					
3d.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	126,070	18,910	144,980	-	144,980	-	-	-	-	-	-	-	-	-
3d.3.2	Prairie Island Indian Community Payments	-	-	-	-	-	-	31,250	-	31,250	-	31,250	-	-	-	-	-	-	-	-	-
3d.3	Subtotal Period 3d Collateral Costs	-	-	-	-	-	-	157,320	18,910	176,230	-	176,230	-	-	-	-	-	-	-	-	-
Period 3d Period-Dependent Costs																					
3d.4.1	Insurance	-	-	-	-	-	-	6,390	639	7,029	-	7,029	-	-	-	-	-	-	-	-	-
3d.4.2	Property taxes	-	-	-	-	-	-	24,558	2,456	27,013	-	27,013	-	-	-	-	-	-	-	-	-
3d.4.4	NRC ISFSI Fees	-	-	-	-	-	-	2,782	278	3,060	-	3,060	-	-	-	-	-	-	-	-	-
3d.4.5	Emergency Planning Fees	-	-	-	-	-	-	1,710	171	1,881	-	1,881	-	-	-	-	-	-	-	-	-
3d.4.6	Fixed Overhead	-	-	-	-	-	-	3,816	572	4,389	-	4,389	-	-	-	-	-	-	-	-	-
3d.4.7	ISFSI Operating Costs	-	-	-	-	-	-	1,291	194	1,485	-	1,485	-	-	-	-	-	-	-	-	-
3d.4.8	Railroad Track Maintenance	-	-	-	-	-	-	1,443	216	1,659	-	1,659	-	-	-	-	-	-	-	-	-
3d.4.9	Security Staff Cost	-	-	-	-	-	-	48,076	7,211	55,287	-	55,287	-	-	-	-	-	-	-	-	676,370
3d.4.10	Utility Staff Cost	-	-	-	-	-	-	12,369	1,855	14,225	-	14,225	-	-	-	-	-	-	-	-	175,596
3d.4	Subtotal Period 3d Period-Dependent Costs	-	-	-	-	-	-	102,435	13,593	116,029	-	116,029	-	-	-	-	-	-	-	-	851,967
3d.0	TOTAL PERIOD 3d COST	-	-	1,331	-	-	8,689	259,755	34,140	303,915	11,656	292,259	-	-	-	-	-	3,746	837,596	-	851,967
PERIOD 3e - ISFSI Decontamination																					
Period 3e Direct Decommissioning Activities																					
Period 3e Additional Costs																					
3e.2.1	License Termination ISFSI	15	1	-	-	-	-	970	247	1,233	1,233	-	-	-	-	-	-	-	-	5,604	972
3e.2	Subtotal Period 3e Additional Costs	15	1	-	-	-	-	970	247	1,233	1,233	-	-	-	-	-	-	-	-	5,604	972

Table E-2
Prairie Island Nuclear Generating Plant, Unit 2
DECON Decommissioning Cost Estimate with 100 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 3e Period-Dependent Costs																					
3e.4.1	Insurance	-	-	-	-	-	-	96	24	121	121	-	-	-	-	-	-	-	-	-	-
3e.4.4	Fixed Overhead	-	-	-	-	-	-	51	13	63	63	-	-	-	-	-	-	-	-	-	-
3e.4.5	Railroad Track Maintenance	-	-	-	-	-	-	19	5	24	24	-	-	-	-	-	-	-	-	-	-
3e.4.6	Security Staff Cost	-	-	-	-	-	-	154	38	192	192	-	-	-	-	-	-	-	-	-	2,500
3e.4.7	Utility Staff Cost	-	-	-	-	-	-	130	33	163	163	-	-	-	-	-	-	-	-	-	1,896
3e.4	Subtotal Period 3e Period-Dependent Costs	-	-	-	-	-	-	450	113	563	563	-	-	-	-	-	-	-	-	-	4,396
3e.0	TOTAL PERIOD 3e COST	15	1	-	-	-	-	1,420	359	1,795	1,795	-	-	-	-	-	-	-	-	5,604	5,368
PERIOD 3f - ISFSI Site Restoration																					
Period 3f Direct Decommissioning Activities																					
Period 3f Additional Costs																					
3f.2.1	Demolition and Site Restoration of ISFSI	-	946	-	-	-	-	154	165	1,265	-	-	1,265	-	-	-	-	-	-	4,922	160
3f.2	Subtotal Period 3f Additional Costs	-	946	-	-	-	-	154	165	1,265	-	-	1,265	-	-	-	-	-	-	4,922	160
Period 3f Collateral Costs																					
3f.3.1	Small tool allowance	-	7	-	-	-	-	-	1	8	-	-	8	-	-	-	-	-	-	-	-
3f.3	Subtotal Period 3f Collateral Costs	-	7	-	-	-	-	-	1	8	-	-	8	-	-	-	-	-	-	-	-
Period 3f Period-Dependent Costs																					
3f.4.3	Heavy equipment rental	-	62	-	-	-	-	-	9	71	-	-	71	-	-	-	-	-	-	-	-
3f.4.4	Plant energy budget	-	-	-	-	-	-	13	2	15	-	-	15	-	-	-	-	-	-	-	-
3f.4.5	Fixed Overhead	-	-	-	-	-	-	25	4	29	-	-	29	-	-	-	-	-	-	-	-
3f.4.6	Railroad Track Maintenance	-	-	-	-	-	-	10	1	11	-	-	11	-	-	-	-	-	-	-	-
3f.4.7	Security Staff Cost	-	-	-	-	-	-	78	12	89	-	-	89	-	-	-	-	-	-	-	1,260
3f.4.8	Utility Staff Cost	-	-	-	-	-	-	52	8	60	-	-	60	-	-	-	-	-	-	-	782
3f.4	Subtotal Period 3f Period-Dependent Costs	-	62	-	-	-	-	177	36	275	-	-	275	-	-	-	-	-	-	-	2,042
3f.0	TOTAL PERIOD 3f COST	-	1,014	-	-	-	-	331	202	1,547	-	-	1,547	-	-	-	-	-	-	4,922	2,202
PERIOD 3 TOTALS		15	36,032	1,331	128	-	10,236	861,445	116,436	1,025,625	13,541	951,777	60,307	-	4,906	-	-	3,746	1,414,161	169,184	3,185,944
TOTAL COST TO DECOMMISSION		**13,423**	**105,135**	**31,016**	**7,480**	**13,927**	**52,404**	**1,255,707**	**224,685**	**1,703,777**	**558,114**	**1,079,137**	**66,527**	**169,551**	**148,394**	**839**	**673**	**3,746**	**17,113,080**	**1,027,670**	**5,942,790**

TOTAL COST TO DECOMMISSION WITH 15.19% CONTINGENCY:	**$1,703,777**	**thousands of 2017 dollars**
TOTAL NRC LICENSE TERMINATION COST IS 32.76% OR:	**$558,114**	**thousands of 2017 dollars**
SPENT FUEL MANAGEMENT COST IS 63.34% OR:	**$1,079,137**	**thousands of 2017 dollars**
NON-NUCLEAR DEMOLITION COST IS 3.9% OR:	**$66,527**	**thousands of 2017 dollars**
TOTAL LOW-LEVEL RADIOACTIVE WASTE VOLUME BURIED (EXCLUDING GTCC):	**149,906**	**cubic feet**
TOTAL GREATER THAN CLASS C RADWASTE VOLUME GENERATED:	**3,746**	**cubic feet**
TOTAL SCRAP METAL REMOVED:	**41,515**	**tons**
TOTAL CRAFT LABOR REQUIREMENTS:	**1,027,670**	**man-hours**

End Notes:
n/a - indicates that this activity not charged as decommissioning expense
a - indicates that this activity performed by decommissioning staff
0 - indicates that this value is less than 0.5 but is non-zero
A cell containing " - " indicates a zero value

APPENDIX F

DETAILED COST ANALYSIS

SCENARIO 4: DECON with 200 Year DFS

Page

Prairie Island Nuclear Generating Plant, Unit 1 ..... F-2

Prairie Island Nuclear Generating Plant, Unit 2 ..... F-10

Table F-1
Prairie Island Nuclear Generating Plant, Unit 1
DECON Decommissioning Cost Estimate with 200 Years of Spent Fuel Storage and Periodic TN-40 Replacement
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
PERIOD 1a - Shutdown through Transition																					
Period 1a Direct Decommissioning Activities																					
1a.1.1	Prepare preliminary decommissioning cost	-	-	-	-	-	-	153	23	175	175	-	-	-	-	-	-	-	-	-	1,300
1a.1.2	Notification of Cessation of Operations									a											
1a.1.3	Remove fuel & source material									n/a											
1a.1.4	Notification of Permanent Defueling									a											
1a.1.5	Deactivate plant systems & process waste									a											
1a.1.6	Prepare and submit PSDAR	-	-	-	-	-	-	235	35	270	270	-	-	-	-	-	-	-	-	-	2,000
1a.1.7	Review plant dwgs & specs.	-	-	-	-	-	-	540	81	621	621	-	-	-	-	-	-	-	-	-	4,600
1a.1.8	Perform detailed rad survey									a											
1a.1.9	Estimate by-product inventory	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1a.1.10	End product description	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1a.1.11	Detailed by-product inventory	-	-	-	-	-	-	153	23	175	175	-	-	-	-	-	-	-	-	-	1,300
1a.1.12	Define major work sequence	-	-	-	-	-	-	880	132	1,012	1,012	-	-	-	-	-	-	-	-	-	7,500
1a.1.13	Perform SER and EA	-	-	-	-	-	-	364	55	418	418	-	-	-	-	-	-	-	-	-	3,100
1a.1.14	Prepare/submit Defueled Technical Specifications	-	-	-	-	-	-	880	132	1,012	1,012	-	-	-	-	-	-	-	-	-	7,500
1a.1.15	Perform Site-Specific Cost Study	-	-	-	-	-	-	587	88	675	675	-	-	-	-	-	-	-	-	-	5,000
1a.1.16	Prepare/submit Irradiated Fuel Management Plan	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
Activity Specifications																					
1a.1.17.1	Plant & temporary facilities	-	-	-	-	-	-	578	87	664	598	-	66	-	-	-	-	-	-	-	4,920
1a.1.17.2	Plant systems	-	-	-	-	-	-	489	73	562	506	-	56	-	-	-	-	-	-	-	4,167
1a.1.17.3	NSSS Decontamination Flush	-	-	-	-	-	-	59	9	67	67	-	-	-	-	-	-	-	-	-	500
1a.1.17.4	Reactor internals	-	-	-	-	-	-	833	125	958	958	-	-	-	-	-	-	-	-	-	7,100
1a.1.17.5	Reactor vessel	-	-	-	-	-	-	763	114	877	877	-	-	-	-	-	-	-	-	-	6,500
1a.1.17.6	Biological shield	-	-	-	-	-	-	59	9	67	67	-	-	-	-	-	-	-	-	-	500
1a.1.17.7	Steam generators	-	-	-	-	-	-	366	55	421	421	-	-	-	-	-	-	-	-	-	3,120
1a.1.17.8	Reinforced concrete	-	-	-	-	-	-	188	28	216	108	-	108	-	-	-	-	-	-	-	1,600
1a.1.17.9	Main Turbine	-	-	-	-	-	-	47	7	54	-	-	54	-	-	-	-	-	-	-	400
1a.1.17.10	Main Condensers	-	-	-	-	-	-	47	7	54	-	-	54	-	-	-	-	-	-	-	400
1a.1.17.11	Plant structures & buildings	-	-	-	-	-	-	366	55	421	211	-	211	-	-	-	-	-	-	-	3,120
1a.1.17.12	Waste management	-	-	-	-	-	-	540	81	621	621	-	-	-	-	-	-	-	-	-	4,600
1a.1.17.13	Facility & site closeout	-	-	-	-	-	-	106	16	121	61	-	61	-	-	-	-	-	-	-	900
1a.1.17	Total	-	-	-	-	-	-	4,440	666	5,106	4,496	-	610	-	-	-	-	-	-	-	37,827
Planning & Site Preparations																					
1a.1.18	Prepare dismantling sequence	-	-	-	-	-	-	282	42	324	324	-	-	-	-	-	-	-	-	-	2,400
1a.1.19	Plant prep. & temp. svces	-	-	-	-	-	-	3,300	495	3,795	3,795	-	-	-	-	-	-	-	-	-	-
1a.1.20	Design water clean-up system	-	-	-	-	-	-	164	25	189	189	-	-	-	-	-	-	-	-	-	1,400
1a.1.21	Rigging/Cont. Cntrl Envlps/tooling/etc.	-	-	-	-	-	-	2,300	345	2,645	2,645	-	-	-	-	-	-	-	-	-	-
1a.1.22	Procure casks/liners & containers	-	-	-	-	-	-	144	22	166	166	-	-	-	-	-	-	-	-	-	1,230
1a.1	Subtotal Period 1a Activity Costs	-	-	-	-	-	-	14,774	2,216	16,990	16,380	-	610	-	-	-	-	-	-	-	78,157
Period 1a Additional Costs																					
1a.2.1	Spent Fuel Pool Isolation	-	-	-	-	-	-	11,691	1,754	13,445	13,445	-	-	-	-	-	-	-	-	-	-
1a.2	Subtotal Period 1a Additional Costs	-	-	-	-	-	-	11,691	1,754	13,445	13,445	-	-	-	-	-	-	-	-	-	-
Period 1a Collateral Costs																					
1a.3.1	Prairie Island Indian Community Payments	-	-	-	-	-	-	2,003	-	2,003	-	2,003	-	-	-	-	-	-	-	-	-
1a.3	Subtotal Period 1a Collateral Costs	-	-	-	-	-	-	2,003	-	2,003	-	2,003	-	-	-	-	-	-	-	-	-
Period 1a Period-Dependent Costs																					
1a.4.1	Insurance	-	-	-	-	-	-	1,730	173	1,903	1,903	-	-	-	-	-	-	-	-	-	-
1a.4.2	Property taxes	-	-	-	-	-	-	2,040	204	2,244	2,244	-	-	-	-	-	-	-	-	-	-
1a.4.3	Health physics supplies	-	515	-	-	-	-	-	129	644	644	-	-	-	-	-	-	-	-	-	-
1a.4.4	Heavy equipment rental	-	567	-	-	-	-	-	85	652	652	-	-	-	-	-	-	-	-	-	-
1a.4.5	Disposal of DAW generated	-	-	13	4	-	50	-	14	81	81	-	-	-	610	-	-	-	12,190	20	-
1a.4.6	Plant energy budget	-	-	-	-	-	-	1,515	227	1,742	1,742	-	-	-	-	-	-	-	-	-	-
1a.4.7	NRC Fees	-	-	-	-	-	-	1,110	111	1,221	1,221	-	-	-	-	-	-	-	-	-	-
1a.4.8	Emergency Planning Fees	-	-	-	-	-	-	1,604	160	1,765	-	1,765	-	-	-	-	-	-	-	-	-
1a.4.9	Fixed Overhead	-	-	-	-	-	-	1,470	220	1,690	1,690	-	-	-	-	-	-	-	-	-	-
1a.4.10	Spent Fuel Pool O&M	-	-	-	-	-	-	401	60	461	-	461	-	-	-	-	-	-	-	-	-
1a.4.11	ISFSI Operating Costs	-	-	-	-	-	-	52	8	59	-	59	-	-	-	-	-	-	-	-	-
1a.4.12	Railroad Track Maintenance	-	-	-	-	-	-	58	9	66	66	-	-	-	-	-	-	-	-	-	-
1a.4.13	Security Staff Cost	-	-	-	-	-	-	7,390	1,108	8,498	8,498	-	-	-	-	-	-	-	-	-	122,720
1a.4.14	Utility Staff Cost	-	-	-	-	-	-	25,791	3,869	29,660	29,660	-	-	-	-	-	-	-	-	-	422,240
1a.4	Subtotal Period 1a Period-Dependent Costs	-	1,083	13	4	-	50	43,160	6,378	50,687	48,402	2,286	-	-	610	-	-	-	12,190	20	544,960

Table F-1
Prairie Island Nuclear Generating Plant, Unit 1
DECON Decommissioning Cost Estimate with 200 Years of Spent Fuel Storage and Periodic TN-40 Replacement
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
1a.0	TOTAL PERIOD 1a COST	-	1,083	13	4	-	50	71,629	10,348	83,126	78,227	4,289	610	-	610	-	-	-	12,190	20	623,117
PERIOD 1b - Decommissioning Preparations																					
Period 1b Direct Decommissioning Activities																					
Detailed Work Procedures																					
1b.1.1.1	Plant systems	-	-	-	-	-	-	556	83	639	575	-	64	-	-	-	-	-	-	-	4,733
1b.1.1.2	NSSS Decontamination Flush	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1b.1.1.3	Reactor internals	-	-	-	-	-	-	293	44	337	337	-	-	-	-	-	-	-	-	-	2,500
1b.1.1.4	Remaining buildings	-	-	-	-	-	-	158	24	182	46	-	137	-	-	-	-	-	-	-	1,350
1b.1.1.5	CRD cooling assembly	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1b.1.1.6	CRD housings & ICI tubes	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1b.1.1.7	Incore instrumentation	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1b.1.1.8	Reactor vessel	-	-	-	-	-	-	426	64	490	490	-	-	-	-	-	-	-	-	-	3,630
1b.1.1.9	Facility closeout	-	-	-	-	-	-	141	21	162	81	-	81	-	-	-	-	-	-	-	1,200
1b.1.1.10	Missile shields	-	-	-	-	-	-	53	8	61	61	-	-	-	-	-	-	-	-	-	450
1b.1.1.11	Biological shield	-	-	-	-	-	-	141	21	162	162	-	-	-	-	-	-	-	-	-	1,200
1b.1.1.12	Steam generators	-	-	-	-	-	-	540	81	621	621	-	-	-	-	-	-	-	-	-	4,600
1b.1.1.13	Reinforced concrete	-	-	-	-	-	-	117	18	135	67	-	67	-	-	-	-	-	-	-	1,000
1b.1.1.14	Main Turbine	-	-	-	-	-	-	183	27	211	-	-	211	-	-	-	-	-	-	-	1,560
1b.1.1.15	Main Condensers	-	-	-	-	-	-	183	27	211	-	-	211	-	-	-	-	-	-	-	1,560
1b.1.1.16	Auxiliary building	-	-	-	-	-	-	320	48	369	332	-	37	-	-	-	-	-	-	-	2,730
1b.1.1.17	Reactor building	-	-	-	-	-	-	320	48	369	332	-	37	-	-	-	-	-	-	-	2,730
1b.1.1	Total	-	-	-	-	-	-	3,902	585	4,487	3,643	-	844	-	-	-	-	-	-	-	33,243
1b.1.2	Decon primary loop	552	-	-	-	-	-	-	276	828	828	-	-	-	-	-	-	-	-	1,067	-
1b.1	Subtotal Period 1b Activity Costs	552	-	-	-	-	-	3,902	861	5,315	4,471	-	844	-	-	-	-	-	-	1,067	33,243
Period 1b Additional Costs																					
1b.2.1	Site Characterization	-	-	-	-	-	-	3,700	1,110	4,810	4,810	-	-	-	-	-	-	-	-	21,020	8,332
1b.2.2	Mixed/Hazardous Waste	-	-	318	75	164	-	-	68	624	624	-	-	6,133	-	-	-	-	351,986	2,361	-
1b.2.3	Asbestos Abatement	-	2,364	2	110	-	1,359	-	947	4,782	4,782	-	-	-	12,843	-	-	-	166,959	20,907	-
1b.2	Subtotal Period 1b Additional Costs	-	2,364	320	185	164	1,359	3,700	2,125	10,216	10,216	-	-	6,133	12,843	-	-	-	518,945	44,288	8,332
Period 1b Collateral Costs																					
1b.3.1	Decon equipment	973	-	-	-	-	-	-	146	1,119	1,119	-	-	-	-	-	-	-	-	-	-
1b.3.2	DOC staff relocation expenses	-	-	-	-	-	-	1,189	178	1,367	1,367	-	-	-	-	-	-	-	-	-	-
1b.3.3	Process decommissioning water waste	24	-	16	41	-	64	-	36	180	180	-	-	-	152	-	-	-	9,121	30	-
1b.3.4	Process decommissioning chemical flush waste	2	-	58	220	-	2,471	-	657	3,408	3,408	-	-	-	-	588	-	-	62,689	110	-
1b.3.5	Small tool allowance	-	34	-	-	-	-	-	5	39	39	-	-	-	-	-	-	-	-	-	-
1b.3.6	Pipe cutting equipment	-	1,200	-	-	-	-	-	180	1,380	1,380	-	-	-	-	-	-	-	-	-	-
1b.3.7	Decon rig	1,987	-	-	-	-	-	-	298	2,285	2,285	-	-	-	-	-	-	-	-	-	-
1b.3.8	Spent Fuel Capital and Transfer	-	-	-	-	-	-	159	24	183	-	183	-	-	-	-	-	-	-	-	-
1b.3.9	Retention and Severance	-	-	-	-	-	-	1,088	163	1,251	1,251	-	-	-	-	-	-	-	-	-	-
1b.3.10	Prairie Island Indian Community Payments	-	-	-	-	-	-	630	-	630	-	630	-	-	-	-	-	-	-	-	-
1b.3	Subtotal Period 1b Collateral Costs	2,986	1,234	74	261	-	2,534	3,065	1,687	11,841	11,028	813	-	-	152	588	-	-	71,810	140	-
Period 1b Period-Dependent Costs																					
1b.4.1	Decon supplies	35	-	-	-	-	-	-	9	44	44	-	-	-	-	-	-	-	-	-	-
1b.4.2	Insurance	-	-	-	-	-	-	872	87	959	959	-	-	-	-	-	-	-	-	-	-
1b.4.3	Property taxes	-	-	-	-	-	-	1,352	135	1,487	1,487	-	-	-	-	-	-	-	-	-	-
1b.4.4	Health physics supplies	-	402	-	-	-	-	-	101	503	503	-	-	-	-	-	-	-	-	-	-
1b.4.5	Heavy equipment rental	-	286	-	-	-	-	-	43	329	329	-	-	-	-	-	-	-	-	-	-
1b.4.6	Disposal of DAW generated	-	-	8	2	-	29	-	8	48	48	-	-	-	360	-	-	-	7,197	12	-
1b.4.7	Plant energy budget	-	-	-	-	-	-	1,527	229	1,756	1,756	-	-	-	-	-	-	-	-	-	-
1b.4.8	NRC Fees	-	-	-	-	-	-	323	32	355	355	-	-	-	-	-	-	-	-	-	-
1b.4.9	Emergency Planning Fees	-	-	-	-	-	-	809	81	890	-	890	-	-	-	-	-	-	-	-	-
1b.4.10	Fixed Overhead	-	-	-	-	-	-	741	111	852	852	-	-	-	-	-	-	-	-	-	-
1b.4.11	Spent Fuel Pool O&M	-	-	-	-	-	-	202	30	233	-	233	-	-	-	-	-	-	-	-	-
1b.4.12	ISFSI Operating Costs	-	-	-	-	-	-	26	4	30	-	30	-	-	-	-	-	-	-	-	-
1b.4.13	Railroad Track Maintenance	-	-	-	-	-	-	29	4	33	33	-	-	-	-	-	-	-	-	-	-
1b.4.14	Security Staff Cost	-	-	-	-	-	-	3,725	559	4,284	4,284	-	-	-	-	-	-	-	-	-	61,864
1b.4.15	DOC Staff Cost	-	-	-	-	-	-	5,656	848	6,504	6,504	-	-	-	-	-	-	-	-	-	63,961
1b.4.16	Utility Staff Cost	-	-	-	-	-	-	13,074	1,961	15,035	15,035	-	-	-	-	-	-	-	-	-	213,904
1b.4	Subtotal Period 1b Period-Dependent Costs	35	688	8	2	-	29	28,336	4,243	33,341	32,189	1,152	-	-	360	-	-	-	7,197	12	339,730
1b.0	TOTAL PERIOD 1b COST	3,573	4,286	402	447	164	3,923	39,002	8,917	60,713	57,904	1,965	844	6,133	13,355	588	-	-	597,952	45,506	381,305

Table F-1
Prairie Island Nuclear Generating Plant, Unit 1
DECON Decommissioning Cost Estimate with 200 Years of Spent Fuel Storage and Periodic TN-40 Replacement
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
PERIOD 1 TOTALS		3,573	5,368	415	451	164	3,972	110,631	19,264	143,839	136,131	6,254	1,454	6,133	13,964	588	-	-	610,142	45,526	1,004,421
PERIOD 2a - Large Component Removal																					
Period 2a Direct Decommissioning Activities																					
Nuclear Steam Supply System Removal																					
2a.1.1.1	Reactor Coolant Piping	51	45	6	8	-	150	-	76	336	336	-	-	-	305	-	-	-	34,809	1,414	-
2a.1.1.2	Pressurizer Relief Tank	22	20	4	5	-	100	-	42	193	193	-	-	-	203	-	-	-	23,193	625	-
2a.1.1.3	Reactor Coolant Pumps & Motors	54	63	101	83	-	736	-	249	1,287	1,287	-	-	-	2,332	-	-	-	295,800	2,049	100
2a.1.1.4	Pressurizer	48	68	467	88	-	693	-	274	1,639	1,639	-	-	-	2,196	-	-	-	185,015	2,355	938
2a.1.1.5	Steam Generators	225	2,943	2,093	1,638	1,246	3,570	-	2,383	14,097	14,097	-	-	18,672	11,316	-	-	-	1,668,341	14,819	2,875
2a.1.1.6	CRDMs/ICIs/Service Structure Removal	286	277	211	48	-	763	-	431	2,016	2,016	-	-	-	4,797	-	-	-	177,400	8,104	-
2a.1.1.7	Reactor Vessel Internals	78	4,468	21,874	1,072	-	7,946	277	13,141	48,856	48,856	-	-	-	501	125	673	-	164,987	23,040	1,080
2a.1.1.8	Reactor Vessel	89	5,717	1,754	719	-	1,956	277	5,970	16,483	16,483	-	-	-	5,690	-	-	-	570,074	23,040	1,080
2a.1.1	Totals	855	13,600	26,512	3,662	1,246	15,913	553	22,568	84,908	84,908	-	-	18,672	27,341	125	673	-	3,119,620	75,446	6,073
Removal of Major Equipment																					
2a.1.2	Main Turbine/Generator	-	305	189	55	272	306	-	221	1,348	1,348	-	-	2,131	1,187	-	-	-	206,316	4,667	-
2a.1.3	Main Condensers	-	2,532	121	49	364	451	-	820	4,336	4,336	-	-	3,800	1,587	-	-	-	275,903	39,151	-
Cascading Costs from Clean Building Demolition																					
2a.1.4.1	Reactor	-	728	-	-	-	-	-	109	837	837	-	-	-	-	-	-	-	-	7,589	-
2a.1.4	Totals	-	728	-	-	-	-	-	109	837	837	-	-	-	-	-	-	-	-	7,589	-
Disposal of Plant Systems																					
2a.1.5.1	Air Removal	-	27	-	-	-	-	-	4	31	-	-	31	-	-	-	-	-	-	452	-
2a.1.5.2	Auxiliary Feedwater	-	40	-	-	-	-	-	6	46	-	-	46	-	-	-	-	-	-	670	-
2a.1.5.3	Auxiliary Feedwater - RCA	-	45	0	1	19	-	-	14	79	79	-	-	215	-	-	-	-	8,722	601	-
2a.1.5.4	Bleed Steam	-	78	-	-	-	-	-	12	90	-	-	90	-	-	-	-	-	-	1,335	-
2a.1.5.5	Caustic Addition - RCA	-	36	0	1	20	-	-	12	71	71	-	-	233	-	-	-	-	9,453	444	-
2a.1.5.6	Chemical Feed	-	17	-	-	-	-	-	3	20	-	-	20	-	-	-	-	-	-	304	-
2a.1.5.7	Chemical Feed - RCA	-	1	0	0	1	-	-	0	2	2	-	-	6	-	-	-	-	243	12	-
2a.1.5.8	Circulating Water	-	37	-	-	-	-	-	6	42	-	-	42	-	-	-	-	-	-	619	-
2a.1.5.9	Condensate	-	414	-	-	-	-	-	62	476	-	-	476	-	-	-	-	-	-	6,837	-
2a.1.5.10	Condensate Polishing	-	205	-	-	-	-	-	31	236	-	-	236	-	-	-	-	-	-	3,420	-
2a.1.5.11	Condensate Polishing - RCA	-	176	4	12	180	-	-	73	444	444	-	-	2,078	-	-	-	-	84,395	2,329	-
2a.1.5.12	Electro-hydraulic	-	8	-	-	-	-	-	1	9	-	-	9	-	-	-	-	-	-	127	-
2a.1.5.13	Feedwater	-	133	-	-	-	-	-	20	153	-	-	153	-	-	-	-	-	-	2,215	-
2a.1.5.14	Feedwater - RCA	-	186	6	19	278	-	-	91	579	579	-	-	3,208	-	-	-	-	130,294	2,651	-
2a.1.5.15	Gland Seal	-	29	-	-	-	-	-	4	34	-	-	34	-	-	-	-	-	-	505	-
2a.1.5.16	Heater Drain	-	349	-	-	-	-	-	52	401	-	-	401	-	-	-	-	-	-	5,881	-
2a.1.5.17	Internal Circ Water & CDSR	-	23	-	-	-	-	-	3	27	-	-	27	-	-	-	-	-	-	389	-
2a.1.5.18	Main Gen/Exciter/Transformer	-	0	-	-	-	-	-	0	0	-	-	0	-	-	-	-	-	-	5	-
2a.1.5.19	Main Steam	-	101	-	-	-	-	-	15	116	-	-	116	-	-	-	-	-	-	1,690	-
2a.1.5.20	Main Steam - RCA	-	350	9	29	436	-	-	158	983	983	-	-	5,044	-	-	-	-	204,825	4,956	-
2a.1.5.21	Steam Generator Blowdown	-	459	21	22	176	195	-	195	1,067	1,067	-	-	2,031	686	-	-	-	127,773	6,667	-
2a.1.5.22	Steam Generators	-	5	-	-	-	-	-	1	5	-	-	5	-	-	-	-	-	-	75	-
2a.1.5.23	Turbine & Moisture Separators	-	337	-	-	-	-	-	51	388	-	-	388	-	-	-	-	-	-	5,609	-
2a.1.5.24	Turbine Oil Purification	-	61	-	-	-	-	-	9	71	-	-	71	-	-	-	-	-	-	1,003	-
2a.1.5	Totals	-	3,117	40	85	1,108	195	-	825	5,370	3,226	-	2,145	12,815	686	-	-	-	565,705	48,794	-
2a.1.6	Scaffolding in support of decommissioning	-	854	3	1	13	3	-	217	1,092	1,092	-	-	138	12	-	-	-	7,016	6,368	-
2a.1	Subtotal Period 2a Activity Costs	855	21,136	26,865	3,852	3,004	16,868	553	24,759	97,891	95,747	-	2,145	37,556	30,812	125	673	-	4,174,560	182,015	6,073
Period 2a Additional Costs																					
2a.2.1	Remedial Action Surveys	-	-	-	-	-	-	2,126	638	2,764	2,764	-	-	-	-	-	-	-	-	27,791	-
2a.2.2	Retired RPV upper internals package	1	659	785	107	-	1,439	-	1,437	4,427	4,427	-	-	-	2,097	125	-	-	205,890	2,175	87
2a.2	Subtotal Period 2a Additional Costs	1	659	785	107	-	1,439	2,126	2,075	7,191	7,191	-	-	-	2,097	125	-	-	205,890	29,966	87
Period 2a Collateral Costs																					
2a.3.1	Process decommissioning water waste	47	-	31	81	-	126	-	70	356	356	-	-	-	302	-	-	-	18,119	59	-
2a.3.3	Small tool allowance	-	223	-	-	-	-	-	33	257	231	-	26	-	-	-	-	-	-	-	-
2a.3.4	Spent Fuel Capital and Transfer	-	-	-	-	-	-	1,476	221	1,698	-	1,698	-	-	-	-	-	-	-	-	-
2a.3.5	Retention and Severance	-	-	-	-	-	-	12,156	1,823	13,980	13,980	-	-	-	-	-	-	-	-	-	-
2a.3.6	Prairie Island Indian Community Payments	-	-	-	-	-	-	1,670	-	1,670	-	1,670	-	-	-	-	-	-	-	-	-
2a.3	Subtotal Period 2a Collateral Costs	47	223	31	81	-	126	15,302	2,149	17,960	14,567	3,367	26	-	302	-	-	-	18,119	59	-

Table F-1
Prairie Island Nuclear Generating Plant, Unit 1
DECON Decommissioning Cost Estimate with 200 Years of Spent Fuel Storage and Periodic TN-40 Replacement
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 2a Period-Dependent Costs																					
2a.4.1	Decon supplies	93	-	-	-	-	-	-	23	116	116	-	-	-	-	-	-	-	-	-	-
2a.4.2	Insurance	-	-	-	-	-	-	683	68	751	751	-	-	-	-	-	-	-	-	-	-
2a.4.3	Property taxes	-	-	-	-	-	-	3,542	354	3,896	3,896	-	-	-	-	-	-	-	-	-	-
2a.4.4	Health physics supplies	-	1,717	-	-	-	-	-	429	2,146	2,146	-	-	-	-	-	-	-	-	-	-
2a.4.5	Heavy equipment rental	-	2,935	-	-	-	-	-	440	3,376	3,376	-	-	-	-	-	-	-	-	-	-
2a.4.6	Disposal of DAW generated	-	-	79	23	-	295	-	85	482	482	-	-	-	3,623	-	-	-	72,452	118	-
2a.4.7	Plant energy budget	-	-	-	-	-	-	1,924	289	2,212	2,212	-	-	-	-	-	-	-	-	-	-
2a.4.8	NRC Fees	-	-	-	-	-	-	774	77	851	851	-	-	-	-	-	-	-	-	-	-
2a.4.9	Emergency Planning Fees	-	-	-	-	-	-	1,717	172	1,888	-	1,888	-	-	-	-	-	-	-	-	-
2a.4.10	Fixed Overhead	-	-	-	-	-	-	1,655	248	1,904	1,904	-	-	-	-	-	-	-	-	-	-
2a.4.11	Spent Fuel Pool O&M	-	-	-	-	-	-	537	80	617	-	617	-	-	-	-	-	-	-	-	-
2a.4.12	ISFSI Operating Costs	-	-	-	-	-	-	69	10	79	-	79	-	-	-	-	-	-	-	-	-
2a.4.13	Railroad Track Maintenance	-	-	-	-	-	-	286	43	328	328	-	-	-	-	-	-	-	-	-	-
2a.4.14	Security Staff Cost	-	-	-	-	-	-	9,811	1,472	11,283	11,283	-	-	-	-	-	-	-	-	-	162,878
2a.4.15	DOC Staff Cost	-	-	-	-	-	-	18,392	2,759	21,150	21,150	-	-	-	-	-	-	-	-	-	211,351
2a.4.16	Utility Staff Cost	-	-	-	-	-	-	24,265	3,640	27,904	27,904	-	-	-	-	-	-	-	-	-	392,305
2a.4	Subtotal Period 2a Period-Dependent Costs	93	4,652	79	23	-	295	63,653	10,190	78,986	76,401	2,585	-	-	3,623	-	-	-	72,452	118	766,534
2a.0	TOTAL PERIOD 2a COST	995	26,670	27,760	4,062	3,004	18,729	81,635	39,172	202,027	193,905	5,952	2,170	37,556	36,834	250	673	-	4,471,020	212,158	772,694
PERIOD 2b - Site Decontamination																					
Period 2b Direct Decommissioning Activities																					
Disposal of Plant Systems																					
2b.1.1.1	Aux Bldg Normal Ventilation	-	2	0	0	0	-	-	1	3	3	-	-	3	-	-	-	-	140	29	-
2b.1.1.2	Battery Rm Special Ventilation	-	0	-	-	-	-	-	0	0	-	-	0	-	-	-	-	-	-	6	-
2b.1.1.3	Buildings Maintenance	-	4	-	-	-	-	-	1	5	-	-	5	-	-	-	-	-	-	65	-
2b.1.1.4	Chemical & Volume Control	1,077	1,331	83	69	389	802	-	1,149	4,901	4,901	-	-	4,498	2,846	-	-	-	369,246	34,533	-
2b.1.1.5	Component Cooling - RCA	-	821	22	72	1,075	-	-	379	2,369	2,369	-	-	12,427	-	-	-	-	504,675	11,242	-
2b.1.1.6	Containment Cooling	-	65	-	-	-	-	-	10	74	-	-	74	-	-	-	-	-	-	1,086	-
2b.1.1.7	Containment Cooling - RCA	-	290	6	20	294	-	-	120	730	730	-	-	3,400	-	-	-	-	138,090	3,971	-
2b.1.1.8	Containment Hydrogen Control - RCA	-	29	0	1	9	-	-	9	48	48	-	-	105	-	-	-	-	4,278	401	-
2b.1.1.9	Containment Spray - RCA	-	90	2	5	75	-	-	35	206	206	-	-	868	-	-	-	-	35,249	1,217	-
2b.1.1.10	Containment Ventilation	-	243	24	40	428	209	-	186	1,130	1,130	-	-	4,951	737	-	-	-	249,786	3,668	-
2b.1.1.11	Cooling Water	-	142	-	-	-	-	-	21	163	-	-	163	-	-	-	-	-	-	2,396	-
2b.1.1.12	Cooling Water - RCA	-	629	14	45	668	-	-	266	1,622	1,622	-	-	7,728	-	-	-	-	313,832	8,594	-
2b.1.1.13	D1 Emergency Diesel	-	44	-	-	-	-	-	7	50	-	-	50	-	-	-	-	-	-	730	-
2b.1.1.14	D2 Emergency Diesel	-	31	-	-	-	-	-	5	36	-	-	36	-	-	-	-	-	-	522	-
2b.1.1.15	Diesel Rooms Ventilation	-	8	-	-	-	-	-	1	10	-	-	10	-	-	-	-	-	-	135	-
2b.1.1.16	Electrical - Clean	-	1,669	-	-	-	-	-	250	1,919	-	-	1,919	-	-	-	-	-	-	26,981	-
2b.1.1.17	Electrical - Contaminated	-	592	6	16	219	27	-	191	1,051	1,051	-	-	2,527	95	-	-	-	108,935	8,377	-
2b.1.1.18	Electrical - Decontaminated	-	3,674	41	137	2,037	-	-	1,249	7,138	7,138	-	-	23,551	-	-	-	-	956,401	49,378	-
2b.1.1.19	Fuel Handling	-	116	6	9	79	62	-	58	329	329	-	-	908	218	-	-	-	51,280	1,784	-
2b.1.1.20	Fuel Oil	-	106	-	-	-	-	-	16	122	-	-	122	-	-	-	-	-	-	1,697	-
2b.1.1.21	HVAC - Clean	-	105	-	-	-	-	-	16	121	-	-	121	-	-	-	-	-	-	1,891	-
2b.1.1.22	HVAC - Contaminated	-	371	8	21	282	35	-	148	864	864	-	-	3,261	123	-	-	-	140,573	5,032	-
2b.1.1.23	Incore Instrumentation	0	27	1	1	5	16	-	12	64	64	-	-	60	57	-	-	-	6,177	425	-
2b.1.1.24	Misc Drains & Vents	-	222	14	10	34	146	-	100	527	527	-	-	390	514	-	-	-	49,900	3,091	-
2b.1.1.25	Reactor Coolant	148	298	21	14	30	221	-	213	945	945	-	-	344	777	-	-	-	65,413	6,470	-
2b.1.1.26	Reactor Hot Sampling	144	131	11	6	6	98	-	132	527	527	-	-	66	342	-	-	-	25,347	3,946	-
2b.1.1.27	Reactor Makeup	-	64	-	-	-	-	-	10	73	-	-	73	-	-	-	-	-	-	1,042	-
2b.1.1.28	Reactor Vessel	9	20	1	0	2	4	-	11	47	47	-	-	26	14	-	-	-	2,011	425	-
2b.1.1.29	Residual Heat Removal	344	399	85	66	250	926	-	559	2,630	2,630	-	-	2,895	3,252	-	-	-	332,849	7,621	-
2b.1.1.30	Safeguards Chilled Water	-	15	-	-	-	-	-	2	18	-	-	18	-	-	-	-	-	-	259	-
2b.1.1.31	Safety Injection	-	853	40	57	587	327	-	396	2,261	2,261	-	-	6,788	1,156	-	-	-	351,793	12,561	-
2b.1.1.32	Sampling	-	58	4	2	5	31	-	23	122	122	-	-	59	107	-	-	-	9,505	811	-
2b.1.1.33	Shield Bldg Ventilation	-	133	14	20	186	139	-	100	593	593	-	-	2,152	491	-	-	-	119,838	2,030	-
2b.1.1.34	Station & Instrument Air	-	17	-	-	-	-	-	3	20	-	-	20	-	-	-	-	-	-	300	-
2b.1.1.35	Station & Instrument Air - RCA	-	79	1	2	29	-	-	24	135	135	-	-	332	-	-	-	-	13,496	1,053	-
2b.1.1.36	Turbine Bldg Traps & Drains	-	44	-	-	-	-	-	7	50	-	-	50	-	-	-	-	-	-	767	-
2b.1.1.37	Unit Coolers	-	37	-	-	-	-	-	6	42	-	-	42	-	-	-	-	-	-	611	-
2b.1.1.38	Unit Coolers - RCA	-	53	0	1	20	-	-	16	91	91	-	-	230	-	-	-	-	9,348	683	-
2b.1.1	Totals	1,724	12,813	403	614	6,710	3,044	-	5,730	31,037	28,333	-	2,704	77,571	10,728	-	-	-	3,858,165	205,829	-
2b.1.2	Scaffolding in support of decommissioning	-	1,067	4	1	17	4	-	271	1,364	1,364	-	-	173	15	-	-	-	8,770	7,960	-

Table F-1
Prairie Island Nuclear Generating Plant, Unit 1
DECON Decommissioning Cost Estimate with 200 Years of Spent Fuel Storage and Periodic TN-40 Replacement
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Decontamination of Site Buildings																					
2b.1.3.1	Reactor	1,150	2,623	139	852	193	11,079	-	4,171	20,208	20,208	-	-	2,230	57,414	-	-	-	3,559,624	50,842	-
2b.1.3.2	Backwash Waste Receiving Tank	-	27	1	11	-	87	-	30	158	158	-	-	-	507	-	-	-	43,896	299	-
2b.1.3	Totals	1,150	2,650	141	864	193	11,166	-	4,202	20,366	20,366	-	-	2,230	57,921	-	-	-	3,603,520	51,140	-
2b.1.4	Prepare/submit License Termination Plan	-	-	-	-	-	-	481	72	553	553	-	-	-	-	-	-	-	-	-	4,096
2b.1.5	Receive NRC approval of termination plan									a											
2b.1	Subtotal Period 2b Activity Costs	2,874	16,530	547	1,479	6,919	14,215	481	10,275	53,320	50,616	-	2,704	79,974	68,664	-	-	-	7,470,455	264,930	4,096
Period 2b Additional Costs																					
2b.2.1	Remedial Action Surveys	-	-	-	-	-	-	1,943	583	2,526	2,526	-	-	-	-	-	-	-	-	25,399	-
2b.2.2	Operational Equipment	-	-	9	29	312	-	-	52	402	402	-	-	5,855	-	-	-	-	146,375	16	-
2b.2	Subtotal Period 2b Additional Costs	-	-	9	29	312	-	1,943	635	2,928	2,928	-	-	5,855	-	-	-	-	146,375	25,415	-
Period 2b Collateral Costs																					
2b.3.1	Process decommissioning water waste	105	-	70	182	-	285	-	158	800	800	-	-	-	680	-	-	-	40,799	133	-
2b.3.2	Process decommissioning chemical flush waste	3	-	87	327	-	651	-	222	1,289	1,289	-	-	-	875	-	-	-	93,252	164	-
2b.3.3	Small tool allowance	-	289	-	-	-	-	-	43	332	332	-	-	-	-	-	-	-	-	-	-
2b.3.4	Spent Fuel Capital and Transfer	-	-	-	-	-	-	4,321	648	4,969	-	4,969	-	-	-	-	-	-	-	-	-
2b.3.5	Retention and Severance	-	-	-	-	-	-	6,994	1,049	8,043	8,043	-	-	-	-	-	-	-	-	-	-
2b.3.6	Prairie Island Indian Community Payments	-	-	-	-	-	-	1,525	-	1,525	-	1,525	-	-	-	-	-	-	-	-	-
2b.3	Subtotal Period 2b Collateral Costs	107	289	157	509	-	936	12,841	2,120	16,958	10,463	6,495	-	-	1,555	-	-	-	134,051	296	-
Period 2b Period-Dependent Costs																					
2b.4.1	Decon supplies	482	-	-	-	-	-	-	121	603	603	-	-	-	-	-	-	-	-	-	-
2b.4.2	Insurance	-	-	-	-	-	-	624	62	687	687	-	-	-	-	-	-	-	-	-	-
2b.4.3	Property taxes	-	-	-	-	-	-	3,099	310	3,409	3,409	-	-	-	-	-	-	-	-	-	-
2b.4.4	Health physics supplies	-	1,969	-	-	-	-	-	492	2,461	2,461	-	-	-	-	-	-	-	-	-	-
2b.4.5	Heavy equipment rental	-	2,759	-	-	-	-	-	414	3,173	3,173	-	-	-	-	-	-	-	-	-	-
2b.4.6	Disposal of DAW generated	-	-	78	23	-	293	-	85	479	479	-	-	-	3,600	-	-	-	71,996	117	-
2b.4.7	Plant energy budget	-	-	-	-	-	-	1,388	208	1,596	1,596	-	-	-	-	-	-	-	-	-	-
2b.4.8	NRC Fees	-	-	-	-	-	-	707	71	778	778	-	-	-	-	-	-	-	-	-	-
2b.4.9	Emergency Planning Fees	-	-	-	-	-	-	1,569	157	1,726	-	1,726	-	-	-	-	-	-	-	-	-
2b.4.10	Fixed Overhead	-	-	-	-	-	-	1,513	227	1,740	1,740	-	-	-	-	-	-	-	-	-	-
2b.4.11	Spent Fuel Pool O&M	-	-	-	-	-	-	490	74	564	-	564	-	-	-	-	-	-	-	-	-
2b.4.12	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	247	37	284	284	-	-	-	-	-	-	-	-	-	-
2b.4.13	ISFSI Operating Costs	-	-	-	-	-	-	63	9	73	-	73	-	-	-	-	-	-	-	-	-
2b.4.14	Railroad Track Maintenance	-	-	-	-	-	-	70	11	81	81	-	-	-	-	-	-	-	-	-	-
2b.4.15	Security Staff Cost	-	-	-	-	-	-	8,299	1,245	9,544	9,544	-	-	-	-	-	-	-	-	-	137,246
2b.4.16	DOC Staff Cost	-	-	-	-	-	-	11,450	1,718	13,168	13,168	-	-	-	-	-	-	-	-	-	137,246
2b.4.17	Utility Staff Cost	-	-	-	-	-	-	15,293	2,294	17,586	17,586	-	-	-	-	-	-	-	-	-	255,430
2b.4	Subtotal Period 2b Period-Dependent Costs	482	4,728	78	23	-	293	44,813	7,533	57,951	55,588	2,362	-	-	3,600	-	-	-	71,996	117	529,921
2b.0	TOTAL PERIOD 2b COST	3,464	21,546	792	2,040	7,231	15,444	60,078	20,563	131,157	119,596	8,857	2,704	85,829	73,819	-	-	-	7,822,876	290,758	534,017
PERIOD 2c - Spent fuel delay prior to SFP decon																					
Period 2c Direct Decommissioning Activities																					
Period 2c Additional Costs																					
2c.2.1	Security Modifications	-	-	-	-	-	-	4,348	652	5,000	5,000	-	-	-	-	-	-	-	-	-	-
2c.2	Subtotal Period 2c Additional Costs	-	-	-	-	-	-	4,348	652	5,000	5,000	-	-	-	-	-	-	-	-	-	-
Period 2c Collateral Costs																					
2c.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	72,993	10,949	83,941	-	83,941	-	-	-	-	-	-	-	-	-
2c.3.2	Retention and Severance	-	-	-	-	-	-	4,478	672	5,149	5,149	-	-	-	-	-	-	-	-	-	-
2c.3.3	Prairie Island Indian Community Payments	-	-	-	-	-	-	2,702	-	2,702	-	2,702	-	-	-	-	-	-	-	-	-
2c.3	Subtotal Period 2c Collateral Costs	-	-	-	-	-	-	80,172	11,621	91,793	5,149	86,643	-	-	-	-	-	-	-	-	-
Period 2c Period-Dependent Costs																					
2c.4.1	Insurance	-	-	-	-	-	-	1,104	110	1,215	1,215	-	-	-	-	-	-	-	-	-	-
2c.4.2	Property taxes	-	-	-	-	-	-	5,154	515	5,669	5,669	-	-	-	-	-	-	-	-	-	-
2c.4.3	Health physics supplies	-	390	-	-	-	-	-	98	488	488	-	-	-	-	-	-	-	-	-	-
2c.4.4	Disposal of DAW generated	-	-	18	5	-	66	-	19	108	108	-	-	-	809	-	-	-	16,171	26	-
2c.4.5	Plant energy budget	-	-	-	-	-	-	655	98	753	753	-	-	-	-	-	-	-	-	-	-
2c.4.6	NRC Fees	-	-	-	-	-	-	555	55	610	610	-	-	-	-	-	-	-	-	-	-
2c.4.7	Emergency Planning Fees	-	-	-	-	-	-	2,776	278	3,053	-	3,053	-	-	-	-	-	-	-	-	-

Table F-1
Prairie Island Nuclear Generating Plant, Unit 1
DECON Decommissioning Cost Estimate with 200 Years of Spent Fuel Storage and Periodic TN-40 Replacement
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Period 2c Period-Dependent Costs (continued)																					
2c.4.8	Fixed Overhead	-	-	-	-	-	-	2,676	401	3,078	3,078	-	-	-	-	-	-	-	-	-	-
2c.4.9	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	87	13	101	101	-	-	-	-	-	-	-	-	-	-
2c.4.10	ISFSI Operating Costs	-	-	-	-	-	-	112	17	128	-	128	-	-	-	-	-	-	-	-	-
2c.4.11	Railroad Track Maintenance	-	-	-	-	-	-	125	19	143	143	-	-	-	-	-	-	-	-	-	-
2c.4.12	Security Staff Cost	-	-	-	-	-	-	14,681	2,202	16,883	16,883	-	-	-	-	-	-	-	-	-	242,796
2c.4.13	Utility Staff Cost	-	-	-	-	-	-	2,064	310	2,374	2,374	-	-	-	-	-	-	-	-	-	33,722
2c.4	Subtotal Period 2c Period-Dependent Costs	-	390	18	5	-	66	29,988	4,135	34,602	31,421	3,181	-	-	809	-	-	-	16,171	26	276,518
2c.0	TOTAL PERIOD 2c COST	-	390	18	5	-	66	114,508	16,408	131,395	41,570	89,825	-	-	809	-	-	-	16,171	26	276,518
PERIOD 2d - Decontamination Following Wet Fuel Storage																					
Period 2d Direct Decommissioning Activities																					
2d.1.1	Remove spent fuel racks	328	32	94	32	-	595	-	335	1,416	1,416	-	-	-	2,092	-	-	-	138,298	576	-
Disposal of Plant Systems																					
2d.1.2.1	Electrical - Contaminated - Fuel Pool	-	147	2	4	53	7	-	47	259	259	-	-	615	23	-	-	-	26,508	2,077	-
2d.1.2.2	Electrical - Decontaminated - Fuel Pool	-	918	10	34	510	-	-	312	1,785	1,785	-	-	5,893	-	-	-	-	239,327	12,340	-
2d.1.2.3	HVAC - Contaminated - Fuel Pool	-	159	3	9	121	15	-	63	370	370	-	-	1,398	53	-	-	-	60,246	2,157	-
2d.1.2.4	Safeguards Chilled Water - RCA	-	82	1	3	43	-	-	27	155	155	-	-	495	-	-	-	-	20,100	1,019	-
2d.1.2.5	Spent Fuel Pool Cooling	293	342	34	25	70	377	-	344	1,484	1,484	-	-	806	1,325	-	-	-	120,439	7,613	-
2d.1.2.6	Station & Instrument Air - RCA Fuel Pool	-	20	0	0	7	-	-	6	34	34	-	-	83	-	-	-	-	3,374	263	-
2d.1.2	Totals	293	1,668	50	75	804	399	-	800	4,088	4,088	-	-	9,290	1,401	-	-	-	469,994	25,468	-
2d.1.4	Scaffolding in support of decommissioning	-	213	1	0	3	1	-	54	273	273	-	-	35	3	-	-	-	1,754	1,592	-
2d.1	Subtotal Period 2d Activity Costs	621	1,913	145	107	807	994	-	1,189	5,777	5,777	-	-	9,325	3,496	-	-	-	610,046	27,637	-
Period 2d Additional Costs																					
2d.2.1	License Termination Survey Planning	-	-	-	-	-	-	845	253	1,098	1,098	-	-	-	-	-	-	-	-	-	6,240
2d.2.2	Remedial Action Surveys	-	-	-	-	-	-	1,237	371	1,608	1,608	-	-	-	-	-	-	-	-	16,173	-
2d.2	Subtotal Period 2d Additional Costs	-	-	-	-	-	-	2,082	625	2,706	2,706	-	-	-	-	-	-	-	-	16,173	6,240
Period 2d Collateral Costs																					
2d.3.1	Process decommissioning water waste	27	-	18	48	-	75	-	41	209	209	-	-	-	179	-	-	-	10,724	35	-
2d.3.2	Process decommissioning chemical flush waste	1	-	32	121	-	241	-	82	478	478	-	-	-	324	-	-	-	34,576	61	-
2d.3.3	Small tool allowance	-	35	-	-	-	-	-	5	41	41	-	-	-	-	-	-	-	-	-	-
2d.3.4	Decommissioning Equipment Disposition	-	-	144	55	575	150	-	147	1,071	1,071	-	-	6,000	529	-	-	-	304,968	88	-
2d.3.5	Spent Fuel Capital and Transfer	-	-	-	-	-	-	12,947	1,942	14,889	-	14,889	-	-	-	-	-	-	-	-	-
2d.3.6	Prairie Island Indian Community Payments	-	-	-	-	-	-	971	-	971	-	971	-	-	-	-	-	-	-	-	-
2d.3	Subtotal Period 2d Collateral Costs	27	35	194	224	575	467	13,917	2,217	17,658	1,798	15,859	-	6,000	1,032	-	-	-	350,268	184	-
Period 2d Period-Dependent Costs																					
2d.4.1	Decon supplies	54	-	-	-	-	-	-	14	68	68	-	-	-	-	-	-	-	-	-	-
2d.4.2	Insurance	-	-	-	-	-	-	398	40	437	437	-	-	-	-	-	-	-	-	-	-
2d.4.3	Property taxes	-	-	-	-	-	-	1,740	174	1,914	1,914	-	-	-	-	-	-	-	-	-	-
2d.4.4	Health physics supplies	-	559	-	-	-	-	-	140	699	699	-	-	-	-	-	-	-	-	-	-
2d.4.5	Heavy equipment rental	-	1,757	-	-	-	-	-	264	2,020	2,020	-	-	-	-	-	-	-	-	-	-
2d.4.6	Disposal of DAW generated	-	-	18	5	-	67	-	19	110	110	-	-	-	829	-	-	-	16,581	27	-
2d.4.7	Plant energy budget	-	-	-	-	-	-	471	71	542	542	-	-	-	-	-	-	-	-	-	-
2d.4.8	NRC Fees	-	-	-	-	-	-	381	38	419	419	-	-	-	-	-	-	-	-	-	-
2d.4.9	Emergency Planning Fees	-	-	-	-	-	-	999	100	1,099	-	1,099	-	-	-	-	-	-	-	-	-
2d.4.10	Fixed Overhead	-	-	-	-	-	-	963	144	1,108	1,108	-	-	-	-	-	-	-	-	-	-
2d.4.11	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	315	47	362	362	-	-	-	-	-	-	-	-	-	-
2d.4.12	ISFSI Operating Costs	-	-	-	-	-	-	40	6	46	-	46	-	-	-	-	-	-	-	-	-
2d.4.13	Railroad Track Maintenance	-	-	-	-	-	-	45	7	52	52	-	-	-	-	-	-	-	-	-	-
2d.4.14	Security Staff Cost	-	-	-	-	-	-	5,123	768	5,891	5,891	-	-	-	-	-	-	-	-	-	84,157
2d.4.15	DOC Staff Cost	-	-	-	-	-	-	6,065	910	6,975	6,975	-	-	-	-	-	-	-	-	-	69,996
2d.4.16	Utility Staff Cost	-	-	-	-	-	-	7,796	1,169	8,966	8,123	843	-	-	-	-	-	-	-	-	126,236
2d.4	Subtotal Period 2d Period-Dependent Costs	54	2,316	18	5	-	67	24,337	3,911	30,708	28,720	1,988	-	-	829	-	-	-	16,581	27	280,390
2d.0	TOTAL PERIOD 2d COST	703	4,264	357	337	1,382	1,528	40,336	7,942	56,849	39,002	17,847	-	15,325	5,357	-	-	-	976,895	44,021	286,630
PERIOD 2f - License Termination																					
Period 2f Direct Decommissioning Activities																					
2f.1.1	ORISE confirmatory survey	-	-	-	-	-	-	176	53	229	229	-	-	-	-	-	-	-	-	-	-
2f.1.2	Terminate license									a											
2f.1	Subtotal Period 2f Activity Costs	-	-	-	-	-	-	176	53	229	229	-	-	-	-	-	-	-	-	-	-

Table F-1
Prairie Island Nuclear Generating Plant, Unit 1
DECON Decommissioning Cost Estimate with 200 Years of Spent Fuel Storage and Periodic TN-40 Replacement
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Period 2f Additional Costs																					
2f.2.1	License Termination Survey	-	-	-	-	-	-	3,217	965	4,182	4,182	-	-	-	-	-	-	-	-	40,172	3,120
2f.2	Subtotal Period 2f Additional Costs	-	-	-	-	-	-	3,217	965	4,182	4,182	-	-	-	-	-	-	-	-	40,172	3,120
Period 2f Collateral Costs																					
2f.3.1	DOC staff relocation expenses	-	-	-	-	-	-	1,189	178	1,367	1,367	-	-	-	-	-	-	-	-	-	-
2f.3.2	Prairie Island Indian Community Payments	-	-	-	-	-	-	934	-	934	-	934	-	-	-	-	-	-	-	-	-
2f.3	Subtotal Period 2f Collateral Costs	-	-	-	-	-	-	2,122	178	2,300	1,367	934	-	-	-	-	-	-	-	-	-
Period 2f Period-Dependent Costs																					
2f.4.1	Insurance	-	-	-	-	-	-	382	38	420	420	-	-	-	-	-	-	-	-	-	-
2f.4.2	Property taxes	-	-	-	-	-	-	1,626	163	1,789	1,789	-	-	-	-	-	-	-	-	-	-
2f.4.3	Health physics supplies	-	420	-	-	-	-	-	105	524	524	-	-	-	-	-	-	-	-	-	-
2f.4.4	Disposal of DAW generated	-	-	7	2	-	27	-	8	44	44	-	-	-	334	-	-	-	6,685	11	-
2f.4.5	Plant energy budget	-	-	-	-	-	-	227	34	261	261	-	-	-	-	-	-	-	-	-	-
2f.4.6	NRC Fees	-	-	-	-	-	-	417	42	459	459	-	-	-	-	-	-	-	-	-	-
2f.4.7	Emergency Planning Fees	-	-	-	-	-	-	51	5	56	-	56	-	-	-	-	-	-	-	-	-
2f.4.8	Fixed Overhead	-	-	-	-	-	-	926	139	1,065	1,065	-	-	-	-	-	-	-	-	-	-
2f.4.9	ISFSI Operating Costs	-	-	-	-	-	-	39	6	44	-	44	-	-	-	-	-	-	-	-	-
2f.4.10	Railroad Track Maintenance	-	-	-	-	-	-	43	6	50	50	-	-	-	-	-	-	-	-	-	-
2f.4.11	Security Staff Cost	-	-	-	-	-	-	4,924	739	5,663	5,663	-	-	-	-	-	-	-	-	-	80,898
2f.4.12	DOC Staff Cost	-	-	-	-	-	-	4,101	615	4,716	4,716	-	-	-	-	-	-	-	-	-	46,283
2f.4.13	Utility Staff Cost	-	-	-	-	-	-	3,854	578	4,433	3,626	807	-	-	-	-	-	-	-	-	59,507
2f.4	Subtotal Period 2f Period-Dependent Costs	-	420	7	2	-	27	16,591	2,477	19,524	18,617	907	-	-	334	-	-	-	6,685	11	186,687
2f.0	TOTAL PERIOD 2f COST	-	420	7	2	-	27	22,106	3,674	26,236	24,395	1,841	-	-	334	-	-	-	6,685	40,183	189,807
PERIOD 2 TOTALS		5,161	53,290	28,935	6,446	11,617	35,794	318,662	87,758	547,664	418,467	124,322	4,875	138,709	117,153	250	673	-	13,293,650	587,146	2,059,666
PERIOD 3b - Site Restoration																					
Period 3b Direct Decommissioning Activities																					
Demolition of Remaining Site Buildings																					
3b.1.1.1	Reactor	-	4,255	-	-	-	-	-	638	4,894	-	-	4,894	-	-	-	-	-	-	44,669	-
3b.1.1.2	Condensate Storage Tank Foundation	-	3	-	-	-	-	-	0	4	-	-	4	-	-	-	-	-	-	16	-
3b.1.1.3	Structures below 3' below grade	-	1,581	-	-	-	-	-	237	1,818	-	-	1,818	-	-	-	-	-	-	8,411	-
3b.1.1.4	Turbine	-	1,983	-	-	-	-	-	297	2,280	-	-	2,280	-	-	-	-	-	-	22,040	-
3b.1.1.5	Turbine Pedestal	-	349	-	-	-	-	-	52	402	-	-	402	-	-	-	-	-	-	1,857	-
3b.1.1	Totals	-	8,171	-	-	-	-	-	1,226	9,397	-	-	9,397	-	-	-	-	-	-	76,993	-
Site Closeout Activities																					
3b.1.2	Grade & landscape site	-	431	-	-	-	-	-	65	495	-	-	495	-	-	-	-	-	-	921	-
3b.1.3	Final report to NRC	-	-	-	-	-	-	183	27	211	211	-	-	-	-	-	-	-	-	-	1,560
3b.1	Subtotal Period 3b Activity Costs	-	8,602	-	-	-	-	183	1,318	10,102	211	-	9,892	-	-	-	-	-	-	77,914	1,560
Period 3b Additional Costs																					
3b.2.1	Clean Concrete Disposal	-	2,213	-	-	-	-	3	332	2,549	-	-	2,549	-	-	-	-	-	-	8,386	-
3b.2.2	Underground Services Excavations	-	811	-	-	-	-	520	200	1,531	-	-	1,531	-	-	-	-	-	-	7,407	-
3b.2.3	Intake Structure Cofferdam	-	596	-	-	-	-	-	89	686	-	-	686	-	-	-	-	-	-	5,168	-
3b.2.4	Construction Debris	-	-	-	-	-	-	10	2	12	-	-	12	-	-	-	-	-	-	-	-
3b.2.5	Backfill	-	2,751	-	-	-	-	-	413	3,164	-	-	3,164	-	-	-	-	-	-	2,904	-
3b.2	Subtotal Period 3b Additional Costs	-	6,371	-	-	-	-	534	1,036	7,941	-	-	7,941	-	-	-	-	-	-	23,865	-
Period 3b Collateral Costs																					
3b.3.1	Small tool allowance	-	110	-	-	-	-	-	16	126	-	-	126	-	-	-	-	-	-	-	-
3b.3.2	Prairie Island Indian Community Payments	-	-	-	-	-	-	2,651	-	2,651	-	2,651	-	-	-	-	-	-	-	-	-
3b.3	Subtotal Period 3b Collateral Costs	-	110	-	-	-	-	2,651	16	2,777	-	2,651	126	-	-	-	-	-	-	-	-
Period 3b Period-Dependent Costs																					
3b.4.1	Insurance	-	-	-	-	-	-	542	54	596	-	596	-	-	-	-	-	-	-	-	-
3b.4.2	Property taxes	-	-	-	-	-	-	4,334	433	4,767	-	4,767	-	-	-	-	-	-	-	-	-
3b.4.3	Heavy equipment rental	-	6,670	-	-	-	-	-	1,000	7,670	-	-	7,670	-	-	-	-	-	-	-	-
3b.4.4	Plant energy budget	-	-	-	-	-	-	321	48	369	-	-	369	-	-	-	-	-	-	-	-
3b.4.5	NRC ISFSI Fees	-	-	-	-	-	-	236	24	259	-	259	-	-	-	-	-	-	-	-	-
3b.4.6	Emergency Planning Fees	-	-	-	-	-	-	145	14	159	-	159	-	-	-	-	-	-	-	-	-
3b.4.7	Fixed Overhead	-	-	-	-	-	-	990	148	1,138	-	-	1,138	-	-	-	-	-	-	-	-
3b.4.8	ISFSI Operating Costs	-	-	-	-	-	-	109	16	126	-	126	-	-	-	-	-	-	-	-	-

Table F-1
Prairie Island Nuclear Generating Plant, Unit 1
DECON Decommissioning Cost Estimate with 200 Years of Spent Fuel Storage and Periodic TN-40 Replacement
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Period 3b Period-Dependent Costs (continued)																					
3b.4.9	Railroad Track Maintenance	-	-	-	-	-	-	331	50	380	-	-	380	-	-	-	-	-	-	-	-
3b.4.10	Security Staff Cost	-	-	-	-	-	-	4,245	637	4,882	-	4,882	-	-	-	-	-	-	-	-	57,340
3b.4.11	DOC Staff Cost	-	-	-	-	-	-	10,467	1,570	12,038	-	-	12,038	-	-	-	-	-	-	-	116,885
3b.4.12	Utility Staff Cost	-	-	-	-	-	-	4,964	745	5,709	(0)	2,283	3,425	-	-	-	-	-	-	-	76,637
3b.4	Subtotal Period 3b Period-Dependent Costs	-	6,670	-	-	-	-	26,684	4,740	38,094	(0)	13,074	25,021	-	-	-	-	-	-	-	250,861
3b.0	TOTAL PERIOD 3b COST	-	21,752	-	-	-	-	30,052	7,110	58,914	211	15,724	42,979	-	-	-	-	-	-	101,779	252,421
PERIOD 3c - Fuel Storage Operations																					
Period 3c Direct Decommissioning Activities																					
Period 3c Additional Costs																					
3c.2.1	ISFSI Disposition of Original Casks	-	-	-	128	-	1,548	-	406	2,082	-	2,082	-	-	4,906	-	-	-	576,566	-	-
3c.2	Subtotal Period 3c Additional Costs	-	-	-	128	-	1,548	-	406	2,082	-	2,082	-	-	4,906	-	-	-	576,566	-	-
Period 3c Collateral Costs																					
3c.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	791,546	118,732	910,278	-	910,278	-	-	-	-	-	-	-	-	-
3c.3.2	Prairie Island Indian Community Payments	-	-	-	-	-	-	186,914	-	186,914	-	186,914	-	-	-	-	-	-	-	-	-
3c.3	Subtotal Period 3c Collateral Costs	-	-	-	-	-	-	978,460	118,732	1,097,192	-	1,097,192	-	-	-	-	-	-	-	-	-
Period 3c Period-Dependent Costs																					
3c.4.1	Insurance	-	-	-	-	-	-	38,227	3,823	42,050	-	42,050	-	-	-	-	-	-	-	-	-
3c.4.2	Property taxes	-	-	-	-	-	-	157,169	15,717	172,886	-	172,886	-	-	-	-	-	-	-	-	-
3c.4.3	Plant energy budget	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3c.4.4	NRC ISFSI Fees	-	-	-	-	-	-	24,486	2,449	26,934	-	26,934	-	-	-	-	-	-	-	-	-
3c.4.5	Emergency Planning Fees	-	-	-	-	-	-	10,232	1,023	11,255	-	11,255	-	-	-	-	-	-	-	-	-
3c.4.6	Fixed Overhead	-	-	-	-	-	-	22,830	3,425	26,255	-	26,255	-	-	-	-	-	-	-	-	-
3c.4.7	ISFSI Operating Costs	-	-	-	-	-	-	7,724	1,159	8,883	-	8,883	-	-	-	-	-	-	-	-	-
3c.4.8	Railroad Track Maintenance	-	-	-	-	-	-	8,629	1,294	9,924	-	9,924	-	-	-	-	-	-	-	-	-
3c.4.9	Security Staff Cost	-	-	-	-	-	-	299,567	44,935	344,502	-	344,502	-	-	-	-	-	-	-	-	4,046,073
3c.4.10	DOC Staff Cost	-	-	-	-	-	-	14,425	2,164	16,589	-	16,589	-	-	-	-	-	-	-	-	155,618
3c.4.11	Utility Staff Cost	-	-	-	-	-	-	140,210	21,032	161,242	-	161,242	-	-	-	-	-	-	-	-	2,061,941
3c.4	Subtotal Period 3c Period-Dependent Costs	-	-	-	-	-	-	723,500	97,019	820,519	-	820,519	-	-	-	-	-	-	-	-	6,263,633
3c.0	TOTAL PERIOD 3c COST	-	-	-	128	-	1,548	1,701,960	216,157	1,919,793	-	1,919,793	-	-	4,906	-	-	-	576,566	-	6,263,633
PERIOD 3d - Spent Fuel/GTCC shipping																					
Period 3d Direct Decommissioning Activities																					
Nuclear Steam Supply System Removal																					
3d.1.1.1	Vessel & Internals GTCC Disposal	-	-	1,331	-	-	8,689	-	1,636	11,656	11,656	-	-	-	-	-	-	3,746	837,596	-	-
3d.1.1	Totals	-	-	1,331	-	-	8,689	-	1,636	11,656	11,656	-	-	-	-	-	-	3,746	837,596	-	-
3d.1	Subtotal Period 3d Activity Costs	-	-	1,331	-	-	8,689	-	1,636	11,656	11,656	-	-	-	-	-	-	3,746	837,596	-	-
Period 3d Collateral Costs																					
3d.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	126,132	18,920	145,052	-	145,052	-	-	-	-	-	-	-	-	-
3d.3.2	Prairie Island Indian Community Payments	-	-	-	-	-	-	31,250	-	31,250	-	31,250	-	-	-	-	-	-	-	-	-
3d.3	Subtotal Period 3d Collateral Costs	-	-	-	-	-	-	157,382	18,920	176,302	-	176,302	-	-	-	-	-	-	-	-	-
Period 3d Period-Dependent Costs																					
3d.4.1	Insurance	-	-	-	-	-	-	6,390	639	7,029	-	7,029	-	-	-	-	-	-	-	-	-
3d.4.2	Property taxes	-	-	-	-	-	-	24,558	2,456	27,013	-	27,013	-	-	-	-	-	-	-	-	-
3d.4.4	NRC ISFSI Fees	-	-	-	-	-	-	2,782	278	3,060	-	3,060	-	-	-	-	-	-	-	-	-
3d.4.5	Emergency Planning Fees	-	-	-	-	-	-	1,710	171	1,881	-	1,881	-	-	-	-	-	-	-	-	-
3d.4.6	Fixed Overhead	-	-	-	-	-	-	3,816	572	4,389	-	4,389	-	-	-	-	-	-	-	-	-
3d.4.7	ISFSI Operating Costs	-	-	-	-	-	-	1,291	194	1,485	-	1,485	-	-	-	-	-	-	-	-	-
3d.4.8	Railroad Track Maintenance	-	-	-	-	-	-	1,443	216	1,659	-	1,659	-	-	-	-	-	-	-	-	-
Period 3d Period-Dependent Costs (continued)																					
3d.4.9	Security Staff Cost	-	-	-	-	-	-	48,076	7,211	55,287	-	55,287	-	-	-	-	-	-	-	-	676,370
3d.4.10	Utility Staff Cost	-	-	-	-	-	-	12,369	1,855	14,225	-	14,225	-	-	-	-	-	-	-	-	175,596
3d.4	Subtotal Period 3d Period-Dependent Costs	-	-	-	-	-	-	102,435	13,593	116,029	-	116,029	-	-	-	-	-	-	-	-	851,967
3d.0	TOTAL PERIOD 3d COST	-	-	1,331	-	-	8,689	259,817	34,149	303,987	11,656	292,330	-	-	-	-	-	3,746	837,596	-	851,967

Table F-1
Prairie Island Nuclear Generating Plant, Unit 1
DECON Decommissioning Cost Estimate with 200 Years of Spent Fuel Storage and Periodic TN-40 Replacement
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
PERIOD 3e - ISFSI Decontamination																					
Period 3e Direct Decommissioning Activities																					
Period 3e Additional Costs																					
3e.2.1	License Termination ISFSI	15	-	-	-	-	-	970	246	1,232	1,232	-	-	-	-	-	-	-	-	5,604	972
3e.2	Subtotal Period 3e Additional Costs	15	-	-	-	-	-	970	246	1,232	1,232	-	-	-	-	-	-	-	-	5,604	972
Period 3e Period-Dependent Costs																					
3e.4.1	Insurance	-	-	-	-	-	-	96	24	121	121	-	-	-	-	-	-	-	-	-	-
3e.4.4	Fixed Overhead	-	-	-	-	-	-	51	13	63	63	-	-	-	-	-	-	-	-	-	-
3e.4.5	Railroad Track Maintenance	-	-	-	-	-	-	19	5	24	24	-	-	-	-	-	-	-	-	-	-
3e.4.6	Security Staff Cost	-	-	-	-	-	-	154	38	192	192	-	-	-	-	-	-	-	-	-	2,500
3e.4.7	Utility Staff Cost	-	-	-	-	-	-	130	33	163	163	-	-	-	-	-	-	-	-	-	1,896
3e.4	Subtotal Period 3e Period-Dependent Costs	-	-	-	-	-	-	450	113	563	563	-	-	-	-	-	-	-	-	-	4,396
3e.0	TOTAL PERIOD 3e COST	15	-	-	-	-	-	1,420	359	1,794	1,794	-	-	-	-	-	-	-	-	5,604	5,368
PERIOD 3f - ISFSI Site Restoration																					
Period 3f Direct Decommissioning Activities																					
Period 3f Additional Costs																					
3f.2.1	Demolition and Site Restoration of ISFSI	-	946	-	-	-	-	154	165	1,265	-	-	1,265	-	-	-	-	-	-	4,922	160
3f.2	Subtotal Period 3f Additional Costs	-	946	-	-	-	-	154	165	1,265	-	-	1,265	-	-	-	-	-	-	4,922	160
Period 3f Collateral Costs																					
3f.3.1	Small tool allowance	-	7	-	-	-	-	-	1	8	-	-	8	-	-	-	-	-	-	-	-
3f.3	Subtotal Period 3f Collateral Costs	-	7	-	-	-	-	-	1	8	-	-	8	-	-	-	-	-	-	-	-
Period 3f Period-Dependent Costs																					
3f.4.3	Heavy equipment rental	-	62	-	-	-	-	-	9	71	-	-	71	-	-	-	-	-	-	-	-
3f.4.4	Plant energy budget	-	-	-	-	-	-	13	2	15	-	-	15	-	-	-	-	-	-	-	-
3f.4.5	Fixed Overhead	-	-	-	-	-	-	25	4	29	-	-	29	-	-	-	-	-	-	-	-
3f.4.6	Railroad Track Maintenance	-	-	-	-	-	-	10	1	11	-	-	11	-	-	-	-	-	-	-	-
3f.4.7	Security Staff Cost	-	-	-	-	-	-	78	12	89	-	-	89	-	-	-	-	-	-	-	1,260
3f.4.8	Utility Staff Cost	-	-	-	-	-	-	52	8	60	-	-	60	-	-	-	-	-	-	-	782
3f.4	Subtotal Period 3f Period-Dependent Costs	-	62	-	-	-	-	177	36	275	-	-	275	-	-	-	-	-	-	-	2,042
3f.0	TOTAL PERIOD 3f COST	-	1,014	-	-	-	-	331	202	1,547	-	-	1,547	-	-	-	-	-	-	4,922	2,202
PERIOD 3 TOTALS		15	22,766	1,331	128	-	10,236	1,993,580	257,977	2,286,035	13,661	2,227,848	44,526	-	4,906	-	-	3,746	1,414,161	112,304	7,375,590
TOTAL COST TO DECOMMISSION		**8,749**	**81,425**	**30,681**	**7,026**	**11,781**	**50,002**	**2,422,874**	**365,000**	**2,977,539**	**568,259**	**2,358,425**	**50,855**	**144,842**	**136,023**	**839**	**673**	**3,746**	**15,317,950**	**744,976**	**10,439,680**

TOTAL COST TO DECOMMISSION WITH 13.97% CONTINGENCY:	**$2,977,539**	**thousands of 2017 dollars**
TOTAL NRC LICENSE TERMINATION COST IS 19.08% OR:	**$568,259**	**thousands of 2017 dollars**
SPENT FUEL MANAGEMENT COST IS 79.21% OR:	**$2,358,425**	**thousands of 2017 dollars**
NON-NUCLEAR DEMOLITION COST IS 1.71% OR:	**$50,855**	**thousands of 2017 dollars**
TOTAL LOW-LEVEL RADIOACTIVE WASTE VOLUME BURIED (EXCLUDING GTCC):	**137,535**	**cubic feet**
TOTAL GREATER THAN CLASS C RADWASTE VOLUME GENERATED:	**3,746**	**cubic feet**
TOTAL SCRAP METAL REMOVED:	**32,925**	**tons**
TOTAL CRAFT LABOR REQUIREMENTS:	**744,976**	**man-hours**

End Notes:
n/a - indicates that this activity not charged as decommissioning expense
a - indicates that this activity performed by decommissioning staff
0 - indicates that this value is less than 0.5 but is non-zero
A cell containing " - " indicates a zero value

Table F-2
Prairie Island Nuclear Generating Plant, Unit 2
DECON Decommissioning Cost Estimate with 200 Years of Spent Fuel Storage and Periodic TN-40 Replacement
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
PERIOD 1a - Shutdown through Transition																					
Period 1a Direct Decommissioning Activities																					
1a.1.1	Prepare preliminary decommissioning cost	-	-	-	-	-	-	65	10	75	75	-	-	-	-	-	-	-	-	-	556
1a.1.2	Notification of Cessation of Operations									a											
1a.1.3	Remove fuel & source material									n/a											
1a.1.4	Notification of Permanent Defueling									a											
1a.1.5	Deactivate plant systems & process waste									a											
1a.1.6	Prepare and submit PSDAR	-	-	-	-	-	-	100	15	115	115	-	-	-	-	-	-	-	-	-	855
1a.1.7	Review plant dwgs & specs.	-	-	-	-	-	-	231	35	266	266	-	-	-	-	-	-	-	-	-	1,967
1a.1.8	Perform detailed rad survey									a											
1a.1.9	Estimate by-product inventory	-	-	-	-	-	-	50	8	58	58	-	-	-	-	-	-	-	-	-	428
1a.1.10	End product description	-	-	-	-	-	-	50	8	58	58	-	-	-	-	-	-	-	-	-	428
1a.1.11	Detailed by-product inventory	-	-	-	-	-	-	65	10	75	75	-	-	-	-	-	-	-	-	-	556
1a.1.12	Define major work sequence	-	-	-	-	-	-	376	56	433	433	-	-	-	-	-	-	-	-	-	3,207
1a.1.13	Perform SER and EA	-	-	-	-	-	-	156	23	179	179	-	-	-	-	-	-	-	-	-	1,326
1a.1.14	Prepare/submit Defueled Technical Specifications	-	-	-	-	-	-	376	56	433	433	-	-	-	-	-	-	-	-	-	3,207
1a.1.15	Perform Site-Specific Cost Study	-	-	-	-	-	-	251	38	289	289	-	-	-	-	-	-	-	-	-	2,138
1a.1.16	Prepare/submit Irradiated Fuel Management Plan	-	-	-	-	-	-	50	8	58	58	-	-	-	-	-	-	-	-	-	428
Activity Specifications																					
1a.1.17.1	Plant & temporary facilities	-	-	-	-	-	-	247	37	284	256	-	28	-	-	-	-	-	-	-	2,104
1a.1.17.2	Plant systems	-	-	-	-	-	-	209	31	241	216	-	24	-	-	-	-	-	-	-	1,782
1a.1.17.3	NSSS Decontamination Flush	-	-	-	-	-	-	25	4	29	29	-	-	-	-	-	-	-	-	-	214
1a.1.17.4	Reactor internals	-	-	-	-	-	-	356	53	410	410	-	-	-	-	-	-	-	-	-	3,036
1a.1.17.5	Reactor vessel	-	-	-	-	-	-	326	49	375	375	-	-	-	-	-	-	-	-	-	2,779
1a.1.17.6	Biological shield	-	-	-	-	-	-	25	4	29	29	-	-	-	-	-	-	-	-	-	214
1a.1.17.7	Steam generators	-	-	-	-	-	-	157	23	180	180	-	-	-	-	-	-	-	-	-	1,334
1a.1.17.8	Reinforced concrete	-	-	-	-	-	-	80	12	92	46	-	46	-	-	-	-	-	-	-	684
1a.1.17.9	Main Turbine	-	-	-	-	-	-	20	3	23	-	-	23	-	-	-	-	-	-	-	171
1a.1.17.10	Main Condensers	-	-	-	-	-	-	20	3	23	-	-	23	-	-	-	-	-	-	-	171
1a.1.17.11	Plant structures & buildings	-	-	-	-	-	-	157	23	180	90	-	90	-	-	-	-	-	-	-	1,334
1a.1.17.12	Waste management	-	-	-	-	-	-	231	35	266	266	-	-	-	-	-	-	-	-	-	1,967
1a.1.17.13	Facility & site closeout	-	-	-	-	-	-	45	7	52	26	-	26	-	-	-	-	-	-	-	385
1a.1.17	Total	-	-	-	-	-	-	1,899	285	2,183	1,923	-	261	-	-	-	-	-	-	-	16,175
Planning & Site Preparations																					
1a.1.18	Prepare dismantling sequence	-	-	-	-	-	-	120	18	139	139	-	-	-	-	-	-	-	-	-	1,026
1a.1.19	Plant prep. & temp. svces	-	-	-	-	-	-	3,300	495	3,795	3,795	-	-	-	-	-	-	-	-	-	-
1a.1.20	Design water clean-up system	-	-	-	-	-	-	70	11	81	81	-	-	-	-	-	-	-	-	-	599
1a.1.21	Rigging/Cont. Cntrl Envlps/tooling/etc.	-	-	-	-	-	-	2,300	345	2,645	2,645	-	-	-	-	-	-	-	-	-	-
1a.1.22	Procure casks/liners & containers	-	-	-	-	-	-	62	9	71	71	-	-	-	-	-	-	-	-	-	526
1a.1	Subtotal Period 1a Activity Costs	-	-	-	-	-	-	9,523	1,428	10,951	10,690	-	261	-	-	-	-	-	-	-	33,420
Period 1a Additional Costs																					
1a.2.1	Spent Fuel Pool Isolation	-	-	-	-	-	-	7,794	1,169	8,963	8,963	-	-	-	-	-	-	-	-	-	-
1a.2	Subtotal Period 1a Additional Costs	-	-	-	-	-	-	7,794	1,169	8,963	8,963	-	-	-	-	-	-	-	-	-	-
Period 1a Collateral Costs																					
1a.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	1,227	184	1,411	-	1,411	-	-	-	-	-	-	-	-	-
1a.3.2	Retention and Severance	-	-	-	-	-	-	8,394	1,259	9,653	9,653	-	-	-	-	-	-	-	-	-	-
1a.3.3	Prairie Island Indian Community Payments	-	-	-	-	-	-	2,281	-	2,281	-	2,281	-	-	-	-	-	-	-	-	-
1a.3	Subtotal Period 1a Collateral Costs	-	-	-	-	-	-	11,902	1,443	13,345	9,653	3,692	-	-	-	-	-	-	-	-	-
Period 1a Period-Dependent Costs																					
1a.4.1	Insurance	-	-	-	-	-	-	1,730	173	1,903	1,903	-	-	-	-	-	-	-	-	-	-
1a.4.2	Property taxes	-	-	-	-	-	-	2,682	268	2,950	2,950	-	-	-	-	-	-	-	-	-	-
1a.4.3	Health physics supplies	-	485	-	-	-	-	-	121	606	606	-	-	-	-	-	-	-	-	-	-
1a.4.4	Heavy equipment rental	-	567	-	-	-	-	-	85	652	652	-	-	-	-	-	-	-	-	-	-
1a.4.5	Disposal of DAW generated	-	-	12	4	-	46	-	13	75	75	-	-	-	565	-	-	-	11,299	18	-
1a.4.6	Plant energy budget	-	-	-	-	-	-	1,515	227	1,742	1,742	-	-	-	-	-	-	-	-	-	-
1a.4.7	NRC Fees	-	-	-	-	-	-	778	78	855	855	-	-	-	-	-	-	-	-	-	-
1a.4.8	Emergency Planning Fees	-	-	-	-	-	-	1,604	160	1,765	-	1,765	-	-	-	-	-	-	-	-	-
1a.4.9	Fixed Overhead	-	-	-	-	-	-	1,470	220	1,690	1,690	-	-	-	-	-	-	-	-	-	-
1a.4.10	Spent Fuel Pool O&M	-	-	-	-	-	-	401	60	461	-	461	-	-	-	-	-	-	-	-	-
1a.4.11	ISFSI Operating Costs	-	-	-	-	-	-	52	8	59	-	59	-	-	-	-	-	-	-	-	-
1a.4.12	Railroad Track Maintenance	-	-	-	-	-	-	58	9	66	66	-	-	-	-	-	-	-	-	-	-
1a.4.13	Security Staff Cost	-	-	-	-	-	-	7,390	1,108	8,498	8,498	-	-	-	-	-	-	-	-	-	122,720
1a.4.14	Utility Staff Cost	-	-	-	-	-	-	20,662	3,099	23,761	23,761	-	-	-	-	-	-	-	-	-	345,280

Table F-2
Prairie Island Nuclear Generating Plant, Unit 2
DECON Decommissioning Cost Estimate with 200 Years of Spent Fuel Storage and Periodic TN-40 Replacement
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
1a.4	Subtotal Period 1a Period-Dependent Costs	-	1,052	12	4	-	46	38,340	5,631	45,085	42,800	2,286	-	-	565	-	-	-	11,299	18	468,000
1a.0	TOTAL PERIOD 1a COST	-	1,052	12	4	-	46	67,559	9,672	78,345	72,107	5,977	261	-	565	-	-	-	11,299	18	501,420
PERIOD 1b - Decommissioning Preparations																					
Period 1b Direct Decommissioning Activities																					
Detailed Work Procedures																					
1b.1.1.1	Plant systems	-	-	-	-	-	-	238	36	273	246	-	27	-	-	-	-	-	-	-	2,024
1b.1.1.2	NSSS Decontamination Flush	-	-	-	-	-	-	50	8	58	58	-	-	-	-	-	-	-	-	-	428
1b.1.1.3	Reactor internals	-	-	-	-	-	-	125	19	144	144	-	-	-	-	-	-	-	-	-	1,069
1b.1.1.4	Remaining buildings	-	-	-	-	-	-	68	10	78	19	-	58	-	-	-	-	-	-	-	577
1b.1.1.5	CRD cooling assembly	-	-	-	-	-	-	50	8	58	58	-	-	-	-	-	-	-	-	-	428
1b.1.1.6	CRD housings & ICI tubes	-	-	-	-	-	-	50	8	58	58	-	-	-	-	-	-	-	-	-	428
1b.1.1.7	Incore instrumentation	-	-	-	-	-	-	50	8	58	58	-	-	-	-	-	-	-	-	-	428
1b.1.1.8	Reactor vessel	-	-	-	-	-	-	182	27	210	210	-	-	-	-	-	-	-	-	-	1,552
1b.1.1.9	Facility closeout	-	-	-	-	-	-	60	9	69	35	-	35	-	-	-	-	-	-	-	513
1b.1.1.10	Missile shields	-	-	-	-	-	-	23	3	26	26	-	-	-	-	-	-	-	-	-	192
1b.1.1.11	Biological shield	-	-	-	-	-	-	60	9	69	69	-	-	-	-	-	-	-	-	-	513
1b.1.1.12	Steam generators	-	-	-	-	-	-	231	35	266	266	-	-	-	-	-	-	-	-	-	1,967
1b.1.1.13	Reinforced concrete	-	-	-	-	-	-	50	8	58	29	-	29	-	-	-	-	-	-	-	428
1b.1.1.14	Main Turbine	-	-	-	-	-	-	78	12	90	-	-	90	-	-	-	-	-	-	-	667
1b.1.1.15	Main Condensers	-	-	-	-	-	-	78	12	90	-	-	90	-	-	-	-	-	-	-	667
1b.1.1.16	Auxiliary building	-	-	-	-	-	-	137	21	158	142	-	16	-	-	-	-	-	-	-	1,167
1b.1.1.17	Reactor building	-	-	-	-	-	-	137	21	158	142	-	16	-	-	-	-	-	-	-	1,167
1b.1.1	Total	-	-	-	-	-	-	1,669	250	1,919	1,558	-	361	-	-	-	-	-	-	-	14,215
1b.1.2	Decon primary loop	552	-	-	-	-	-	-	276	828	828	-	-	-	-	-	-	-	-	1,067	-
1b.1	Subtotal Period 1b Activity Costs	552	-	-	-	-	-	1,669	526	2,747	2,386	-	361	-	-	-	-	-	-	1,067	14,215
Period 1b Additional Costs																					
1b.2.1	Site Characterization	-	-	-	-	-	-	1,582	475	2,057	2,057	-	-	-	-	-	-	-	-	8,988	3,563
1b.2.2	Mixed/Hazardous Waste	-	-	326	75	169	-	-	69	639	639	-	-	6,324	-	-	-	-	362,914	2,410	-
1b.2.3	Asbestos Abatement	-	2,364	2	110	-	1,359	-	947	4,782	4,782	-	-	-	12,843	-	-	-	166,959	20,907	-
1b.2	Subtotal Period 1b Additional Costs	-	2,364	328	185	169	1,359	1,582	1,491	7,478	7,478	-	-	6,324	12,843	-	-	-	529,873	32,305	3,563
Period 1b Collateral Costs																					
1b.3.1	Decon equipment	973	-	-	-	-	-	-	146	1,119	1,119	-	-	-	-	-	-	-	-	-	-
1b.3.2	DOC staff relocation expenses	-	-	-	-	-	-	1,189	178	1,367	1,367	-	-	-	-	-	-	-	-	-	-
1b.3.3	Process decommissioning water waste	24	-	16	41	-	64	-	36	180	180	-	-	-	152	-	-	-	9,121	30	-
1b.3.4	Process decommissioning chemical flush waste	2	-	58	220	-	2,471	-	657	3,408	3,408	-	-	-	-	588	-	-	62,689	110	-
1b.3.5	Small tool allowance	-	34	-	-	-	-	-	5	39	39	-	-	-	-	-	-	-	-	-	-
1b.3.6	Pipe cutting equipment	-	1,200	-	-	-	-	-	180	1,380	1,380	-	-	-	-	-	-	-	-	-	-
1b.3.7	Decon rig	1,987	-	-	-	-	-	-	298	2,285	2,285	-	-	-	-	-	-	-	-	-	-
1b.3.8	Spent Fuel Capital and Transfer	-	-	-	-	-	-	370	56	426	-	426	-	-	-	-	-	-	-	-	-
1b.3.9	Retention and Severance	-	-	-	-	-	-	4,055	608	4,664	4,664	-	-	-	-	-	-	-	-	-	-
1b.3.10	Prairie Island Indian Community Payments	-	-	-	-	-	-	629	-	629	-	629	-	-	-	-	-	-	-	-	-
1b.3	Subtotal Period 1b Collateral Costs	2,986	1,234	74	261	-	2,534	6,243	2,164	15,495	14,441	1,055	-	-	152	588	-	-	71,810	140	-
Period 1b Period-Dependent Costs																					
1b.4.1	Decon supplies	35	-	-	-	-	-	-	9	44	44	-	-	-	-	-	-	-	-	-	-
1b.4.2	Insurance	-	-	-	-	-	-	872	87	959	959	-	-	-	-	-	-	-	-	-	-
1b.4.3	Property taxes	-	-	-	-	-	-	1,319	132	1,451	1,451	-	-	-	-	-	-	-	-	-	-
1b.4.4	Health physics supplies	-	380	-	-	-	-	-	95	475	475	-	-	-	-	-	-	-	-	-	-
1b.4.5	Heavy equipment rental	-	286	-	-	-	-	-	43	329	329	-	-	-	-	-	-	-	-	-	-
1b.4.6	Disposal of DAW generated	-	-	7	2	-	27	-	8	44	44	-	-	-	327	-	-	-	6,541	11	-
1b.4.7	Plant energy budget	-	-	-	-	-	-	1,527	229	1,756	1,756	-	-	-	-	-	-	-	-	-	-
1b.4.8	NRC Fees	-	-	-	-	-	-	214	21	236	236	-	-	-	-	-	-	-	-	-	-
1b.4.9	Emergency Planning Fees	-	-	-	-	-	-	809	81	890	-	890	-	-	-	-	-	-	-	-	-
1b.4.10	Fixed Overhead	-	-	-	-	-	-	741	111	852	852	-	-	-	-	-	-	-	-	-	-
1b.4.11	Spent Fuel Pool O&M	-	-	-	-	-	-	202	30	233	-	233	-	-	-	-	-	-	-	-	-
1b.4.12	ISFSI Operating Costs	-	-	-	-	-	-	26	4	30	-	30	-	-	-	-	-	-	-	-	-
1b.4.13	Railroad Track Maintenance	-	-	-	-	-	-	29	4	33	33	-	-	-	-	-	-	-	-	-	-
1b.4.14	Security Staff Cost	-	-	-	-	-	-	3,725	559	4,284	4,284	-	-	-	-	-	-	-	-	-	61,864
1b.4.15	DOC Staff Cost	-	-	-	-	-	-	4,009	601	4,610	4,610	-	-	-	-	-	-	-	-	-	47,185
1b.4.16	Utility Staff Cost	-	-	-	-	-	-	10,416	1,562	11,978	11,978	-	-	-	-	-	-	-	-	-	174,059
1b.4	Subtotal Period 1b Period-Dependent Costs	35	666	7	2	-	27	23,890	3,577	28,204	27,052	1,152	-	-	327	-	-	-	6,541	11	283,108

Table F-2
Prairie Island Nuclear Generating Plant, Unit 2
DECON Decommissioning Cost Estimate with 200 Years of Spent Fuel Storage and Periodic TN-40 Replacement
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
1b.0	TOTAL PERIOD 1b COST	3,573	4,264	410	447	169	3,920	33,383	7,759	53,923	51,356	2,207	361	6,324	13,322	588	-	-	608,224	33,522	300,885
PERIOD 1 TOTALS		3,573	5,316	422	451	169	3,966	100,942	17,430	132,268	123,462	8,184	622	6,324	13,887	588	-	-	619,523	33,540	802,305
PERIOD 2a - Large Component Removal																					
Period 2a Direct Decommissioning Activities																					
Nuclear Steam Supply System Removal																					
2a.1.1.1	Reactor Coolant Piping	51	45	6	8	-	150	-	76	336	336	-	-	-	305	-	-	-	34,809	1,414	-
2a.1.1.2	Pressurizer Relief Tank	22	20	4	5	-	100	-	42	193	193	-	-	-	203	-	-	-	23,193	625	-
2a.1.1.3	Reactor Coolant Pumps & Motors	54	63	101	83	-	736	-	249	1,287	1,287	-	-	-	2,332	-	-	-	295,800	2,049	100
2a.1.1.4	Pressurizer	48	68	467	88	-	693	-	274	1,639	1,639	-	-	-	2,196	-	-	-	185,015	2,355	938
2a.1.1.5	Steam Generators	225	2,943	2,093	1,638	1,246	3,570	-	2,383	14,097	14,097	-	-	18,672	11,316	-	-	-	1,668,341	14,819	2,875
2a.1.1.6	CRDMs/ICIs/Service Structure Removal	286	277	211	48	-	763	-	431	2,016	2,016	-	-	-	4,797	-	-	-	177,400	8,104	-
2a.1.1.7	Reactor Vessel Internals	78	4,468	21,874	1,072	-	7,946	277	13,141	48,856	48,856	-	-	-	501	125	673	-	164,987	23,040	1,080
2a.1.1.8	Reactor Vessel	89	5,717	1,754	719	-	1,956	277	5,970	16,483	16,483	-	-	-	5,690	-	-	-	570,074	23,040	1,080
2a.1.1	Totals	855	13,600	26,512	3,662	1,246	15,913	553	22,568	84,908	84,908	-	-	18,672	27,341	125	673	-	3,119,620	75,446	6,073
Removal of Major Equipment																					
2a.1.2	Main Turbine/Generator	-	305	189	55	272	306	-	221	1,348	1,348	-	-	2,131	1,187	-	-	-	206,316	4,667	-
2a.1.3	Main Condensers	-	2,532	121	49	364	451	-	820	4,336	4,336	-	-	3,800	1,587	-	-	-	275,903	39,151	-
Cascading Costs from Clean Building Demolition																					
2a.1.4.1	Reactor	-	728	-	-	-	-	-	109	837	837	-	-	-	-	-	-	-	-	7,589	-
2a.1.4.2	Auxiliary	-	210	-	-	-	-	-	32	242	242	-	-	-	-	-	-	-	-	1,309	-
2a.1.4.3	Radwaste	-	8	-	-	-	-	-	1	9	9	-	-	-	-	-	-	-	-	65	-
2a.1.4	Totals	-	946	-	-	-	-	-	142	1,088	1,088	-	-	-	-	-	-	-	-	8,963	-
Disposal of Plant Systems																					
2a.1.5.1	Admin Bldg Ventilation	-	6	-	-	-	-	-	1	6	-	-	6	-	-	-	-	-	-	90	-
2a.1.5.2	Air Removal	-	25	-	-	-	-	-	4	29	-	-	29	-	-	-	-	-	-	422	-
2a.1.5.3	Auxiliary Feedwater	-	40	-	-	-	-	-	6	46	-	-	46	-	-	-	-	-	-	676	-
2a.1.5.4	Auxiliary Feedwater - RCA	-	36	0	1	15	-	-	12	65	65	-	-	178	-	-	-	-	7,214	486	-
2a.1.5.5	Bleed Steam	-	78	-	-	-	-	-	12	90	-	-	90	-	-	-	-	-	-	1,331	-
2a.1.5.6	Caustic Addition - RCA	-	38	0	1	21	-	-	13	74	74	-	-	240	-	-	-	-	9,761	468	-
2a.1.5.7	Chemical Feed	-	15	-	-	-	-	-	2	17	-	-	17	-	-	-	-	-	-	261	-
2a.1.5.8	Chemical Feed - RCA	-	3	0	0	1	-	-	1	5	5	-	-	16	-	-	-	-	634	31	-
2a.1.5.9	Circulating Water	-	24	-	-	-	-	-	4	28	-	-	28	-	-	-	-	-	-	401	-
2a.1.5.10	Condensate	-	459	-	-	-	-	-	69	527	-	-	527	-	-	-	-	-	-	7,537	-
2a.1.5.11	Condensate Polishing	-	181	-	-	-	-	-	27	209	-	-	209	-	-	-	-	-	-	2,987	-
2a.1.5.12	Condensate Polishing - RCA	-	36	1	3	42	-	-	16	98	98	-	-	483	-	-	-	-	19,616	493	-
2a.1.5.13	Electro-Hydraulic	-	8	-	-	-	-	-	1	10	-	-	10	-	-	-	-	-	-	143	-
2a.1.5.14	External Circulating Water	-	23	-	-	-	-	-	3	26	-	-	26	-	-	-	-	-	-	385	-
2a.1.5.15	External Circulating Water - RCA	-	70	1	4	62	-	-	28	165	165	-	-	721	-	-	-	-	29,284	938	-
2a.1.5.16	Feedwater	-	111	-	-	-	-	-	17	128	-	-	128	-	-	-	-	-	-	1,840	-
2a.1.5.17	Feedwater - RCA	-	236	7	24	359	-	-	117	744	744	-	-	4,147	-	-	-	-	168,414	3,377	-
2a.1.5.18	Gland Seal	-	29	-	-	-	-	-	4	34	-	-	34	-	-	-	-	-	-	504	-
2a.1.5.19	Heater Drain	-	334	-	-	-	-	-	50	384	-	-	384	-	-	-	-	-	-	5,638	-
2a.1.5.20	Hypobromous Acid Feed	-	5	-	-	-	-	-	1	6	-	-	6	-	-	-	-	-	-	86	-
2a.1.5.21	Hypobromous Acid Feed - RCA	-	1	0	0	0	-	-	0	1	1	-	-	2	-	-	-	-	100	12	-
2a.1.5.22	Internal Circ Water & CDSR	-	22	-	-	-	-	-	3	25	-	-	25	-	-	-	-	-	-	366	-
2a.1.5.23	Main Gen/Exciter/Transformer	-	0	-	-	-	-	-	0	0	-	-	0	-	-	-	-	-	-	5	-
2a.1.5.24	Main Steam	-	88	-	-	-	-	-	13	101	-	-	101	-	-	-	-	-	-	1,482	-
2a.1.5.25	Main Steam - RCA	-	364	9	30	447	-	-	163	1,013	1,013	-	-	5,166	-	-	-	-	209,799	5,146	-
2a.1.5.26	Repairable Spare Snubbers	-	6	0	0	1	-	-	2	8	8	-	-	12	-	-	-	-	490	82	-
2a.1.5.27	Steam Exclusion	-	2	-	-	-	-	-	0	2	-	-	2	-	-	-	-	-	-	32	-
2a.1.5.28	Steam Exclusion - RCA	-	4	0	0	2	-	-	1	8	8	-	-	24	-	-	-	-	966	47	-
2a.1.5.29	Steam Generator Blowdown	-	398	20	21	165	179	-	174	957	957	-	-	1,906	631	-	-	-	119,126	5,778	-
2a.1.5.30	Steam Generators	-	5	-	-	-	-	-	1	5	-	-	5	-	-	-	-	-	-	75	-
2a.1.5.31	Turbine & Moisture Separators	-	329	-	-	-	-	-	49	379	-	-	379	-	-	-	-	-	-	5,472	-
2a.1.5.32	Turbine Oil Purification	-	46	-	-	-	-	-	7	53	-	-	53	-	-	-	-	-	-	737	-
2a.1.5.33	Water Treatment	-	394	-	-	-	-	-	59	453	-	-	453	-	-	-	-	-	-	6,677	-
2a.1.5.34	Water Treatment - RCA	-	19	0	1	10	-	-	6	37	37	-	-	115	-	-	-	-	4,652	252	-
2a.1.5	Totals	-	3,437	39	85	1,125	179	-	867	5,733	3,174	-	2,559	13,010	631	-	-	-	570,056	54,280	-
2a.1.6	Scaffolding in support of decommissioning	-	2,833	24	8	97	25	-	733	3,721	3,721	-	-	1,012	89	-	-	-	51,445	26,270	-
2a.1	Subtotal Period 2a Activity Costs	855	23,653	26,885	3,859	3,105	16,875	553	25,350	101,134	98,575	-	2,559	38,625	30,835	125	673	-	4,223,340	208,777	6,073

Table F-2
Prairie Island Nuclear Generating Plant, Unit 2
DECON Decommissioning Cost Estimate with 200 Years of Spent Fuel Storage and Periodic TN-40 Replacement
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 2a Additional Costs																					
2a.2.1	Remedial Action Surveys	-	-	-	-	-	-	1,560	468	2,027	2,027	-	-	-	-	-	-	-	-	20,388	-
2a.2.2	Retired RPV upper internals package	1	659	785	107	-	1,439	-	1,437	4,427	4,427	-	-	-	2,097	125	-	-	205,890	2,175	87
2a.2	Subtotal Period 2a Additional Costs	1	659	785	107	-	1,439	1,560	1,905	6,454	6,454	-	-	-	2,097	125	-	-	205,890	22,562	87
Period 2a Collateral Costs																					
2a.3.1	Process decommissioning water waste	51	-	33	86	-	135	-	75	381	381	-	-	-	323	-	-	-	19,358	63	-
2a.3.3	Small tool allowance	-	251	-	-	-	-	-	38	289	260	-	29	-	-	-	-	-	-	-	-
2a.3.4	Spent Fuel Capital and Transfer	-	-	-	-	-	-	2,138	321	2,459	-	2,459	-	-	-	-	-	-	-	-	-
2a.3.5	Retention and Severance	-	-	-	-	-	-	6,105	916	7,021	7,021	-	-	-	-	-	-	-	-	-	-
2a.3.6	Prairie Island Indian Community Payments	-	-	-	-	-	-	1,224	-	1,224	-	1,224	-	-	-	-	-	-	-	-	-
2a.3	Subtotal Period 2a Collateral Costs	51	251	33	86	-	135	9,467	1,349	11,373	7,661	3,682	29	-	323	-	-	-	19,358	63	-
Period 2a Period-Dependent Costs																					
2a.4.1	Decon supplies	68	-	-	-	-	-	-	17	85	85	-	-	-	-	-	-	-	-	-	-
2a.4.2	Insurance	-	-	-	-	-	-	501	50	551	551	-	-	-	-	-	-	-	-	-	-
2a.4.3	Property taxes	-	-	-	-	-	-	2,507	251	2,758	2,758	-	-	-	-	-	-	-	-	-	-
2a.4.4	Health physics supplies	-	1,622	-	-	-	-	-	406	2,028	2,028	-	-	-	-	-	-	-	-	-	-
2a.4.5	Heavy equipment rental	-	2,153	-	-	-	-	-	323	2,477	2,477	-	-	-	-	-	-	-	-	-	-
2a.4.6	Disposal of DAW generated	-	-	89	26	-	331	-	95	541	541	-	-	-	4,063	-	-	-	81,252	133	-
2a.4.7	Plant energy budget	-	-	-	-	-	-	1,411	212	1,623	1,623	-	-	-	-	-	-	-	-	-	-
2a.4.8	NRC Fees	-	-	-	-	-	-	389	39	428	428	-	-	-	-	-	-	-	-	-	-
2a.4.9	Emergency Planning Fees	-	-	-	-	-	-	1,259	126	1,385	-	1,385	-	-	-	-	-	-	-	-	-
2a.4.10	Fixed Overhead	-	-	-	-	-	-	1,214	182	1,396	1,396	-	-	-	-	-	-	-	-	-	-
2a.4.11	Spent Fuel Pool O&M	-	-	-	-	-	-	394	59	453	-	453	-	-	-	-	-	-	-	-	-
2a.4.12	ISFSI Operating Costs	-	-	-	-	-	-	51	8	58	-	58	-	-	-	-	-	-	-	-	-
2a.4.13	Railroad Track Maintenance	-	-	-	-	-	-	265	40	305	305	-	-	-	-	-	-	-	-	-	-
2a.4.14	Security Staff Cost	-	-	-	-	-	-	6,661	999	7,661	7,661	-	-	-	-	-	-	-	-	-	110,166
2a.4.15	DOC Staff Cost	-	-	-	-	-	-	13,492	2,024	15,516	15,516	-	-	-	-	-	-	-	-	-	155,048
2a.4.16	Utility Staff Cost	-	-	-	-	-	-	17,880	2,682	20,562	20,562	-	-	-	-	-	-	-	-	-	288,676
2a.4	Subtotal Period 2a Period-Dependent Costs	68	3,776	89	26	-	331	46,025	7,512	57,825	55,929	1,896	-	-	4,063	-	-	-	81,252	133	553,890
2a.0	TOTAL PERIOD 2a COST	974	28,339	27,792	4,078	3,105	18,780	57,604	36,116	176,787	168,620	5,579	2,588	38,625	37,317	250	673	-	4,529,841	231,534	560,049
PERIOD 2b - Site Decontamination																					
Period 2b Direct Decommissioning Activities																					
Disposal of Plant Systems																					
2b.1.1.1	ADT & Misc Ventilation	-	24	0	1	13	3	-	9	50	50	-	-	153	9	-	-	-	6,814	363	-
2b.1.1.2	Aux Bldg Normal Ventilation	-	67	2	5	60	11	-	29	174	174	-	-	692	39	-	-	-	30,671	1,013	-
2b.1.1.3	Aux Bldg Special Ventilation	-	13	0	0	6	2	-	5	26	26	-	-	70	6	-	-	-	3,243	197	-
2b.1.1.4	Battery Rm Special Ventilation	-	1	-	-	-	-	-	0	2	-	-	2	-	-	-	-	-	-	24	-
2b.1.1.5	Boron Recycle	0	4	0	0	0	3	-	2	9	9	-	-	3	9	-	-	-	709	50	-
2b.1.1.6	Chemical & Volume Control	722	902	59	44	204	560	-	770	3,260	3,260	-	-	2,356	1,977	-	-	-	225,854	23,197	-
2b.1.1.7	Cold Chemical Lab Ventilation	-	1	-	-	-	-	-	0	1	-	-	1	-	-	-	-	-	-	9	-
2b.1.1.8	Component Cooling - RCA	-	617	21	70	1,038	-	-	322	2,068	2,068	-	-	11,996	-	-	-	-	487,169	8,583	-
2b.1.1.9	Containment Cooling	-	31	-	-	-	-	-	5	35	-	-	35	-	-	-	-	-	-	502	-
2b.1.1.10	Containment Cooling - RCA	-	288	5	16	237	-	-	110	656	656	-	-	2,743	-	-	-	-	111,390	3,949	-
2b.1.1.11	Containment Hydrogen Control - RCA	-	35	0	1	12	-	-	11	60	60	-	-	141	-	-	-	-	5,742	494	-
2b.1.1.12	Containment Spray - RCA	-	186	3	8	126	-	-	67	389	389	-	-	1,453	-	-	-	-	59,019	2,617	-
2b.1.1.13	Containment Ventilation	-	224	23	38	408	205	-	177	1,075	1,075	-	-	4,721	722	-	-	-	239,450	3,375	-
2b.1.1.14	Control/Relay/Cmptr Rm Vent	-	30	1	2	23	6	-	13	74	74	-	-	260	20	-	-	-	11,915	454	-
2b.1.1.15	Cooling Water	-	139	-	-	-	-	-	21	160	-	-	160	-	-	-	-	-	-	2,344	-
2b.1.1.16	Cooling Water - RCA	-	456	15	49	730	-	-	232	1,482	1,482	-	-	8,442	-	-	-	-	342,822	6,311	-
2b.1.1.17	Cranes/Hoists/Elevators - RCA	-	3	0	1	9	-	-	2	15	15	-	-	103	-	-	-	-	4,184	48	-
2b.1.1.18	D3 Emergency Diesel	-	9	-	-	-	-	-	1	10	-	-	10	-	-	-	-	-	-	141	-
2b.1.1.19	D4 Emergency Diesel	-	9	-	-	-	-	-	1	10	-	-	10	-	-	-	-	-	-	141	-
2b.1.1.20	D5 Emergency Diesel	-	0	-	-	-	-	-	0	0	-	-	0	-	-	-	-	-	-	5	-
2b.1.1.21	Electrical - Clean	-	1,502	-	-	-	-	-	225	1,727	-	-	1,727	-	-	-	-	-	-	24,276	-
2b.1.1.22	Electrical - Contaminated	-	461	5	13	173	21	-	149	821	821	-	-	1,997	75	-	-	-	86,080	6,503	-
2b.1.1.23	Electrical - Decontaminated	-	2,866	33	109	1,622	-	-	980	5,610	5,610	-	-	18,753	-	-	-	-	761,569	38,423	-
2b.1.1.24	Filter Rm Ventilation	-	4	0	0	2	0	-	2	9	9	-	-	24	1	-	-	-	1,020	69	-
2b.1.1.25	Fire Protection & Detection	-	178	-	-	-	-	-	27	205	-	-	205	-	-	-	-	-	-	3,009	-
2b.1.1.26	Fire Protection & Detection - RCA	-	236	3	11	158	-	-	85	492	492	-	-	1,828	-	-	-	-	74,245	3,134	-
2b.1.1.27	Fuel Handling	-	71	1	2	17	14	-	24	130	130	-	-	200	49	-	-	-	11,396	1,101	-
2b.1.1.28	Fuel Oil	-	1	-	-	-	-	-	0	1	-	-	1	-	-	-	-	-	-	9	-
2b.1.1.29	HVAC - Clean	-	132	-	-	-	-	-	20	151	-	-	151	-	-	-	-	-	-	2,373	-
2b.1.1.30	HVAC - Contaminated	-	1,222	26	69	929	115	-	487	2,848	2,848	-	-	10,745	405	-	-	-	463,144	16,579	-

Table F-2
Prairie Island Nuclear Generating Plant, Unit 2
DECON Decommissioning Cost Estimate with 200 Years of Spent Fuel Storage and Periodic TN-40 Replacement
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Disposal of Plant Systems (continued)																					
2b.1.1.31	Heating	-	279	-	-	-	-	-	42	321	-	-	321	-	-	-	-	-	-	4,804	-
2b.1.1.32	Heating - RCA	-	323	3	11	165	-	-	107	609	609	-	-	1,907	-	-	-	-	77,458	4,086	-
2b.1.1.33	Hot Lab & Sample Rm Ventilation	-	19	0	1	9	1	-	6	37	37	-	-	107	4	-	-	-	4,632	285	-
2b.1.1.34	Incore Instrumentation	0	29	1	1	5	16	-	13	67	67	-	-	60	58	-	-	-	6,264	458	-
2b.1.1.35	Misc Drains & Vents	-	223	12	9	40	121	-	95	500	500	-	-	458	426	-	-	-	46,850	3,180	-
2b.1.1.36	Misc Lab & Service Areas Vent	-	123	8	6	32	70	-	55	293	293	-	-	370	244	-	-	-	31,186	1,713	-
2b.1.1.37	Miscellaneous Gas	-	63	-	-	-	-	-	9	72	-	-	72	-	-	-	-	-	-	1,073	-
2b.1.1.38	Miscellaneous Gas - RCA	-	129	1	3	52	-	-	41	226	226	-	-	600	-	-	-	-	24,378	1,636	-
2b.1.1.39	Radiation Monitoring	-	6	-	-	-	-	-	1	7	-	-	7	-	-	-	-	-	-	111	-
2b.1.1.40	Radiation Monitoring - RCA	-	62	1	2	27	-	-	20	112	112	-	-	316	-	-	-	-	12,826	782	-
2b.1.1.41	Reactor Coolant	158	227	20	12	20	208	-	195	839	839	-	-	229	730	-	-	-	57,672	5,517	-
2b.1.1.42	Reactor Hot Sampling	135	121	10	5	5	89	-	123	489	489	-	-	54	312	-	-	-	22,919	3,686	-
2b.1.1.43	Reactor Makeup	-	36	-	-	-	-	-	5	41	-	-	41	-	-	-	-	-	-	583	-
2b.1.1.44	Reactor Makeup - RCA	-	4	0	0	2	-	-	1	8	8	-	-	28	-	-	-	-	1,148	47	-
2b.1.1.45	Reactor Vessel	9	17	0	0	2	4	-	10	43	43	-	-	22	14	-	-	-	1,826	385	-
2b.1.1.46	Residual Heat Removal	336	374	84	66	247	924	-	548	2,578	2,578	-	-	2,853	3,244	-	-	-	330,651	7,112	-
2b.1.1.47	Safeguards Chilled Water	-	4	-	-	-	-	-	1	5	-	-	5	-	-	-	-	-	-	75	-
2b.1.1.48	Safety Injection	-	836	40	56	577	329	-	390	2,228	2,228	-	-	6,676	1,161	-	-	-	347,600	12,284	-
2b.1.1.49	Sampling	-	51	3	2	3	27	-	20	105	105	-	-	37	93	-	-	-	7,697	714	-
2b.1.1.50	Service Bldg & New Cmptr Vent	-	0	-	-	-	-	-	0	0	-	-	0	-	-	-	-	-	-	6	-
2b.1.1.51	Shield Bldg Ventilation	-	114	13	19	175	138	-	94	554	554	-	-	2,028	484	-	-	-	114,378	1,743	-
2b.1.1.52	Station & Instrument Air	-	140	-	-	-	-	-	21	161	-	-	161	-	-	-	-	-	-	2,424	-
2b.1.1.53	Station & Instrument Air - RCA	-	288	3	9	141	-	-	95	535	535	-	-	1,625	-	-	-	-	65,986	3,638	-
2b.1.1.54	Turbine Bldg Traps & Drains	-	26	-	-	-	-	-	4	30	-	-	30	-	-	-	-	-	-	462	-
2b.1.1.55	Turbine Bldg Traps & Drains - RCA	-	28	0	1	16	-	-	10	55	55	-	-	180	-	-	-	-	7,321	344	-
2b.1.1.56	Turbine Bldg Ventilation	-	40	-	-	-	-	-	6	46	-	-	46	-	-	-	-	-	-	655	-
2b.1.1.57	Unit Coolers	-	20	-	-	-	-	-	3	23	-	-	23	-	-	-	-	-	-	332	-
2b.1.1.58	Unit Coolers - RCA	-	54	0	1	20	-	-	17	93	93	-	-	232	-	-	-	-	9,413	690	-
2b.1.1.59	Waste Gas Disposal	531	457	40	35	212	381	-	516	2,173	2,173	-	-	2,453	1,358	-	-	-	188,334	14,308	-
2b.1.1.60	Waste Liquid Disposal	1,386	1,733	108	76	316	1,019	-	1,451	6,089	6,089	-	-	3,655	3,594	-	-	-	385,370	44,485	-
2b.1.1.61	Waste Solid Disposal	111	139	11	8	34	112	-	126	541	541	-	-	389	393	-	-	-	41,732	3,481	-
2b.1.1	Totals	3,390	15,678	558	763	7,868	4,377	-	7,798	40,433	37,423	-	3,010	90,963	15,429	-	-	-	4,712,076	270,390	-
2b.1.2	Scaffolding in support of decommissioning	-	3,542	30	10	121	32	-	916	4,651	4,651	-	-	1,265	112	-	-	-	64,307	32,837	-
Decontamination of Site Buildings																					
2b.1.3.1	Reactor	1,150	2,624	139	853	193	11,080	-	4,172	20,210	20,210	-	-	2,230	57,418	-	-	-	3,559,977	50,853	-
2b.1.3.2	Auxiliary	1,223	400	12	80	92	582	-	884	3,272	3,272	-	-	1,060	3,355	-	-	-	332,498	23,808	-
2b.1.3.3	Backwash Waste Receiving Tank	-	27	1	11	-	87	-	30	158	158	-	-	-	507	-	-	-	43,896	299	-
2b.1.3.4	Drum Transfer & Truck Loading Enclosure	17	8	0	2	2	13	-	14	56	56	-	-	19	74	-	-	-	7,118	368	-
2b.1.3.5	LLRW Storage Enclosure	117	51	1	11	3	87	-	95	366	366	-	-	38	502	-	-	-	44,971	2,424	-
2b.1.3.6	Radwaste	52	23	1	5	4	39	-	43	166	166	-	-	42	225	-	-	-	21,136	1,082	-
2b.1.3.7	Resin Disposal	15	11	0	2	7	12	-	15	64	64	-	-	83	69	-	-	-	9,271	383	-
2b.1.3	Totals	2,574	3,145	155	964	300	11,900	-	5,253	24,292	24,292	-	-	3,471	62,151	-	-	-	4,018,868	79,216	-
2b.1.4	Prepare/submit License Termination Plan	-	-	-	-	-	-	206	31	236	236	-	-	-	-	-	-	-	-	-	1,751
2b.1.5	Receive NRC approval of termination plan									a											
2b.1	Subtotal Period 2b Activity Costs	5,965	22,365	744	1,737	8,290	16,309	206	13,998	69,612	66,602	-	3,010	95,700	77,691	-	-	-	8,795,250	382,443	1,751
Period 2b Additional Costs																					
2b.2.1	Remedial Action Surveys	-	-	-	-	-	-	1,930	579	2,509	2,509	-	-	-	-	-	-	-	-	25,228	-
2b.2.2	Operational Equipment	-	-	9	29	312	-	-	52	402	402	-	-	5,855	-	-	-	-	146,375	16	-
2b.2	Subtotal Period 2b Additional Costs	-	-	9	29	312	-	1,930	631	2,911	2,911	-	-	5,855	-	-	-	-	146,375	25,244	-
Period 2b Collateral Costs																					
2b.3.1	Process decommissioning water waste	167	-	112	289	-	453	-	251	1,272	1,272	-	-	-	1,081	-	-	-	64,837	211	-
2b.3.2	Process decommissioning chemical flush waste	3	-	114	431	-	858	-	292	1,700	1,700	-	-	-	1,154	-	-	-	122,948	216	-
2b.3.3	Small tool allowance	-	414	-	-	-	-	-	62	476	476	-	-	-	-	-	-	-	-	-	-
2b.3.4	Spent Fuel Capital and Transfer	-	-	-	-	-	-	9,529	1,429	10,958	-	10,958	-	-	-	-	-	-	-	-	-
2b.3.5	Retention and Severance	-	-	-	-	-	-	4,127	619	4,746	4,746	-	-	-	-	-	-	-	-	-	-
2b.3.6	Prairie Island Indian Community Payments	-	-	-	-	-	-	1,517	-	1,517	-	1,517	-	-	-	-	-	-	-	-	-
2b.3.7	On-site survey and release of 0.437 tons clean metallic waste	-	-	-	-	-	-	1	0	1	1	-	-	-	-	-	-	-	-	-	-
2b.3	Subtotal Period 2b Collateral Costs	170	414	226	721	-	1,311	15,174	2,654	20,670	8,195	12,475	-	-	2,234	-	-	-	187,785	427	-

Table F-2
Prairie Island Nuclear Generating Plant, Unit 2
DECON Decommissioning Cost Estimate with 200 Years of Spent Fuel Storage and Periodic TN-40 Replacement
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 2b Period-Dependent Costs																					
2b.4.1	Decon supplies	1,135	-	-	-	-	-	-	284	1,419	1,419	-	-	-	-	-	-	-	-	-	-
2b.4.2	Insurance	-	-	-	-	-	-	620	62	682	682	-	-	-	-	-	-	-	-	-	-
2b.4.3	Property taxes	-	-	-	-	-	-	2,983	298	3,281	3,281	-	-	-	-	-	-	-	-	-	-
2b.4.4	Health physics supplies	-	2,580	-	-	-	-	-	645	3,225	3,225	-	-	-	-	-	-	-	-	-	-
2b.4.5	Heavy equipment rental	-	2,740	-	-	-	-	-	411	3,151	3,151	-	-	-	-	-	-	-	-	-	-
2b.4.6	Disposal of DAW generated	-	-	115	34	-	431	-	124	704	704	-	-	-	5,291	-	-	-	105,826	173	-
2b.4.7	Plant energy budget	-	-	-	-	-	-	1,379	207	1,586	1,586	-	-	-	-	-	-	-	-	-	-
2b.4.8	NRC Fees	-	-	-	-	-	-	481	48	529	529	-	-	-	-	-	-	-	-	-	-
2b.4.9	Emergency Planning Fees	-	-	-	-	-	-	1,558	156	1,714	-	1,714	-	-	-	-	-	-	-	-	-
2b.4.10	Fixed Overhead	-	-	-	-	-	-	1,503	225	1,728	1,728	-	-	-	-	-	-	-	-	-	-
2b.4.11	Spent Fuel Pool O&M	-	-	-	-	-	-	487	73	560	-	560	-	-	-	-	-	-	-	-	-
2b.4.12	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	246	37	282	282	-	-	-	-	-	-	-	-	-	-
2b.4.13	ISFSI Operating Costs	-	-	-	-	-	-	63	9	72	-	72	-	-	-	-	-	-	-	-	-
2b.4.14	Railroad Track Maintenance	-	-	-	-	-	-	70	10	80	80	-	-	-	-	-	-	-	-	-	-
2b.4.15	Security Staff Cost	-	-	-	-	-	-	8,243	1,236	9,479	9,479	-	-	-	-	-	-	-	-	-	136,323
2b.4.16	DOC Staff Cost	-	-	-	-	-	-	16,150	2,422	18,572	18,572	-	-	-	-	-	-	-	-	-	184,288
2b.4.17	Utility Staff Cost	-	-	-	-	-	-	21,222	3,183	24,405	24,405	-	-	-	-	-	-	-	-	-	342,069
2b.4	Subtotal Period 2b Period-Dependent Costs	1,135	5,320	115	34	-	431	55,004	9,432	71,472	69,125	2,346	-	-	5,291	-	-	-	105,826	173	662,680
2b.0	TOTAL PERIOD 2b COST	7,270	28,099	1,095	2,520	8,602	18,050	72,314	26,716	164,664	146,833	14,822	3,010	101,555	85,217	-	-	-	9,235,236	408,286	664,431
PERIOD 2c - Spent fuel delay prior to SFP decon																					
Period 2c Direct Decommissioning Activities																					
Period 2c Additional Costs																					
2c.2.1	Security Modifications	-	-	-	-	-	-	4,348	652	5,000	5,000	-	-	-	-	-	-	-	-	-	-
2c.2	Subtotal Period 2c Additional Costs	-	-	-	-	-	-	4,348	652	5,000	5,000	-	-	-	-	-	-	-	-	-	-
Period 2c Collateral Costs																					
2c.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	65,685	9,853	75,538	-	75,538	-	-	-	-	-	-	-	-	-
2c.3.2	Retention and Severance	-	-	-	-	-	-	2,034	305	2,339	2,339	-	-	-	-	-	-	-	-	-	-
2c.3.3	Prairie Island Indian Community Payments	-	-	-	-	-	-	1,630	-	1,630	-	1,630	-	-	-	-	-	-	-	-	-
2c.3	Subtotal Period 2c Collateral Costs	-	-	-	-	-	-	69,349	10,158	79,507	2,339	77,168	-	-	-	-	-	-	-	-	-
Period 2c Period-Dependent Costs																					
2c.4.1	Insurance	-	-	-	-	-	-	666	67	733	733	-	-	-	-	-	-	-	-	-	-
2c.4.2	Property taxes	-	-	-	-	-	-	3,060	306	3,366	3,366	-	-	-	-	-	-	-	-	-	-
2c.4.3	Health physics supplies	-	270	-	-	-	-	-	67	337	337	-	-	-	-	-	-	-	-	-	-
2c.4.4	Disposal of DAW generated	-	-	12	3	-	44	-	13	72	72	-	-	-	538	-	-	-	10,761	18	-
2c.4.5	Plant energy budget	-	-	-	-	-	-	395	59	454	454	-	-	-	-	-	-	-	-	-	-
2c.4.6	NRC Fees	-	-	-	-	-	-	305	31	336	336	-	-	-	-	-	-	-	-	-	-
2c.4.7	Emergency Planning Fees	-	-	-	-	-	-	1,674	167	1,842	-	1,842	-	-	-	-	-	-	-	-	-
2c.4.8	Fixed Overhead	-	-	-	-	-	-	1,615	242	1,857	1,857	-	-	-	-	-	-	-	-	-	-
2c.4.9	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	53	8	61	61	-	-	-	-	-	-	-	-	-	-
2c.4.10	ISFSI Operating Costs	-	-	-	-	-	-	67	10	77	-	77	-	-	-	-	-	-	-	-	-
2c.4.11	Railroad Track Maintenance	-	-	-	-	-	-	75	11	86	86	-	-	-	-	-	-	-	-	-	-
2c.4.12	Security Staff Cost	-	-	-	-	-	-	8,857	1,329	10,185	10,185	-	-	-	-	-	-	-	-	-	146,478
2c.4.13	Utility Staff Cost	-	-	-	-	-	-	6,575	986	7,561	7,561	-	-	-	-	-	-	-	-	-	107,146
2c.4	Subtotal Period 2c Period-Dependent Costs	-	270	12	3	-	44	23,343	3,296	26,968	25,049	1,919	-	-	538	-	-	-	10,761	18	253,623
2c.0	TOTAL PERIOD 2c COST	-	270	12	3	-	44	97,040	14,106	111,475	32,387	79,087	-	-	538	-	-	-	10,761	18	253,623
PERIOD 2d - Decontamination Following Wet Fuel Storage																					
Period 2d Direct Decommissioning Activities																					
2d.1.1	Remove spent fuel racks	328	32	94	32	-	595	-	335	1,416	1,416	-	-	-	2,092	-	-	-	138,298	576	-
Disposal of Plant Systems																					
2d.1.2.1	Electrical - Contaminated - Fuel Pool	-	197	2	6	75	9	-	64	353	353	-	-	864	33	-	-	-	37,250	2,783	-
2d.1.2.2	Electrical - Decontaminated - Fuel Pool	-	1,230	14	47	698	-	-	421	2,410	2,410	-	-	8,069	-	-	-	-	327,668	16,495	-
2d.1.2.3	Fire Protection & Detection - RCA Fuel P	-	36	1	2	25	-	-	13	76	76	-	-	286	-	-	-	-	11,622	476	-
2d.1.2.4	HVAC - Contaminated - Fuel Pool	-	549	12	31	418	52	-	219	1,280	1,280	-	-	4,828	182	-	-	-	208,080	7,448	-
2d.1.2.5	Safeguards Chilled Water - RCA	-	4	0	0	2	-	-	1	8	8	-	-	26	-	-	-	-	1,045	51	-
2d.1.2.6	Spent Fuel Pool Cooling	31	35	3	2	3	30	-	33	137	137	-	-	39	107	-	-	-	8,635	882	-
2d.1.2.7	Spent Fuel Pool Normal Ventilation	-	26	1	2	23	3	-	11	66	66	-	-	265	12	-	-	-	11,532	394	-
2d.1.2	Totals	31	2,077	32	89	1,244	95	-	761	4,328	4,328	-	-	14,376	333	-	-	-	605,832	28,530	-

Table F-2
Prairie Island Nuclear Generating Plant, Unit 2
DECON Decommissioning Cost Estimate with 200 Years of Spent Fuel Storage and Periodic TN-40 Replacement
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Decontamination of Site Buildings																					
2d.1.3.1	Fuel Handling of Aux Building	975	1,082	9	32	209	173	-	838	3,319	3,319	-	-	2,417	944	-	-	-	177,818	30,401	-
2d.1.3	Totals	975	1,082	9	32	209	173	-	838	3,319	3,319	-	-	2,417	944	-	-	-	177,818	30,401	-
2d.1.4	Scaffolding in support of decommissioning	-	708	6	2	24	6	-	183	930	930	-	-	253	22	-	-	-	12,861	6,567	-
2d.1	Subtotal Period 2d Activity Costs	1,334	3,900	142	155	1,477	868	-	2,118	9,994	9,994	-	-	17,046	3,391	-	-	-	934,809	66,074	-
Period 2d Additional Costs																					
2d.2.1	License Termination Survey Planning	-	-	-	-	-	-	845	253	1,098	1,098	-	-	-	-	-	-	-	-	-	6,240
2d.2.2	Remedial Action Surveys	-	-	-	-	-	-	1,237	371	1,608	1,608	-	-	-	-	-	-	-	-	16,173	-
2d.2	Subtotal Period 2d Additional Costs	-	-	-	-	-	-	2,082	625	2,706	2,706	-	-	-	-	-	-	-	-	16,173	6,240
Period 2d Collateral Costs																					
2d.3.1	Process decommissioning water waste	39	-	27	70	-	109	-	60	306	306	-	-	-	261	-	-	-	15,670	51	-
2d.3.2	Process decommissioning chemical flush waste	0	-	1	5	-	10	-	3	20	20	-	-	-	13	-	-	-	1,422	2	-
2d.3.3	Small tool allowance	-	79	-	-	-	-	-	12	91	91	-	-	-	-	-	-	-	-	-	-
2d.3.4	Decommissioning Equipment Disposition	-	-	144	55	575	150	-	147	1,071	1,071	-	-	6,000	529	-	-	-	304,968	88	-
2d.3.5	Spent Fuel Capital and Transfer	-	-	-	-	-	-	12,947	1,942	14,889	-	14,889	-	-	-	-	-	-	-	-	-
2d.3.6	Prairie Island Indian Community Payments	-	-	-	-	-	-	971	-	971	-	971	-	-	-	-	-	-	-	-	-
2d.3	Subtotal Period 2d Collateral Costs	39	79	172	130	575	270	13,917	2,164	17,347	1,488	15,859	-	6,000	804	-	-	-	322,060	142	-
Period 2d Period-Dependent Costs																					
2d.4.1	Decon supplies	218	-	-	-	-	-	-	54	272	272	-	-	-	-	-	-	-	-	-	-
2d.4.2	Insurance	-	-	-	-	-	-	398	40	437	437	-	-	-	-	-	-	-	-	-	-
2d.4.3	Property taxes	-	-	-	-	-	-	1,740	174	1,914	1,914	-	-	-	-	-	-	-	-	-	-
2d.4.4	Health physics supplies	-	742	-	-	-	-	-	186	928	928	-	-	-	-	-	-	-	-	-	-
2d.4.5	Heavy equipment rental	-	1,757	-	-	-	-	-	264	2,020	2,020	-	-	-	-	-	-	-	-	-	-
2d.4.6	Disposal of DAW generated	-	-	44	13	-	163	-	47	266	266	-	-	-	2,000	-	-	-	40,003	65	-
2d.4.7	Plant energy budget	-	-	-	-	-	-	471	71	542	542	-	-	-	-	-	-	-	-	-	-
2d.4.8	NRC Fees	-	-	-	-	-	-	256	26	282	282	-	-	-	-	-	-	-	-	-	-
2d.4.9	Emergency Planning Fees	-	-	-	-	-	-	999	100	1,099	-	1,099	-	-	-	-	-	-	-	-	-
2d.4.10	Fixed Overhead	-	-	-	-	-	-	963	144	1,108	1,108	-	-	-	-	-	-	-	-	-	-
2d.4.11	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	315	47	362	362	-	-	-	-	-	-	-	-	-	-
2d.4.12	ISFSI Operating Costs	-	-	-	-	-	-	40	6	46	-	46	-	-	-	-	-	-	-	-	-
2d.4.13	Railroad Track Maintenance	-	-	-	-	-	-	45	7	52	52	-	-	-	-	-	-	-	-	-	-
2d.4.14	Security Staff Cost	-	-	-	-	-	-	5,123	768	5,891	5,891	-	-	-	-	-	-	-	-	-	84,157
2d.4.15	DOC Staff Cost	-	-	-	-	-	-	6,065	910	6,975	6,975	-	-	-	-	-	-	-	-	-	69,996
2d.4.16	Utility Staff Cost	-	-	-	-	-	-	7,796	1,169	8,966	8,123	843	-	-	-	-	-	-	-	-	126,236
2d.4	Subtotal Period 2d Period-Dependent Costs	218	2,499	44	13	-	163	24,212	4,013	31,160	29,173	1,988	-	-	2,000	-	-	-	40,003	65	280,390
2d.0	TOTAL PERIOD 2d COST	1,591	6,478	357	298	2,052	1,301	40,212	8,919	61,208	43,361	17,847	-	23,046	6,195	-	-	-	1,296,872	82,455	286,630
PERIOD 2f - License Termination																					
Period 2f Direct Decommissioning Activities																					
2f.1.1	ORISE confirmatory survey	-	-	-	-	-	-	176	53	229	229	-	-	-	-	-	-	-	-	-	-
2f.1.2	Terminate license									a											
2f.1	Subtotal Period 2f Activity Costs	-	-	-	-	-	-	176	53	229	229	-	-	-	-	-	-	-	-	-	-
Period 2f Additional Costs																					
2f.2.1	License Termination Survey	-	-	-	-	-	-	7,406	2,222	9,628	9,628	-	-	-	-	-	-	-	-	102,642	3,120
2f.2	Subtotal Period 2f Additional Costs	-	-	-	-	-	-	7,406	2,222	9,628	9,628	-	-	-	-	-	-	-	-	102,642	3,120
Period 2f Collateral Costs																					
2f.3.1	DOC staff relocation expenses	-	-	-	-	-	-	1,189	178	1,367	1,367	-	-	-	-	-	-	-	-	-	-
2f.3.2	Prairie Island Indian Community Payments	-	-	-	-	-	-	934	-	934	-	934	-	-	-	-	-	-	-	-	-
2f.3	Subtotal Period 2f Collateral Costs	-	-	-	-	-	-	2,122	178	2,300	1,367	934	-	-	-	-	-	-	-	-	-
Period 2f Period-Dependent Costs																					
2f.4.1	Insurance	-	-	-	-	-	-	382	38	420	420	-	-	-	-	-	-	-	-	-	-
2f.4.2	Property taxes	-	-	-	-	-	-	1,626	163	1,789	1,789	-	-	-	-	-	-	-	-	-	-
2f.4.3	Health physics supplies	-	602	-	-	-	-	-	150	752	752	-	-	-	-	-	-	-	-	-	-
2f.4.4	Disposal of DAW generated	-	-	7	2	-	27	-	8	44	44	-	-	-	334	-	-	-	6,685	11	-
2f.4.5	Plant energy budget	-	-	-	-	-	-	227	34	261	261	-	-	-	-	-	-	-	-	-	-
2f.4.6	NRC Fees	-	-	-	-	-	-	272	27	299	299	-	-	-	-	-	-	-	-	-	-
2f.4.7	Emergency Planning Fees	-	-	-	-	-	-	51	5	56	-	56	-	-	-	-	-	-	-	-	-
2f.4.8	Fixed Overhead	-	-	-	-	-	-	926	139	1,065	1,065	-	-	-	-	-	-	-	-	-	-
2f.4.9	ISFSI Operating Costs	-	-	-	-	-	-	39	6	44	-	44	-	-	-	-	-	-	-	-	-

Table F-2
Prairie Island Nuclear Generating Plant, Unit 2
DECON Decommissioning Cost Estimate with 200 Years of Spent Fuel Storage and Periodic TN-40 Replacement
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 2f Period-Dependent Costs (continued)																					
2f.4.10	Railroad Track Maintenance	-	-	-	-	-	-	43	6	50	50	-	-	-	-	-	-	-	-	-	-
2f.4.11	Security Staff Cost	-	-	-	-	-	-	4,924	739	5,663	5,663	-	-	-	-	-	-	-	-	-	80,898
2f.4.12	DOC Staff Cost	-	-	-	-	-	-	4,101	615	4,716	4,716	-	-	-	-	-	-	-	-	-	46,283
2f.4.13	Utility Staff Cost	-	-	-	-	-	-	3,854	578	4,433	3,626	807	-	-	-	-	-	-	-	-	59,507
2f.4	Subtotal Period 2f Period-Dependent Costs	-	602	7	2	-	27	16,445	2,508	19,592	18,684	907	-	-	334	-	-	-	6,685	11	186,687
2f.0	TOTAL PERIOD 2f COST	-	602	7	2	-	27	26,150	4,962	31,750	29,909	1,841	-	-	334	-	-	-	6,685	102,653	189,807
PERIOD 2 TOTALS		9,835	63,787	29,263	6,901	13,758	38,202	293,319	90,819	545,884	421,110	119,176	5,598	163,227	129,602	250	673	-	15,079,400	824,945	1,954,541
PERIOD 3b - Site Restoration																					
Period 3b Direct Decommissioning Activities																					
Demolition of Remaining Site Buildings																					
3b.1.1.1	Reactor	-	4,256	-	-	-	-	-	638	4,895	-	-	4,895	-	-	-	-	-	-	44,679	-
3b.1.1.2	Auxiliary	-	1,897	-	-	-	-	-	285	2,182	-	-	2,182	-	-	-	-	-	-	11,902	-
3b.1.1.3	Condensate Storage Tank Foundation	-	6	-	-	-	-	-	1	7	-	-	7	-	-	-	-	-	-	33	-
3b.1.1.4	Construction Warehouse & Fab Shop	-	118	-	-	-	-	-	18	135	-	-	135	-	-	-	-	-	-	1,405	-
3b.1.1.5	D3/D4 Emergency Generator	-	13	-	-	-	-	-	2	15	-	-	15	-	-	-	-	-	-	84	-
3b.1.1.6	Drum Transfer & Truck Loading Enclosure	-	19	-	-	-	-	-	3	21	-	-	21	-	-	-	-	-	-	221	-
3b.1.1.7	Hydrogen House	-	6	-	-	-	-	-	1	7	-	-	7	-	-	-	-	-	-	47	-
3b.1.1.8	LLRW Storage Enclosure	-	121	-	-	-	-	-	18	139	-	-	139	-	-	-	-	-	-	853	-
3b.1.1.9	Misc Structures 2017	-	1,391	-	-	-	-	-	209	1,599	-	-	1,599	-	-	-	-	-	-	12,939	-
3b.1.1.10	Radwaste	-	165	-	-	-	-	-	25	190	-	-	190	-	-	-	-	-	-	1,400	-
3b.1.1.11	Resin Disposal	-	13	-	-	-	-	-	2	15	-	-	15	-	-	-	-	-	-	120	-
3b.1.1.12	Structures below 3' below grade	-	1,713	-	-	-	-	-	257	1,969	-	-	1,969	-	-	-	-	-	-	9,238	-
3b.1.1.13	Sulfuric Acid Tank Enclosure	-	3	-	-	-	-	-	0	3	-	-	3	-	-	-	-	-	-	35	-
3b.1.1.14	Turbine	-	1,983	-	-	-	-	-	298	2,281	-	-	2,281	-	-	-	-	-	-	22,052	-
3b.1.1.15	Turbine Pedestal	-	349	-	-	-	-	-	52	402	-	-	402	-	-	-	-	-	-	1,857	-
3b.1.1.16	Warehouse #2	-	22	-	-	-	-	-	3	25	-	-	25	-	-	-	-	-	-	213	-
3b.1.1.17	Waste Neutralizing Tank House	-	7	-	-	-	-	-	1	8	-	-	8	-	-	-	-	-	-	56	-
3b.1.1.18	Waste Oil Storage	-	8	-	-	-	-	-	1	10	-	-	10	-	-	-	-	-	-	70	-
3b.1.1.19	Water Treatment	-	303	-	-	-	-	-	46	349	-	-	349	-	-	-	-	-	-	2,690	-
3b.1.1.20	Fuel Handling of Aux Building	-	1,032	-	-	-	-	-	155	1,186	-	-	1,186	-	-	-	-	-	-	8,240	-
3b.1.1	Totals	-	13,424	-	-	-	-	-	2,014	15,438	-	-	15,438	-	-	-	-	-	-	118,134	-
Site Closeout Activities																					
3b.1.2	Remove Rubble	-	1,308	-	-	-	-	-	196	1,505	-	-	1,505	-	-	-	-	-	-	6,495	-
3b.1.3	Grade & landscape site	-	431	-	-	-	-	-	65	495	-	-	495	-	-	-	-	-	-	921	-
3b.1.4	Final report to NRC	-	-	-	-	-	-	78	12	90	90	-	-	-	-	-	-	-	-	-	667
3b.1	Subtotal Period 3b Activity Costs	-	15,163	-	-	-	-	78	2,286	17,528	90	-	17,438	-	-	-	-	-	-	125,549	667
Period 3b Additional Costs																					
3b.2.1	Clean Concrete Disposal	-	3,313	-	-	-	-	8	498	3,818	-	-	3,818	-	-	-	-	-	-	12,824	-
3b.2.2	Underground Services Excavations	-	811	-	-	-	-	520	200	1,531	-	-	1,531	-	-	-	-	-	-	7,407	-
3b.2.3	Intake Structure Cofferdam	-	423	-	-	-	-	-	63	486	-	-	486	-	-	-	-	-	-	3,552	-
3b.2.4	Construction Debris	-	-	-	-	-	-	463	69	532	-	-	532	-	-	-	-	-	-	-	-
3b.2.5	Backfill	-	8,465	-	-	-	-	-	1,270	9,735	-	-	9,735	-	-	-	-	-	-	9,327	-
3b.2	Subtotal Period 3b Additional Costs	-	13,012	-	-	-	-	991	2,100	16,103	-	-	16,103	-	-	-	-	-	-	33,110	-
Period 3b Collateral Costs																					
3b.3.1	Small tool allowance	-	172	-	-	-	-	-	26	198	-	-	198	-	-	-	-	-	-	-	-
3b.3.2	Prairie Island Indian Community Payments	-	-	-	-	-	-	2,651	-	2,651	-	2,651	-	-	-	-	-	-	-	-	-
3b.3	Subtotal Period 3b Collateral Costs	-	172	-	-	-	-	2,651	26	2,848	-	2,651	198	-	-	-	-	-	-	-	-
Period 3b Period-Dependent Costs																					
3b.4.1	Insurance	-	-	-	-	-	-	542	54	596	-	596	-	-	-	-	-	-	-	-	-
3b.4.2	Property taxes	-	-	-	-	-	-	4,334	433	4,767	-	4,767	-	-	-	-	-	-	-	-	-
3b.4.3	Heavy equipment rental	-	6,670	-	-	-	-	-	1,000	7,670	-	-	7,670	-	-	-	-	-	-	-	-
3b.4.4	Plant energy budget	-	-	-	-	-	-	321	48	369	-	-	369	-	-	-	-	-	-	-	-
3b.4.5	NRC ISFSI Fees	-	-	-	-	-	-	236	24	259	-	259	-	-	-	-	-	-	-	-	-
3b.4.6	Emergency Planning Fees	-	-	-	-	-	-	145	14	159	-	159	-	-	-	-	-	-	-	-	-
3b.4.7	Fixed Overhead	-	-	-	-	-	-	990	148	1,138	-	-	1,138	-	-	-	-	-	-	-	-
3b.4.8	ISFSI Operating Costs	-	-	-	-	-	-	109	16	126	-	126	-	-	-	-	-	-	-	-	-
3b.4.9	Railroad Track Maintenance	-	-	-	-	-	-	331	50	380	-	-	380	-	-	-	-	-	-	-	-
3b.4.10	Security Staff Cost	-	-	-	-	-	-	4,245	637	4,882	-	4,882	-	-	-	-	-	-	-	-	57,340
3b.4.11	DOC Staff Cost	-	-	-	-	-	-	10,467	1,570	12,038	-	-	12,038	-	-	-	-	-	-	-	116,885

Table F-2
Prairie Island Nuclear Generating Plant, Unit 2
DECON Decommissioning Cost Estimate with 200 Years of Spent Fuel Storage and Periodic TN-40 Replacement
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 3b Period-Dependent Costs (continued)																					
3b.4.12	Utility Staff Cost	-	-	-	-	-	-	4,964	745	5,709	(0)	2,283	3,425	-	-	-	-	-	-	-	76,637
3b.4	Subtotal Period 3b Period-Dependent Costs	-	6,670	-	-	-	-	26,684	4,740	38,094	(0)	13,074	25,021	-	-	-	-	-	-	-	250,861
3b.0	TOTAL PERIOD 3b COST	-	35,017	-	-	-	-	30,404	9,153	74,574	90	15,724	58,760	-	-	-	-	-	-	158,659	251,528
PERIOD 3c - Fuel Storage Operations																					
Period 3c Direct Decommissioning Activities																					
Period 3c Additional Costs																					
3c.2.1	ISFSI Disposition of Original Casks	-	-	-	128	-	1,548	-	406	2,082	-	2,082	-	-	4,906	-	-	-	576,566	-	-
3c.2	Subtotal Period 3c Additional Costs	-	-	-	128	-	1,548	-	406	2,082	-	2,082	-	-	4,906	-	-	-	576,566	-	-
Period 3c Collateral Costs																					
3c.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	791,546	118,732	910,278	-	910,278	-	-	-	-	-	-	-	-	-
3c.3.2	Prairie Island Indian Community Payments	-	-	-	-	-	-	186,914	-	186,914	-	186,914	-	-	-	-	-	-	-	-	-
3c.3	Subtotal Period 3c Collateral Costs	-	-	-	-	-	-	978,460	118,732	1,097,192	-	1,097,192	-	-	-	-	-	-	-	-	-
Period 3c Period-Dependent Costs																					
3c.4.1	Insurance	-	-	-	-	-	-	38,227	3,823	42,050	-	42,050	-	-	-	-	-	-	-	-	-
3c.4.2	Property taxes	-	-	-	-	-	-	157,169	15,717	172,886	-	172,886	-	-	-	-	-	-	-	-	-
3c.4.4	NRC ISFSI Fees	-	-	-	-	-	-	24,486	2,449	26,934	-	26,934	-	-	-	-	-	-	-	-	-
3c.4.5	Emergency Planning Fees	-	-	-	-	-	-	10,232	1,023	11,255	-	11,255	-	-	-	-	-	-	-	-	-
3c.4.6	Fixed Overhead	-	-	-	-	-	-	22,830	3,425	26,255	-	26,255	-	-	-	-	-	-	-	-	-
3c.4.7	ISFSI Operating Costs	-	-	-	-	-	-	7,724	1,159	8,883	-	8,883	-	-	-	-	-	-	-	-	-
3c.4.8	Railroad Track Maintenance	-	-	-	-	-	-	8,629	1,294	9,924	-	9,924	-	-	-	-	-	-	-	-	-
3c.4.9	Security Staff Cost	-	-	-	-	-	-	299,567	44,935	344,502	-	344,502	-	-	-	-	-	-	-	-	4,046,073
3c.4.10	DOC Staff Cost	-	-	-	-	-	-	14,425	2,164	16,589	-	16,589	-	-	-	-	-	-	-	-	155,618
3c.4.11	Utility Staff Cost	-	-	-	-	-	-	140,210	21,032	161,242	-	161,242	-	-	-	-	-	-	-	-	2,061,941
3c.4	Subtotal Period 3c Period-Dependent Costs	-	-	-	-	-	-	723,500	97,019	820,519	-	820,519	-	-	-	-	-	-	-	-	6,263,633
3c.0	TOTAL PERIOD 3c COST	-	-	-	128	-	1,548	1,701,960	216,157	1,919,793	-	1,919,793	-	-	4,906	-	-	-	576,566	-	6,263,633
PERIOD 3d - Spent Fuel/GTCC shipping																					
Period 3d Direct Decommissioning Activities																					
Nuclear Steam Supply System Removal																					
3d.1.1.1	Vessel & Internals GTCC Disposal	-	-	1,331	-	-	8,689	-	1,636	11,656	11,656	-	-	-	-	-	-	3,746	837,596	-	-
3d.1.1	Totals	-	-	1,331	-	-	8,689	-	1,636	11,656	11,656	-	-	-	-	-	-	3,746	837,596	-	-
3d.1	Subtotal Period 3d Activity Costs	-	-	1,331	-	-	8,689	-	1,636	11,656	11,656	-	-	-	-	-	-	3,746	837,596	-	-
Period 3d Collateral Costs																					
3d.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	126,132	18,920	145,052	-	145,052	-	-	-	-	-	-	-	-	-
3d.3.2	Prairie Island Indian Community Payments	-	-	-	-	-	-	31,250	-	31,250	-	31,250	-	-	-	-	-	-	-	-	-
3d.3	Subtotal Period 3d Collateral Costs	-	-	-	-	-	-	157,382	18,920	176,302	-	176,302	-	-	-	-	-	-	-	-	-
Period 3d Period-Dependent Costs																					
3d.4.1	Insurance	-	-	-	-	-	-	6,390	639	7,029	-	7,029	-	-	-	-	-	-	-	-	-
3d.4.2	Property taxes	-	-	-	-	-	-	24,558	2,456	27,013	-	27,013	-	-	-	-	-	-	-	-	-
3d.4.4	NRC ISFSI Fees	-	-	-	-	-	-	2,782	278	3,060	-	3,060	-	-	-	-	-	-	-	-	-
3d.4.5	Emergency Planning Fees	-	-	-	-	-	-	1,710	171	1,881	-	1,881	-	-	-	-	-	-	-	-	-
3d.4.6	Fixed Overhead	-	-	-	-	-	-	3,816	572	4,389	-	4,389	-	-	-	-	-	-	-	-	-
3d.4.7	ISFSI Operating Costs	-	-	-	-	-	-	1,291	194	1,485	-	1,485	-	-	-	-	-	-	-	-	-
3d.4.8	Railroad Track Maintenance	-	-	-	-	-	-	1,443	216	1,659	-	1,659	-	-	-	-	-	-	-	-	-
3d.4.9	Security Staff Cost	-	-	-	-	-	-	48,076	7,211	55,287	-	55,287	-	-	-	-	-	-	-	-	676,370
3d.4.10	Utility Staff Cost	-	-	-	-	-	-	12,369	1,855	14,225	-	14,225	-	-	-	-	-	-	-	-	175,596
3d.4	Subtotal Period 3d Period-Dependent Costs	-	-	-	-	-	-	102,435	13,593	116,029	-	116,029	-	-	-	-	-	-	-	-	851,967
3d.0	TOTAL PERIOD 3d COST	-	-	1,331	-	-	8,689	259,817	34,149	303,987	11,656	292,330	-	-	-	-	-	3,746	837,596	-	851,967
PERIOD 3e - ISFSI Decontamination																					
Period 3e Direct Decommissioning Activities																					
Period 3e Additional Costs																					
3e.2.1	License Termination ISFSI	15	-	-	-	-	-	970	246	1,232	1,232	-	-	-	-	-	-	-	-	5,604	972
3e.2	Subtotal Period 3e Additional Costs	15	-	-	-	-	-	970	246	1,232	1,232	-	-	-	-	-	-	-	-	5,604	972

Table F-2
Prairie Island Nuclear Generating Plant, Unit 2
DECON Decommissioning Cost Estimate with 200 Years of Spent Fuel Storage and Periodic TN-40 Replacement
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 3e Period-Dependent Costs																					
3e.4.1	Insurance	-	-	-	-	-	-	96	24	121	121	-	-	-	-	-	-	-	-	-	-
3e.4.4	Fixed Overhead	-	-	-	-	-	-	51	13	63	63	-	-	-	-	-	-	-	-	-	-
3e.4.5	Railroad Track Maintenance	-	-	-	-	-	-	19	5	24	24	-	-	-	-	-	-	-	-	-	-
3e.4.6	Security Staff Cost	-	-	-	-	-	-	154	38	192	192	-	-	-	-	-	-	-	-	-	2,500
3e.4.7	Utility Staff Cost	-	-	-	-	-	-	130	33	163	163	-	-	-	-	-	-	-	-	-	1,896
3e.4	Subtotal Period 3e Period-Dependent Costs	-	-	-	-	-	-	450	113	563	563	-	-	-	-	-	-	-	-	-	4,396
3e.0	TOTAL PERIOD 3e COST	15	-	-	-	-	-	1,420	359	1,794	1,794	-	-	-	-	-	-	-	-	5,604	5,368
PERIOD 3f - ISFSI Site Restoration																					
Period 3f Direct Decommissioning Activities																					
Period 3f Additional Costs																					
3f.2.1	Demolition and Site Restoration of ISFSI	-	946	-	-	-	-	154	165	1,265	-	-	1,265	-	-	-	-	-	-	4,922	160
3f.2	Subtotal Period 3f Additional Costs	-	946	-	-	-	-	154	165	1,265	-	-	1,265	-	-	-	-	-	-	4,922	160
Period 3f Collateral Costs																					
3f.3.1	Small tool allowance	-	7	-	-	-	-	-	1	8	-	-	8	-	-	-	-	-	-	-	-
3f.3	Subtotal Period 3f Collateral Costs	-	7	-	-	-	-	-	1	8	-	-	8	-	-	-	-	-	-	-	-
Period 3f Period-Dependent Costs																					
3f.4.3	Heavy equipment rental	-	62	-	-	-	-	-	9	71	-	-	71	-	-	-	-	-	-	-	-
3f.4.4	Plant energy budget	-	-	-	-	-	-	13	2	15	-	-	15	-	-	-	-	-	-	-	-
3f.4.5	Fixed Overhead	-	-	-	-	-	-	25	4	29	-	-	29	-	-	-	-	-	-	-	-
3f.4.6	Railroad Track Maintenance	-	-	-	-	-	-	10	1	11	-	-	11	-	-	-	-	-	-	-	-
3f.4.7	Security Staff Cost	-	-	-	-	-	-	78	12	89	-	-	89	-	-	-	-	-	-	-	1,260
3f.4.8	Utility Staff Cost	-	-	-	-	-	-	52	8	60	-	-	60	-	-	-	-	-	-	-	782
3f.4	Subtotal Period 3f Period-Dependent Costs	-	62	-	-	-	-	177	36	275	-	-	275	-	-	-	-	-	-	-	2,042
3f.0	TOTAL PERIOD 3f COST	-	1,014	-	-	-	-	331	202	1,547	-	-	1,547	-	-	-	-	-	-	4,922	2,202
PERIOD 3 TOTALS		15	36,032	1,331	128	-	10,236	1,993,933	260,020	2,301,695	13,540	2,227,848	60,307	-	4,906	-	-	3,746	1,414,161	169,184	7,374,698
TOTAL COST TO DECOMMISSION		**13,423**	**105,134**	**31,016**	**7,480**	**13,927**	**52,404**	**2,388,194**	**368,269**	**2,979,847**	**558,112**	**2,355,208**	**66,527**	**169,551**	**148,394**	**839**	**673**	**3,746**	**17,113,080**	**1,027,670**	**10,131,540**

TOTAL COST TO DECOMMISSION WITH 14.1% CONTINGENCY:	**$2,979,847**	**thousands of 2017 dollars**
TOTAL NRC LICENSE TERMINATION COST IS 18.73% OR:	**$558,112**	**thousands of 2017 dollars**
SPENT FUEL MANAGEMENT COST IS 79.04% OR:	**$2,355,208**	**thousands of 2017 dollars**
NON-NUCLEAR DEMOLITION COST IS 2.23% OR:	**$66,527**	**thousands of 2017 dollars**
TOTAL LOW-LEVEL RADIOACTIVE WASTE VOLUME BURIED (EXCLUDING GTCC):	**149,906**	**cubic feet**
TOTAL GREATER THAN CLASS C RADWASTE VOLUME GENERATED	**3,746**	**cubic feet**
TOTAL SCRAP METAL REMOVED:	**41,515**	**tons**
TOTAL CRAFT LABOR REQUIREMENTS:	**1,027,670**	**man-hours**

End Notes:
n/a - indicates that this activity not charged as decommissioning expense
a - indicates that this activity performed by decommissioning staff
0 - indicates that this value is less than 0.5 but is non-zero
A cell containing " - " indicates a zero value

APPENDIX G

DETAILED COST ANALYSIS

SCENARIO 5: DECON with 60 Year DFS with Recasking

Page

Prairie Island Nuclear Generating Plant, Unit 1 .....G-2

Prairie Island Nuclear Generating Plant, Unit 2 .....G-10

Table G-1
Prairie Island Nuclear Generating Plant, Unit 1
DECON Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage and Periodic TN-40 Replacement
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
PERIOD 1a - Shutdown through Transition																					
Period 1a Direct Decommissioning Activities																					
1a.1.1	Prepare preliminary decommissioning cost	-	-	-	-	-	-	153	23	175	175	-	-	-	-	-	-	-	-	-	1,300
1a.1.2	Notification of Cessation of Operations									a											
1a.1.3	Remove fuel & source material									n/a											
1a.1.4	Notification of Permanent Defueling									a											
1a.1.5	Deactivate plant systems & process waste									a											
1a.1.6	Prepare and submit PSDAR	-	-	-	-	-	-	235	35	270	270	-	-	-	-	-	-	-	-	-	2,000
1a.1.7	Review plant dwgs & specs.	-	-	-	-	-	-	540	81	621	621	-	-	-	-	-	-	-	-	-	4,600
1a.1.8	Perform detailed rad survey									a											
1a.1.9	Estimate by-product inventory	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1a.1.10	End product description	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1a.1.11	Detailed by-product inventory	-	-	-	-	-	-	153	23	175	175	-	-	-	-	-	-	-	-	-	1,300
1a.1.12	Define major work sequence	-	-	-	-	-	-	880	132	1,012	1,012	-	-	-	-	-	-	-	-	-	7,500
1a.1.13	Perform SER and EA	-	-	-	-	-	-	364	55	418	418	-	-	-	-	-	-	-	-	-	3,100
1a.1.14	Prepare/submit Defueled Technical Specifications	-	-	-	-	-	-	880	132	1,012	1,012	-	-	-	-	-	-	-	-	-	7,500
1a.1.15	Perform Site-Specific Cost Study	-	-	-	-	-	-	587	88	675	675	-	-	-	-	-	-	-	-	-	5,000
1a.1.16	Prepare/submit Irradiated Fuel Management Plan	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
Activity Specifications																					
1a.1.17.1	Plant & temporary facilities	-	-	-	-	-	-	578	87	664	598	-	66	-	-	-	-	-	-	-	4,920
1a.1.17.2	Plant systems	-	-	-	-	-	-	489	73	562	506	-	56	-	-	-	-	-	-	-	4,167
1a.1.17.3	NSSS Decontamination Flush	-	-	-	-	-	-	59	9	67	67	-	-	-	-	-	-	-	-	-	500
1a.1.17.4	Reactor internals	-	-	-	-	-	-	833	125	958	958	-	-	-	-	-	-	-	-	-	7,100
1a.1.17.5	Reactor vessel	-	-	-	-	-	-	763	114	877	877	-	-	-	-	-	-	-	-	-	6,500
1a.1.17.6	Biological shield	-	-	-	-	-	-	59	9	67	67	-	-	-	-	-	-	-	-	-	500
1a.1.17.7	Steam generators	-	-	-	-	-	-	366	55	421	421	-	-	-	-	-	-	-	-	-	3,120
1a.1.17.8	Reinforced concrete	-	-	-	-	-	-	188	28	216	108	-	108	-	-	-	-	-	-	-	1,600
1a.1.17.9	Main Turbine	-	-	-	-	-	-	47	7	54	-	-	54	-	-	-	-	-	-	-	400
1a.1.17.10	Main Condensers	-	-	-	-	-	-	47	7	54	-	-	54	-	-	-	-	-	-	-	400
1a.1.17.11	Plant structures & buildings	-	-	-	-	-	-	366	55	421	211	-	211	-	-	-	-	-	-	-	3,120
1a.1.17.12	Waste management	-	-	-	-	-	-	540	81	621	621	-	-	-	-	-	-	-	-	-	4,600
1a.1.17.13	Facility & site closeout	-	-	-	-	-	-	106	16	121	61	-	61	-	-	-	-	-	-	-	900
1a.1.17	Total	-	-	-	-	-	-	4,440	666	5,106	4,496	-	610	-	-	-	-	-	-	-	37,827
Planning & Site Preparations																					
1a.1.18	Prepare dismantling sequence	-	-	-	-	-	-	282	42	324	324	-	-	-	-	-	-	-	-	-	2,400
1a.1.19	Plant prep. & temp. svces	-	-	-	-	-	-	3,300	495	3,795	3,795	-	-	-	-	-	-	-	-	-	-
1a.1.20	Design water clean-up system	-	-	-	-	-	-	164	25	189	189	-	-	-	-	-	-	-	-	-	1,400
1a.1.21	Rigging/Cont. Cntrl Envlps/tooling/etc.	-	-	-	-	-	-	2,300	345	2,645	2,645	-	-	-	-	-	-	-	-	-	-
1a.1.22	Procure casks/liners & containers	-	-	-	-	-	-	144	22	166	166	-	-	-	-	-	-	-	-	-	1,230
1a.1	Subtotal Period 1a Activity Costs	-	-	-	-	-	-	14,774	2,216	16,990	16,380	-	610	-	-	-	-	-	-	-	78,157
Period 1a Additional Costs																					
1a.2.1	Spent Fuel Pool Isolation	-	-	-	-	-	-	11,691	1,754	13,445	13,445	-	-	-	-	-	-	-	-	-	-
1a.2	Subtotal Period 1a Additional Costs	-	-	-	-	-	-	11,691	1,754	13,445	13,445	-	-	-	-	-	-	-	-	-	-
Period 1a Collateral Costs																					
1a.3.1	Prairie Island Indian Community Payments	-	-	-	-	-	-	2,003	-	2,003	-	2,003	-	-	-	-	-	-	-	-	-
1a.3	Subtotal Period 1a Collateral Costs	-	-	-	-	-	-	2,003	-	2,003	-	2,003	-	-	-	-	-	-	-	-	-
Period 1a Period-Dependent Costs																					
1a.4.1	Insurance	-	-	-	-	-	-	1,730	173	1,903	1,903	-	-	-	-	-	-	-	-	-	-
1a.4.2	Property taxes	-	-	-	-	-	-	2,040	204	2,244	2,244	-	-	-	-	-	-	-	-	-	-
1a.4.3	Health physics supplies	-	515	-	-	-	-	-	129	644	644	-	-	-	-	-	-	-	-	-	-
1a.4.4	Heavy equipment rental	-	567	-	-	-	-	-	85	652	652	-	-	-	-	-	-	-	-	-	-
1a.4.5	Disposal of DAW generated	-	-	13	4	-	50	-	14	81	81	-	-	-	610	-	-	-	12,190	20	-
1a.4.6	Plant energy budget	-	-	-	-	-	-	1,515	227	1,742	1,742	-	-	-	-	-	-	-	-	-	-
1a.4.7	NRC Fees	-	-	-	-	-	-	1,110	111	1,221	1,221	-	-	-	-	-	-	-	-	-	-
1a.4.8	Emergency Planning Fees	-	-	-	-	-	-	1,604	160	1,765	-	1,765	-	-	-	-	-	-	-	-	-
1a.4.9	Fixed Overhead	-	-	-	-	-	-	1,470	220	1,690	1,690	-	-	-	-	-	-	-	-	-	-
1a.4.10	Spent Fuel Pool O&M	-	-	-	-	-	-	401	60	461	-	461	-	-	-	-	-	-	-	-	-
1a.4.11	ISFSI Operating Costs	-	-	-	-	-	-	52	8	59	-	59	-	-	-	-	-	-	-	-	-
1a.4.12	Railroad Track Maintenance	-	-	-	-	-	-	58	9	66	66	-	-	-	-	-	-	-	-	-	-
1a.4.13	Security Staff Cost	-	-	-	-	-	-	7,390	1,108	8,498	8,498	-	-	-	-	-	-	-	-	-	122,720
1a.4.14	Utility Staff Cost	-	-	-	-	-	-	25,791	3,869	29,660	29,660	-	-	-	-	-	-	-	-	-	422,240
1a.4	Subtotal Period 1a Period-Dependent Costs	-	1,083	13	4	-	50	43,160	6,378	50,687	48,402	2,286	-	-	610	-	-	-	12,190	20	544,960

Table G-1
Prairie Island Nuclear Generating Plant, Unit 1
DECON Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage and Periodic TN-40 Replacement
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
1a.0	TOTAL PERIOD 1a COST	-	1,083	13	4	-	50	71,629	10,348	83,126	78,227	4,289	610	-	610	-	-	-	12,190	20	623,117
PERIOD 1b - Decommissioning Preparations																					
Period 1b Direct Decommissioning Activities																					
Detailed Work Procedures																					
1b.1.1.1	Plant systems	-	-	-	-	-	-	556	83	639	575	-	64	-	-	-	-	-	-	-	4,733
1b.1.1.2	NSSS Decontamination Flush	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1b.1.1.3	Reactor internals	-	-	-	-	-	-	293	44	337	337	-	-	-	-	-	-	-	-	-	2,500
1b.1.1.4	Remaining buildings	-	-	-	-	-	-	158	24	182	46	-	137	-	-	-	-	-	-	-	1,350
1b.1.1.5	CRD cooling assembly	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1b.1.1.6	CRD housings & ICI tubes	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1b.1.1.7	Incore instrumentation	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1b.1.1.8	Reactor vessel	-	-	-	-	-	-	426	64	490	490	-	-	-	-	-	-	-	-	-	3,630
1b.1.1.9	Facility closeout	-	-	-	-	-	-	141	21	162	81	-	81	-	-	-	-	-	-	-	1,200
1b.1.1.10	Missile shields	-	-	-	-	-	-	53	8	61	61	-	-	-	-	-	-	-	-	-	450
1b.1.1.11	Biological shield	-	-	-	-	-	-	141	21	162	162	-	-	-	-	-	-	-	-	-	1,200
1b.1.1.12	Steam generators	-	-	-	-	-	-	540	81	621	621	-	-	-	-	-	-	-	-	-	4,600
1b.1.1.13	Reinforced concrete	-	-	-	-	-	-	117	18	135	67	-	67	-	-	-	-	-	-	-	1,000
1b.1.1.14	Main Turbine	-	-	-	-	-	-	183	27	211	-	-	211	-	-	-	-	-	-	-	1,560
1b.1.1.15	Main Condensers	-	-	-	-	-	-	183	27	211	-	-	211	-	-	-	-	-	-	-	1,560
1b.1.1.16	Auxiliary building	-	-	-	-	-	-	320	48	369	332	-	37	-	-	-	-	-	-	-	2,730
1b.1.1.17	Reactor building	-	-	-	-	-	-	320	48	369	332	-	37	-	-	-	-	-	-	-	2,730
1b.1.1	Total	-	-	-	-	-	-	3,902	585	4,487	3,643	-	844	-	-	-	-	-	-	-	33,243
1b.1.2	Decon primary loop	552	-	-	-	-	-	-	276	828	828	-	-	-	-	-	-	-	-	1,067	-
1b.1	Subtotal Period 1b Activity Costs	552	-	-	-	-	-	3,902	861	5,315	4,471	-	844	-	-	-	-	-	-	1,067	33,243
Period 1b Additional Costs																					
1b.2.1	Site Characterization	-	-	-	-	-	-	3,700	1,110	4,810	4,810	-	-	-	-	-	-	-	-	21,020	8,332
1b.2.2	Mixed/Hazardous Waste	-	-	318	75	164	-	-	68	624	624	-	-	6,133	-	-	-	-	351,986	2,361	-
1b.2.3	Asbestos Abatement	-	2,364	2	110	-	1,359	-	947	4,782	4,782	-	-	-	12,843	-	-	-	166,959	20,907	-
1b.2	Subtotal Period 1b Additional Costs	-	2,364	320	185	164	1,359	3,700	2,125	10,216	10,216	-	-	6,133	12,843	-	-	-	518,945	44,288	8,332
Period 1b Collateral Costs																					
1b.3.1	Decon equipment	973	-	-	-	-	-	-	146	1,119	1,119	-	-	-	-	-	-	-	-	-	-
1b.3.2	DOC staff relocation expenses	-	-	-	-	-	-	1,189	178	1,367	1,367	-	-	-	-	-	-	-	-	-	-
1b.3.3	Process decommissioning water waste	24	-	16	41	-	64	-	36	180	180	-	-	-	152	-	-	-	9,121	30	-
1b.3.4	Process decommissioning chemical flush waste	2	-	58	220	-	2,471	-	657	3,408	3,408	-	-	-	-	588	-	-	62,689	110	-
1b.3.5	Small tool allowance	-	34	-	-	-	-	-	5	39	39	-	-	-	-	-	-	-	-	-	-
1b.3.6	Pipe cutting equipment	-	1,200	-	-	-	-	-	180	1,380	1,380	-	-	-	-	-	-	-	-	-	-
1b.3.7	Decon rig	1,987	-	-	-	-	-	-	298	2,285	2,285	-	-	-	-	-	-	-	-	-	-
1b.3.8	Spent Fuel Capital and Transfer	-	-	-	-	-	-	159	24	183	-	183	-	-	-	-	-	-	-	-	-
1b.3.9	Retention and Severance	-	-	-	-	-	-	1,088	163	1,251	1,251	-	-	-	-	-	-	-	-	-	-
1b.3.10	Prairie Island Indian Community Payments	-	-	-	-	-	-	630	-	630	-	630	-	-	-	-	-	-	-	-	-
1b.3	Subtotal Period 1b Collateral Costs	2,986	1,234	74	261	-	2,534	3,065	1,687	11,841	11,028	813	-	-	152	588	-	-	71,810	140	-
Period 1b Period-Dependent Costs																					
1b.4.1	Decon supplies	35	-	-	-	-	-	-	9	44	44	-	-	-	-	-	-	-	-	-	-
1b.4.2	Insurance	-	-	-	-	-	-	872	87	959	959	-	-	-	-	-	-	-	-	-	-
1b.4.3	Property taxes	-	-	-	-	-	-	1,352	135	1,487	1,487	-	-	-	-	-	-	-	-	-	-
1b.4.4	Health physics supplies	-	402	-	-	-	-	-	101	503	503	-	-	-	-	-	-	-	-	-	-
1b.4.5	Heavy equipment rental	-	286	-	-	-	-	-	43	329	329	-	-	-	-	-	-	-	-	-	-
1b.4.6	Disposal of DAW generated	-	-	8	2	-	29	-	8	48	48	-	-	-	360	-	-	-	7,197	12	-
1b.4.7	Plant energy budget	-	-	-	-	-	-	1,527	229	1,756	1,756	-	-	-	-	-	-	-	-	-	-
1b.4.8	NRC Fees	-	-	-	-	-	-	323	32	355	355	-	-	-	-	-	-	-	-	-	-
1b.4.9	Emergency Planning Fees	-	-	-	-	-	-	809	81	890	-	890	-	-	-	-	-	-	-	-	-
1b.4.10	Fixed Overhead	-	-	-	-	-	-	741	111	852	852	-	-	-	-	-	-	-	-	-	-
1b.4.11	Spent Fuel Pool O&M	-	-	-	-	-	-	202	30	233	-	233	-	-	-	-	-	-	-	-	-
1b.4.12	ISFSI Operating Costs	-	-	-	-	-	-	26	4	30	-	30	-	-	-	-	-	-	-	-	-
1b.4.13	Railroad Track Maintenance	-	-	-	-	-	-	29	4	33	33	-	-	-	-	-	-	-	-	-	-
1b.4.14	Security Staff Cost	-	-	-	-	-	-	3,725	559	4,284	4,284	-	-	-	-	-	-	-	-	-	61,864
1b.4.15	DOC Staff Cost	-	-	-	-	-	-	5,656	848	6,504	6,504	-	-	-	-	-	-	-	-	-	63,961
1b.4.16	Utility Staff Cost	-	-	-	-	-	-	13,074	1,961	15,035	15,035	-	-	-	-	-	-	-	-	-	213,904
1b.4	Subtotal Period 1b Period-Dependent Costs	35	688	8	2	-	29	28,336	4,243	33,341	32,189	1,152	-	-	360	-	-	-	7,197	12	339,730
1b.0	TOTAL PERIOD 1b COST	3,573	4,286	402	447	164	3,923	39,002	8,917	60,713	57,904	1,965	844	6,133	13,355	588	-	-	597,952	45,506	381,305

Table G-1
Prairie Island Nuclear Generating Plant, Unit 1
DECON Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage and Periodic TN-40 Replacement
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
PERIOD 1 TOTALS		3,573	5,368	415	451	164	3,972	110,631	19,264	143,839	136,131	6,254	1,454	6,133	13,964	588	-	-	610,142	45,526	1,004,421
PERIOD 2a - Large Component Removal																					
Period 2a Direct Decommissioning Activities																					
Nuclear Steam Supply System Removal																					
2a.1.1.1	Reactor Coolant Piping	51	45	6	8	-	150	-	76	336	336	-	-	-	305	-	-	-	34,809	1,414	-
2a.1.1.2	Pressurizer Relief Tank	22	20	4	5	-	100	-	42	193	193	-	-	-	203	-	-	-	23,193	625	-
2a.1.1.3	Reactor Coolant Pumps & Motors	54	63	101	83	-	736	-	249	1,287	1,287	-	-	-	2,332	-	-	-	295,800	2,049	100
2a.1.1.4	Pressurizer	48	68	467	88	-	693	-	274	1,639	1,639	-	-	-	2,196	-	-	-	185,015	2,355	938
2a.1.1.5	Steam Generators	225	2,943	2,093	1,638	1,246	3,570	-	2,383	14,097	14,097	-	-	18,672	11,316	-	-	-	1,668,341	14,819	2,875
2a.1.1.6	CRDMs/ICIs/Service Structure Removal	286	277	211	48	-	763	-	431	2,016	2,016	-	-	-	4,797	-	-	-	177,400	8,104	-
2a.1.1.7	Reactor Vessel Internals	78	4,468	21,874	1,072	-	7,946	277	13,141	48,856	48,856	-	-	-	501	125	673	-	164,987	23,040	1,080
2a.1.1.8	Reactor Vessel	89	5,717	1,754	719	-	1,956	277	5,970	16,483	16,483	-	-	-	5,690	-	-	-	570,074	23,040	1,080
2a.1.1	Totals	855	13,600	26,512	3,662	1,246	15,913	553	22,568	84,908	84,908	-	-	18,672	27,341	125	673	-	3,119,620	75,446	6,073
Removal of Major Equipment																					
2a.1.2	Main Turbine/Generator	-	305	189	55	272	306	-	221	1,348	1,348	-	-	2,131	1,187	-	-	-	206,316	4,667	-
2a.1.3	Main Condensers	-	2,532	121	49	364	451	-	820	4,336	4,336	-	-	3,800	1,587	-	-	-	275,903	39,151	-
Cascading Costs from Clean Building Demolition																					
2a.1.4.1	Reactor	-	728	-	-	-	-	-	109	837	837	-	-	-	-	-	-	-	-	7,589	-
2a.1.4	Totals	-	728	-	-	-	-	-	109	837	837	-	-	-	-	-	-	-	-	7,589	-
Disposal of Plant Systems																					
2a.1.5.1	Air Removal	-	27	-	-	-	-	-	4	31	-	-	31	-	-	-	-	-	-	452	-
2a.1.5.2	Auxiliary Feedwater	-	40	-	-	-	-	-	6	46	-	-	46	-	-	-	-	-	-	670	-
2a.1.5.3	Auxiliary Feedwater - RCA	-	45	0	1	19	-	-	14	79	79	-	-	215	-	-	-	-	8,722	601	-
2a.1.5.4	Bleed Steam	-	78	-	-	-	-	-	12	90	-	-	90	-	-	-	-	-	-	1,335	-
2a.1.5.5	Caustic Addition - RCA	-	36	0	1	20	-	-	12	71	71	-	-	233	-	-	-	-	9,453	444	-
2a.1.5.6	Chemical Feed	-	17	-	-	-	-	-	3	20	-	-	20	-	-	-	-	-	-	304	-
2a.1.5.7	Chemical Feed - RCA	-	1	0	0	1	-	-	0	2	2	-	-	6	-	-	-	-	243	12	-
2a.1.5.8	Circulating Water	-	37	-	-	-	-	-	6	42	-	-	42	-	-	-	-	-	-	619	-
2a.1.5.9	Condensate	-	414	-	-	-	-	-	62	476	-	-	476	-	-	-	-	-	-	6,837	-
2a.1.5.10	Condensate Polishing	-	205	-	-	-	-	-	31	236	-	-	236	-	-	-	-	-	-	3,420	-
2a.1.5.11	Condensate Polishing - RCA	-	176	4	12	180	-	-	73	444	444	-	-	2,078	-	-	-	-	84,395	2,329	-
2a.1.5.12	Electro-hydraulic	-	8	-	-	-	-	-	1	9	-	-	9	-	-	-	-	-	-	127	-
2a.1.5.13	Feedwater	-	133	-	-	-	-	-	20	153	-	-	153	-	-	-	-	-	-	2,215	-
2a.1.5.14	Feedwater - RCA	-	186	6	19	278	-	-	91	579	579	-	-	3,208	-	-	-	-	130,294	2,651	-
2a.1.5.15	Gland Seal	-	29	-	-	-	-	-	4	34	-	-	34	-	-	-	-	-	-	505	-
2a.1.5.16	Heater Drain	-	349	-	-	-	-	-	52	401	-	-	401	-	-	-	-	-	-	5,881	-
2a.1.5.17	Internal Circ Water & CDSR	-	23	-	-	-	-	-	3	27	-	-	27	-	-	-	-	-	-	389	-
2a.1.5.18	Main Gen/Exciter/Transformer	-	0	-	-	-	-	-	0	0	-	-	0	-	-	-	-	-	-	5	-
2a.1.5.19	Main Steam	-	101	-	-	-	-	-	15	116	-	-	116	-	-	-	-	-	-	1,690	-
2a.1.5.20	Main Steam - RCA	-	350	9	29	436	-	-	158	983	983	-	-	5,044	-	-	-	-	204,825	4,956	-
2a.1.5.21	Steam Generator Blowdown	-	459	21	22	176	195	-	195	1,067	1,067	-	-	2,031	686	-	-	-	127,773	6,667	-
2a.1.5.22	Steam Generators	-	5	-	-	-	-	-	1	5	-	-	5	-	-	-	-	-	-	75	-
2a.1.5.23	Turbine & Moisture Separators	-	337	-	-	-	-	-	51	388	-	-	388	-	-	-	-	-	-	5,609	-
2a.1.5.24	Turbine Oil Purification	-	61	-	-	-	-	-	9	71	-	-	71	-	-	-	-	-	-	1,003	-
2a.1.5	Totals	-	3,117	40	85	1,108	195	-	825	5,370	3,226	-	2,145	12,815	686	-	-	-	565,705	48,794	-
2a.1.6	Scaffolding in support of decommissioning	-	854	3	1	13	3	-	217	1,092	1,092	-	-	138	12	-	-	-	7,016	6,368	-
2a.1	Subtotal Period 2a Activity Costs	855	21,136	26,865	3,852	3,004	16,868	553	24,759	97,891	95,747	-	2,145	37,556	30,812	125	673	-	4,174,560	182,015	6,073
Period 2a Additional Costs																					
2a.2.1	Remedial Action Surveys	-	-	-	-	-	-	2,126	638	2,764	2,764	-	-	-	-	-	-	-	-	27,791	-
2a.2.2	Retired RPV upper internals package	1	659	785	107	-	1,439	-	1,437	4,427	4,427	-	-	-	2,097	125	-	-	205,890	2,175	87
2a.2	Subtotal Period 2a Additional Costs	1	659	785	107	-	1,439	2,126	2,075	7,191	7,191	-	-	-	2,097	125	-	-	205,890	29,966	87
Period 2a Collateral Costs																					
2a.3.1	Process decommissioning water waste	47	-	31	81	-	126	-	70	356	356	-	-	-	302	-	-	-	18,119	59	-
2a.3.3	Small tool allowance	-	223	-	-	-	-	-	33	257	231	-	26	-	-	-	-	-	-	-	-
2a.3.4	Spent Fuel Capital and Transfer	-	-	-	-	-	-	1,476	221	1,698	-	1,698	-	-	-	-	-	-	-	-	-
2a.3.5	Retention and Severance	-	-	-	-	-	-	12,156	1,823	13,980	13,980	-	-	-	-	-	-	-	-	-	-
2a.3.6	Prairie Island Indian Community Payments	-	-	-	-	-	-	1,670	-	1,670	-	1,670	-	-	-	-	-	-	-	-	-
2a.3	Subtotal Period 2a Collateral Costs	47	223	31	81	-	126	15,302	2,149	17,960	14,567	3,367	26	-	302	-	-	-	18,119	59	-

Table G-1
Prairie Island Nuclear Generating Plant, Unit 1
DECON Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage and Periodic TN-40 Replacement
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 2a Period-Dependent Costs																					
2a.4.1	Decon supplies	93	-	-	-	-	-	-	23	116	116	-	-	-	-	-	-	-	-	-	-
2a.4.2	Insurance	-	-	-	-	-	-	683	68	751	751	-	-	-	-	-	-	-	-	-	-
2a.4.3	Property taxes	-	-	-	-	-	-	3,542	354	3,896	3,896	-	-	-	-	-	-	-	-	-	-
2a.4.4	Health physics supplies	-	1,717	-	-	-	-	-	429	2,146	2,146	-	-	-	-	-	-	-	-	-	-
2a.4.5	Heavy equipment rental	-	2,935	-	-	-	-	-	440	3,376	3,376	-	-	-	-	-	-	-	-	-	-
2a.4.6	Disposal of DAW generated	-	-	79	23	-	295	-	85	482	482	-	-	-	3,623	-	-	-	72,452	118	-
2a.4.7	Plant energy budget	-	-	-	-	-	-	1,924	289	2,212	2,212	-	-	-	-	-	-	-	-	-	-
2a.4.8	NRC Fees	-	-	-	-	-	-	774	77	851	851	-	-	-	-	-	-	-	-	-	-
2a.4.9	Emergency Planning Fees	-	-	-	-	-	-	1,717	172	1,888	-	1,888	-	-	-	-	-	-	-	-	-
2a.4.10	Fixed Overhead	-	-	-	-	-	-	1,655	248	1,904	1,904	-	-	-	-	-	-	-	-	-	-
2a.4.11	Spent Fuel Pool O&M	-	-	-	-	-	-	537	80	617	-	617	-	-	-	-	-	-	-	-	-
2a.4.12	ISFSI Operating Costs	-	-	-	-	-	-	69	10	79	-	79	-	-	-	-	-	-	-	-	-
2a.4.13	Railroad Track Maintenance	-	-	-	-	-	-	286	43	328	328	-	-	-	-	-	-	-	-	-	-
2a.4.14	Security Staff Cost	-	-	-	-	-	-	9,811	1,472	11,283	11,283	-	-	-	-	-	-	-	-	-	162,878
2a.4.15	DOC Staff Cost	-	-	-	-	-	-	18,392	2,759	21,150	21,150	-	-	-	-	-	-	-	-	-	211,351
2a.4.16	Utility Staff Cost	-	-	-	-	-	-	24,265	3,640	27,904	27,904	-	-	-	-	-	-	-	-	-	392,305
2a.4	Subtotal Period 2a Period-Dependent Costs	93	4,652	79	23	-	295	63,653	10,190	78,986	76,401	2,585	-	-	3,623	-	-	-	72,452	118	766,534
2a.0	TOTAL PERIOD 2a COST	995	26,670	27,760	4,062	3,004	18,729	81,635	39,172	202,027	193,905	5,952	2,170	37,556	36,834	250	673	-	4,471,020	212,158	772,694
PERIOD 2b - Site Decontamination																					
Period 2b Direct Decommissioning Activities																					
Disposal of Plant Systems																					
2b.1.1.1	Aux Bldg Normal Ventilation	-	2	0	0	0	-	-	1	3	3	-	-	3	-	-	-	-	140	29	-
2b.1.1.2	Battery Rm Special Ventilation	-	0	-	-	-	-	-	0	0	-	-	0	-	-	-	-	-	-	6	-
2b.1.1.3	Buildings Maintenance	-	4	-	-	-	-	-	1	5	-	-	5	-	-	-	-	-	-	65	-
2b.1.1.4	Chemical & Volume Control	1,077	1,331	83	69	389	802	-	1,149	4,901	4,901	-	-	4,498	2,846	-	-	-	369,246	34,533	-
2b.1.1.5	Component Cooling - RCA	-	821	22	72	1,075	-	-	379	2,369	2,369	-	-	12,427	-	-	-	-	504,675	11,242	-
2b.1.1.6	Containment Cooling	-	65	-	-	-	-	-	10	74	-	-	74	-	-	-	-	-	-	1,086	-
2b.1.1.7	Containment Cooling - RCA	-	290	6	20	294	-	-	120	730	730	-	-	3,400	-	-	-	-	138,090	3,971	-
2b.1.1.8	Containment Hydrogen Control - RCA	-	29	0	1	9	-	-	9	48	48	-	-	105	-	-	-	-	4,278	401	-
2b.1.1.9	Containment Spray - RCA	-	90	2	5	75	-	-	35	206	206	-	-	868	-	-	-	-	35,249	1,217	-
2b.1.1.10	Containment Ventilation	-	243	24	40	428	209	-	186	1,130	1,130	-	-	4,951	737	-	-	-	249,786	3,668	-
2b.1.1.11	Cooling Water	-	142	-	-	-	-	-	21	163	-	-	163	-	-	-	-	-	-	2,396	-
2b.1.1.12	Cooling Water - RCA	-	629	14	45	668	-	-	266	1,622	1,622	-	-	7,728	-	-	-	-	313,832	8,594	-
2b.1.1.13	D1 Emergency Diesel	-	44	-	-	-	-	-	7	50	-	-	50	-	-	-	-	-	-	730	-
2b.1.1.14	D2 Emergency Diesel	-	31	-	-	-	-	-	5	36	-	-	36	-	-	-	-	-	-	522	-
2b.1.1.15	Diesel Rooms Ventilation	-	8	-	-	-	-	-	1	10	-	-	10	-	-	-	-	-	-	135	-
2b.1.1.16	Electrical - Clean	-	1,669	-	-	-	-	-	250	1,919	-	-	1,919	-	-	-	-	-	-	26,981	-
2b.1.1.17	Electrical - Contaminated	-	592	6	16	219	27	-	191	1,051	1,051	-	-	2,527	95	-	-	-	108,935	8,377	-
2b.1.1.18	Electrical - Decontaminated	-	3,674	41	137	2,037	-	-	1,249	7,138	7,138	-	-	23,551	-	-	-	-	956,401	49,378	-
2b.1.1.19	Fuel Handling	-	116	6	9	79	62	-	58	329	329	-	-	908	218	-	-	-	51,280	1,784	-
2b.1.1.20	Fuel Oil	-	106	-	-	-	-	-	16	122	-	-	122	-	-	-	-	-	-	1,697	-
2b.1.1.21	HVAC - Clean	-	105	-	-	-	-	-	16	121	-	-	121	-	-	-	-	-	-	1,891	-
2b.1.1.22	HVAC - Contaminated	-	371	8	21	282	35	-	148	864	864	-	-	3,261	123	-	-	-	140,573	5,032	-
2b.1.1.23	Incore Instrumentation	0	27	1	1	5	16	-	12	64	64	-	-	60	57	-	-	-	6,177	425	-
2b.1.1.24	Misc Drains & Vents	-	222	14	10	34	146	-	100	527	527	-	-	390	514	-	-	-	49,900	3,091	-
2b.1.1.25	Reactor Coolant	148	298	21	14	30	221	-	213	945	945	-	-	344	777	-	-	-	65,413	6,470	-
2b.1.1.26	Reactor Hot Sampling	144	131	11	6	6	98	-	132	527	527	-	-	66	342	-	-	-	25,347	3,946	-
2b.1.1.27	Reactor Makeup	-	64	-	-	-	-	-	10	73	-	-	73	-	-	-	-	-	-	1,042	-
2b.1.1.28	Reactor Vessel	9	20	1	0	2	4	-	11	47	47	-	-	26	14	-	-	-	2,011	425	-
2b.1.1.29	Residual Heat Removal	344	399	85	66	250	926	-	559	2,630	2,630	-	-	2,895	3,252	-	-	-	332,849	7,621	-
2b.1.1.30	Safeguards Chilled Water	-	15	-	-	-	-	-	2	18	-	-	18	-	-	-	-	-	-	259	-
2b.1.1.31	Safety Injection	-	853	40	57	587	327	-	396	2,261	2,261	-	-	6,788	1,156	-	-	-	351,793	12,561	-
2b.1.1.32	Sampling	-	58	4	2	5	31	-	23	122	122	-	-	59	107	-	-	-	9,505	811	-
2b.1.1.33	Shield Bldg Ventilation	-	133	14	20	186	139	-	100	593	593	-	-	2,152	491	-	-	-	119,838	2,030	-
2b.1.1.34	Station & Instrument Air	-	17	-	-	-	-	-	3	20	-	-	20	-	-	-	-	-	-	300	-
2b.1.1.35	Station & Instrument Air - RCA	-	79	1	2	29	-	-	24	135	135	-	-	332	-	-	-	-	13,496	1,053	-
2b.1.1.36	Turbine Bldg Traps & Drains	-	44	-	-	-	-	-	7	50	-	-	50	-	-	-	-	-	-	767	-
2b.1.1.37	Unit Coolers	-	37	-	-	-	-	-	6	42	-	-	42	-	-	-	-	-	-	611	-
2b.1.1.38	Unit Coolers - RCA	-	53	0	1	20	-	-	16	91	91	-	-	230	-	-	-	-	9,348	683	-
2b.1.1	Totals	1,724	12,813	403	614	6,710	3,044	-	5,730	31,037	28,333	-	2,704	77,571	10,728	-	-	-	3,858,165	205,829	-
2b.1.2	Scaffolding in support of decommissioning	-	1,067	4	1	17	4	-	271	1,364	1,364	-	-	173	15	-	-	-	8,770	7,960	-

Table G-1
Prairie Island Nuclear Generating Plant, Unit 1
DECON Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage and Periodic TN-40 Replacement
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Decontamination of Site Buildings																					
2b.1.3.1	Reactor	1,150	2,623	139	852	193	11,079	-	4,171	20,208	20,208	-	-	2,230	57,414	-	-	-	3,559,624	50,842	-
2b.1.3.2	Backwash Waste Receiving Tank	-	27	1	11	-	87	-	30	158	158	-	-	-	507	-	-	-	43,896	299	-
2b.1.3	Totals	1,150	2,650	141	864	193	11,166	-	4,202	20,366	20,366	-	-	2,230	57,921	-	-	-	3,603,520	51,140	-
2b.1.4	Prepare/submit License Termination Plan	-	-	-	-	-	-	481	72	553	553	-	-	-	-	-	-	-	-	-	4,096
2b.1.5	Receive NRC approval of termination plan									a											
2b.1	Subtotal Period 2b Activity Costs	2,874	16,530	547	1,479	6,919	14,215	481	10,275	53,320	50,616	-	2,704	79,974	68,664	-	-	-	7,470,455	264,930	4,096
Period 2b Additional Costs																					
2b.2.1	Remedial Action Surveys	-	-	-	-	-	-	1,943	583	2,526	2,526	-	-	-	-	-	-	-	-	25,399	-
2b.2.2	Operational Equipment	-	-	9	29	312	-	-	52	402	402	-	-	5,855	-	-	-	-	146,375	16	-
2b.2	Subtotal Period 2b Additional Costs	-	-	9	29	312	-	1,943	635	2,928	2,928	-	-	5,855	-	-	-	-	146,375	25,415	-
Period 2b Collateral Costs																					
2b.3.1	Process decommissioning water waste	105	-	70	182	-	285	-	158	800	800	-	-	-	680	-	-	-	40,799	133	-
2b.3.2	Process decommissioning chemical flush waste	3	-	87	327	-	651	-	222	1,289	1,289	-	-	-	875	-	-	-	93,252	164	-
2b.3.3	Small tool allowance	-	289	-	-	-	-	-	43	332	332	-	-	-	-	-	-	-	-	-	-
2b.3.4	Spent Fuel Capital and Transfer	-	-	-	-	-	-	4,321	648	4,969	-	4,969	-	-	-	-	-	-	-	-	-
2b.3.5	Retention and Severance	-	-	-	-	-	-	6,994	1,049	8,043	8,043	-	-	-	-	-	-	-	-	-	-
2b.3.6	Prairie Island Indian Community Payments	-	-	-	-	-	-	1,525	-	1,525	-	1,525	-	-	-	-	-	-	-	-	-
2b.3	Subtotal Period 2b Collateral Costs	107	289	157	509	-	936	12,841	2,120	16,958	10,463	6,495	-	-	1,555	-	-	-	134,051	296	-
Period 2b Period-Dependent Costs																					
2b.4.1	Decon supplies	482	-	-	-	-	-	-	121	603	603	-	-	-	-	-	-	-	-	-	-
2b.4.2	Insurance	-	-	-	-	-	-	624	62	687	687	-	-	-	-	-	-	-	-	-	-
2b.4.3	Property taxes	-	-	-	-	-	-	3,099	310	3,409	3,409	-	-	-	-	-	-	-	-	-	-
2b.4.4	Health physics supplies	-	1,969	-	-	-	-	-	492	2,461	2,461	-	-	-	-	-	-	-	-	-	-
2b.4.5	Heavy equipment rental	-	2,759	-	-	-	-	-	414	3,173	3,173	-	-	-	-	-	-	-	-	-	-
2b.4.6	Disposal of DAW generated	-	-	78	23	-	293	-	85	479	479	-	-	-	3,600	-	-	-	71,996	117	-
2b.4.7	Plant energy budget	-	-	-	-	-	-	1,388	208	1,596	1,596	-	-	-	-	-	-	-	-	-	-
2b.4.8	NRC Fees	-	-	-	-	-	-	707	71	778	778	-	-	-	-	-	-	-	-	-	-
2b.4.9	Emergency Planning Fees	-	-	-	-	-	-	1,569	157	1,726	-	1,726	-	-	-	-	-	-	-	-	-
2b.4.10	Fixed Overhead	-	-	-	-	-	-	1,513	227	1,740	1,740	-	-	-	-	-	-	-	-	-	-
2b.4.11	Spent Fuel Pool O&M	-	-	-	-	-	-	490	74	564	-	564	-	-	-	-	-	-	-	-	-
2b.4.12	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	247	37	284	284	-	-	-	-	-	-	-	-	-	-
2b.4.13	ISFSI Operating Costs	-	-	-	-	-	-	63	9	73	-	73	-	-	-	-	-	-	-	-	-
2b.4.14	Railroad Track Maintenance	-	-	-	-	-	-	70	11	81	81	-	-	-	-	-	-	-	-	-	-
2b.4.15	Security Staff Cost	-	-	-	-	-	-	8,299	1,245	9,544	9,544	-	-	-	-	-	-	-	-	-	137,246
2b.4.16	DOC Staff Cost	-	-	-	-	-	-	11,450	1,718	13,168	13,168	-	-	-	-	-	-	-	-	-	137,246
2b.4.17	Utility Staff Cost	-	-	-	-	-	-	15,293	2,294	17,586	17,586	-	-	-	-	-	-	-	-	-	255,430
2b.4	Subtotal Period 2b Period-Dependent Costs	482	4,728	78	23	-	293	44,813	7,533	57,951	55,588	2,362	-	-	3,600	-	-	-	71,996	117	529,921
2b.0	TOTAL PERIOD 2b COST	3,464	21,546	792	2,040	7,231	15,444	60,078	20,563	131,157	119,596	8,857	2,704	85,829	73,819	-	-	-	7,822,876	290,758	534,017
PERIOD 2c - Spent fuel delay prior to SFP decon																					
Period 2c Direct Decommissioning Activities																					
Period 2c Additional Costs																					
2c.2.1	Security Modifications	-	-	-	-	-	-	4,348	652	5,000	5,000	-	-	-	-	-	-	-	-	-	-
2c.2	Subtotal Period 2c Additional Costs	-	-	-	-	-	-	4,348	652	5,000	5,000	-	-	-	-	-	-	-	-	-	-
Period 2c Collateral Costs																					
2c.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	73,918	11,088	85,005	-	85,005	-	-	-	-	-	-	-	-	-
2c.3.2	Retention and Severance	-	-	-	-	-	-	4,478	672	5,149	5,149	-	-	-	-	-	-	-	-	-	-
2c.3.3	Prairie Island Indian Community Payments	-	-	-	-	-	-	2,702	-	2,702	-	2,702	-	-	-	-	-	-	-	-	-
2c.3	Subtotal Period 2c Collateral Costs	-	-	-	-	-	-	81,097	11,759	92,857	5,149	87,707	-	-	-	-	-	-	-	-	-
Period 2c Period-Dependent Costs																					
2c.4.1	Insurance	-	-	-	-	-	-	1,104	110	1,215	1,215	-	-	-	-	-	-	-	-	-	-
2c.4.2	Property taxes	-	-	-	-	-	-	5,154	515	5,669	5,669	-	-	-	-	-	-	-	-	-	-
2c.4.3	Health physics supplies	-	390	-	-	-	-	-	98	488	488	-	-	-	-	-	-	-	-	-	-
2c.4.4	Disposal of DAW generated	-	-	18	5	-	66	-	19	108	108	-	-	-	809	-	-	-	16,171	26	-
2c.4.5	Plant energy budget	-	-	-	-	-	-	655	98	753	753	-	-	-	-	-	-	-	-	-	-
2c.4.6	NRC Fees	-	-	-	-	-	-	555	55	610	610	-	-	-	-	-	-	-	-	-	-
2c.4.7	Emergency Planning Fees	-	-	-	-	-	-	2,776	278	3,053	-	3,053	-	-	-	-	-	-	-	-	-

Table G-1
Prairie Island Nuclear Generating Plant, Unit 1
DECON Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage and Periodic TN-40 Replacement
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 2c Period-Dependent Costs (continued)																					
2c.4.8	Fixed Overhead	-	-	-	-	-	-	2,676	401	3,078	3,078	-	-	-	-	-	-	-	-	-	-
2c.4.9	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	87	13	101	101	-	-	-	-	-	-	-	-	-	-
2c.4.10	ISFSI Operating Costs	-	-	-	-	-	-	112	17	128	-	128	-	-	-	-	-	-	-	-	-
2c.4.11	Railroad Track Maintenance	-	-	-	-	-	-	125	19	143	143	-	-	-	-	-	-	-	-	-	-
2c.4.12	Security Staff Cost	-	-	-	-	-	-	14,681	2,202	16,883	16,883	-	-	-	-	-	-	-	-	-	242,796
2c.4.13	Utility Staff Cost	-	-	-	-	-	-	2,064	310	2,374	2,374	-	-	-	-	-	-	-	-	-	33,722
2c.4	Subtotal Period 2c Period-Dependent Costs	-	390	18	5	-	66	29,988	4,135	34,602	31,421	3,181	-	-	809	-	-	-	16,171	26	276,518
2c.0	TOTAL PERIOD 2c COST	-	390	18	5	-	66	115,434	16,547	132,459	41,570	90,889	-	-	809	-	-	-	16,171	26	276,518
PERIOD 2d - Decontamination Following Wet Fuel Storage																					
Period 2d Direct Decommissioning Activities																					
2d.1.1	Remove spent fuel racks	328	32	94	32	-	595	-	335	1,416	1,416	-	-	-	2,092	-	-	-	138,298	576	-
Disposal of Plant Systems																					
2d.1.2.1	Electrical - Contaminated - Fuel Pool	-	147	2	4	53	7	-	47	259	259	-	-	615	23	-	-	-	26,508	2,077	-
2d.1.2.2	Electrical - Decontaminated - Fuel Pool	-	918	10	34	510	-	-	312	1,785	1,785	-	-	5,893	-	-	-	-	239,327	12,340	-
2d.1.2.3	HVAC - Contaminated - Fuel Pool	-	159	3	9	121	15	-	63	370	370	-	-	1,398	53	-	-	-	60,246	2,157	-
2d.1.2.4	Safeguards Chilled Water - RCA	-	82	1	3	43	-	-	27	155	155	-	-	495	-	-	-	-	20,100	1,019	-
2d.1.2.5	Spent Fuel Pool Cooling	293	342	34	25	70	377	-	344	1,484	1,484	-	-	806	1,325	-	-	-	120,439	7,613	-
2d.1.2.6	Station & Instrument Air - RCA Fuel Pool	-	20	0	0	7	-	-	6	34	34	-	-	83	-	-	-	-	3,374	263	-
2d.1.2	Totals	293	1,668	50	75	804	399	-	800	4,088	4,088	-	-	9,290	1,401	-	-	-	469,994	25,468	-
2d.1.4	Scaffolding in support of decommissioning	-	213	1	0	3	1	-	54	273	273	-	-	35	3	-	-	-	1,754	1,592	-
2d.1	Subtotal Period 2d Activity Costs	621	1,913	145	107	807	994	-	1,189	5,777	5,777	-	-	9,325	3,496	-	-	-	610,046	27,637	-
Period 2d Additional Costs																					
2d.2.1	License Termination Survey Planning	-	-	-	-	-	-	845	253	1,098	1,098	-	-	-	-	-	-	-	-	-	6,240
2d.2.2	Remedial Action Surveys	-	-	-	-	-	-	1,237	371	1,608	1,608	-	-	-	-	-	-	-	-	16,173	-
2d.2	Subtotal Period 2d Additional Costs	-	-	-	-	-	-	2,082	625	2,706	2,706	-	-	-	-	-	-	-	-	16,173	6,240
Period 2d Collateral Costs																					
2d.3.1	Process decommissioning water waste	27	-	18	48	-	75	-	41	209	209	-	-	-	179	-	-	-	10,724	35	-
2d.3.2	Process decommissioning chemical flush waste	1	-	32	121	-	241	-	82	478	478	-	-	-	324	-	-	-	34,576	61	-
2d.3.3	Small tool allowance	-	35	-	-	-	-	-	5	41	41	-	-	-	-	-	-	-	-	-	-
2d.3.4	Decommissioning Equipment Disposition	-	-	144	55	575	150	-	147	1,071	1,071	-	-	6,000	529	-	-	-	304,968	88	-
2d.3.5	Spent Fuel Capital and Transfer	-	-	-	-	-	-	13,144	1,972	15,115	-	15,115	-	-	-	-	-	-	-	-	-
2d.3.6	Prairie Island Indian Community Payments	-	-	-	-	-	-	971	-	971	-	971	-	-	-	-	-	-	-	-	-
2d.3	Subtotal Period 2d Collateral Costs	27	35	194	224	575	467	14,114	2,247	17,884	1,798	16,086	-	6,000	1,032	-	-	-	350,268	184	-
Period 2d Period-Dependent Costs																					
2d.4.1	Decon supplies	54	-	-	-	-	-	-	14	68	68	-	-	-	-	-	-	-	-	-	-
2d.4.2	Insurance	-	-	-	-	-	-	398	40	437	437	-	-	-	-	-	-	-	-	-	-
2d.4.3	Property taxes	-	-	-	-	-	-	1,740	174	1,914	1,914	-	-	-	-	-	-	-	-	-	-
2d.4.4	Health physics supplies	-	559	-	-	-	-	-	140	699	699	-	-	-	-	-	-	-	-	-	-
2d.4.5	Heavy equipment rental	-	1,757	-	-	-	-	-	264	2,020	2,020	-	-	-	-	-	-	-	-	-	-
2d.4.6	Disposal of DAW generated	-	-	18	5	-	67	-	19	110	110	-	-	-	829	-	-	-	16,581	27	-
2d.4.7	Plant energy budget	-	-	-	-	-	-	471	71	542	542	-	-	-	-	-	-	-	-	-	-
2d.4.8	NRC Fees	-	-	-	-	-	-	381	38	419	419	-	-	-	-	-	-	-	-	-	-
2d.4.9	Emergency Planning Fees	-	-	-	-	-	-	999	100	1,099	-	1,099	-	-	-	-	-	-	-	-	-
2d.4.10	Fixed Overhead	-	-	-	-	-	-	963	144	1,108	1,108	-	-	-	-	-	-	-	-	-	-
2d.4.11	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	315	47	362	362	-	-	-	-	-	-	-	-	-	-
2d.4.12	ISFSI Operating Costs	-	-	-	-	-	-	40	6	46	-	46	-	-	-	-	-	-	-	-	-
2d.4.13	Railroad Track Maintenance	-	-	-	-	-	-	45	7	52	52	-	-	-	-	-	-	-	-	-	-
2d.4.14	Security Staff Cost	-	-	-	-	-	-	5,123	768	5,891	5,891	-	-	-	-	-	-	-	-	-	84,157
2d.4.15	DOC Staff Cost	-	-	-	-	-	-	6,065	910	6,975	6,975	-	-	-	-	-	-	-	-	-	69,996
2d.4.16	Utility Staff Cost	-	-	-	-	-	-	7,796	1,169	8,966	8,527	439	-	-	-	-	-	-	-	-	126,236
2d.4	Subtotal Period 2d Period-Dependent Costs	54	2,316	18	5	-	67	24,337	3,911	30,708	29,123	1,584	-	-	829	-	-	-	16,581	27	280,390
2d.0	TOTAL PERIOD 2d COST	703	4,264	357	337	1,382	1,528	40,533	7,971	57,075	39,405	17,670	-	15,325	5,357	-	-	-	976,895	44,021	286,630

Table G-1
Prairie Island Nuclear Generating Plant, Unit 1
DECON Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage and Periodic TN-40 Replacement
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
PERIOD 2f - License Termination																					
Period 2f Direct Decommissioning Activities																					
2f.1.1	ORISE confirmatory survey	-	-	-	-	-	-	176	53	229	229	-	-	-	-	-	-	-	-	-	-
2f.1.2	Terminate license									a											
2f.1	Subtotal Period 2f Activity Costs	-	-	-	-	-	-	176	53	229	229	-	-	-	-	-	-	-	-	-	-
Period 2f Additional Costs																					
2f.2.1	License Termination Survey	-	-	-	-	-	-	3,217	965	4,182	4,182	-	-	-	-	-	-	-	-	40,172	3,120
2f.2	Subtotal Period 2f Additional Costs	-	-	-	-	-	-	3,217	965	4,182	4,182	-	-	-	-	-	-	-	-	40,172	3,120
Period 2f Collateral Costs																					
2f.3.1	DOC staff relocation expenses	-	-	-	-	-	-	1,189	178	1,367	1,367	-	-	-	-	-	-	-	-	-	-
2f.3.2	Prairie Island Indian Community Payments	-	-	-	-	-	-	934	-	934	-	934	-	-	-	-	-	-	-	-	-
2f.3	Subtotal Period 2f Collateral Costs	-	-	-	-	-	-	2,122	178	2,300	1,367	934	-	-	-	-	-	-	-	-	-
Period 2f Period-Dependent Costs																					
2f.4.1	Insurance	-	-	-	-	-	-	382	38	420	420	-	-	-	-	-	-	-	-	-	-
2f.4.2	Property taxes	-	-	-	-	-	-	1,626	163	1,789	1,789	-	-	-	-	-	-	-	-	-	-
2f.4.3	Health physics supplies	-	420	-	-	-	-	-	105	524	524	-	-	-	-	-	-	-	-	-	-
2f.4.4	Disposal of DAW generated	-	-	7	2	-	27	-	8	44	44	-	-	-	334	-	-	-	6,685	11	-
2f.4.5	Plant energy budget	-	-	-	-	-	-	227	34	261	261	-	-	-	-	-	-	-	-	-	-
2f.4.6	NRC Fees	-	-	-	-	-	-	417	42	459	459	-	-	-	-	-	-	-	-	-	-
2f.4.7	Emergency Planning Fees	-	-	-	-	-	-	51	5	56	-	56	-	-	-	-	-	-	-	-	-
2f.4.8	Fixed Overhead	-	-	-	-	-	-	926	139	1,065	1,065	-	-	-	-	-	-	-	-	-	-
2f.4.9	ISFSI Operating Costs	-	-	-	-	-	-	39	6	44	-	44	-	-	-	-	-	-	-	-	-
2f.4.10	Railroad Track Maintenance	-	-	-	-	-	-	43	6	50	50	-	-	-	-	-	-	-	-	-	-
2f.4.11	Security Staff Cost	-	-	-	-	-	-	4,924	739	5,663	5,663	-	-	-	-	-	-	-	-	-	80,898
2f.4.12	DOC Staff Cost	-	-	-	-	-	-	4,101	615	4,716	4,716	-	-	-	-	-	-	-	-	-	46,283
2f.4.13	Utility Staff Cost	-	-	-	-	-	-	3,854	578	4,433	4,007	426	-	-	-	-	-	-	-	-	59,507
2f.4	Subtotal Period 2f Period-Dependent Costs	-	420	7	2	-	27	16,591	2,477	19,524	18,998	526	-	-	334	-	-	-	6,685	11	186,687
2f.0	TOTAL PERIOD 2f COST	-	420	7	2	-	27	22,106	3,674	26,236	24,776	1,460	-	-	334	-	-	-	6,685	40,183	189,807
PERIOD 2 TOTALS		5,161	53,290	28,935	6,446	11,617	35,794	319,784	87,926	548,954	419,252	124,828	4,875	138,709	117,153	250	673	-	13,293,650	587,146	2,059,666
PERIOD 3b - Site Restoration																					
Period 3b Direct Decommissioning Activities																					
Demolition of Remaining Site Buildings																					
3b.1.1.1	Reactor	-	4,255	-	-	-	-	-	638	4,894	-	-	4,894	-	-	-	-	-	-	44,669	-
3b.1.1.2	Condensate Storage Tank Foundation	-	3	-	-	-	-	-	0	4	-	-	4	-	-	-	-	-	-	16	-
3b.1.1.3	Structures below 3' below grade	-	1,581	-	-	-	-	-	237	1,818	-	-	1,818	-	-	-	-	-	-	8,411	-
3b.1.1.4	Turbine	-	1,983	-	-	-	-	-	297	2,280	-	-	2,280	-	-	-	-	-	-	22,040	-
3b.1.1.5	Turbine Pedestal	-	349	-	-	-	-	-	52	402	-	-	402	-	-	-	-	-	-	1,857	-
3b.1.1	Totals	-	8,171	-	-	-	-	-	1,226	9,397	-	-	9,397	-	-	-	-	-	-	76,993	-
Site Closeout Activities																					
3b.1.2	Grade & landscape site	-	431	-	-	-	-	-	65	495	-	-	495	-	-	-	-	-	-	921	-
3b.1.3	Final report to NRC	-	-	-	-	-	-	183	27	211	211	-	-	-	-	-	-	-	-	-	1,560
3b.1	Subtotal Period 3b Activity Costs	-	8,602	-	-	-	-	183	1,318	10,102	211	-	9,892	-	-	-	-	-	-	77,914	1,560
Period 3b Additional Costs																					
3b.2.1	Clean Concrete Disposal	-	2,213	-	-	-	-	3	332	2,549	-	-	2,549	-	-	-	-	-	-	8,386	-
3b.2.2	Underground Services Excavations	-	811	-	-	-	-	520	200	1,531	-	-	1,531	-	-	-	-	-	-	7,407	-
3b.2.3	Intake Structure Cofferdam	-	596	-	-	-	-	-	89	686	-	-	686	-	-	-	-	-	-	5,168	-
3b.2.4	Construction Debris	-	-	-	-	-	-	10	2	12	12	-	-	-	-	-	-	-	-	-	-
3b.2.5	Backfill	-	2,751	-	-	-	-	-	413	3,164	-	-	3,164	-	-	-	-	-	-	2,904	-
3b.2	Subtotal Period 3b Additional Costs	-	6,371	-	-	-	-	534	1,036	7,941	12	-	7,929	-	-	-	-	-	-	23,865	-
Period 3b Collateral Costs																					
3b.3.1	Small tool allowance	-	110	-	-	-	-	-	16	126	-	-	126	-	-	-	-	-	-	-	-
3b.3.2	Prairie Island Indian Community Payments	-	-	-	-	-	-	2,651	-	2,651	-	2,651	-	-	-	-	-	-	-	-	-
3b.3	Subtotal Period 3b Collateral Costs	-	110	-	-	-	-	2,651	16	2,777	-	2,651	126	-	-	-	-	-	-	-	-

Table G-1
Prairie Island Nuclear Generating Plant, Unit 1
DECON Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage and Periodic TN-40 Replacement
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 3b Period-Dependent Costs																					
3b.4.1	Insurance	-	-	-	-	-	-	542	54	596	-	596	-	-	-	-	-	-	-	-	-
3b.4.2	Property taxes	-	-	-	-	-	-	4,334	433	4,767	-	4,767	-	-	-	-	-	-	-	-	-
3b.4.3	Heavy equipment rental	-	6,670	-	-	-	-	-	1,000	7,670	-	-	7,670	-	-	-	-	-	-	-	-
3b.4.4	Plant energy budget	-	-	-	-	-	-	321	48	369	-	-	369	-	-	-	-	-	-	-	-
3b.4.5	NRC ISFSI Fees	-	-	-	-	-	-	236	24	259	-	259	-	-	-	-	-	-	-	-	-
3b.4.6	Emergency Planning Fees	-	-	-	-	-	-	145	14	159	-	159	-	-	-	-	-	-	-	-	-
3b.4.7	Fixed Overhead	-	-	-	-	-	-	990	148	1,138	-	-	1,138	-	-	-	-	-	-	-	-
3b.4.8	ISFSI Operating Costs	-	-	-	-	-	-	109	16	126	-	126	-	-	-	-	-	-	-	-	-
3b.4.9	Railroad Track Maintenance	-	-	-	-	-	-	331	50	380	-	-	380	-	-	-	-	-	-	-	-
3b.4.10	Security Staff Cost	-	-	-	-	-	-	4,245	637	4,882	-	4,882	-	-	-	-	-	-	-	-	57,340
3b.4.11	DOC Staff Cost	-	-	-	-	-	-	10,467	1,570	12,038	-	-	12,038	-	-	-	-	-	-	-	116,885
3b.4.12	Utility Staff Cost	-	-	-	-	-	-	4,813	722	5,535	(0)	1,207	4,329	-	-	-	-	-	-	-	74,431
3b.4	Subtotal Period 3b Period-Dependent Costs	-	6,670	-	-	-	-	26,534	4,718	37,921	(0)	11,997	25,924	-	-	-	-	-	-	-	248,656
3b.0	TOTAL PERIOD 3b COST	-	21,752	-	-	-	-	29,901	7,088	58,741	222	14,648	43,871	-	-	-	-	-	-	101,779	250,216
PERIOD 3c - Fuel Storage Operations/Shipping																					
Period 3c Direct Decommissioning Activities																					
Period 3c Collateral Costs																					
3c.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	84,962	12,744	97,707	-	97,707	-	-	-	-	-	-	-	-	-
3c.3.2	Prairie Island Indian Community Payments	-	-	-	-	-	-	43,116	-	43,116	-	43,116	-	-	-	-	-	-	-	-	-
3c.3	Subtotal Period 3c Collateral Costs	-	-	-	-	-	-	128,079	12,744	140,823	-	140,823	-	-	-	-	-	-	-	-	-
Period 3c Period-Dependent Costs																					
3c.4.1	Insurance	-	-	-	-	-	-	8,818	882	9,700	-	9,700	-	-	-	-	-	-	-	-	-
3c.4.2	Property taxes	-	-	-	-	-	-	39,829	3,983	43,812	-	43,812	-	-	-	-	-	-	-	-	-
3c.4.4	NRC ISFSI Fees	-	-	-	-	-	-	5,648	565	6,213	-	6,213	-	-	-	-	-	-	-	-	-
3c.4.5	Emergency Planning Fees	-	-	-	-	-	-	2,360	236	2,596	-	2,596	-	-	-	-	-	-	-	-	-
3c.4.6	Fixed Overhead	-	-	-	-	-	-	5,267	790	6,057	-	6,057	-	-	-	-	-	-	-	-	-
3c.4.7	ISFSI Operating Costs	-	-	-	-	-	-	1,782	267	2,049	-	2,049	-	-	-	-	-	-	-	-	-
3c.4.8	Railroad Track Maintenance	-	-	-	-	-	-	1,991	299	2,289	-	2,289	-	-	-	-	-	-	-	-	-
3c.4.9	Security Staff Cost	-	-	-	-	-	-	69,105	10,366	79,471	-	79,471	-	-	-	-	-	-	-	-	933,362
3c.4.10	Utility Staff Cost	-	-	-	-	-	-	17,069	2,560	19,629	-	19,629	-	-	-	-	-	-	-	-	242,315
3c.4	Subtotal Period 3c Period-Dependent Costs	-	-	-	-	-	-	151,870	19,948	171,817	-	171,817	-	-	-	-	-	-	-	-	1,175,677
3c.0	TOTAL PERIOD 3c COST	-	-	-	-	-	-	279,948	32,692	312,640	-	312,640	-	-	-	-	-	-	-	-	1,175,677
PERIOD 3d - GTCC shipping																					
Period 3d Direct Decommissioning Activities																					
Nuclear Steam Supply System Removal																					
3d.1.1.1	Vessel & Internals GTCC Disposal	-	-	1,331	-	-	8,689	-	1,636	11,656	11,656	-	-	-	-	-	-	-	3,746	837,596	-	-
3d.1.1	Totals	-	-	1,331	-	-	8,689	-	1,636	11,656	11,656	-	-	-	-	-	-	-	3,746	837,596	-	-
3d.1	Subtotal Period 3d Activity Costs	-	-	1,331	-	-	8,689	-	1,636	11,656	11,656	-	-	-	-	-	-	-	3,746	837,596	-	-
Period 3d Collateral Costs																					
3d.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	26	4	29	-	29	-	-	-	-	-	-	-	-	-	-
3d.3.2	Prairie Island Indian Community Payments	-	-	-	-	-	-	48	-	48	-	48	-	-	-	-	-	-	-	-	-	-
3d.3	Subtotal Period 3d Collateral Costs	-	-	-	-	-	-	73	4	77	-	77	-	-	-	-	-	-	-	-	-	-
Period 3d Period-Dependent Costs																					
3d.4.1	Insurance	-	-	-	-	-	-	10	1	11	11	-	-	-	-	-	-	-	-	-	-	-
3d.4.2	Property taxes	-	-	-	-	-	-	39	4	43	43	-	-	-	-	-	-	-	-	-	-	-
3d.4.4	NRC ISFSI Fees	-	-	-	-	-	-	4	0	5	-	5	-	-	-	-	-	-	-	-	-	-
3d.4.5	Emergency Planning Fees	-	-	-	-	-	-	3	0	3	-	3	-	-	-	-	-	-	-	-	-	-
3d.4.6	Fixed Overhead	-	-	-	-	-	-	6	1	7	7	-	-	-	-	-	-	-	-	-	-	-
3d.4.7	ISFSI Operating Costs	-	-	-	-	-	-	2	0	2	-	2	-	-	-	-	-	-	-	-	-	-
3d.4.8	Railroad Track Maintenance	-	-	-	-	-	-	2	0	3	3	-	-	-	-	-	-	-	-	-	-	-
3d.4.9	Security Staff Cost	-	-	-	-	-	-	77	12	88	88	-	-	-	-	-	-	-	-	-	-	1,037
3d.4.10	Utility Staff Cost	-	-	-	-	-	-	19	3	22	22	-	-	-	-	-	-	-	-	-	-	269
3d.4	Subtotal Period 3d Period-Dependent Costs	-	-	-	-	-	-	162	21	183	173	10	-	-	-	-	-	-	-	-	-	1,306
3d.0	TOTAL PERIOD 3d COST	-	-	1,331	-	-	8,689	235	1,661	11,916	11,829	87	-	-	-	-	-	-	3,746	837,596	-	1,306

Table G-1
Prairie Island Nuclear Generating Plant, Unit 1
DECON Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage and Periodic TN-40 Replacement
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
PERIOD 3e - ISFSI Decontamination																					
Period 3e Direct Decommissioning Activities																					
Period 3e Additional Costs																					
3e.2.1	License Termination ISFSI	15	48	2	214	-	2,289	867	859	4,293	4,293	-	-	-	8,229	-	-	-	1,119,503	5,267	924
3e.2	Subtotal Period 3e Additional Costs	15	48	2	214	-	2,289	867	859	4,293	4,293	-	-	-	8,229	-	-	-	1,119,503	5,267	924
Period 3e Period-Dependent Costs																					
3e.4.1	Insurance	-	-	-	-	-	-	96	24	121	121	-	-	-	-	-	-	-	-	-	-
3e.4.2	Property taxes	-	-	-	-	-	-	26	6	32	32	-	-	-	-	-	-	-	-	-	-
3e.4.4	Fixed Overhead	-	-	-	-	-	-	51	13	63	63	-	-	-	-	-	-	-	-	-	-
3e.4.5	Railroad Track Maintenance	-	-	-	-	-	-	19	5	24	24	-	-	-	-	-	-	-	-	-	-
3e.4.6	Security Staff Cost	-	-	-	-	-	-	154	38	192	192	-	-	-	-	-	-	-	-	-	2,500
3e.4.7	Utility Staff Cost	-	-	-	-	-	-	130	33	163	163	-	-	-	-	-	-	-	-	-	1,896
3e.4	Subtotal Period 3e Period-Dependent Costs	-	-	-	-	-	-	476	119	595	595	-	-	-	-	-	-	-	-	-	4,396
3e.0	TOTAL PERIOD 3e COST	15	48	2	214	-	2,289	1,343	978	4,888	4,888	-	-	-	8,229	-	-	-	1,119,503	5,267	5,320
PERIOD 3f - ISFSI Site Restoration																					
Period 3f Direct Decommissioning Activities																					
Period 3f Additional Costs																					
3f.2.1	Demolition and Site Restoration of ISFSI	-	715	-	-	-	-	109	124	948	-	-	948	-	-	-	-	-	-	3,748	160
3f.2	Subtotal Period 3f Additional Costs	-	715	-	-	-	-	109	124	948	-	-	948	-	-	-	-	-	-	3,748	160
Period 3f Collateral Costs																					
3f.3.1	Small tool allowance	-	6	-	-	-	-	-	1	7	-	-	7	-	-	-	-	-	-	-	-
3f.3	Subtotal Period 3f Collateral Costs	-	6	-	-	-	-	-	1	7	-	-	7	-	-	-	-	-	-	-	-
Period 3f Period-Dependent Costs																					
3f.4.2	Property taxes	-	-	-	-	-	-	13	1	14	-	-	14	-	-	-	-	-	-	-	-
3f.4.3	Heavy equipment rental	-	62	-	-	-	-	-	9	71	-	-	71	-	-	-	-	-	-	-	-
3f.4.4	Plant energy budget	-	-	-	-	-	-	13	2	15	-	-	15	-	-	-	-	-	-	-	-
3f.4.5	Fixed Overhead	-	-	-	-	-	-	25	4	29	-	-	29	-	-	-	-	-	-	-	-
3f.4.6	Railroad Track Maintenance	-	-	-	-	-	-	10	1	11	-	-	11	-	-	-	-	-	-	-	-
3f.4.7	Security Staff Cost	-	-	-	-	-	-	78	12	89	-	-	89	-	-	-	-	-	-	-	1,260
3f.4.8	Utility Staff Cost	-	-	-	-	-	-	52	8	60	-	-	60	-	-	-	-	-	-	-	782
3f.4	Subtotal Period 3f Period-Dependent Costs	-	62	-	-	-	-	190	37	289	-	-	289	-	-	-	-	-	-	-	2,042
3f.0	TOTAL PERIOD 3f COST	-	782	-	-	-	-	300	162	1,243	-	-	1,243	-	-	-	-	-	-	3,748	2,202
PERIOD 3 TOTALS		15	22,582	1,333	214	-	10,978	311,727	42,580	389,429	16,940	327,375	45,114	-	8,229	-	-	3,746	1,957,099	110,795	1,434,720
TOTAL COST TO DECOMMISSION		**8,749**	**81,241**	**30,683**	**7,111**	**11,781**	**50,744**	**742,143**	**149,771**	**1,082,223**	**572,323**	**458,457**	**51,443**	**144,842**	**139,346**	**839**	**673**	**3,746**	**15,860,890**	**743,467**	**4,498,807**

TOTAL COST TO DECOMMISSION WITH 16.06% CONTINGENCY:	**$1,082,223**	**thousands of 2017 dollars**
TOTAL NRC LICENSE TERMINATION COST IS 52.88% OR:	**$572,323**	**thousands of 2017 dollars**
SPENT FUEL MANAGEMENT COST IS 42.36% OR:	**$458,457**	**thousands of 2017 dollars**
NON-NUCLEAR DEMOLITION COST IS 4.75% OR:	**$51,443**	**thousands of 2017 dollars**
TOTAL LOW-LEVEL RADIOACTIVE WASTE VOLUME BURIED (EXCLUDING GTCC):	**140,858**	**cubic feet**
TOTAL GREATER THAN CLASS C RADWASTE VOLUME GENERATED:	**3,746**	**cubic feet**
TOTAL SCRAP METAL REMOVED:	**32,925**	**tons**
TOTAL CRAFT LABOR REQUIREMENTS:	**743,467**	**man-hours**

End Notes:
n/a - indicates that this activity not charged as decommissioning expense
a - indicates that this activity performed by decommissioning staff
0 - indicates that this value is less than 0.5 but is non-zero
A cell containing " - " indicates a zero value

Table G-2
Prairie Island Nuclear Generating Plant, Unit 2
DECON Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage and Periodic TN-40 Replacement
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
PERIOD 1a - Shutdown through Transition																					
Period 1a Direct Decommissioning Activities																					
1a.1.1	Prepare preliminary decommissioning cost	-	-	-	-	-	-	65	10	75	75	-	-	-	-	-	-	-	-	-	556
1a.1.2	Notification of Cessation of Operations									a											
1a.1.3	Remove fuel & source material									n/a											
1a.1.4	Notification of Permanent Defueling									a											
1a.1.5	Deactivate plant systems & process waste									a											
1a.1.6	Prepare and submit PSDAR	-	-	-	-	-	-	100	15	115	115	-	-	-	-	-	-	-	-	-	855
1a.1.7	Review plant dwgs & specs.	-	-	-	-	-	-	231	35	266	266	-	-	-	-	-	-	-	-	-	1,967
1a.1.8	Perform detailed rad survey									a											
1a.1.9	Estimate by-product inventory	-	-	-	-	-	-	50	8	58	58	-	-	-	-	-	-	-	-	-	428
1a.1.10	End product description	-	-	-	-	-	-	50	8	58	58	-	-	-	-	-	-	-	-	-	428
1a.1.11	Detailed by-product inventory	-	-	-	-	-	-	65	10	75	75	-	-	-	-	-	-	-	-	-	556
1a.1.12	Define major work sequence	-	-	-	-	-	-	376	56	433	433	-	-	-	-	-	-	-	-	-	3,207
1a.1.13	Perform SER and EA	-	-	-	-	-	-	156	23	179	179	-	-	-	-	-	-	-	-	-	1,326
1a.1.14	Prepare/submit Defueled Technical Specifications	-	-	-	-	-	-	376	56	433	433	-	-	-	-	-	-	-	-	-	3,207
1a.1.15	Perform Site-Specific Cost Study	-	-	-	-	-	-	251	38	289	289	-	-	-	-	-	-	-	-	-	2,138
1a.1.16	Prepare/submit Irradiated Fuel Management Plan	-	-	-	-	-	-	50	8	58	58	-	-	-	-	-	-	-	-	-	428
Activity Specifications																					
1a.1.17.1	Plant & temporary facilities	-	-	-	-	-	-	247	37	284	256	-	28	-	-	-	-	-	-	-	2,104
1a.1.17.2	Plant systems	-	-	-	-	-	-	209	31	241	216	-	24	-	-	-	-	-	-	-	1,782
1a.1.17.3	NSSS Decontamination Flush	-	-	-	-	-	-	25	4	29	29	-	-	-	-	-	-	-	-	-	214
1a.1.17.4	Reactor internals	-	-	-	-	-	-	356	53	410	410	-	-	-	-	-	-	-	-	-	3,036
1a.1.17.5	Reactor vessel	-	-	-	-	-	-	326	49	375	375	-	-	-	-	-	-	-	-	-	2,779
1a.1.17.6	Biological shield	-	-	-	-	-	-	25	4	29	29	-	-	-	-	-	-	-	-	-	214
1a.1.17.7	Steam generators	-	-	-	-	-	-	157	23	180	180	-	-	-	-	-	-	-	-	-	1,334
1a.1.17.8	Reinforced concrete	-	-	-	-	-	-	80	12	92	46	-	46	-	-	-	-	-	-	-	684
1a.1.17.9	Main Turbine	-	-	-	-	-	-	20	3	23	-	-	23	-	-	-	-	-	-	-	171
1a.1.17.10	Main Condensers	-	-	-	-	-	-	20	3	23	-	-	23	-	-	-	-	-	-	-	171
1a.1.17.11	Plant structures & buildings	-	-	-	-	-	-	157	23	180	90	-	90	-	-	-	-	-	-	-	1,334
1a.1.17.12	Waste management	-	-	-	-	-	-	231	35	266	266	-	-	-	-	-	-	-	-	-	1,967
1a.1.17.13	Facility & site closeout	-	-	-	-	-	-	45	7	52	26	-	26	-	-	-	-	-	-	-	385
1a.1.17	Total	-	-	-	-	-	-	1,899	285	2,183	1,923	-	261	-	-	-	-	-	-	-	16,175
Planning & Site Preparations																					
1a.1.18	Prepare dismantling sequence	-	-	-	-	-	-	120	18	139	139	-	-	-	-	-	-	-	-	-	1,026
1a.1.19	Plant prep. & temp. svces	-	-	-	-	-	-	3,300	495	3,795	3,795	-	-	-	-	-	-	-	-	-	-
1a.1.20	Design water clean-up system	-	-	-	-	-	-	70	11	81	81	-	-	-	-	-	-	-	-	-	599
1a.1.21	Rigging/Cont. Cntrl Envlps/tooling/etc.	-	-	-	-	-	-	2,300	345	2,645	2,645	-	-	-	-	-	-	-	-	-	-
1a.1.22	Procure casks/liners & containers	-	-	-	-	-	-	62	9	71	71	-	-	-	-	-	-	-	-	-	526
1a.1	Subtotal Period 1a Activity Costs	-	-	-	-	-	-	9,523	1,428	10,951	10,690	-	261	-	-	-	-	-	-	-	33,420
Period 1a Additional Costs																					
1a.2.1	Spent Fuel Pool Isolation	-	-	-	-	-	-	7,794	1,169	8,963	8,963	-	-	-	-	-	-	-	-	-	-
1a.2	Subtotal Period 1a Additional Costs	-	-	-	-	-	-	7,794	1,169	8,963	8,963	-	-	-	-	-	-	-	-	-	-
Period 1a Collateral Costs																					
1a.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	1,227	184	1,411	-	1,411	-	-	-	-	-	-	-	-	-
1a.3.2	Retention and Severance	-	-	-	-	-	-	8,394	1,259	9,653	9,653	-	-	-	-	-	-	-	-	-	-
1a.3.3	Prairie Island Indian Community Payments	-	-	-	-	-	-	2,281	-	2,281	-	2,281	-	-	-	-	-	-	-	-	-
1a.3	Subtotal Period 1a Collateral Costs	-	-	-	-	-	-	11,902	1,443	13,345	9,653	3,692	-	-	-	-	-	-	-	-	-
Period 1a Period-Dependent Costs																					
1a.4.1	Insurance	-	-	-	-	-	-	1,730	173	1,903	1,903	-	-	-	-	-	-	-	-	-	-
1a.4.2	Property taxes	-	-	-	-	-	-	2,682	268	2,950	2,950	-	-	-	-	-	-	-	-	-	-
1a.4.3	Health physics supplies	-	485	-	-	-	-	-	121	606	606	-	-	-	-	-	-	-	-	-	-
1a.4.4	Heavy equipment rental	-	567	-	-	-	-	-	85	652	652	-	-	-	-	-	-	-	-	-	-
1a.4.5	Disposal of DAW generated	-	-	12	4	-	46	-	13	75	75	-	-	-	565	-	-	-	11,299	18	-
1a.4.6	Plant energy budget	-	-	-	-	-	-	1,515	227	1,742	1,742	-	-	-	-	-	-	-	-	-	-
1a.4.7	NRC Fees	-	-	-	-	-	-	778	78	855	855	-	-	-	-	-	-	-	-	-	-
1a.4.8	Emergency Planning Fees	-	-	-	-	-	-	1,604	160	1,765	-	1,765	-	-	-	-	-	-	-	-	-
1a.4.9	Fixed Overhead	-	-	-	-	-	-	1,470	220	1,690	1,690	-	-	-	-	-	-	-	-	-	-
1a.4.10	Spent Fuel Pool O&M	-	-	-	-	-	-	401	60	461	-	461	-	-	-	-	-	-	-	-	-
1a.4.11	ISFSI Operating Costs	-	-	-	-	-	-	52	8	59	-	59	-	-	-	-	-	-	-	-	-
1a.4.12	Railroad Track Maintenance	-	-	-	-	-	-	58	9	66	66	-	-	-	-	-	-	-	-	-	-
1a.4.13	Security Staff Cost	-	-	-	-	-	-	7,390	1,108	8,498	8,498	-	-	-	-	-	-	-	-	-	122,720
1a.4.14	Utility Staff Cost	-	-	-	-	-	-	20,662	3,099	23,761	23,761	-	-	-	-	-	-	-	-	-	345,280

Table G-2
Prairie Island Nuclear Generating Plant, Unit 2
DECON Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage and Periodic TN-40 Replacement
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
1a.4	Subtotal Period 1a Period-Dependent Costs	-	1,052	12	4	-	46	38,340	5,631	45,085	42,800	2,286	-	-	565	-	-	-	11,299	18	468,000
1a.0	TOTAL PERIOD 1a COST	-	1,052	12	4	-	46	67,559	9,672	78,345	72,107	5,977	261	-	565	-	-	-	11,299	18	501,420
PERIOD 1b - Decommissioning Preparations																					
Period 1b Direct Decommissioning Activities																					
Detailed Work Procedures																					
1b.1.1.1	Plant systems	-	-	-	-	-	-	238	36	273	246	-	27	-	-	-	-	-	-	-	2,024
1b.1.1.2	NSSS Decontamination Flush	-	-	-	-	-	-	50	8	58	58	-	-	-	-	-	-	-	-	-	428
1b.1.1.3	Reactor internals	-	-	-	-	-	-	125	19	144	144	-	-	-	-	-	-	-	-	-	1,069
1b.1.1.4	Remaining buildings	-	-	-	-	-	-	68	10	78	19	-	58	-	-	-	-	-	-	-	577
1b.1.1.5	CRD cooling assembly	-	-	-	-	-	-	50	8	58	58	-	-	-	-	-	-	-	-	-	428
1b.1.1.6	CRD housings & ICI tubes	-	-	-	-	-	-	50	8	58	58	-	-	-	-	-	-	-	-	-	428
1b.1.1.7	Incore instrumentation	-	-	-	-	-	-	50	8	58	58	-	-	-	-	-	-	-	-	-	428
1b.1.1.8	Reactor vessel	-	-	-	-	-	-	182	27	210	210	-	-	-	-	-	-	-	-	-	1,552
1b.1.1.9	Facility closeout	-	-	-	-	-	-	60	9	69	35	-	35	-	-	-	-	-	-	-	513
1b.1.1.10	Missile shields	-	-	-	-	-	-	23	3	26	26	-	-	-	-	-	-	-	-	-	192
1b.1.1.11	Biological shield	-	-	-	-	-	-	60	9	69	69	-	-	-	-	-	-	-	-	-	513
1b.1.1.12	Steam generators	-	-	-	-	-	-	231	35	266	266	-	-	-	-	-	-	-	-	-	1,967
1b.1.1.13	Reinforced concrete	-	-	-	-	-	-	50	8	58	29	-	29	-	-	-	-	-	-	-	428
1b.1.1.14	Main Turbine	-	-	-	-	-	-	78	12	90	-	-	90	-	-	-	-	-	-	-	667
1b.1.1.15	Main Condensers	-	-	-	-	-	-	78	12	90	-	-	90	-	-	-	-	-	-	-	667
1b.1.1.16	Auxiliary building	-	-	-	-	-	-	137	21	158	142	-	16	-	-	-	-	-	-	-	1,167
1b.1.1.17	Reactor building	-	-	-	-	-	-	137	21	158	142	-	16	-	-	-	-	-	-	-	1,167
1b.1.1	Total	-	-	-	-	-	-	1,669	250	1,919	1,558	-	361	-	-	-	-	-	-	-	14,215
1b.1.2	Decon primary loop	552	-	-	-	-	-	-	276	828	828	-	-	-	-	-	-	-	-	1,067	-
1b.1	Subtotal Period 1b Activity Costs	552	-	-	-	-	-	1,669	526	2,747	2,386	-	361	-	-	-	-	-	-	1,067	14,215
Period 1b Additional Costs																					
1b.2.1	Site Characterization	-	-	-	-	-	-	1,582	475	2,057	2,057	-	-	-	-	-	-	-	-	8,988	3,563
1b.2.2	Mixed/Hazardous Waste	-	-	326	75	169	-	-	69	639	639	-	-	6,324	-	-	-	-	362,914	2,410	-
1b.2.3	Asbestos Abatement	-	2,364	2	110	-	1,359	-	947	4,782	4,782	-	-	-	12,843	-	-	-	166,959	20,907	-
1b.2	Subtotal Period 1b Additional Costs	-	2,364	328	185	169	1,359	1,582	1,491	7,478	7,478	-	-	6,324	12,843	-	-	-	529,873	32,305	3,563
Period 1b Collateral Costs																					
1b.3.1	Decon equipment	973	-	-	-	-	-	-	146	1,119	1,119	-	-	-	-	-	-	-	-	-	-
1b.3.2	DOC staff relocation expenses	-	-	-	-	-	-	1,189	178	1,367	1,367	-	-	-	-	-	-	-	-	-	-
1b.3.3	Process decommissioning water waste	24	-	16	41	-	64	-	36	180	180	-	-	-	152	-	-	-	9,121	30	-
1b.3.4	Process decommissioning chemical flush waste	2	-	58	220	-	2,471	-	657	3,408	3,408	-	-	-	-	588	-	-	62,689	110	-
1b.3.5	Small tool allowance	-	34	-	-	-	-	-	5	39	39	-	-	-	-	-	-	-	-	-	-
1b.3.6	Pipe cutting equipment	-	1,200	-	-	-	-	-	180	1,380	1,380	-	-	-	-	-	-	-	-	-	-
1b.3.7	Decon rig	1,987	-	-	-	-	-	-	298	2,285	2,285	-	-	-	-	-	-	-	-	-	-
1b.3.8	Spent Fuel Capital and Transfer	-	-	-	-	-	-	370	56	426	-	426	-	-	-	-	-	-	-	-	-
1b.3.9	Retention and Severance	-	-	-	-	-	-	4,055	608	4,664	4,664	-	-	-	-	-	-	-	-	-	-
1b.3.10	Prairie Island Indian Community Payments	-	-	-	-	-	-	629	-	629	-	629	-	-	-	-	-	-	-	-	-
1b.3	Subtotal Period 1b Collateral Costs	2,986	1,234	74	261	-	2,534	6,243	2,164	15,495	14,441	1,055	-	-	152	588	-	-	71,810	140	-
Period 1b Period-Dependent Costs																					
1b.4.1	Decon supplies	35	-	-	-	-	-	-	9	44	44	-	-	-	-	-	-	-	-	-	-
1b.4.2	Insurance	-	-	-	-	-	-	872	87	959	959	-	-	-	-	-	-	-	-	-	-
1b.4.3	Property taxes	-	-	-	-	-	-	1,319	132	1,451	1,451	-	-	-	-	-	-	-	-	-	-
1b.4.4	Health physics supplies	-	380	-	-	-	-	-	95	475	475	-	-	-	-	-	-	-	-	-	-
1b.4.5	Heavy equipment rental	-	286	-	-	-	-	-	43	329	329	-	-	-	-	-	-	-	-	-	-
1b.4.6	Disposal of DAW generated	-	-	7	2	-	27	-	8	44	44	-	-	-	327	-	-	-	6,541	11	-
1b.4.7	Plant energy budget	-	-	-	-	-	-	1,527	229	1,756	1,756	-	-	-	-	-	-	-	-	-	-
1b.4.8	NRC Fees	-	-	-	-	-	-	214	21	236	236	-	-	-	-	-	-	-	-	-	-
1b.4.9	Emergency Planning Fees	-	-	-	-	-	-	809	81	890	-	890	-	-	-	-	-	-	-	-	-
1b.4.10	Fixed Overhead	-	-	-	-	-	-	741	111	852	852	-	-	-	-	-	-	-	-	-	-
1b.4.11	Spent Fuel Pool O&M	-	-	-	-	-	-	202	30	233	-	233	-	-	-	-	-	-	-	-	-
1b.4.12	ISFSI Operating Costs	-	-	-	-	-	-	26	4	30	-	30	-	-	-	-	-	-	-	-	-
1b.4.13	Railroad Track Maintenance	-	-	-	-	-	-	29	4	33	33	-	-	-	-	-	-	-	-	-	-
1b.4.14	Security Staff Cost	-	-	-	-	-	-	3,725	559	4,284	4,284	-	-	-	-	-	-	-	-	-	61,864
1b.4.15	DOC Staff Cost	-	-	-	-	-	-	4,009	601	4,610	4,610	-	-	-	-	-	-	-	-	-	47,185
1b.4.16	Utility Staff Cost	-	-	-	-	-	-	10,416	1,562	11,978	11,978	-	-	-	-	-	-	-	-	-	174,059
1b.4	Subtotal Period 1b Period-Dependent Costs	35	666	7	2	-	27	23,890	3,577	28,204	27,052	1,152	-	-	327	-	-	-	6,541	11	283,108

Table G-2
Prairie Island Nuclear Generating Plant, Unit 2
DECON Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage and Periodic TN-40 Replacement
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
1b.0	TOTAL PERIOD 1b COST	3,573	4,264	410	447	169	3,920	33,383	7,759	53,923	51,356	2,207	361	6,324	13,322	588	-	-	608,224	33,522	300,885
PERIOD 1 TOTALS		3,573	5,316	422	451	169	3,966	100,942	17,430	132,268	123,462	8,184	622	6,324	13,887	588	-	-	619,523	33,540	802,305
PERIOD 2a - Large Component Removal																					
Period 2a Direct Decommissioning Activities																					
Nuclear Steam Supply System Removal																					
2a.1.1.1	Reactor Coolant Piping	51	45	6	8	-	150	-	76	336	336	-	-	-	305	-	-	-	34,809	1,414	-
2a.1.1.2	Pressurizer Relief Tank	22	20	4	5	-	100	-	42	193	193	-	-	-	203	-	-	-	23,193	625	-
2a.1.1.3	Reactor Coolant Pumps & Motors	54	63	101	83	-	736	-	249	1,287	1,287	-	-	-	2,332	-	-	-	295,800	2,049	100
2a.1.1.4	Pressurizer	48	68	467	88	-	693	-	274	1,639	1,639	-	-	-	2,196	-	-	-	185,015	2,355	938
2a.1.1.5	Steam Generators	225	2,943	2,093	1,638	1,246	3,570	-	2,383	14,097	14,097	-	-	18,672	11,316	-	-	-	1,668,341	14,819	2,875
2a.1.1.6	CRDMs/ICIs/Service Structure Removal	286	277	211	48	-	763	-	431	2,016	2,016	-	-	-	4,797	-	-	-	177,400	8,104	-
2a.1.1.7	Reactor Vessel Internals	78	4,468	21,874	1,072	-	7,946	277	13,141	48,856	48,856	-	-	-	501	125	673	-	164,987	23,040	1,080
2a.1.1.8	Reactor Vessel	89	5,717	1,754	719	-	1,956	277	5,970	16,483	16,483	-	-	-	5,690	-	-	-	570,074	23,040	1,080
2a.1.1	Totals	855	13,600	26,512	3,662	1,246	15,913	553	22,568	84,908	84,908	-	-	18,672	27,341	125	673	-	3,119,620	75,446	6,073
Removal of Major Equipment																					
2a.1.2	Main Turbine/Generator	-	305	189	55	272	306	-	221	1,348	1,348	-	-	2,131	1,187	-	-	-	206,316	4,667	-
2a.1.3	Main Condensers	-	2,532	121	49	364	451	-	820	4,336	4,336	-	-	3,800	1,587	-	-	-	275,903	39,151	-
Cascading Costs from Clean Building Demolition																					
2a.1.4.1	Reactor	-	728	-	-	-	-	-	109	837	837	-	-	-	-	-	-	-	-	7,589	-
2a.1.4.2	Auxiliary	-	210	-	-	-	-	-	32	242	242	-	-	-	-	-	-	-	-	1,309	-
2a.1.4.3	Radwaste	-	8	-	-	-	-	-	1	9	9	-	-	-	-	-	-	-	-	65	-
2a.1.4	Totals	-	946	-	-	-	-	-	142	1,088	1,088	-	-	-	-	-	-	-	-	8,963	-
Disposal of Plant Systems																					
2a.1.5.1	Admin Bldg Ventilation	-	6	-	-	-	-	-	1	6	-	-	6	-	-	-	-	-	-	90	-
2a.1.5.2	Air Removal	-	25	-	-	-	-	-	4	29	-	-	29	-	-	-	-	-	-	422	-
2a.1.5.3	Auxiliary Feedwater	-	40	-	-	-	-	-	6	46	-	-	46	-	-	-	-	-	-	676	-
2a.1.5.4	Auxiliary Feedwater - RCA	-	36	0	1	15	-	-	12	65	65	-	-	178	-	-	-	-	7,214	486	-
2a.1.5.5	Bleed Steam	-	78	-	-	-	-	-	12	90	-	-	90	-	-	-	-	-	-	1,331	-
2a.1.5.6	Caustic Addition - RCA	-	38	0	1	21	-	-	13	74	74	-	-	240	-	-	-	-	9,761	468	-
2a.1.5.7	Chemical Feed	-	15	-	-	-	-	-	2	17	-	-	17	-	-	-	-	-	-	261	-
2a.1.5.8	Chemical Feed - RCA	-	3	0	0	1	-	-	1	5	5	-	-	16	-	-	-	-	634	31	-
2a.1.5.9	Circulating Water	-	24	-	-	-	-	-	4	28	-	-	28	-	-	-	-	-	-	401	-
2a.1.5.10	Condensate	-	459	-	-	-	-	-	69	527	-	-	527	-	-	-	-	-	-	7,537	-
2a.1.5.11	Condensate Polishing	-	181	-	-	-	-	-	27	209	-	-	209	-	-	-	-	-	-	2,987	-
2a.1.5.12	Condensate Polishing - RCA	-	36	1	3	42	-	-	16	98	98	-	-	483	-	-	-	-	19,616	493	-
2a.1.5.13	Electro-Hydraulic	-	8	-	-	-	-	-	1	10	-	-	10	-	-	-	-	-	-	143	-
2a.1.5.14	External Circulating Water	-	23	-	-	-	-	-	3	26	-	-	26	-	-	-	-	-	-	385	-
2a.1.5.15	External Circulating Water - RCA	-	70	1	4	62	-	-	28	165	165	-	-	721	-	-	-	-	29,284	938	-
2a.1.5.16	Feedwater	-	111	-	-	-	-	-	17	128	-	-	128	-	-	-	-	-	-	1,840	-
2a.1.5.17	Feedwater - RCA	-	236	7	24	359	-	-	117	744	744	-	-	4,147	-	-	-	-	168,414	3,377	-
2a.1.5.18	Gland Seal	-	29	-	-	-	-	-	4	34	-	-	34	-	-	-	-	-	-	504	-
2a.1.5.19	Heater Drain	-	334	-	-	-	-	-	50	384	-	-	384	-	-	-	-	-	-	5,638	-
2a.1.5.20	Hypobromous Acid Feed	-	5	-	-	-	-	-	1	6	-	-	6	-	-	-	-	-	-	86	-
2a.1.5.21	Hypobromous Acid Feed - RCA	-	1	0	0	0	-	-	0	1	1	-	-	2	-	-	-	-	100	12	-
2a.1.5.22	Internal Circ Water & CDSR	-	22	-	-	-	-	-	3	25	-	-	25	-	-	-	-	-	-	366	-
2a.1.5.23	Main Gen/Exciter/Transformer	-	0	-	-	-	-	-	0	0	-	-	0	-	-	-	-	-	-	5	-
2a.1.5.24	Main Steam	-	88	-	-	-	-	-	13	101	-	-	101	-	-	-	-	-	-	1,482	-
2a.1.5.25	Main Steam - RCA	-	364	9	30	447	-	-	163	1,013	1,013	-	-	5,166	-	-	-	-	209,799	5,146	-
2a.1.5.26	Repairable Spare Snubbers	-	6	0	0	1	-	-	2	8	8	-	-	12	-	-	-	-	490	82	-
2a.1.5.27	Steam Exclusion	-	2	-	-	-	-	-	0	2	-	-	2	-	-	-	-	-	-	32	-
2a.1.5.28	Steam Exclusion - RCA	-	4	0	0	2	-	-	1	8	8	-	-	24	-	-	-	-	966	47	-
2a.1.5.29	Steam Generator Blowdown	-	398	20	21	165	179	-	174	957	957	-	-	1,906	631	-	-	-	119,126	5,778	-
2a.1.5.30	Steam Generators	-	5	-	-	-	-	-	1	5	-	-	5	-	-	-	-	-	-	75	-
2a.1.5.31	Turbine & Moisture Separators	-	329	-	-	-	-	-	49	379	-	-	379	-	-	-	-	-	-	5,472	-
2a.1.5.32	Turbine Oil Purification	-	46	-	-	-	-	-	7	53	-	-	53	-	-	-	-	-	-	757	-
2a.1.5.33	Water Treatment	-	394	-	-	-	-	-	59	453	-	-	453	-	-	-	-	-	-	6,677	-
2a.1.5.34	Water Treatment - RCA	-	19	0	1	10	-	-	6	37	37	-	-	115	-	-	-	-	4,652	252	-
2a.1.5	Totals	-	3,437	39	85	1,125	179	-	867	5,733	3,174	-	2,559	13,010	631	-	-	-	570,056	54,280	-
2a.1.6	Scaffolding in support of decommissioning	-	2,833	24	8	97	25	-	733	3,721	3,721	-	-	1,012	89	-	-	-	51,445	26,270	-
2a.1	Subtotal Period 2a Activity Costs	855	23,653	26,885	3,859	3,105	16,875	553	25,350	101,134	98,575	-	2,559	38,625	30,835	125	673	-	4,223,340	208,777	6,073

Table G-2
Prairie Island Nuclear Generating Plant, Unit 2
DECON Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage and Periodic TN-40 Replacement
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Period 2a Additional Costs																					
2a.2.1	Remedial Action Surveys	-	-	-	-	-	-	1,560	468	2,027	2,027	-	-	-	-	-	-	-	-	20,388	-
2a.2.2	Retired RPV upper internals package	1	659	785	107	-	1,439	-	1,437	4,427	4,427	-	-	-	2,097	125	-	-	205,890	2,175	87
2a.2	Subtotal Period 2a Additional Costs	1	659	785	107	-	1,439	1,560	1,905	6,454	6,454	-	-	-	2,097	125	-	-	205,890	22,562	87
Period 2a Collateral Costs																					
2a.3.1	Process decommissioning water waste	51	-	33	86	-	135	-	75	381	381	-	-	-	323	-	-	-	19,358	63	-
2a.3.3	Small tool allowance	-	251	-	-	-	-	-	38	289	260	-	29	-	-	-	-	-	-	-	-
2a.3.4	Spent Fuel Capital and Transfer	-	-	-	-	-	-	2,138	321	2,459	-	2,459	-	-	-	-	-	-	-	-	-
2a.3.5	Retention and Severance	-	-	-	-	-	-	6,105	916	7,021	7,021	-	-	-	-	-	-	-	-	-	-
2a.3.6	Prairie Island Indian Community Payments	-	-	-	-	-	-	1,224	-	1,224	-	1,224	-	-	-	-	-	-	-	-	-
2a.3	Subtotal Period 2a Collateral Costs	51	251	33	86	-	135	9,467	1,349	11,373	7,661	3,682	29	-	323	-	-	-	19,358	63	-
Period 2a Period-Dependent Costs																					
2a.4.1	Decon supplies	68	-	-	-	-	-	-	17	85	85	-	-	-	-	-	-	-	-	-	-
2a.4.2	Insurance	-	-	-	-	-	-	501	50	551	551	-	-	-	-	-	-	-	-	-	-
2a.4.3	Property taxes	-	-	-	-	-	-	2,507	251	2,758	2,758	-	-	-	-	-	-	-	-	-	-
2a.4.4	Health physics supplies	-	1,622	-	-	-	-	-	406	2,028	2,028	-	-	-	-	-	-	-	-	-	-
2a.4.5	Heavy equipment rental	-	2,153	-	-	-	-	-	323	2,477	2,477	-	-	-	-	-	-	-	-	-	-
2a.4.6	Disposal of DAW generated	-	-	89	26	-	331	-	95	541	541	-	-	-	4,063	-	-	-	81,252	133	-
2a.4.7	Plant energy budget	-	-	-	-	-	-	1,411	212	1,623	1,623	-	-	-	-	-	-	-	-	-	-
2a.4.8	NRC Fees	-	-	-	-	-	-	389	39	428	428	-	-	-	-	-	-	-	-	-	-
2a.4.9	Emergency Planning Fees	-	-	-	-	-	-	1,259	126	1,385	-	1,385	-	-	-	-	-	-	-	-	-
2a.4.10	Fixed Overhead	-	-	-	-	-	-	1,214	182	1,396	1,396	-	-	-	-	-	-	-	-	-	-
2a.4.11	Spent Fuel Pool O&M	-	-	-	-	-	-	394	59	453	-	453	-	-	-	-	-	-	-	-	-
2a.4.12	ISFSI Operating Costs	-	-	-	-	-	-	51	8	58	-	58	-	-	-	-	-	-	-	-	-
2a.4.13	Railroad Track Maintenance	-	-	-	-	-	-	265	40	305	305	-	-	-	-	-	-	-	-	-	-
2a.4.14	Security Staff Cost	-	-	-	-	-	-	6,661	999	7,661	7,661	-	-	-	-	-	-	-	-	-	110,166
2a.4.15	DOC Staff Cost	-	-	-	-	-	-	13,492	2,024	15,516	15,516	-	-	-	-	-	-	-	-	-	155,048
2a.4.16	Utility Staff Cost	-	-	-	-	-	-	17,880	2,682	20,562	20,562	-	-	-	-	-	-	-	-	-	288,676
2a.4	Subtotal Period 2a Period-Dependent Costs	68	3,776	89	26	-	331	46,025	7,512	57,825	55,929	1,896	-	-	4,063	-	-	-	81,252	133	553,890
2a.0	TOTAL PERIOD 2a COST	974	28,339	27,792	4,078	3,105	18,780	57,604	36,116	176,787	168,620	5,579	2,588	38,625	37,317	250	673	-	4,529,841	231,534	560,049
PERIOD 2b - Site Decontamination																					
Period 2b Direct Decommissioning Activities																					
Disposal of Plant Systems																					
2b.1.1.1	ADT & Misc Ventilation	-	24	0	1	13	3	-	9	50	50	-	-	153	9	-	-	-	6,814	363	-
2b.1.1.2	Aux Bldg Normal Ventilation	-	67	2	5	60	11	-	29	174	174	-	-	692	39	-	-	-	30,671	1,013	-
2b.1.1.3	Aux Bldg Special Ventilation	-	13	0	0	6	2	-	5	26	26	-	-	70	6	-	-	-	3,243	197	-
2b.1.1.4	Battery Rm Special Ventilation	-	1	-	-	-	-	-	0	2	-	-	2	-	-	-	-	-	-	24	-
2b.1.1.5	Boron Recycle	0	4	0	0	0	3	-	2	9	9	-	-	3	9	-	-	-	709	50	-
2b.1.1.6	Chemical & Volume Control	722	902	59	44	204	560	-	770	3,260	3,260	-	-	2,356	1,977	-	-	-	225,854	23,197	-
2b.1.1.7	Cold Chemical Lab Ventilation	-	1	-	-	-	-	-	0	1	-	-	1	-	-	-	-	-	-	9	-
2b.1.1.8	Component Cooling - RCA	-	617	21	70	1,038	-	-	322	2,068	2,068	-	-	11,996	-	-	-	-	487,169	8,583	-
2b.1.1.9	Containment Cooling	-	31	-	-	-	-	-	5	35	-	-	35	-	-	-	-	-	-	502	-
2b.1.1.10	Containment Cooling - RCA	-	288	5	16	237	-	-	110	656	656	-	-	2,743	-	-	-	-	111,390	3,949	-
2b.1.1.11	Containment Hydrogen Control - RCA	-	35	0	1	12	-	-	11	60	60	-	-	141	-	-	-	-	5,742	494	-
2b.1.1.12	Containment Spray - RCA	-	186	3	8	126	-	-	67	389	389	-	-	1,453	-	-	-	-	59,019	2,617	-
2b.1.1.13	Containment Ventilation	-	224	23	38	408	205	-	177	1,075	1,075	-	-	4,721	722	-	-	-	239,450	3,375	-
2b.1.1.14	Control/Relay/Cmptr Rm Vent	-	30	1	2	23	6	-	13	74	74	-	-	260	20	-	-	-	11,915	454	-
2b.1.1.15	Cooling Water	-	139	-	-	-	-	-	21	160	-	-	160	-	-	-	-	-	-	2,344	-
2b.1.1.16	Cooling Water - RCA	-	456	15	49	730	-	-	232	1,482	1,482	-	-	8,442	-	-	-	-	342,822	6,311	-
2b.1.1.17	Cranes/Hoists/Elevators - RCA	-	3	0	1	9	-	-	2	15	15	-	-	103	-	-	-	-	4,184	48	-
2b.1.1.18	D3 Emergency Diesel	-	9	-	-	-	-	-	1	10	-	-	10	-	-	-	-	-	-	141	-
2b.1.1.19	D4 Emergency Diesel	-	9	-	-	-	-	-	1	10	-	-	10	-	-	-	-	-	-	141	-
2b.1.1.20	D5 Emergency Diesel	-	0	-	-	-	-	-	0	0	-	-	0	-	-	-	-	-	-	5	-
2b.1.1.21	Electrical - Clean	-	1,502	-	-	-	-	-	225	1,727	-	-	1,727	-	-	-	-	-	-	24,276	-
2b.1.1.22	Electrical - Contaminated	-	461	5	13	173	21	-	149	821	821	-	-	1,997	75	-	-	-	86,080	6,503	-
2b.1.1.23	Electrical - Decontaminated	-	2,866	33	109	1,622	-	-	980	5,610	5,610	-	-	18,753	-	-	-	-	761,569	38,423	-
2b.1.1.24	Filter Rm Ventilation	-	4	0	0	2	0	-	2	9	9	-	-	24	1	-	-	-	1,020	69	-
2b.1.1.25	Fire Protection & Detection	-	178	-	-	-	-	-	27	205	-	-	205	-	-	-	-	-	-	3,009	-
2b.1.1.26	Fire Protection & Detection - RCA	-	236	3	11	158	-	-	85	492	492	-	-	1,828	-	-	-	-	74,245	3,134	-
2b.1.1.27	Fuel Handling	-	71	1	2	17	14	-	24	130	130	-	-	200	49	-	-	-	11,396	1,101	-
2b.1.1.28	Fuel Oil	-	1	-	-	-	-	-	0	1	-	-	1	-	-	-	-	-	-	9	-
2b.1.1.29	HVAC - Clean	-	132	-	-	-	-	-	20	151	-	-	151	-	-	-	-	-	-	2,373	-
2b.1.1.30	HVAC - Contaminated	-	1,222	26	69	929	115	-	487	2,848	2,848	-	-	10,745	405	-	-	-	463,144	16,579	-

Table G-2
Prairie Island Nuclear Generating Plant, Unit 2
DECON Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage and Periodic TN-40 Replacement
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Disposal of Plant Systems (continued)																					
2b.1.1.31	Heating	-	279	-	-	-	-	-	42	321	-	-	321	-	-	-	-	-	-	4,804	-
2b.1.1.32	Heating - RCA	-	323	3	11	165	-	-	107	609	609	-	-	1,907	-	-	-	-	77,458	4,086	-
2b.1.1.33	Hot Lab & Sample Rm Ventilation	-	19	0	1	9	1	-	6	37	37	-	-	107	4	-	-	-	4,632	285	-
2b.1.1.34	Incore Instrumentation	0	29	1	1	5	16	-	13	67	67	-	-	60	58	-	-	-	6,264	458	-
2b.1.1.35	Misc Drains & Vents	-	223	12	9	40	121	-	95	500	500	-	-	458	426	-	-	-	46,850	3,180	-
2b.1.1.36	Misc Lab & Service Areas Vent	-	123	8	6	32	70	-	55	293	293	-	-	370	244	-	-	-	31,186	1,713	-
2b.1.1.37	Miscellaneous Gas	-	63	-	-	-	-	-	9	72	-	-	72	-	-	-	-	-	-	1,073	-
2b.1.1.38	Miscellaneous Gas - RCA	-	129	1	3	52	-	-	41	226	226	-	-	600	-	-	-	-	24,378	1,636	-
2b.1.1.39	Radiation Monitoring	-	6	-	-	-	-	-	1	7	-	-	7	-	-	-	-	-	-	111	-
2b.1.1.40	Radiation Monitoring - RCA	-	62	1	2	27	-	-	20	112	112	-	-	316	-	-	-	-	12,826	782	-
2b.1.1.41	Reactor Coolant	158	227	20	12	20	208	-	195	839	839	-	-	229	730	-	-	-	57,672	5,517	-
2b.1.1.42	Reactor Hot Sampling	135	121	10	5	5	89	-	123	489	489	-	-	54	312	-	-	-	22,919	3,686	-
2b.1.1.43	Reactor Makeup	-	36	-	-	-	-	-	5	41	-	-	41	-	-	-	-	-	-	583	-
2b.1.1.44	Reactor Makeup - RCA	-	4	0	0	2	-	-	1	8	8	-	-	28	-	-	-	-	1,148	47	-
2b.1.1.45	Reactor Vessel	9	17	0	0	2	4	-	10	43	43	-	-	22	14	-	-	-	1,826	385	-
2b.1.1.46	Residual Heat Removal	336	374	84	66	247	924	-	548	2,578	2,578	-	-	2,853	3,244	-	-	-	330,651	7,112	-
2b.1.1.47	Safeguards Chilled Water	-	4	-	-	-	-	-	1	5	-	-	5	-	-	-	-	-	-	75	-
2b.1.1.48	Safety Injection	-	836	40	56	577	329	-	390	2,228	2,228	-	-	6,676	1,161	-	-	-	347,600	12,284	-
2b.1.1.49	Sampling	-	51	3	2	3	27	-	20	105	105	-	-	37	93	-	-	-	7,697	714	-
2b.1.1.50	Service Bldg & New Cmptr Vent	-	0	-	-	-	-	-	0	0	-	-	0	-	-	-	-	-	-	6	-
2b.1.1.51	Shield Bldg Ventilation	-	114	13	19	175	138	-	94	554	554	-	-	2,028	484	-	-	-	114,378	1,743	-
2b.1.1.52	Station & Instrument Air	-	140	-	-	-	-	-	21	161	-	-	161	-	-	-	-	-	-	2,424	-
2b.1.1.53	Station & Instrument Air - RCA	-	288	3	9	141	-	-	95	535	535	-	-	1,625	-	-	-	-	65,986	3,638	-
2b.1.1.54	Turbine Bldg Traps & Drains	-	26	-	-	-	-	-	4	30	-	-	30	-	-	-	-	-	-	462	-
2b.1.1.55	Turbine Bldg Traps & Drains - RCA	-	28	0	1	16	-	-	10	55	55	-	-	180	-	-	-	-	7,321	344	-
2b.1.1.56	Turbine Bldg Ventilation	-	40	-	-	-	-	-	6	46	-	-	46	-	-	-	-	-	-	655	-
2b.1.1.57	Unit Coolers	-	20	-	-	-	-	-	3	23	-	-	23	-	-	-	-	-	-	332	-
2b.1.1.58	Unit Coolers - RCA	-	54	0	1	20	-	-	17	93	93	-	-	232	-	-	-	-	9,413	690	-
2b.1.1.59	Waste Gas Disposal	531	457	40	35	212	381	-	516	2,173	2,173	-	-	2,453	1,358	-	-	-	188,334	14,308	-
2b.1.1.60	Waste Liquid Disposal	1,386	1,733	108	76	316	1,019	-	1,451	6,089	6,089	-	-	3,655	3,594	-	-	-	385,370	44,485	-
2b.1.1.61	Waste Solid Disposal	111	139	11	8	34	112	-	126	541	541	-	-	389	393	-	-	-	41,732	3,481	-
2b.1.1	Totals	3,390	15,678	558	763	7,868	4,377	-	7,798	40,433	37,423	-	3,010	90,963	15,429	-	-	-	4,712,076	270,390	-
2b.1.2	Scaffolding in support of decommissioning	-	3,542	30	10	121	32	-	916	4,651	4,651	-	-	1,265	112	-	-	-	64,307	32,837	-
Decontamination of Site Buildings																					
2b.1.3.1	Reactor	1,150	2,624	139	853	193	11,080	-	4,172	20,210	20,210	-	-	2,230	57,418	-	-	-	3,559,977	50,853	-
2b.1.3.2	Auxiliary	1,223	400	12	80	92	582	-	884	3,272	3,272	-	-	1,060	3,355	-	-	-	332,498	23,808	-
2b.1.3.3	Backwash Waste Receiving Tank	-	27	1	11	-	87	-	30	158	158	-	-	-	507	-	-	-	43,896	299	-
2b.1.3.4	Drum Transfer & Truck Loading Enclosure	17	8	0	2	2	13	-	14	56	56	-	-	19	74	-	-	-	7,118	368	-
2b.1.3.5	LLRW Storage Enclosure	117	51	1	11	3	87	-	95	366	366	-	-	38	502	-	-	-	44,971	2,424	-
2b.1.3.6	Radwaste	52	23	1	5	4	39	-	43	166	166	-	-	42	225	-	-	-	21,136	1,082	-
2b.1.3.7	Resin Disposal	15	11	0	2	7	12	-	15	64	64	-	-	83	69	-	-	-	9,271	383	-
2b.1.3	Totals	2,574	3,145	155	964	300	11,900	-	5,253	24,292	24,292	-	-	3,471	62,151	-	-	-	4,018,868	79,216	-
2b.1.4	Prepare/submit License Termination Plan	-	-	-	-	-	-	206	31	236	236	-	-	-	-	-	-	-	-	-	1,751
2b.1.5	Receive NRC approval of termination plan									a											
2b.1	Subtotal Period 2b Activity Costs	5,965	22,365	744	1,737	8,290	16,309	206	13,998	69,612	66,602	-	3,010	95,700	77,691	-	-	-	8,795,250	382,443	1,751
Period 2b Additional Costs																					
2b.2.1	Remedial Action Surveys	-	-	-	-	-	-	1,930	579	2,509	2,509	-	-	-	-	-	-	-	-	25,228	-
2b.2.2	Operational Equipment	-	-	9	29	312	-	-	52	402	402	-	-	5,855	-	-	-	-	146,375	16	-
2b.2	Subtotal Period 2b Additional Costs	-	-	9	29	312	-	1,930	631	2,911	2,911	-	-	5,855	-	-	-	-	146,375	25,244	-
Period 2b Collateral Costs																					
2b.3.1	Process decommissioning water waste	167	-	112	289	-	453	-	251	1,272	1,272	-	-	-	1,081	-	-	-	64,837	211	-
2b.3.2	Process decommissioning chemical flush waste	3	-	114	431	-	858	-	292	1,700	1,700	-	-	-	1,154	-	-	-	122,948	216	-
2b.3.3	Small tool allowance	-	414	-	-	-	-	-	62	476	476	-	-	-	-	-	-	-	-	-	-
2b.3.4	Spent Fuel Capital and Transfer	-	-	-	-	-	-	9,529	1,429	10,958	-	10,958	-	-	-	-	-	-	-	-	-
2b.3.5	Retention and Severance	-	-	-	-	-	-	4,127	619	4,746	4,746	-	-	-	-	-	-	-	-	-	-
2b.3.6	Prairie Island Indian Community Payments	-	-	-	-	-	-	1,517	-	1,517	-	1,517	-	-	-	-	-	-	-	-	-
2b.3.7	On-site survey and release of 0.437 tons clean metallic waste	-	-	-	-	-	-	1	0	1	1	-	-	-	-	-	-	-	-	-	-
2b.3	Subtotal Period 2b Collateral Costs	170	414	226	721	-	1,311	15,174	2,654	20,670	8,195	12,475	-	-	2,234	-	-	-	187,785	427	-

Table G-2
Prairie Island Nuclear Generating Plant, Unit 2
DECON Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage and Periodic TN-40 Replacement
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Period 2b Period-Dependent Costs																					
2b.4.1	Decon supplies	1,135	-	-	-	-	-	-	284	1,419	1,419	-	-	-	-	-	-	-	-	-	-
2b.4.2	Insurance	-	-	-	-	-	-	620	62	682	682	-	-	-	-	-	-	-	-	-	-
2b.4.3	Property taxes	-	-	-	-	-	-	2,983	298	3,281	3,281	-	-	-	-	-	-	-	-	-	-
2b.4.4	Health physics supplies	-	2,580	-	-	-	-	-	645	3,225	3,225	-	-	-	-	-	-	-	-	-	-
2b.4.5	Heavy equipment rental	-	2,740	-	-	-	-	-	411	3,151	3,151	-	-	-	-	-	-	-	-	-	-
2b.4.6	Disposal of DAW generated	-	-	115	34	-	431	-	124	704	704	-	-	-	5,291	-	-	-	105,826	173	-
2b.4.7	Plant energy budget	-	-	-	-	-	-	1,379	207	1,586	1,586	-	-	-	-	-	-	-	-	-	-
2b.4.8	NRC Fees	-	-	-	-	-	-	481	48	529	529	-	-	-	-	-	-	-	-	-	-
2b.4.9	Emergency Planning Fees	-	-	-	-	-	-	1,558	156	1,714	-	1,714	-	-	-	-	-	-	-	-	-
2b.4.10	Fixed Overhead	-	-	-	-	-	-	1,503	225	1,728	1,728	-	-	-	-	-	-	-	-	-	-
2b.4.11	Spent Fuel Pool O&M	-	-	-	-	-	-	487	73	560	-	560	-	-	-	-	-	-	-	-	-
2b.4.12	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	246	37	282	282	-	-	-	-	-	-	-	-	-	-
2b.4.13	ISFSI Operating Costs	-	-	-	-	-	-	63	9	72	-	72	-	-	-	-	-	-	-	-	-
2b.4.14	Railroad Track Maintenance	-	-	-	-	-	-	70	10	80	80	-	-	-	-	-	-	-	-	-	-
2b.4.15	Security Staff Cost	-	-	-	-	-	-	8,243	1,236	9,479	9,479	-	-	-	-	-	-	-	-	-	136,323
2b.4.16	DOC Staff Cost	-	-	-	-	-	-	16,150	2,422	18,572	18,572	-	-	-	-	-	-	-	-	-	184,288
2b.4.17	Utility Staff Cost	-	-	-	-	-	-	21,222	3,183	24,405	24,405	-	-	-	-	-	-	-	-	-	342,069
2b.4	Subtotal Period 2b Period-Dependent Costs	1,135	5,320	115	34	-	431	55,004	9,432	71,472	69,125	2,346	-	-	5,291	-	-	-	105,826	173	662,680
2b.0	TOTAL PERIOD 2b COST	7,270	28,099	1,095	2,520	8,602	18,050	72,314	26,716	164,664	146,833	14,822	3,010	101,555	85,217	-	-	-	9,235,236	408,286	664,431
PERIOD 2c - Spent fuel delay prior to SFP decon																					
Period 2c Direct Decommissioning Activities																					
Period 2c Additional Costs																					
2c.2.1	Security Modifications	-	-	-	-	-	-	4,348	652	5,000	5,000	-	-	-	-	-	-	-	-	-	-
2c.2	Subtotal Period 2c Additional Costs	-	-	-	-	-	-	4,348	652	5,000	5,000	-	-	-	-	-	-	-	-	-	-
Period 2c Collateral Costs																					
2c.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	66,610	9,992	76,602	-	76,602	-	-	-	-	-	-	-	-	-
2c.3.2	Retention and Severance	-	-	-	-	-	-	2,034	305	2,339	2,339	-	-	-	-	-	-	-	-	-	-
2c.3.3	Prairie Island Indian Community Payments	-	-	-	-	-	-	1,630	-	1,630	-	1,630	-	-	-	-	-	-	-	-	-
2c.3	Subtotal Period 2c Collateral Costs	-	-	-	-	-	-	70,274	10,297	80,571	2,339	78,232	-	-	-	-	-	-	-	-	-
Period 2c Period-Dependent Costs																					
2c.4.1	Insurance	-	-	-	-	-	-	666	67	733	733	-	-	-	-	-	-	-	-	-	-
2c.4.2	Property taxes	-	-	-	-	-	-	3,060	306	3,366	3,366	-	-	-	-	-	-	-	-	-	-
2c.4.3	Health physics supplies	-	270	-	-	-	-	-	67	337	337	-	-	-	-	-	-	-	-	-	-
2c.4.4	Disposal of DAW generated	-	-	12	3	-	44	-	13	72	72	-	-	-	538	-	-	-	10,761	18	-
2c.4.5	Plant energy budget	-	-	-	-	-	-	395	59	454	454	-	-	-	-	-	-	-	-	-	-
2c.4.6	NRC Fees	-	-	-	-	-	-	305	31	336	336	-	-	-	-	-	-	-	-	-	-
2c.4.7	Emergency Planning Fees	-	-	-	-	-	-	1,674	167	1,842	-	1,842	-	-	-	-	-	-	-	-	-
2c.4.8	Fixed Overhead	-	-	-	-	-	-	1,615	242	1,857	1,857	-	-	-	-	-	-	-	-	-	-
2c.4.9	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	53	8	61	61	-	-	-	-	-	-	-	-	-	-
2c.4.10	ISFSI Operating Costs	-	-	-	-	-	-	67	10	77	-	77	-	-	-	-	-	-	-	-	-
2c.4.11	Railroad Track Maintenance	-	-	-	-	-	-	75	11	86	86	-	-	-	-	-	-	-	-	-	-
2c.4.12	Security Staff Cost	-	-	-	-	-	-	8,857	1,329	10,185	10,185	-	-	-	-	-	-	-	-	-	146,478
2c.4.13	Utility Staff Cost	-	-	-	-	-	-	6,575	986	7,561	7,561	-	-	-	-	-	-	-	-	-	107,146
2c.4	Subtotal Period 2c Period-Dependent Costs	-	270	12	3	-	44	23,343	3,296	26,968	25,049	1,919	-	-	538	-	-	-	10,761	18	253,623
2c.0	TOTAL PERIOD 2c COST	-	270	12	3	-	44	97,965	14,245	112,539	32,387	80,151	-	-	538	-	-	-	10,761	18	253,623
PERIOD 2d - Decontamination Following Wet Fuel Storage																					
Period 2d Direct Decommissioning Activities																					
2d.1.1	Remove spent fuel racks	328	32	94	32	-	595	-	335	1,416	1,416	-	-	-	2,092	-	-	-	138,298	576	-
Disposal of Plant Systems																					
2d.1.2.1	Electrical - Contaminated - Fuel Pool	-	197	2	6	75	9	-	64	353	353	-	-	864	33	-	-	-	37,250	2,783	-
2d.1.2.2	Electrical - Decontaminated - Fuel Pool	-	1,230	14	47	698	-	-	421	2,410	2,410	-	-	8,069	-	-	-	-	327,668	16,495	-
2d.1.2.3	Fire Protection & Detection - RCA Fuel P	-	36	1	2	25	-	-	13	76	76	-	-	286	-	-	-	-	11,622	476	-
2d.1.2.4	HVAC - Contaminated - Fuel Pool	-	549	12	31	418	52	-	219	1,280	1,280	-	-	4,828	182	-	-	-	208,080	7,448	-
2d.1.2.5	Safeguards Chilled Water - RCA	-	4	0	0	2	-	-	1	8	8	-	-	26	-	-	-	-	1,045	51	-
2d.1.2.6	Spent Fuel Pool Cooling	31	35	3	2	3	30	-	33	137	137	-	-	39	107	-	-	-	8,635	882	-
2d.1.2.7	Spent Fuel Pool Normal Ventilation	-	26	1	2	23	3	-	11	66	66	-	-	265	12	-	-	-	11,532	394	-
2d.1.2	Totals	31	2,077	32	89	1,244	95	-	761	4,328	4,328	-	-	14,376	333	-	-	-	605,832	28,530	-

Xcel Energy

Table G-2
Prairie Island Nuclear Generating Plant, Unit 2
DECON Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage and Periodic TN-40 Replacement
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Decontamination of Site Buildings																					
2d.1.3.1	Fuel Handling of Aux Building	975	1,082	9	32	209	173	-	838	3,319	3,319	-	-	2,417	944	-	-	-	177,818	30,401	-
2d.1.3	Totals	975	1,082	9	32	209	173	-	838	3,319	3,319	-	-	2,417	944	-	-	-	177,818	30,401	-
2d.1.4	Scaffolding in support of decommissioning	-	708	6	2	24	6	-	183	930	930	-	-	253	22	-	-	-	12,861	6,567	-
2d.1	Subtotal Period 2d Activity Costs	1,334	3,900	142	155	1,477	868	-	2,118	9,994	9,994	-	-	17,046	3,391	-	-	-	934,809	66,074	-
Period 2d Additional Costs																					
2d.2.1	License Termination Survey Planning	-	-	-	-	-	-	845	253	1,098	1,098	-	-	-	-	-	-	-	-	-	6,240
2d.2.2	Remedial Action Surveys	-	-	-	-	-	-	1,237	371	1,608	1,608	-	-	-	-	-	-	-	-	16,173	-
2d.2	Subtotal Period 2d Additional Costs	-	-	-	-	-	-	2,082	625	2,706	2,706	-	-	-	-	-	-	-	-	16,173	6,240
Period 2d Collateral Costs																					
2d.3.1	Process decommissioning water waste	39	-	27	70	-	109	-	60	306	306	-	-	-	261	-	-	-	15,670	51	-
2d.3.2	Process decommissioning chemical flush waste	0	-	1	5	-	10	-	3	20	20	-	-	-	13	-	-	-	1,422	2	-
2d.3.3	Small tool allowance	-	79	-	-	-	-	-	12	91	91	-	-	-	-	-	-	-	-	-	-
2d.3.4	Decommissioning Equipment Disposition	-	-	144	55	575	150	-	147	1,071	1,071	-	-	6,000	529	-	-	-	304,968	88	-
2d.3.5	Spent Fuel Capital and Transfer	-	-	-	-	-	-	13,144	1,972	15,115	-	15,115	-	-	-	-	-	-	-	-	-
2d.3.6	Prairie Island Indian Community Payments	-	-	-	-	-	-	971	-	971	-	971	-	-	-	-	-	-	-	-	-
2d.3	Subtotal Period 2d Collateral Costs	39	79	172	130	575	270	14,114	2,194	17,573	1,488	16,086	-	6,000	804	-	-	-	322,060	142	-
Period 2d Period-Dependent Costs																					
2d.4.1	Decon supplies	218	-	-	-	-	-	-	54	272	272	-	-	-	-	-	-	-	-	-	-
2d.4.2	Insurance	-	-	-	-	-	-	398	40	437	437	-	-	-	-	-	-	-	-	-	-
2d.4.3	Property taxes	-	-	-	-	-	-	1,740	174	1,914	1,914	-	-	-	-	-	-	-	-	-	-
2d.4.4	Health physics supplies	-	742	-	-	-	-	-	186	928	928	-	-	-	-	-	-	-	-	-	-
2d.4.5	Heavy equipment rental	-	1,757	-	-	-	-	-	264	2,020	2,020	-	-	-	-	-	-	-	-	-	-
2d.4.6	Disposal of DAW generated	-	-	44	13	-	163	-	47	266	266	-	-	-	2,000	-	-	-	40,003	65	-
2d.4.7	Plant energy budget	-	-	-	-	-	-	471	71	542	542	-	-	-	-	-	-	-	-	-	-
2d.4.8	NRC Fees	-	-	-	-	-	-	256	26	282	282	-	-	-	-	-	-	-	-	-	-
2d.4.9	Emergency Planning Fees	-	-	-	-	-	-	999	100	1,099	-	1,099	-	-	-	-	-	-	-	-	-
2d.4.10	Fixed Overhead	-	-	-	-	-	-	963	144	1,108	1,108	-	-	-	-	-	-	-	-	-	-
2d.4.11	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	315	47	362	362	-	-	-	-	-	-	-	-	-	-
2d.4.12	ISFSI Operating Costs	-	-	-	-	-	-	40	6	46	-	46	-	-	-	-	-	-	-	-	-
2d.4.13	Railroad Track Maintenance	-	-	-	-	-	-	45	7	52	52	-	-	-	-	-	-	-	-	-	-
2d.4.14	Security Staff Cost	-	-	-	-	-	-	5,123	768	5,891	5,891	-	-	-	-	-	-	-	-	-	84,157
2d.4.15	DOC Staff Cost	-	-	-	-	-	-	6,065	910	6,975	6,975	-	-	-	-	-	-	-	-	-	69,996
2d.4.16	Utility Staff Cost	-	-	-	-	-	-	7,796	1,169	8,966	8,527	439	-	-	-	-	-	-	-	-	126,236
2d.4	Subtotal Period 2d Period-Dependent Costs	218	2,499	44	13	-	163	24,212	4,013	31,160	29,576	1,584	-	-	2,000	-	-	-	40,003	65	280,390
2d.0	TOTAL PERIOD 2d COST	1,591	6,478	357	298	2,052	1,301	40,408	8,949	61,434	43,764	17,670	-	23,046	6,195	-	-	-	1,296,872	82,455	286,630
PERIOD 2f - License Termination																					
Period 2f Direct Decommissioning Activities																					
2f.1.1	ORISE confirmatory survey	-	-	-	-	-	-	176	53	229	229	-	-	-	-	-	-	-	-	-	-
2f.1.2	Terminate license									a											
2f.1	Subtotal Period 2f Activity Costs	-	-	-	-	-	-	176	53	229	229	-	-	-	-	-	-	-	-	-	-
Period 2f Additional Costs																					
2f.2.1	License Termination Survey	-	-	-	-	-	-	7,406	2,222	9,628	9,628	-	-	-	-	-	-	-	-	102,642	3,120
2f.2	Subtotal Period 2f Additional Costs	-	-	-	-	-	-	7,406	2,222	9,628	9,628	-	-	-	-	-	-	-	-	102,642	3,120
Period 2f Collateral Costs																					
2f.3.1	DOC staff relocation expenses	-	-	-	-	-	-	1,189	178	1,367	1,367	-	-	-	-	-	-	-	-	-	-
2f.3.2	Prairie Island Indian Community Payments	-	-	-	-	-	-	934	-	934	-	934	-	-	-	-	-	-	-	-	-
2f.3	Subtotal Period 2f Collateral Costs	-	-	-	-	-	-	2,122	178	2,300	1,367	934	-	-	-	-	-	-	-	-	-
Period 2f Period-Dependent Costs																					
2f.4.1	Insurance	-	-	-	-	-	-	382	38	420	420	-	-	-	-	-	-	-	-	-	-
2f.4.2	Property taxes	-	-	-	-	-	-	1,626	163	1,789	1,789	-	-	-	-	-	-	-	-	-	-
2f.4.3	Health physics supplies	-	602	-	-	-	-	-	150	752	752	-	-	-	-	-	-	-	-	-	-
2f.4.4	Disposal of DAW generated	-	-	7	2	-	27	-	8	44	44	-	-	-	334	-	-	-	6,685	11	-
2f.4.5	Plant energy budget	-	-	-	-	-	-	227	34	261	261	-	-	-	-	-	-	-	-	-	-
2f.4.6	NRC Fees	-	-	-	-	-	-	272	27	299	299	-	-	-	-	-	-	-	-	-	-
2f.4.7	Emergency Planning Fees	-	-	-	-	-	-	51	5	56	-	56	-	-	-	-	-	-	-	-	-
2f.4.8	Fixed Overhead	-	-	-	-	-	-	926	139	1,065	1,065	-	-	-	-	-	-	-	-	-	-
2f.4.9	ISFSI Operating Costs	-	-	-	-	-	-	39	6	44	-	44	-	-	-	-	-	-	-	-	-

Table G-2
Prairie Island Nuclear Generating Plant, Unit 2
DECON Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage and Periodic TN-40 Replacement
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 2f Period-Dependent Costs (continued)																					
2f.4.10	Railroad Track Maintenance	-	-	-	-	-	-	43	6	50	50	-	-	-	-	-	-	-	-	-	-
2f.4.11	Security Staff Cost	-	-	-	-	-	-	4,924	739	5,663	5,663	-	-	-	-	-	-	-	-	-	80,898
2f.4.12	DOC Staff Cost	-	-	-	-	-	-	4,101	615	4,716	4,716	-	-	-	-	-	-	-	-	-	46,283
2f.4.13	Utility Staff Cost	-	-	-	-	-	-	3,854	578	4,433	4,007	426	-	-	-	-	-	-	-	-	59,507
2f.4	Subtotal Period 2f Period-Dependent Costs	-	602	7	2	-	27	16,445	2,508	19,592	19,066	526	-	-	334	-	-	-	6,685	11	186,687
2f.0	TOTAL PERIOD 2f COST	-	602	7	2	-	27	26,150	4,962	31,750	30,290	1,460	-	-	334	-	-	-	6,685	102,653	189,807
PERIOD 2 TOTALS		9,835	63,787	29,263	6,901	13,758	38,202	294,441	90,987	547,174	421,894	119,682	5,598	163,227	129,602	250	673	-	15,079,400	824,945	1,954,541
PERIOD 3b - Site Restoration																					
Period 3b Direct Decommissioning Activities																					
Demolition of Remaining Site Buildings																					
3b.1.1.1	Reactor	-	4,256	-	-	-	-	-	638	4,895	-	-	4,895	-	-	-	-	-	-	44,679	-
3b.1.1.2	Auxiliary	-	1,897	-	-	-	-	-	285	2,182	-	-	2,182	-	-	-	-	-	-	11,902	-
3b.1.1.3	Condensate Storage Tank Foundation	-	6	-	-	-	-	-	1	7	-	-	7	-	-	-	-	-	-	33	-
3b.1.1.4	Construction Warehouse & Fab Shop	-	118	-	-	-	-	-	18	135	-	-	135	-	-	-	-	-	-	1,405	-
3b.1.1.5	D3/D4 Emergency Generator	-	13	-	-	-	-	-	2	15	-	-	15	-	-	-	-	-	-	84	-
3b.1.1.6	Drum Transfer & Truck Loading Enclosure	-	19	-	-	-	-	-	3	21	-	-	21	-	-	-	-	-	-	221	-
3b.1.1.7	Hydrogen House	-	6	-	-	-	-	-	1	7	-	-	7	-	-	-	-	-	-	47	-
3b.1.1.8	LLRW Storage Enclosure	-	121	-	-	-	-	-	18	139	-	-	139	-	-	-	-	-	-	853	-
3b.1.1.9	Misc Structures 2017	-	1,391	-	-	-	-	-	209	1,599	-	-	1,599	-	-	-	-	-	-	12,939	-
3b.1.1.10	Radwaste	-	165	-	-	-	-	-	25	190	-	-	190	-	-	-	-	-	-	1,400	-
3b.1.1.11	Resin Disposal	-	13	-	-	-	-	-	2	15	-	-	15	-	-	-	-	-	-	120	-
3b.1.1.12	Structures below 3' below grade	-	1,713	-	-	-	-	-	257	1,969	-	-	1,969	-	-	-	-	-	-	9,238	-
3b.1.1.13	Sulfuric Acid Tank Enclosure	-	3	-	-	-	-	-	0	3	-	-	3	-	-	-	-	-	-	35	-
3b.1.1.14	Turbine	-	1,983	-	-	-	-	-	298	2,281	-	-	2,281	-	-	-	-	-	-	22,052	-
3b.1.1.15	Turbine Pedestal	-	349	-	-	-	-	-	52	402	-	-	402	-	-	-	-	-	-	1,857	-
3b.1.1.16	Warehouse #2	-	22	-	-	-	-	-	3	25	-	-	25	-	-	-	-	-	-	213	-
3b.1.1.17	Waste Neutralizing Tank House	-	7	-	-	-	-	-	1	8	-	-	8	-	-	-	-	-	-	56	-
3b.1.1.18	Waste Oil Storage	-	8	-	-	-	-	-	1	10	-	-	10	-	-	-	-	-	-	70	-
3b.1.1.19	Water Treatment	-	303	-	-	-	-	-	46	349	-	-	349	-	-	-	-	-	-	2,690	-
3b.1.1.20	Fuel Handling of Aux Building	-	1,032	-	-	-	-	-	155	1,186	-	-	1,186	-	-	-	-	-	-	8,240	-
3b.1.1	Totals	-	13,424	-	-	-	-	-	2,014	15,438	-	-	15,438	-	-	-	-	-	-	118,134	-
Site Closeout Activities																					
3b.1.2	Remove Rubble	-	1,308	-	-	-	-	-	196	1,505	-	-	1,505	-	-	-	-	-	-	6,495	-
3b.1.3	Grade & landscape site	-	431	-	-	-	-	-	65	495	-	-	495	-	-	-	-	-	-	921	-
3b.1.4	Final report to NRC	-	-	-	-	-	-	78	12	90	90	-	-	-	-	-	-	-	-	-	667
3b.1	Subtotal Period 3b Activity Costs	-	15,163	-	-	-	-	78	2,286	17,528	90	-	17,438	-	-	-	-	-	-	125,549	667
Period 3b Additional Costs																					
3b.2.1	Clean Concrete Disposal	-	3,313	-	-	-	-	8	498	3,818	-	-	3,818	-	-	-	-	-	-	12,824	-
3b.2.2	Underground Services Excavations	-	811	-	-	-	-	520	200	1,531	-	-	1,531	-	-	-	-	-	-	7,407	-
3b.2.3	Intake Structure Cofferdam	-	423	-	-	-	-	-	63	486	-	-	486	-	-	-	-	-	-	3,552	-
3b.2.4	Construction Debris	-	-	-	-	-	-	463	69	532	-	-	532	-	-	-	-	-	-	-	-
3b.2.5	Backfill	-	8,465	-	-	-	-	-	1,270	9,735	-	-	9,735	-	-	-	-	-	-	9,327	-
3b.2	Subtotal Period 3b Additional Costs	-	13,012	-	-	-	-	991	2,100	16,103	-	-	16,103	-	-	-	-	-	-	33,110	-
Period 3b Collateral Costs																					
3b.3.1	Small tool allowance	-	172	-	-	-	-	-	26	198	-	-	198	-	-	-	-	-	-	-	-
3b.3.2	Prairie Island Indian Community Payments	-	-	-	-	-	-	2,651	-	2,651	-	2,651	-	-	-	-	-	-	-	-	-
3b.3	Subtotal Period 3b Collateral Costs	-	172	-	-	-	-	2,651	26	2,848	-	2,651	198	-	-	-	-	-	-	-	-
Period 3b Period-Dependent Costs																					
3b.4.1	Insurance	-	-	-	-	-	-	542	54	596	-	596	-	-	-	-	-	-	-	-	-
3b.4.2	Property taxes	-	-	-	-	-	-	4,334	433	4,767	-	4,767	-	-	-	-	-	-	-	-	-
3b.4.3	Heavy equipment rental	-	6,670	-	-	-	-	-	1,000	7,670	-	-	7,670	-	-	-	-	-	-	-	-
3b.4.4	Plant energy budget	-	-	-	-	-	-	321	48	369	-	-	369	-	-	-	-	-	-	-	-
3b.4.5	NRC ISFSI Fees	-	-	-	-	-	-	236	24	259	-	259	-	-	-	-	-	-	-	-	-
3b.4.6	Emergency Planning Fees	-	-	-	-	-	-	145	14	159	-	159	-	-	-	-	-	-	-	-	-
3b.4.7	Fixed Overhead	-	-	-	-	-	-	990	148	1,138	-	-	1,138	-	-	-	-	-	-	-	-
3b.4.8	ISFSI Operating Costs	-	-	-	-	-	-	109	16	126	-	126	-	-	-	-	-	-	-	-	-
3b.4.9	Railroad Track Maintenance	-	-	-	-	-	-	331	50	380	-	-	380	-	-	-	-	-	-	-	-
3b.4.10	Security Staff Cost	-	-	-	-	-	-	4,245	637	4,882	-	4,882	-	-	-	-	-	-	-	-	57,340
3b.4.11	DOC Staff Cost	-	-	-	-	-	-	10,467	1,570	12,038	-	-	12,038	-	-	-	-	-	-	-	116,885

Table G-2
Prairie Island Nuclear Generating Plant, Unit 2
DECON Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage and Periodic TN-40 Replacement
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Period 3b Period-Dependent Costs (continued)																					
3b.4.12	Utility Staff Cost	-	-	-	-	-	-	4,813	722	5,535	(0)	1,207	4,329	-	-	-	-	-	-	-	74,431
3b.4	Subtotal Period 3b Period-Dependent Costs	-	6,670	-	-	-	-	26,534	4,718	37,921	(0)	11,997	25,924	-	-	-	-	-	-	-	248,656
3b.0	TOTAL PERIOD 3b COST	-	35,017	-	-	-	-	30,253	9,130	74,401	90	14,648	59,663	-	-	-	-	-	-	158,659	249,323
PERIOD 3c - Fuel Storage Operations/Shipping																					
Period 3c Direct Decommissioning Activities																					
Period 3c Collateral Costs																					
3c.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	84,962	12,744	97,707	-	97,707	-	-	-	-	-	-	-	-	-
3c.3.2	Prairie Island Indian Community Payments	-	-	-	-	-	-	43,116	-	43,116	-	43,116	-	-	-	-	-	-	-	-	-
3c.3	Subtotal Period 3c Collateral Costs	-	-	-	-	-	-	128,079	12,744	140,823	-	140,823	-	-	-	-	-	-	-	-	-
Period 3c Period-Dependent Costs																					
3c.4.1	Insurance	-	-	-	-	-	-	8,818	882	9,700	-	9,700	-	-	-	-	-	-	-	-	-
3c.4.2	Property taxes	-	-	-	-	-	-	39,829	3,983	43,812	-	43,812	-	-	-	-	-	-	-	-	-
3c.4.4	NRC ISFSI Fees	-	-	-	-	-	-	5,648	565	6,213	-	6,213	-	-	-	-	-	-	-	-	-
3c.4.5	Emergency Planning Fees	-	-	-	-	-	-	2,360	236	2,596	-	2,596	-	-	-	-	-	-	-	-	-
3c.4.6	Fixed Overhead	-	-	-	-	-	-	5,267	790	6,057	-	6,057	-	-	-	-	-	-	-	-	-
3c.4.7	ISFSI Operating Costs	-	-	-	-	-	-	1,782	267	2,049	-	2,049	-	-	-	-	-	-	-	-	-
3c.4.8	Railroad Track Maintenance	-	-	-	-	-	-	1,991	299	2,289	-	2,289	-	-	-	-	-	-	-	-	-
3c.4.9	Security Staff Cost	-	-	-	-	-	-	69,105	10,366	79,471	-	79,471	-	-	-	-	-	-	-	-	933,362
3c.4.10	Utility Staff Cost	-	-	-	-	-	-	17,069	2,560	19,629	-	19,629	-	-	-	-	-	-	-	-	242,315
3c.4	Subtotal Period 3c Period-Dependent Costs	-	-	-	-	-	-	151,870	19,948	171,817	-	171,817	-	-	-	-	-	-	-	-	1,175,677
3c.0	TOTAL PERIOD 3c COST	-	-	-	-	-	-	279,948	32,692	312,640	-	312,640	-	-	-	-	-	-	-	-	1,175,677
PERIOD 3d - GTCC shipping																					
Period 3d Direct Decommissioning Activities																					
Nuclear Steam Supply System Removal																					
3d.1.1.1	Vessel & Internals GTCC Disposal	-	-	1,331	-	-	8,689	-	1,636	11,656	11,656	-	-	-	-	-	-	3,746	837,596	-	-
3d.1.1	Totals	-	-	1,331	-	-	8,689	-	1,636	11,656	11,656	-	-	-	-	-	-	3,746	837,596	-	-
3d.1	Subtotal Period 3d Activity Costs	-	-	1,331	-	-	8,689	-	1,636	11,656	11,656	-	-	-	-	-	-	3,746	837,596	-	-
Period 3d Collateral Costs																					
3d.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	26	4	29	-	29	-	-	-	-	-	-	-	-	-
3d.3.2	Prairie Island Indian Community Payments	-	-	-	-	-	-	48	-	48	-	48	-	-	-	-	-	-	-	-	-
3d.3	Subtotal Period 3d Collateral Costs	-	-	-	-	-	-	73	4	77	-	77	-	-	-	-	-	-	-	-	-
Period 3d Period-Dependent Costs																					
3d.4.1	Insurance	-	-	-	-	-	-	10	1	11	11	-	-	-	-	-	-	-	-	-	-
3d.4.2	Property taxes	-	-	-	-	-	-	39	4	43	43	-	-	-	-	-	-	-	-	-	-
3d.4.4	NRC ISFSI Fees	-	-	-	-	-	-	4	0	5	-	5	-	-	-	-	-	-	-	-	-
3d.4.5	Emergency Planning Fees	-	-	-	-	-	-	3	0	3	-	3	-	-	-	-	-	-	-	-	-
3d.4.6	Fixed Overhead	-	-	-	-	-	-	6	1	7	7	-	-	-	-	-	-	-	-	-	-
3d.4.7	ISFSI Operating Costs	-	-	-	-	-	-	2	0	2	-	2	-	-	-	-	-	-	-	-	-
3d.4.8	Railroad Track Maintenance	-	-	-	-	-	-	2	0	3	3	-	-	-	-	-	-	-	-	-	-
3d.4.9	Security Staff Cost	-	-	-	-	-	-	77	12	88	88	-	-	-	-	-	-	-	-	-	1,037
3d.4.10	Utility Staff Cost	-	-	-	-	-	-	19	3	22	22	-	-	-	-	-	-	-	-	-	269
3d.4	Subtotal Period 3d Period-Dependent Costs	-	-	-	-	-	-	162	21	183	173	10	-	-	-	-	-	-	-	-	1,306
3d.0	TOTAL PERIOD 3d COST	-	-	1,331	-	-	8,689	235	1,661	11,916	11,829	87	-	-	-	-	-	3,746	837,596	-	1,306
PERIOD 3e - ISFSI Decontamination																					
Period 3e Direct Decommissioning Activities																					
Period 3e Additional Costs																					
3e.2.1	License Termination ISFSI	15	48	2	214	-	2,289	867	859	4,293	4,293	-	-	-	8,229	-	-	-	1,119,503	5,267	924
3e.2	Subtotal Period 3e Additional Costs	15	48	2	214	-	2,289	867	859	4,293	4,293	-	-	-	8,229	-	-	-	1,119,503	5,267	924
Period 3e Period-Dependent Costs																					
3e.4.1	Insurance	-	-	-	-	-	-	96	24	121	121	-	-	-	-	-	-	-	-	-	-
3e.4.2	Property taxes	-	-	-	-	-	-	26	6	32	32	-	-	-	-	-	-	-	-	-	-
3e.4.4	Fixed Overhead	-	-	-	-	-	-	51	13	63	63	-	-	-	-	-	-	-	-	-	-

Table G-2
Prairie Island Nuclear Generating Plant, Unit 2
DECON Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage and Periodic TN-40 Replacement
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Period 3e Period-Dependent Costs (continued)																					
3e.4.5	Railroad Track Maintenance	-	-	-	-	-	-	19	5	24	24	-	-	-	-	-	-	-	-	-	-
3e.4.6	Security Staff Cost	-	-	-	-	-	-	154	38	192	192	-	-	-	-	-	-	-	-	-	2,500
3e.4.7	Utility Staff Cost	-	-	-	-	-	-	130	33	163	163	-	-	-	-	-	-	-	-	-	1,896
3e.4	Subtotal Period 3e Period-Dependent Costs	-	-	-	-	-	-	476	119	595	595	-	-	-	-	-	-	-	-	-	4,396
3e.0	TOTAL PERIOD 3e COST	15	48	2	214	-	2,289	1,343	978	4,888	4,888	-	-	-	8,229	-	-	-	1,119,503	5,267	5,320
PERIOD 3f - ISFSI Site Restoration																					
Period 3f Direct Decommissioning Activities																					
Period 3f Additional Costs																					
3f.2.1	Demolition and Site Restoration of ISFSI	-	715	-	-	-	-	109	124	948	-	-	948	-	-	-	-	-	-	3,748	160
3f.2	Subtotal Period 3f Additional Costs	-	715	-	-	-	-	109	124	948	-	-	948	-	-	-	-	-	-	3,748	160
Period 3f Collateral Costs																					
3f.3.1	Small tool allowance	-	6	-	-	-	-	-	1	7	-	-	7	-	-	-	-	-	-	-	-
3f.3	Subtotal Period 3f Collateral Costs	-	6	-	-	-	-	-	1	7	-	-	7	-	-	-	-	-	-	-	-
Period 3f Period-Dependent Costs																					
3f.4.2	Property taxes	-	-	-	-	-	-	13	1	14	-	-	14	-	-	-	-	-	-	-	-
3f.4.3	Heavy equipment rental	-	62	-	-	-	-	-	9	71	-	-	71	-	-	-	-	-	-	-	-
3f.4.4	Plant energy budget	-	-	-	-	-	-	13	2	15	-	-	15	-	-	-	-	-	-	-	-
3f.4.5	Fixed Overhead	-	-	-	-	-	-	25	4	29	-	-	29	-	-	-	-	-	-	-	-
3f.4.6	Railroad Track Maintenance	-	-	-	-	-	-	10	1	11	-	-	11	-	-	-	-	-	-	-	-
3f.4.7	Security Staff Cost	-	-	-	-	-	-	78	12	89	-	-	89	-	-	-	-	-	-	-	1,260
3f.4.8	Utility Staff Cost	-	-	-	-	-	-	52	8	60	-	-	60	-	-	-	-	-	-	-	782
3f.4	Subtotal Period 3f Period-Dependent Costs	-	62	-	-	-	-	190	37	289	-	-	289	-	-	-	-	-	-	-	2,042
3f.0	TOTAL PERIOD 3f COST	-	782	-	-	-	-	300	162	1,243	-	-	1,243	-	-	-	-	-	-	3,748	2,202
PERIOD 3 TOTALS		15	35,847	1,333	214	-	10,978	312,079	44,623	405,089	16,808	327,375	60,906	-	8,229	-	-	3,746	1,957,099	167,675	1,433,828
TOTAL COST TO DECOMMISSION		**13,423**	**104,950**	**31,018**	**7,565**	**13,927**	**53,146**	**707,463**	**153,040**	**1,084,531**	**562,164**	**455,241**	**67,126**	**169,551**	**151,717**	**839**	**673**	**3,746**	**17,656,020**	**1,026,161**	**4,190,673**

TOTAL COST TO DECOMMISSION WITH 16.43% CONTINGENCY:	**$1,084,531**	**thousands of 2017 dollars**
TOTAL NRC LICENSE TERMINATION COST IS 51.83% OR:	**$562,164**	**thousands of 2017 dollars**
SPENT FUEL MANAGEMENT COST IS 41.98% OR:	**$455,241**	**thousands of 2017 dollars**
NON-NUCLEAR DEMOLITION COST IS 6.19% OR:	**$67,126**	**thousands of 2017 dollars**
TOTAL LOW-LEVEL RADIOACTIVE WASTE VOLUME BURIED (EXCLUDING GTCC):	**153,229**	**cubic feet**
TOTAL GREATER THAN CLASS C RADWASTE VOLUME GENERATED:	**3,746**	**cubic feet**
TOTAL SCRAP METAL REMOVED:	**41,515**	**tons**
TOTAL CRAFT LABOR REQUIREMENTS:	**1,026,161**	**man-hours**

End Notes:
n/a - indicates that this activity not charged as decommissioning expense
a - indicates that this activity performed by decommissioning staff
0 - indicates that this value is less than 0.5 but is non-zero
A cell containing " - " indicates a zero value

APPENDIX H

DETAILED COST ANALYSIS

SCENARIO 6: SAFSTOR with 32 Year DFS

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Prairie Island Nuclear Generating Plant, Unit 2 .....H-11

Table H-1
Prairie Island Nuclear Generating Plant, Unit 1
SAFSTOR Decommissioning Cost Estimate with DOE Pickup of Industry Spent Fuel Starting in 2025
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
PERIOD 1a - Shutdown through Transition																					
Period 1a Direct Decommissioning Activities																					
1a.1.1	SAFSTOR site characterization survey	-	-	-	-	-	-	571	171	742	742	-	-	-	-	-	-	-	-	-	-
1a.1.2	Prepare preliminary decommissioning cost	-	-	-	-	-	-	153	23	175	175	-	-	-	-	-	-	-	-	-	1,300
1a.1.3	Notification of Cessation of Operations									a											
1a.1.4	Remove fuel & source material									n/a											
1a.1.5	Notification of Permanent Defueling									a											
1a.1.6	Deactivate plant systems & process waste									a											
1a.1.7	Prepare and submit PSDAR	-	-	-	-	-	-	235	35	270	270	-	-	-	-	-	-	-	-	-	2,000
1a.1.8	Review plant dwgs & specs.	-	-	-	-	-	-	153	23	175	175	-	-	-	-	-	-	-	-	-	1,300
1a.1.9	Perform detailed rad survey									a											
1a.1.10	Estimate by-product inventory	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1a.1.11	End product description	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1a.1.12	Detailed by-product inventory	-	-	-	-	-	-	176	26	202	202	-	-	-	-	-	-	-	-	-	1,500
1a.1.13	Define major work sequence	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1a.1.14	Perform SER and EA	-	-	-	-	-	-	364	55	418	418	-	-	-	-	-	-	-	-	-	3,100
1a.1.15	Prepare/submit Defueled Technical Specifications	-	-	-	-	-	-	880	132	1,012	1,012	-	-	-	-	-	-	-	-	-	7,500
1a.1.16	Perform Site-Specific Cost Study	-	-	-	-	-	-	587	88	675	675	-	-	-	-	-	-	-	-	-	5,000
1a.1.17	Prepare/submit Irradiated Fuel Management Plan	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
Activity Specifications																					
1a.1.18.1	Prepare plant and facilities for SAFSTOR	-	-	-	-	-	-	578	87	664	664	-	-	-	-	-	-	-	-	-	4,920
1a.1.18.2	Plant systems	-	-	-	-	-	-	489	73	562	562	-	-	-	-	-	-	-	-	-	4,167
1a.1.18.3	Plant structures and buildings	-	-	-	-	-	-	366	55	421	421	-	-	-	-	-	-	-	-	-	3,120
1a.1.18.4	Waste management	-	-	-	-	-	-	235	35	270	270	-	-	-	-	-	-	-	-	-	2,000
1a.1.18.5	Facility and site dormancy	-	-	-	-	-	-	235	35	270	270	-	-	-	-	-	-	-	-	-	2,000
1a.1.18	Total	-	-	-	-	-	-	1,902	285	2,188	2,188	-	-	-	-	-	-	-	-	-	16,207
Detailed Work Procedures																					
1a.1.19.1	Plant systems	-	-	-	-	-	-	139	21	160	160	-	-	-	-	-	-	-	-	-	1,183
1a.1.19.2	Facility closeout & dormancy	-	-	-	-	-	-	141	21	162	162	-	-	-	-	-	-	-	-	-	1,200
1a.1.19	Total	-	-	-	-	-	-	280	42	322	322	-	-	-	-	-	-	-	-	-	2,383
1a.1.20	Procure vacuum drying system	-	-	-	-	-	-	12	2	13	13	-	-	-	-	-	-	-	-	-	100
1a.1.21	Drain/de-energize non-cont. systems									a											
1a.1.22	Drain & dry NSSS									a											
1a.1.23	Drain/de-energize contaminated systems									a											
1a.1.24	Decon/secure contaminated systems									a											
1a.1	Subtotal Period 1a Activity Costs	-	-	-	-	-	-	5,781	953	6,734	6,734	-	-	-	-	-	-	-	-	-	44,390
Period 1a Collateral Costs																					
1a.3.1	Prairie Island Indian Community Payments	-	-	-	-	-	-	2,003	-	2,003	-	2,003	-	-	-	-	-	-	-	-	-
1a.3	Subtotal Period 1a Collateral Costs	-	-	-	-	-	-	2,003	-	2,003	-	2,003	-	-	-	-	-	-	-	-	-
Period 1a Period-Dependent Costs																					
1a.4.1	Insurance	-	-	-	-	-	-	1,730	173	1,903	1,903	-	-	-	-	-	-	-	-	-	-
1a.4.2	Property taxes	-	-	-	-	-	-	2,682	268	2,950	2,950	-	-	-	-	-	-	-	-	-	-
1a.4.3	Health physics supplies	-	515	-	-	-	-	-	129	644	644	-	-	-	-	-	-	-	-	-	-
1a.4.4	Heavy equipment rental	-	567	-	-	-	-	-	85	652	652	-	-	-	-	-	-	-	-	-	-
1a.4.5	Disposal of DAW generated	-	-	13	4	-	50	-	14	81	81	-	-	-	610	-	-	-	12,190	20	-
1a.4.6	Plant energy budget	-	-	-	-	-	-	1,515	227	1,742	1,742	-	-	-	-	-	-	-	-	-	-
1a.4.7	NRC Fees	-	-	-	-	-	-	1,110	111	1,221	1,221	-	-	-	-	-	-	-	-	-	-
1a.4.8	Emergency Planning Fees	-	-	-	-	-	-	1,604	160	1,765	-	1,765	-	-	-	-	-	-	-	-	-
1a.4.9	Fixed Overhead	-	-	-	-	-	-	1,470	220	1,690	1,690	-	-	-	-	-	-	-	-	-	-
1a.4.10	Spent Fuel Pool O&M	-	-	-	-	-	-	401	60	461	-	461	-	-	-	-	-	-	-	-	-
1a.4.11	ISFSI Operating Costs	-	-	-	-	-	-	52	8	59	-	59	-	-	-	-	-	-	-	-	-
1a.4.12	Railroad Track Maintenance	-	-	-	-	-	-	58	9	66	66	-	-	-	-	-	-	-	-	-	-
1a.4.13	Security Staff Cost	-	-	-	-	-	-	7,390	1,108	8,498	8,498	-	-	-	-	-	-	-	-	-	122,720
1a.4.14	Utility Staff Cost	-	-	-	-	-	-	25,791	3,869	29,660	29,660	-	-	-	-	-	-	-	-	-	422,240
1a.4	Subtotal Period 1a Period-Dependent Costs	-	1,083	13	4	-	50	43,802	6,442	51,394	49,108	2,286	-	-	610	-	-	-	12,190	20	544,960
1a.0	TOTAL PERIOD 1a COST	-	1,083	13	4	-	50	51,587	7,395	60,131	55,842	4,289	-	-	610	-	-	-	12,190	20	589,350

Table H-1
Prairie Island Nuclear Generating Plant, Unit 1
SAFSTOR Decommissioning Cost Estimate with DOE Pickup of Industry Spent Fuel Starting in 2025
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
PERIOD 1b - SAFSTOR Limited DECON Activities																					
Period 1b Direct Decommissioning Activities																					
Decontamination of Site Buildings																					
1b.1.1.1	Reactor	1,135	-	-	-	-	-	-	568	1,703	1,703	-	-	-	-	-	-	-	-	17,003	-
1b.1.1	Totals	1,135	-	-	-	-	-	-	568	1,703	1,703	-	-	-	-	-	-	-	-	17,003	-
1b.1	Subtotal Period 1b Activity Costs	1,135	-	-	-	-	-	-	568	1,703	1,703	-	-	-	-	-	-	-	-	17,003	-
Period 1b Additional Costs																					
1b.2.1	Spent fuel pool isolation	-	-	-	-	-	-	11,691	1,754	13,445	13,445	-	-	-	-	-	-	-	-	-	-
1b.2	Subtotal Period 1b Additional Costs	-	-	-	-	-	-	11,691	1,754	13,445	13,445	-	-	-	-	-	-	-	-	-	-
Period 1b Collateral Costs																					
1b.3.1	Decon equipment	973	-	-	-	-	-	-	146	1,119	1,119	-	-	-	-	-	-	-	-	-	-
1b.3.2	Process decommissioning water waste	77	-	50	130	-	204	-	114	575	575	-	-	-	486	-	-	-	29,184	95	-
1b.3.4	Small tool allowance	-	19	-	-	-	-	-	3	22	22	-	-	-	-	-	-	-	-	-	-
1b.3.5	Prairie Island Indian Community Payments	-	-	-	-	-	-	315	-	315	-	315	-	-	-	-	-	-	-	-	-
1b.3	Subtotal Period 1b Collateral Costs	1,050	19	50	130	-	204	315	263	2,031	1,716	315	-	-	486	-	-	-	29,184	95	-
Period 1b Period-Dependent Costs																					
1b.4.1	Decon supplies	415	-	-	-	-	-	-	104	518	518	-	-	-	-	-	-	-	-	-	-
1b.4.2	Insurance	-	-	-	-	-	-	436	44	480	480	-	-	-	-	-	-	-	-	-	-
1b.4.3	Property taxes	-	-	-	-	-	-	676	68	744	744	-	-	-	-	-	-	-	-	-	-
1b.4.4	Health physics supplies	-	212	-	-	-	-	-	53	264	264	-	-	-	-	-	-	-	-	-	-
1b.4.5	Heavy equipment rental	-	143	-	-	-	-	-	21	164	164	-	-	-	-	-	-	-	-	-	-
1b.4.6	Disposal of DAW generated	-	-	7	2	-	27	-	8	43	43	-	-	-	326	-	-	-	6,519	11	-
1b.4.7	Plant energy budget	-	-	-	-	-	-	382	57	439	439	-	-	-	-	-	-	-	-	-	-
1b.4.8	NRC Fees	-	-	-	-	-	-	161	16	178	178	-	-	-	-	-	-	-	-	-	-
1b.4.9	Emergency Planning Fees	-	-	-	-	-	-	404	40	445	-	445	-	-	-	-	-	-	-	-	-
1b.4.10	Fixed Overhead	-	-	-	-	-	-	370	56	426	426	-	-	-	-	-	-	-	-	-	-
1b.4.11	Spent Fuel Pool O&M	-	-	-	-	-	-	101	15	116	-	116	-	-	-	-	-	-	-	-	-
1b.4.12	ISFSI Operating Costs	-	-	-	-	-	-	13	2	15	-	15	-	-	-	-	-	-	-	-	-
1b.4.13	Railroad Track Maintenance	-	-	-	-	-	-	15	2	17	17	-	-	-	-	-	-	-	-	-	-
1b.4.14	Security Staff Cost	-	-	-	-	-	-	1,863	279	2,142	2,142	-	-	-	-	-	-	-	-	-	30,932
1b.4.15	Utility Staff Cost	-	-	-	-	-	-	6,501	975	7,476	7,476	-	-	-	-	-	-	-	-	-	106,428
1b.4	Subtotal Period 1b Period-Dependent Costs	415	355	7	2	-	27	10,922	1,740	13,467	12,891	576	-	-	326	-	-	-	6,519	11	137,360
1b.0	TOTAL PERIOD 1b COST	2,600	373	57	132	-	230	22,929	4,324	30,645	29,754	891	-	-	812	-	-	-	35,703	17,108	137,360
PERIOD 1c - Preparations for SAFSTOR Dormancy																					
Period 1c Direct Decommissioning Activities																					
1c.1.1	Prepare support equipment for storage	-	486	-	-	-	-	-	73	559	559	-	-	-	-	-	-	-	-	3,000	-
1c.1.2	Install containment pressure equal. lines	-	48	-	-	-	-	-	7	55	55	-	-	-	-	-	-	-	-	700	-
1c.1.3	Interim survey prior to dormancy	-	-	-	-	-	-	733	220	953	953	-	-	-	-	-	-	-	-	9,017	-
1c.1.4	Secure building accesses									a											
1c.1.5	Prepare & submit interim report	-	-	-	-	-	-	68	10	79	79	-	-	-	-	-	-	-	-	-	583
1c.1	Subtotal Period 1c Activity Costs	-	534	-	-	-	-	801	310	1,646	1,646	-	-	-	-	-	-	-	-	12,717	583
Period 1c Collateral Costs																					
1c.3.1	Process decommissioning water waste	88	-	58	150	-	234	-	131	661	661	-	-	-	560	-	-	-	33,579	109	-
1c.3.3	Small tool allowance	-	4	-	-	-	-	-	1	5	5	-	-	-	-	-	-	-	-	-	-
1c.3.4	Spent Fuel Capital and Transfer	-	-	-	-	-	-	230	35	265	-	265	-	-	-	-	-	-	-	-	-
1c.3.5	Retention and Severance	-	-	-	-	-	-	1,088	163	1,251	1,251	-	-	-	-	-	-	-	-	-	-
1c.3.6	Prairie Island Indian Community Payments	-	-	-	-	-	-	315	-	315	-	315	-	-	-	-	-	-	-	-	-
1c.3	Subtotal Period 1c Collateral Costs	88	4	58	150	-	234	1,633	329	2,497	1,917	580	-	-	560	-	-	-	33,579	109	-
Period 1c Period-Dependent Costs																					
1c.4.1	Insurance	-	-	-	-	-	-	436	44	480	480	-	-	-	-	-	-	-	-	-	-
1c.4.2	Property taxes	-	-	-	-	-	-	676	68	744	744	-	-	-	-	-	-	-	-	-	-
1c.4.3	Health physics supplies	-	191	-	-	-	-	-	48	239	239	-	-	-	-	-	-	-	-	-	-
1c.4.4	Heavy equipment rental	-	143	-	-	-	-	-	21	164	164	-	-	-	-	-	-	-	-	-	-
1c.4.5	Disposal of DAW generated	-	-	3	1	-	13	-	4	20	20	-	-	-	154	-	-	-	3,073	5	-
1c.4.6	Plant energy budget	-	-	-	-	-	-	382	57	439	439	-	-	-	-	-	-	-	-	-	-

Table H-1
Prairie Island Nuclear Generating Plant, Unit 1
SAFSTOR Decommissioning Cost Estimate with DOE Pickup of Industry Spent Fuel Starting in 2025
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Period 1c Period-Dependent Costs (continued)																					
1c.4.7	NRC Fees	-	-	-	-	-	-	161	16	178	178	-	-	-	-	-	-	-	-	-	-
1c.4.8	Emergency Planning Fees	-	-	-	-	-	-	404	40	445	-	445	-	-	-	-	-	-	-	-	-
1c.4.9	Fixed Overhead	-	-	-	-	-	-	370	56	426	426	-	-	-	-	-	-	-	-	-	-
1c.4.10	Spent Fuel Pool O&M	-	-	-	-	-	-	101	15	116	-	116	-	-	-	-	-	-	-	-	-
1c.4.11	ISFSI Operating Costs	-	-	-	-	-	-	13	2	15	-	15	-	-	-	-	-	-	-	-	-
1c.4.12	Railroad Track Maintenance	-	-	-	-	-	-	15	2	17	17	-	-	-	-	-	-	-	-	-	-
1c.4.13	Security Staff Cost	-	-	-	-	-	-	1,863	279	2,142	2,142	-	-	-	-	-	-	-	-	-	30,932
1c.4.14	Utility Staff Cost	-	-	-	-	-	-	6,501	975	7,476	7,476	-	-	-	-	-	-	-	-	-	106,428
1c.4	Subtotal Period 1c Period-Dependent Costs	-	334	3	1	-	13	10,922	1,627	12,900	12,324	576	-	-	154	-	-	-	3,073	5	137,360
1c.0	TOTAL PERIOD 1c COST	88	873	61	151	-	247	13,356	2,267	17,043	15,887	1,156	-	-	713	-	-	-	36,652	12,832	137,943
PERIOD 1 TOTALS		2,688	2,329	132	287	-	527	87,872	13,986	107,820	101,484	6,336	-	-	2,135	-	-	-	84,545	29,960	864,653
PERIOD 2a - SAFSTOR Dormancy with Wet Spent Fuel Storage																					
Period 2a Direct Decommissioning Activities																					
2a.1.1	Quarterly Inspection									a											
2a.1.2	Semi-annual environmental survey									a											
2a.1.3	Prepare reports									a											
2a.1.4	Bituminous roof replacement	-	-	-	-	-	-	68	10	78	78	-	-	-	-	-	-	-	-	-	-
2a.1.5	Maintenance supplies	-	-	-	-	-	-	643	161	804	804	-	-	-	-	-	-	-	-	-	-
2a.1	Subtotal Period 2a Activity Costs	-	-	-	-	-	-	711	171	882	882	-	-	-	-	-	-	-	-	-	-
Period 2a Additional Costs																					
2a.2.1	Security Modifications	-	-	-	-	-	-	4,348	652	5,000	5,000	-	-	-	-	-	-	-	-	-	-
2a.2	Subtotal Period 2a Additional Costs	-	-	-	-	-	-	4,348	652	5,000	5,000	-	-	-	-	-	-	-	-	-	-
Period 2a Collateral Costs																					
2a.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	65,860	9,879	75,739	-	75,739	-	-	-	-	-	-	-	-	-
2a.3.2	Retention and Severance	-	-	-	-	-	-	23,628	3,544	27,172	27,172	-	-	-	-	-	-	-	-	-	-
2a.3.3	Prairie Island Indian Community Payments	-	-	-	-	-	-	5,897	-	5,897	-	5,897	-	-	-	-	-	-	-	-	-
2a.3	Subtotal Period 2a Collateral Costs	-	-	-	-	-	-	95,385	13,423	108,808	27,172	81,636	-	-	-	-	-	-	-	-	-
Period 2a Period-Dependent Costs																					
2a.4.1	Insurance	-	-	-	-	-	-	2,412	241	2,653	2,653	-	-	-	-	-	-	-	-	-	-
2a.4.2	Property taxes	-	-	-	-	-	-	12,654	1,265	13,919	13,919	-	-	-	-	-	-	-	-	-	-
2a.4.3	Health physics supplies	-	898	-	-	-	-	-	224	1,122	1,122	-	-	-	-	-	-	-	-	-	-
2a.4.4	Disposal of DAW generated	-	-	21	6	-	79	-	23	129	129	-	-	-	972	-	-	-	19,431	32	-
2a.4.5	Plant energy budget	-	-	-	-	-	-	1,430	214	1,644	1,644	-	-	-	-	-	-	-	-	-	-
2a.4.6	NRC Fees	-	-	-	-	-	-	1,211	121	1,332	1,332	-	-	-	-	-	-	-	-	-	-
2a.4.7	Emergency Planning Fees	-	-	-	-	-	-	6,061	606	6,667	-	6,667	-	-	-	-	-	-	-	-	-
2a.4.8	Fixed Overhead	-	-	-	-	-	-	6,938	1,041	7,979	7,979	-	-	-	-	-	-	-	-	-	-
2a.4.9	Spent Fuel Pool O&M	-	-	-	-	-	-	1,894	284	2,178	-	2,178	-	-	-	-	-	-	-	-	-
2a.4.10	ISFSI Operating Costs	-	-	-	-	-	-	244	37	280	-	280	-	-	-	-	-	-	-	-	-
2a.4.11	Railroad Track Maintenance	-	-	-	-	-	-	481	72	553	553	-	-	-	-	-	-	-	-	-	-
2a.4.12	Security Staff Cost	-	-	-	-	-	-	32,791	4,919	37,709	26,849	10,860	-	-	-	-	-	-	-	-	542,920
2a.4.13	Utility Staff Cost	-	-	-	-	-	-	11,657	1,748	13,405	9,531	3,874	-	-	-	-	-	-	-	-	190,075
2a.4	Subtotal Period 2a Period-Dependent Costs	-	898	21	6	-	79	77,772	10,796	89,573	65,713	23,860	-	-	972	-	-	-	19,431	32	732,995
2a.0	TOTAL PERIOD 2a COST	-	898	21	6	-	79	178,216	25,043	204,263	98,767	105,496	-	-	972	-	-	-	19,431	32	732,995
PERIOD 2b - SAFSTOR Dormancy with Dry Spent Fuel Storage																					
Period 2b Direct Decommissioning Activities																					
2b.1.1	Quarterly Inspection									a											
2b.1.2	Semi-annual environmental survey									a											
2b.1.3	Prepare reports									a											
2b.1.4	Bituminous roof replacement	-	-	-	-	-	-	362	54	416	416	-	-	-	-	-	-	-	-	-	-
2b.1.5	Maintenance supplies	-	-	-	-	-	-	3,433	858	4,291	4,291	-	-	-	-	-	-	-	-	-	-
2b.1	Subtotal Period 2b Activity Costs	-	-	-	-	-	-	3,795	913	4,707	4,707	-	-	-	-	-	-	-	-	-	-
Period 2b Collateral Costs																					
2b.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	20,705	3,106	23,811	-	23,811	-	-	-	-	-	-	-	-	-
2b.3.2	Prairie Island Indian Community Payments	-	-	-	-	-	-	31,469	-	31,469	-	31,469	-	-	-	-	-	-	-	-	-
2b.3	Subtotal Period 2b Collateral Costs	-	-	-	-	-	-	52,174	3,106	55,280	-	55,280	-	-	-	-	-	-	-	-	-

Xcel Energy

Table H-1
Prairie Island Nuclear Generating Plant, Unit 1
SAFSTOR Decommissioning Cost Estimate with DOE Pickup of Industry Spent Fuel Starting in 2025
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 2b Period-Dependent Costs																					
2b.4.1	Insurance	-	-	-	-	-	-	12,873	1,287	14,160	14,160	-	-	-	-	-	-	-	-	-	-
2b.4.2	Property taxes	-	-	-	-	-	-	65,863	6,586	72,449	72,449	-	-	-	-	-	-	-	-	-	-
2b.4.3	Health physics supplies	-	2,403	-	-	-	-	-	601	3,003	3,003	-	-	-	-	-	-	-	-	-	-
2b.4.4	Disposal of DAW generated	-	-	57	17	-	212	-	61	346	346	-	-	-	2,602	-	-	-	52,049	85	-
2b.4.5	Plant energy budget	-	-	-	-	-	-	3,816	572	4,388	4,388	-	-	-	-	-	-	-	-	-	-
2b.4.6	NRC Fees	-	-	-	-	-	-	6,141	614	6,756	6,756	-	-	-	-	-	-	-	-	-	-
2b.4.7	Emergency Planning Fees	-	-	-	-	-	-	1,723	172	1,895	-	1,895	-	-	-	-	-	-	-	-	-
2b.4.8	Fixed Overhead	-	-	-	-	-	-	3,844	577	4,421	4,421	-	-	-	-	-	-	-	-	-	-
2b.4.9	ISFSI Operating Costs	-	-	-	-	-	-	1,301	195	1,496	-	1,496	-	-	-	-	-	-	-	-	-
2b.4.10	Railroad Track Maintenance	-	-	-	-	-	-	1,453	218	1,671	1,671	-	-	-	-	-	-	-	-	-	-
2b.4.11	Security Staff Cost	-	-	-	-	-	-	63,533	9,530	73,063	15,051	58,012	-	-	-	-	-	-	-	-	943,283
2b.4.12	Utility Staff Cost	-	-	-	-	-	-	32,977	4,946	37,923	23,588	14,335	-	-	-	-	-	-	-	-	524,046
2b.4	Subtotal Period 2b Period-Dependent Costs	-	2,403	57	17	-	212	193,523	25,360	221,571	145,834	75,737	-	-	2,602	-	-	-	52,049	85	1,467,329
2b.0	TOTAL PERIOD 2b COST	-	2,403	57	17	-	212	249,492	29,379	281,559	150,541	131,017	-	-	2,602	-	-	-	52,049	85	1,467,329
PERIOD 2c - SAFSTOR Dormancy without Spent Fuel Storage																					
Period 2c Direct Decommissioning Activities																					
2c.1.1	Quarterly Inspection									a											
2c.1.2	Semi-annual environmental survey									a											
2c.1.3	Prepare reports									a											
2c.1.4	Bituminous roof replacement	-	-	-	-	-	-	325	49	374	374	-	-	-	-	-	-	-	-	-	-
2c.1.5	Maintenance supplies	-	-	-	-	-	-	3,085	771	3,857	3,857	-	-	-	-	-	-	-	-	-	-
2c.1	Subtotal Period 2c Activity Costs	-	-	-	-	-	-	3,410	820	4,230	4,230	-	-	-	-	-	-	-	-	-	-
Period 2c Period-Dependent Costs																					
2c.4.1	Insurance	-	-	-	-	-	-	11,351	1,135	12,487	12,487	-	-	-	-	-	-	-	-	-	-
2c.4.2	Property taxes	-	-	-	-	-	-	49,013	4,901	53,914	53,914	-	-	-	-	-	-	-	-	-	-
2c.4.3	Health physics supplies	-	2,136	-	-	-	-	-	534	2,670	2,670	-	-	-	-	-	-	-	-	-	-
2c.4.4	Disposal of DAW generated	-	-	50	15	-	188	-	54	307	307	-	-	-	2,305	-	-	-	46,092	75	-
2c.4.5	Plant energy budget	-	-	-	-	-	-	3,429	514	3,944	3,944	-	-	-	-	-	-	-	-	-	-
2c.4.6	NRC Fees	-	-	-	-	-	-	5,036	504	5,539	5,539	-	-	-	-	-	-	-	-	-	-
2c.4.7	Fixed Overhead	-	-	-	-	-	-	3,454	518	3,973	3,973	-	-	-	-	-	-	-	-	-	-
2c.4.8	Railroad Track Maintenance	-	-	-	-	-	-	1,306	196	1,502	1,502	-	-	-	-	-	-	-	-	-	-
2c.4.9	Security Staff Cost	-	-	-	-	-	-	48,790	7,318	56,108	56,108	-	-	-	-	-	-	-	-	-	706,402
2c.4.10	Utility Staff Cost	-	-	-	-	-	-	25,156	3,773	28,930	28,930	-	-	-	-	-	-	-	-	-	412,068
2c.4	Subtotal Period 2c Period-Dependent Costs	-	2,136	50	15	-	188	147,535	19,448	169,372	169,372	-	-	-	2,305	-	-	-	46,092	75	1,118,470
2c.0	TOTAL PERIOD 2c COST	-	2,136	50	15	-	188	150,946	20,268	173,602	173,602	-	-	-	2,305	-	-	-	46,092	75	1,118,470
PERIOD 2 TOTALS		-	5,436	128	37	-	479	578,654	74,690	659,424	422,910	236,514	-	-	5,879	-	-	-	117,573	192	3,318,794
PERIOD 3a - Reactivate Site Following SAFSTOR Dormancy																					
Period 3a Direct Decommissioning Activities																					
3a.1.1	Prepare preliminary decommissioning cost	-	-	-	-	-	-	153	23	175	175	-	-	-	-	-	-	-	-	-	1,300
3a.1.2	Review plant dwgs & specs.	-	-	-	-	-	-	540	81	621	621	-	-	-	-	-	-	-	-	-	4,600
3a.1.3	Perform detailed rad survey									a											
3a.1.4	End product description	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
3a.1.5	Detailed by-product inventory	-	-	-	-	-	-	153	23	175	175	-	-	-	-	-	-	-	-	-	1,300
3a.1.6	Define major work sequence	-	-	-	-	-	-	880	132	1,012	1,012	-	-	-	-	-	-	-	-	-	7,500
3a.1.7	Perform SER and EA	-	-	-	-	-	-	364	55	418	418	-	-	-	-	-	-	-	-	-	3,100
3a.1.8	Perform Site-Specific Cost Study	-	-	-	-	-	-	587	88	675	675	-	-	-	-	-	-	-	-	-	5,000
Activity Specifications																					
3a.1.9.1	Re-activate plant & temporary facilities	-	-	-	-	-	-	865	130	995	895	-	99	-	-	-	-	-	-	-	7,370
3a.1.9.2	Plant systems	-	-	-	-	-	-	489	73	562	506	-	56	-	-	-	-	-	-	-	4,167
3a.1.9.3	Reactor internals	-	-	-	-	-	-	833	125	958	958	-	-	-	-	-	-	-	-	-	7,100
3a.1.9.4	Reactor vessel	-	-	-	-	-	-	763	114	877	877	-	-	-	-	-	-	-	-	-	6,500
3a.1.9.5	Biological shield	-	-	-	-	-	-	59	9	67	67	-	-	-	-	-	-	-	-	-	500
3a.1.9.6	Steam generators	-	-	-	-	-	-	366	55	421	421	-	-	-	-	-	-	-	-	-	3,120
3a.1.9.7	Reinforced concrete	-	-	-	-	-	-	188	28	216	108	-	108	-	-	-	-	-	-	-	1,600
3a.1.9.8	Main Turbine	-	-	-	-	-	-	47	7	54	-	-	54	-	-	-	-	-	-	-	400
3a.1.9.9	Main Condensers	-	-	-	-	-	-	47	7	54	-	-	54	-	-	-	-	-	-	-	400
3a.1.9.10	Plant structures & buildings	-	-	-	-	-	-	366	55	421	211	-	211	-	-	-	-	-	-	-	3,120
3a.1.9.11	Waste management	-	-	-	-	-	-	540	81	621	621	-	-	-	-	-	-	-	-	-	4,600

Table H-1
Prairie Island Nuclear Generating Plant, Unit 1
SAFSTOR Decommissioning Cost Estimate with DOE Pickup of Industry Spent Fuel Starting in 2025
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Activity Specifications (continued)																					
3a.1.9.12	Facility & site closeout	-	-	-	-	-	-	106	16	121	61	-	61	-	-	-	-	-	-	-	900
3a.1.9	Total	-	-	-	-	-	-	4,669	700	5,369	4,726	-	643	-	-	-	-	-	-	-	39,777
Planning & Site Preparations																					
3a.1.10	Prepare dismantling sequence	-	-	-	-	-	-	282	42	324	324	-	-	-	-	-	-	-	-	-	2,400
3a.1.11	Plant prep. & temp. svces	-	-	-	-	-	-	3,300	495	3,795	3,795	-	-	-	-	-	-	-	-	-	-
3a.1.12	Design water clean-up system	-	-	-	-	-	-	164	25	189	189	-	-	-	-	-	-	-	-	-	1,400
3a.1.13	Rigging/Cont. Cntrl Envlps/tooling/etc.	-	-	-	-	-	-	2,300	345	2,645	2,645	-	-	-	-	-	-	-	-	-	-
3a.1.14	Procure casks/liners & containers	-	-	-	-	-	-	144	22	166	166	-	-	-	-	-	-	-	-	-	1,230
3a.1	Subtotal Period 3a Activity Costs	-	-	-	-	-	-	13,653	2,048	15,701	15,058	-	643	-	-	-	-	-	-	-	68,607
Period 3a Additional Costs																					
3a.2.1	Site Characterization	-	-	-	-	-	-	3,700	1,110	4,810	4,810	-	-	-	-	-	-	-	-	21,020	8,332
3a.2.2	Mixed/Hazardous Waste	-	-	318	75	164	-	-	68	624	624	-	-	6,133	-	-	-	-	351,986	2,361	-
3a.2.3	Asbestos Abatement	-	2,364	2	110	-	1,359	-	947	4,782	4,782	-	-	-	12,843	-	-	-	166,959	20,907	-
3a.2	Subtotal Period 3a Additional Costs	-	2,364	320	185	164	1,359	3,700	2,125	10,216	10,216	-	-	6,133	12,843	-	-	-	518,945	44,288	8,332
Period 3a Collateral Costs																					
3a.3.1	Small tool allowance	-	32	-	-	-	-	-	5	37	37	-	-	-	-	-	-	-	-	-	-
3a.3	Subtotal Period 3a Collateral Costs	-	32	-	-	-	-	-	5	37	37	-	-	-	-	-	-	-	-	-	-
Period 3a Period-Dependent Costs																					
3a.4.1	Insurance	-	-	-	-	-	-	501	50	552	552	-	-	-	-	-	-	-	-	-	-
3a.4.2	Property taxes	-	-	-	-	-	-	1,737	174	1,910	1,910	-	-	-	-	-	-	-	-	-	-
3a.4.3	Health physics supplies	-	562	-	-	-	-	-	140	702	702	-	-	-	-	-	-	-	-	-	-
3a.4.4	Heavy equipment rental	-	567	-	-	-	-	-	85	652	652	-	-	-	-	-	-	-	-	-	-
3a.4.5	Disposal of DAW generated	-	-	11	3	-	42	-	12	68	68	-	-	-	514	-	-	-	10,287	17	-
3a.4.6	Plant energy budget	-	-	-	-	-	-	1,515	227	1,742	1,742	-	-	-	-	-	-	-	-	-	-
3a.4.7	NRC Fees	-	-	-	-	-	-	341	34	376	376	-	-	-	-	-	-	-	-	-	-
3a.4.8	Fixed Overhead	-	-	-	-	-	-	1,470	220	1,690	1,690	-	-	-	-	-	-	-	-	-	-
3a.4.9	Railroad Track Maintenance	-	-	-	-	-	-	58	9	66	66	-	-	-	-	-	-	-	-	-	-
3a.4.10	Security Staff Cost	-	-	-	-	-	-	3,843	576	4,419	4,419	-	-	-	-	-	-	-	-	-	65,000
3a.4.11	Utility Staff Cost	-	-	-	-	-	-	15,819	2,373	18,191	18,191	-	-	-	-	-	-	-	-	-	257,920
3a.4	Subtotal Period 3a Period-Dependent Costs	-	1,129	11	3	-	42	25,283	3,901	30,369	30,369	-	-	-	514	-	-	-	10,287	17	322,920
3a.0	TOTAL PERIOD 3a COST	-	3,524	331	188	164	1,401	42,636	8,079	56,322	55,679	-	643	6,133	13,357	-	-	-	529,232	44,305	399,859
PERIOD 3b - Decommissioning Preparations																					
Period 3b Direct Decommissioning Activities																					
Detailed Work Procedures																					
3b.1.1.1	Plant systems	-	-	-	-	-	-	556	83	639	575	-	64	-	-	-	-	-	-	-	4,733
3b.1.1.2	Reactor internals	-	-	-	-	-	-	293	44	337	337	-	-	-	-	-	-	-	-	-	2,500
3b.1.1.3	Remaining buildings	-	-	-	-	-	-	158	24	182	46	-	137	-	-	-	-	-	-	-	1,350
3b.1.1.4	CRD cooling assembly	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
3b.1.1.5	CRD housings & ICI tubes	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
3b.1.1.6	Incore instrumentation	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
3b.1.1.7	Reactor vessel	-	-	-	-	-	-	426	64	490	490	-	-	-	-	-	-	-	-	-	3,630
3b.1.1.8	Facility closeout	-	-	-	-	-	-	141	21	162	81	-	81	-	-	-	-	-	-	-	1,200
3b.1.1.9	Missile shields	-	-	-	-	-	-	53	8	61	61	-	-	-	-	-	-	-	-	-	450
3b.1.1.10	Biological shield	-	-	-	-	-	-	141	21	162	162	-	-	-	-	-	-	-	-	-	1,200
3b.1.1.11	Steam generators	-	-	-	-	-	-	540	81	621	621	-	-	-	-	-	-	-	-	-	4,600
3b.1.1.12	Reinforced concrete	-	-	-	-	-	-	117	18	135	67	-	67	-	-	-	-	-	-	-	1,000
3b.1.1.13	Main Turbine	-	-	-	-	-	-	183	27	211	-	-	211	-	-	-	-	-	-	-	1,560
3b.1.1.14	Main Condensers	-	-	-	-	-	-	183	27	211	-	-	211	-	-	-	-	-	-	-	1,560
3b.1.1.15	Auxiliary building	-	-	-	-	-	-	320	48	369	332	-	37	-	-	-	-	-	-	-	2,730
3b.1.1.16	Reactor building	-	-	-	-	-	-	320	48	369	332	-	37	-	-	-	-	-	-	-	2,730
3b.1.1	Total	-	-	-	-	-	-	3,785	568	4,352	3,508	-	844	-	-	-	-	-	-	-	32,243
3b.1	Subtotal Period 3b Activity Costs	-	-	-	-	-	-	3,785	568	4,352	3,508	-	844	-	-	-	-	-	-	-	32,243
Period 3b Collateral Costs																					
3b.3.1	Decon equipment	973	-	-	-	-	-	-	146	1,119	1,119	-	-	-	-	-	-	-	-	-	-
3b.3.2	DOC staff relocation expenses	-	-	-	-	-	-	1,189	178	1,367	1,367	-	-	-	-	-	-	-	-	-	-
3b.3.3	Pipe cutting equipment	-	1,200	-	-	-	-	-	180	1,380	1,380	-	-	-	-	-	-	-	-	-	-
3b.3	Subtotal Period 3b Collateral Costs	973	1,200	-	-	-	-	1,189	504	3,866	3,866	-	-	-	-	-	-	-	-	-	-

Xcel Energy

Table H-1
Prairie Island Nuclear Generating Plant, Unit 1
SAFSTOR Decommissioning Cost Estimate with DOE Pickup of Industry Spent Fuel Starting in 2025
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 3b Period-Dependent Costs																					
3b.4.1	Decon supplies	35	-	-	-	-	-	-	9	43	43	-	-	-	-	-	-	-	-	-	-
3b.4.2	Insurance	-	-	-	-	-	-	255	25	280	280	-	-	-	-	-	-	-	-	-	-
3b.4.3	Property taxes	-	-	-	-	-	-	840	84	924	924	-	-	-	-	-	-	-	-	-	-
3b.4.4	Health physics supplies	-	248	-	-	-	-	-	62	309	309	-	-	-	-	-	-	-	-	-	-
3b.4.5	Heavy equipment rental	-	283	-	-	-	-	-	42	325	325	-	-	-	-	-	-	-	-	-	-
3b.4.6	Disposal of DAW generated	-	-	6	2	-	24	-	7	39	39	-	-	-	290	-	-	-	5,802	9	-
3b.4.7	Plant energy budget	-	-	-	-	-	-	755	113	869	869	-	-	-	-	-	-	-	-	-	-
3b.4.8	NRC Fees	-	-	-	-	-	-	170	17	187	187	-	-	-	-	-	-	-	-	-	-
3b.4.9	Fixed Overhead	-	-	-	-	-	-	733	110	843	843	-	-	-	-	-	-	-	-	-	-
3b.4.10	Railroad Track Maintenance	-	-	-	-	-	-	29	4	33	33	-	-	-	-	-	-	-	-	-	-
3b.4.11	Security Staff Cost	-	-	-	-	-	-	1,916	287	2,204	2,204	-	-	-	-	-	-	-	-	-	32,411
3b.4.12	DOC Staff Cost	-	-	-	-	-	-	5,123	769	5,892	5,892	-	-	-	-	-	-	-	-	-	58,080
3b.4.13	Utility Staff Cost	-	-	-	-	-	-	7,888	1,183	9,071	9,071	-	-	-	-	-	-	-	-	-	128,607
3b.4	Subtotal Period 3b Period-Dependent Costs	35	530	6	2	-	24	17,709	2,713	21,019	21,019	-	-	-	290	-	-	-	5,802	9	219,098
3b.0	TOTAL PERIOD 3b COST	1,008	1,730	6	2	-	24	22,682	3,785	29,237	28,393	-	844	-	290	-	-	-	5,802	9	251,341
PERIOD 3 TOTALS		1,008	5,254	338	190	164	1,425	65,318	11,863	85,559	84,072	-	1,487	6,133	13,647	-	-	-	535,034	44,314	651,200
PERIOD 4a - Large Component Removal																					
Period 4a Direct Decommissioning Activities																					
Nuclear Steam Supply System Removal																					
4a.1.1.1	Reactor Coolant Piping	11	40	6	5	34	75	-	41	212	212	-	-	144	152	-	-	-	33,380	771	-
4a.1.1.2	Pressurizer Relief Tank	5	18	4	3	23	50	-	24	126	126	-	-	96	101	-	-	-	22,241	347	-
4a.1.1.3	Reactor Coolant Pumps & Motors	13	56	43	76	-	736	-	220	1,143	1,143	-	-	-	2,332	-	-	-	295,800	1,226	80
4a.1.1.4	Pressurizer	10	68	359	82	-	693	-	244	1,456	1,456	-	-	-	2,196	-	-	-	158,199	1,499	750
4a.1.1.5	Steam Generators	47	2,943	1,576	1,614	1,246	3,467	-	2,212	13,104	13,104	-	-	18,672	10,990	-	-	-	1,560,086	10,964	2,250
4a.1.1.6	CRDMs/ICIs/Service Structure Removal	60	243	199	32	169	369	-	233	1,305	1,305	-	-	2,138	2,146	-	-	-	165,025	4,449	-
4a.1.1.7	Reactor Vessel Internals	61	4,189	21,537	971	-	7,954	239	12,812	47,763	47,763	-	-	-	757	-	742	-	166,435	19,373	933
4a.1.1.8	Vessel & Internals GTCC Disposal	-	-	-	-	-	8,689	-	1,303	9,992	9,992	-	-	-	-	-	-	3,746	837,596	-	-
4a.1.1.9	Reactor Vessel	-	5,439	1,328	198	-	1,804	239	5,398	14,406	14,406	-	-	-	5,719	-	-	-	569,974	19,373	933
4a.1.1	Totals	206	12,996	25,052	2,982	1,471	23,836	478	22,487	89,506	89,506	-	-	21,050	24,393	-	742	3,746	3,808,735	58,003	4,947
Removal of Major Equipment																					
4a.1.2	Main Turbine/Generator	-	269	128	27	287	-	-	127	838	838	-	-	2,243	-	-	-	-	134,601	4,116	-
4a.1.3	Main Condensers	-	2,269	87	26	383	-	-	637	3,403	3,403	-	-	4,000	-	-	-	-	180,000	34,978	-
Cascading Costs from Clean Building Demolition																					
4a.1.4.1	Reactor	-	728	-	-	-	-	-	109	837	837	-	-	-	-	-	-	-	-	7,589	-
4a.1.4	Totals	-	728	-	-	-	-	-	109	837	837	-	-	-	-	-	-	-	-	7,589	-
Disposal of Plant Systems																					
4a.1.5.1	Air Removal	-	27	-	-	-	-	-	4	31	-	-	31	-	-	-	-	-	-	452	-
4a.1.5.2	Auxiliary Feedwater	-	40	-	-	-	-	-	6	46	-	-	46	-	-	-	-	-	-	670	-
4a.1.5.3	Auxiliary Feedwater - RCA	-	45	0	1	19	-	-	14	79	79	-	-	215	-	-	-	-	8,722	601	-
4a.1.5.4	Bleed Steam	-	78	-	-	-	-	-	12	90	-	-	90	-	-	-	-	-	-	1,335	-
4a.1.5.5	Caustic Addition - RCA	-	36	0	1	20	-	-	12	71	71	-	-	233	-	-	-	-	9,453	444	-
4a.1.5.6	Chemical Feed	-	17	-	-	-	-	-	3	20	-	-	20	-	-	-	-	-	-	304	-
4a.1.5.7	Chemical Feed - RCA	-	1	0	0	1	-	-	0	2	2	-	-	6	-	-	-	-	243	12	-
4a.1.5.8	Circulating Water	-	37	-	-	-	-	-	6	42	-	-	42	-	-	-	-	-	-	619	-
4a.1.5.9	Condensate	-	414	-	-	-	-	-	62	476	-	-	476	-	-	-	-	-	-	6,837	-
4a.1.5.10	Condensate Polishing	-	205	-	-	-	-	-	31	236	-	-	236	-	-	-	-	-	-	3,420	-
4a.1.5.11	Condensate Polishing - RCA	-	176	4	12	180	-	-	73	444	444	-	-	2,078	-	-	-	-	84,395	2,329	-
4a.1.5.12	Electro-hydraulic	-	8	-	-	-	-	-	1	9	-	-	9	-	-	-	-	-	-	127	-
4a.1.5.13	Feedwater	-	133	-	-	-	-	-	20	153	-	-	153	-	-	-	-	-	-	2,215	-
4a.1.5.14	Feedwater - RCA	-	186	6	19	278	-	-	91	579	579	-	-	3,208	-	-	-	-	130,294	2,651	-
4a.1.5.15	Gland Seal	-	29	-	-	-	-	-	4	34	-	-	34	-	-	-	-	-	-	505	-
4a.1.5.16	Heater Drain	-	349	-	-	-	-	-	52	401	-	-	401	-	-	-	-	-	-	5,881	-
4a.1.5.17	Internal Circ Water & CDSR	-	23	-	-	-	-	-	3	27	-	-	27	-	-	-	-	-	-	389	-
4a.1.5.18	Main Gen/Exciter/Transformer	-	0	-	-	-	-	-	0	0	-	-	0	-	-	-	-	-	-	5	-
4a.1.5.19	Main Steam	-	101	-	-	-	-	-	15	116	-	-	116	-	-	-	-	-	-	1,690	-
4a.1.5.20	Main Steam - RCA	-	350	9	29	436	-	-	158	983	983	-	-	5,044	-	-	-	-	204,825	4,956	-
4a.1.5.21	Steam Generator Blowdown	-	416	21	22	176	195	-	185	1,014	1,014	-	-	2,031	686	-	-	-	127,773	5,974	-
4a.1.5.22	Steam Generators	-	5	-	-	-	-	-	1	5	-	-	5	-	-	-	-	-	-	75	-
4a.1.5.23	Turbine & Moisture Separators	-	337	-	-	-	-	-	51	388	-	-	388	-	-	-	-	-	-	5,609	-

Table H-1
Prairie Island Nuclear Generating Plant, Unit 1
SAFSTOR Decommissioning Cost Estimate with DOE Pickup of Industry Spent Fuel Starting in 2025
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Disposal of Plant Systems (continued)																					
4a.1.5.24	Turbine Oil Purification	-	61	-	-	-	-	-	9	71	-	-	71	-	-	-	-	-	-	1,003	-
4a.1.5	Totals	-	3,075	40	85	1,108	195	-	814	5,317	3,172	-	2,145	12,815	686	-	-	-	565,705	48,101	-
4a.1.6	Scaffolding in support of decommissioning	-	833	3	1	13	3	-	212	1,066	1,066	-	-	138	12	-	-	-	7,016	6,020	-
4a.1	Subtotal Period 4a Activity Costs	206	20,170	25,310	3,121	3,263	24,034	478	24,386	100,967	98,823	-	2,145	40,246	25,091	-	742	3,746	4,696,057	158,807	4,947
Period 4a Additional Costs																					
4a.2.1	Remedial Action Surveys	-	-	-	-	-	-	1,865	559	2,424	2,424	-	-	-	-	-	-	-	-	24,374	-
4a.2.2	Retired RPV upper internals package	1	659	785	107	-	1,439	-	1,437	4,427	4,427	-	-	-	2,097	125	-	-	205,890	2,175	87
4a.2	Subtotal Period 4a Additional Costs	1	659	785	107	-	1,439	1,865	1,996	6,851	6,851	-	-	-	2,097	125	-	-	205,890	26,549	87
Period 4a Collateral Costs																					
4a.3.1	Process decommissioning water waste	2	-	4	10	-	16	-	7	40	40	-	-	-	39	-	-	-	2,331	8	-
4a.3.3	Small tool allowance	-	195	-	-	-	-	-	29	224	201	-	22	-	-	-	-	-	-	-	-
4a.3	Subtotal Period 4a Collateral Costs	2	195	4	10	-	16	-	36	264	242	-	22	-	39	-	-	-	2,331	8	-
Period 4a Period-Dependent Costs																					
4a.4.1	Decon supplies	84	-	-	-	-	-	-	21	105	105	-	-	-	-	-	-	-	-	-	-
4a.4.2	Insurance	-	-	-	-	-	-	617	62	679	679	-	-	-	-	-	-	-	-	-	-
4a.4.3	Property taxes	-	-	-	-	-	-	1,841	184	2,025	2,025	-	-	-	-	-	-	-	-	-	-
4a.4.4	Health physics supplies	-	1,494	-	-	-	-	-	374	1,868	1,868	-	-	-	-	-	-	-	-	-	-
4a.4.5	Heavy equipment rental	-	2,653	-	-	-	-	-	398	3,051	3,051	-	-	-	-	-	-	-	-	-	-
4a.4.6	Disposal of DAW generated	-	-	62	18	-	230	-	66	376	376	-	-	-	2,823	-	-	-	56,462	92	-
4a.4.7	Plant energy budget	-	-	-	-	-	-	1,738	261	1,999	1,999	-	-	-	-	-	-	-	-	-	-
4a.4.8	NRC Fees	-	-	-	-	-	-	673	67	741	741	-	-	-	-	-	-	-	-	-	-
4a.4.9	Fixed Overhead	-	-	-	-	-	-	1,496	224	1,720	1,720	-	-	-	-	-	-	-	-	-	-
4a.4.10	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	489	73	562	562	-	-	-	-	-	-	-	-	-	-
4a.4.11	Railroad Track Maintenance	-	-	-	-	-	-	70	10	80	80	-	-	-	-	-	-	-	-	-	-
4a.4.12	Security Staff Cost	-	-	-	-	-	-	3,379	507	3,886	3,886	-	-	-	-	-	-	-	-	-	57,844
4a.4.13	DOC Staff Cost	-	-	-	-	-	-	14,773	2,216	16,989	16,989	-	-	-	-	-	-	-	-	-	171,797
4a.4.14	Utility Staff Cost	-	-	-	-	-	-	18,389	2,758	21,147	21,147	-	-	-	-	-	-	-	-	-	303,691
4a.4	Subtotal Period 4a Period-Dependent Costs	84	4,147	62	18	-	230	43,466	7,222	55,228	55,228	-	-	-	2,823	-	-	-	56,462	92	533,332
4a.0	TOTAL PERIOD 4a COST	293	25,171	26,160	3,256	3,263	25,719	45,808	33,641	163,310	161,143	-	2,167	40,246	30,050	125	742	3,746	4,960,740	185,455	538,365
PERIOD 4b - Site Decontamination																					
Period 4b Direct Decommissioning Activities																					
4b.1.1	Remove spent fuel racks	297	32	94	32	-	595	-	319	1,369	1,369	-	-	-	2,092	-	-	-	138,298	576	-
Disposal of Plant Systems																					
4b.1.2.1	Aux Bldg Normal Ventilation	-	2	0	0	0	-	-	0	3	3	-	-	3	-	-	-	-	140	26	-
4b.1.2.2	Battery Rm Special Ventilation	-	0	-	-	-	-	-	0	0	-	-	0	-	-	-	-	-	-	6	-
4b.1.2.3	Buildings Maintenance	-	4	-	-	-	-	-	1	5	-	-	5	-	-	-	-	-	-	65	-
4b.1.2.4	Chemical & Volume Control	-	1,210	83	69	389	802	-	580	3,134	3,134	-	-	4,498	2,846	-	-	-	369,246	17,235	-
4b.1.2.5	Component Cooling - RCA	-	821	22	72	1,075	-	-	379	2,369	2,369	-	-	12,427	-	-	-	-	504,675	11,242	-
4b.1.2.6	Containment Cooling	-	65	-	-	-	-	-	10	74	-	-	74	-	-	-	-	-	-	1,086	-
4b.1.2.7	Containment Cooling - RCA	-	290	6	20	294	-	-	120	730	730	-	-	3,400	-	-	-	-	138,090	3,971	-
4b.1.2.8	Containment Hydrogen Control - RCA	-	29	0	1	9	-	-	9	48	48	-	-	105	-	-	-	-	4,278	401	-
4b.1.2.9	Containment Spray - RCA	-	90	2	5	75	-	-	35	206	206	-	-	868	-	-	-	-	35,249	1,217	-
4b.1.2.10	Containment Ventilation	-	219	24	40	428	209	-	180	1,100	1,100	-	-	4,951	737	-	-	-	249,786	3,278	-
4b.1.2.11	Cooling Water	-	142	-	-	-	-	-	21	163	-	-	163	-	-	-	-	-	-	2,396	-
4b.1.2.12	Cooling Water - RCA	-	629	14	45	668	-	-	266	1,622	1,622	-	-	7,728	-	-	-	-	313,832	8,594	-
4b.1.2.13	D1 Emergency Diesel	-	44	-	-	-	-	-	7	50	-	-	50	-	-	-	-	-	-	730	-
4b.1.2.14	D2 Emergency Diesel	-	31	-	-	-	-	-	5	36	-	-	36	-	-	-	-	-	-	522	-
4b.1.2.15	Diesel Rooms Ventilation	-	8	-	-	-	-	-	1	10	-	-	10	-	-	-	-	-	-	135	-
4b.1.2.16	Electrical - Clean	-	1,669	-	-	-	-	-	250	1,919	-	-	1,919	-	-	-	-	-	-	26,981	-
4b.1.2.17	Electrical - Contaminated	-	536	6	16	219	27	-	177	980	980	-	-	2,527	95	-	-	-	108,935	7,488	-
4b.1.2.18	Electrical - Contaminated - Fuel Pool	-	133	2	4	53	7	-	44	242	242	-	-	615	23	-	-	-	26,508	1,857	-
4b.1.2.19	Electrical - Decontaminated	-	3,674	41	137	2,037	-	-	1,249	7,138	7,138	-	-	23,551	-	-	-	-	956,401	49,378	-
4b.1.2.20	Electrical - Decontaminated - Fuel Pool	-	918	10	34	510	-	-	312	1,785	1,785	-	-	5,893	-	-	-	-	239,327	12,340	-
4b.1.2.21	Fuel Handling	-	104	6	9	79	62	-	55	314	314	-	-	908	218	-	-	-	51,280	1,595	-
4b.1.2.22	Fuel Oil	-	106	-	-	-	-	-	16	122	-	-	122	-	-	-	-	-	-	1,697	-
4b.1.2.23	HVAC - Clean	-	105	-	-	-	-	-	16	121	-	-	121	-	-	-	-	-	-	1,891	-
4b.1.2.24	HVAC - Contaminated	-	335	8	21	282	35	-	139	819	819	-	-	3,261	123	-	-	-	140,573	4,335	-
4b.1.2.25	HVAC - Contaminated - Fuel Pool	-	143	3	9	121	15	-	59	351	351	-	-	1,398	53	-	-	-	60,246	1,858	-

Table H-1
Prairie Island Nuclear Generating Plant, Unit 1
SAFSTOR Decommissioning Cost Estimate with DOE Pickup of Industry Spent Fuel Starting in 2025
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Disposal of Plant Systems (continued)																					
4b.1.2.26	Incore Instrumentation	-	24	1	1	5	16	-	11	59	59	-	-	60	57	-	-	-	6,177	382	-
4b.1.2.27	Misc Drains & Vents	-	203	14	10	34	146	-	95	503	503	-	-	390	514	-	-	-	49,900	2,764	-
4b.1.2.28	Reactor Coolant	-	271	21	14	30	221	-	132	689	689	-	-	344	777	-	-	-	65,413	3,865	-
4b.1.2.29	Reactor Hot Sampling	-	120	11	6	6	98	-	57	297	297	-	-	66	342	-	-	-	25,347	1,611	-
4b.1.2.30	Reactor Makeup	-	64	-	-	-	-	-	10	73	-	-	73	-	-	-	-	-	-	1,042	-
4b.1.2.31	Reactor Vessel	-	18	1	0	2	4	-	6	31	31	-	-	26	14	-	-	-	2,011	260	-
4b.1.2.32	Residual Heat Removal	-	360	85	66	250	926	-	377	2,065	2,065	-	-	2,895	3,252	-	-	-	332,849	5,374	-
4b.1.2.33	Safeguards Chilled Water	-	15	-	-	-	-	-	2	18	-	-	18	-	-	-	-	-	-	259	-
4b.1.2.34	Safeguards Chilled Water - RCA	-	82	1	3	43	-	-	27	155	155	-	-	495	-	-	-	-	20,100	1,019	-
4b.1.2.35	Safety Injection	-	774	40	57	587	327	-	376	2,161	2,161	-	-	6,788	1,156	-	-	-	351,793	11,276	-
4b.1.2.36	Sampling	-	53	4	2	5	31	-	22	116	116	-	-	59	107	-	-	-	9,505	731	-
4b.1.2.37	Shield Bldg Ventilation	-	120	14	20	186	139	-	97	576	576	-	-	2,152	491	-	-	-	119,838	1,811	-
4b.1.2.38	Spent Fuel Pool Cooling	-	311	34	25	70	377	-	190	1,006	1,006	-	-	806	1,325	-	-	-	120,439	4,400	-
4b.1.2.39	Station & Instrument Air	-	17	-	-	-	-	-	3	20	-	-	20	-	-	-	-	-	-	300	-
4b.1.2.40	Station & Instrument Air - RCA	-	79	1	2	29	-	-	24	135	135	-	-	332	-	-	-	-	13,496	1,053	-
4b.1.2.41	Station & Instrument Air - RCA Fuel Pool	-	20	0	0	7	-	-	6	34	34	-	-	83	-	-	-	-	3,374	263	-
4b.1.2.42	Turbine Bldg Traps & Drains	-	44	-	-	-	-	-	7	50	-	-	50	-	-	-	-	-	-	767	-
4b.1.2.43	Unit Coolers	-	37	-	-	-	-	-	6	42	-	-	42	-	-	-	-	-	-	611	-
4b.1.2.44	Unit Coolers - RCA	-	53	0	1	20	-	-	16	91	91	-	-	230	-	-	-	-	9,348	683	-
4b.1.2	Totals	-	13,970	453	689	7,514	3,443	-	5,394	31,463	28,759	-	2,704	86,861	12,129	-	-	-	4,328,159	198,796	-
4b.1.3	Scaffolding in support of decommissioning	-	1,250	5	2	20	5	-	317	1,599	1,599	-	-	207	18	-	-	-	10,524	9,030	-
Decontamination of Site Buildings																					
4b.1.4.1	Reactor	1,037	2,360	118	833	193	6,372	-	2,868	13,781	13,781	-	-	2,230	36,899	-	-	-	3,286,398	45,584	-
4b.1.4.2	Backwash Waste Receiving Tank	-	24	1	11	-	87	-	30	154	154	-	-	-	507	-	-	-	43,896	264	-
4b.1.4	Totals	1,037	2,385	119	845	193	6,460	-	2,897	13,936	13,936	-	-	2,230	37,406	-	-	-	3,330,294	45,848	-
4b.1.5	Prepare/submit License Termination Plan	-	-	-	-	-	-	481	72	553	553	-	-	-	-	-	-	-	-	-	4,096
4b.1.6	Receive NRC approval of termination plan									a											
4b.1	Subtotal Period 4b Activity Costs	1,334	17,637	671	1,567	7,726	10,503	481	9,000	48,919	46,215	-	2,704	89,298	51,645	-	-	-	7,807,274	254,251	4,096
Period 4b Additional Costs																					
4b.2.1	License Termination Survey Planning	-	-	-	-	-	-	845	253	1,098	1,098	-	-	-	-	-	-	-	-	-	6,240
4b.2.2	Remedial Action Surveys	-	-	-	-	-	-	2,832	849	3,681	3,681	-	-	-	-	-	-	-	-	37,017	-
4b.2.3	Excavation of Underground Services	-	811	-	-	-	-	520	200	1,531	-	-	1,531	-	-	-	-	-	-	7,407	-
4b.2.4	Operational Equipment	-	-	9	29	312	-	-	52	402	402	-	-	5,855	-	-	-	-	146,375	16	-
4b.2.5	License Termination ISFSI	-	37	2	211	-	2,157	1,158	891	4,456	4,456	-	-	-	7,458	-	-	-	1,071,985	3,403	5,284
4b.2.6	Demolition and Site Restoration ISFSI	-	399	-	-	-	-	87	73	558	-	-	558	-	-	-	-	-	-	1,900	160
4b.2	Subtotal Period 4b Additional Costs	-	1,246	11	240	312	2,157	5,441	2,319	11,726	9,637	-	2,089	5,855	7,458	-	-	-	1,218,360	49,742	11,684
Period 4b Collateral Costs																					
4b.3.1	Process decommissioning water waste	5	-	9	23	-	36	-	16	88	88	-	-	-	85	-	-	-	5,091	17	-
4b.3.3	Small tool allowance	-	288	-	-	-	-	-	43	331	331	-	-	-	-	-	-	-	-	-	-
4b.3.4	Decommissioning Equipment Disposition	-	-	144	55	575	150	-	147	1,071	1,071	-	-	6,000	529	-	-	-	304,968	88	-
4b.3	Subtotal Period 4b Collateral Costs	5	288	152	78	575	186	-	205	1,489	1,489	-	-	6,000	614	-	-	-	310,059	105	-
Period 4b Period-Dependent Costs																					
4b.4.1	Decon supplies	521	-	-	-	-	-	-	130	651	651	-	-	-	-	-	-	-	-	-	-
4b.4.2	Insurance	-	-	-	-	-	-	910	91	1,001	1,001	-	-	-	-	-	-	-	-	-	-
4b.4.3	Property taxes	-	-	-	-	-	-	2,625	262	2,887	2,887	-	-	-	-	-	-	-	-	-	-
4b.4.4	Health physics supplies	-	2,245	-	-	-	-	-	561	2,806	2,806	-	-	-	-	-	-	-	-	-	-
4b.4.5	Heavy equipment rental	-	4,021	-	-	-	-	-	603	4,624	4,624	-	-	-	-	-	-	-	-	-	-
4b.4.6	Disposal of DAW generated	-	-	85	25	-	318	-	92	520	520	-	-	-	3,905	-	-	-	78,097	127	-
4b.4.7	Plant energy budget	-	-	-	-	-	-	2,023	303	2,326	2,326	-	-	-	-	-	-	-	-	-	-
4b.4.8	NRC Fees	-	-	-	-	-	-	992	99	1,092	1,092	-	-	-	-	-	-	-	-	-	-
4b.4.9	Fixed Overhead	-	-	-	-	-	-	2,205	331	2,535	2,535	-	-	-	-	-	-	-	-	-	-
4b.4.10	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	721	108	829	829	-	-	-	-	-	-	-	-	-	-
4b.4.11	Railroad Track Maintenance	-	-	-	-	-	-	103	15	118	118	-	-	-	-	-	-	-	-	-	-
4b.4.12	Security Staff Cost	-	-	-	-	-	-	1,017	153	1,170	1,170	-	-	-	-	-	-	-	-	-	20,373
4b.4.13	DOC Staff Cost	-	-	-	-	-	-	14,220	2,133	16,353	16,353	-	-	-	-	-	-	-	-	-	174,093
4b.4.14	Utility Staff Cost	-	-	-	-	-	-	18,286	2,743	21,029	21,029	-	-	-	-	-	-	-	-	-	311,145
4b.4	Subtotal Period 4b Period-Dependent Costs	521	6,266	85	25	-	318	43,101	7,625	57,941	57,941	-	-	-	3,905	-	-	-	78,097	127	505,611
4b.0	TOTAL PERIOD 4b COST	1,860	25,436	919	1,910	8,613	13,164	49,023	19,149	120,075	115,282	-	4,793	101,153	63,622	-	-	-	9,413,790	304,226	521,391

Table H-1
Prairie Island Nuclear Generating Plant, Unit 1
SAFSTOR Decommissioning Cost Estimate with DOE Pickup of Industry Spent Fuel Starting in 2025
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
PERIOD 4e - Delay before License Termination																					
Period 4e Period-Dependent Costs																					
4e.4.1	Insurance	-	-	-	-	-	-	381	38	419	419	-	-	-	-	-	-	-	-	-	-
4e.4.2	Property taxes	-	-	-	-	-	-	1,046	105	1,150	1,150	-	-	-	-	-	-	-	-	-	-
4e.4.3	Health physics supplies	-	69	-	-	-	-	-	17	87	87	-	-	-	-	-	-	-	-	-	-
4e.4.4	Disposal of DAW generated	-	-	2	0	-	6	-	2	10	10	-	-	-	74	-	-	-	1,486	2	-
4e.4.6	NRC Fees	-	-	-	-	-	-	166	17	182	182	-	-	-	-	-	-	-	-	-	-
4e.4.7	Fixed Overhead	-	-	-	-	-	-	923	138	1,061	1,061	-	-	-	-	-	-	-	-	-	-
4e.4.8	Railroad Track Maintenance	-	-	-	-	-	-	43	6	49	49	-	-	-	-	-	-	-	-	-	-
4e.4.9	Utility Staff Cost	-	-	-	-	-	-	662	99	761	761	-	-	-	-	-	-	-	-	-	10,850
4e.4	Subtotal Period 4e Period-Dependent Costs	-	69	2	0	-	6	3,220	422	3,720	3,720	-	-	-	74	-	-	-	1,486	2	10,850
4e.0	TOTAL PERIOD 4e COST	-	69	2	0	-	6	3,220	422	3,720	3,720	-	-	-	74	-	-	-	1,486	2	10,850
PERIOD 4f - License Termination																					
Period 4f Direct Decommissioning Activities																					
4f.1.1	ORISE confirmatory survey	-	-	-	-	-	-	176	53	229	229	-	-	-	-	-	-	-	-	-	-
4f.1.2	Terminate license									a											
4f.1	Subtotal Period 4f Activity Costs	-	-	-	-	-	-	176	53	229	229	-	-	-	-	-	-	-	-	-	-
Period 4f Additional Costs																					
4f.2.1	License Termination Survey	-	-	-	-	-	-	3,217	965	4,182	4,182	-	-	-	-	-	-	-	-	40,172	3,120
4f.2	Subtotal Period 4f Additional Costs	-	-	-	-	-	-	3,217	965	4,182	4,182	-	-	-	-	-	-	-	-	40,172	3,120
Period 4f Collateral Costs																					
4f.3.1	DOC staff relocation expenses	-	-	-	-	-	-	1,189	178	1,367	1,367	-	-	-	-	-	-	-	-	-	-
4f.3	Subtotal Period 4f Collateral Costs	-	-	-	-	-	-	1,189	178	1,367	1,367	-	-	-	-	-	-	-	-	-	-
Period 4f Period-Dependent Costs																					
4f.4.1	Insurance	-	-	-	-	-	-	382	38	420	420	-	-	-	-	-	-	-	-	-	-
4f.4.2	Property taxes	-	-	-	-	-	-	1,002	100	1,102	1,102	-	-	-	-	-	-	-	-	-	-
4f.4.3	Health physics supplies	-	418	-	-	-	-	-	105	523	523	-	-	-	-	-	-	-	-	-	-
4f.4.4	Disposal of DAW generated	-	-	7	2	-	27	-	8	44	44	-	-	-	332	-	-	-	6,649	11	-
4f.4.5	Plant energy budget	-	-	-	-	-	-	227	34	261	261	-	-	-	-	-	-	-	-	-	-
4f.4.6	NRC Fees	-	-	-	-	-	-	417	42	459	459	-	-	-	-	-	-	-	-	-	-
4f.4.7	Fixed Overhead	-	-	-	-	-	-	926	139	1,065	1,065	-	-	-	-	-	-	-	-	-	-
4f.4.8	Railroad Track Maintenance	-	-	-	-	-	-	43	6	50	50	-	-	-	-	-	-	-	-	-	-
4f.4.9	Security Staff Cost	-	-	-	-	-	-	707	106	813	813	-	-	-	-	-	-	-	-	-	11,668
4f.4.10	DOC Staff Cost	-	-	-	-	-	-	4,101	615	4,716	4,716	-	-	-	-	-	-	-	-	-	46,283
4f.4.11	Utility Staff Cost	-	-	-	-	-	-	3,630	544	4,174	4,174	-	-	-	-	-	-	-	-	-	56,395
4f.4	Subtotal Period 4f Period-Dependent Costs	-	418	7	2	-	27	11,435	1,738	13,627	13,627	-	-	-	332	-	-	-	6,649	11	114,346
4f.0	TOTAL PERIOD 4f COST	-	418	7	2	-	27	16,016	2,934	19,405	19,405	-	-	-	332	-	-	-	6,649	40,183	117,466
PERIOD 4 TOTALS		2,153	51,095	27,089	5,168	11,876	38,916	114,068	56,146	306,510	299,549	-	6,960	141,399	94,078	125	742	3,746	14,382,660	529,866	1,188,072
PERIOD 5b - Site Restoration																					
Period 5b Direct Decommissioning Activities																					
Demolition of Remaining Site Buildings																					
5b.1.1.1	Reactor	-	4,255	-	-	-	-	-	638	4,894	-	-	4,894	-	-	-	-	-	-	44,669	-
5b.1.1.2	Condensate Storage Tank Foundation	-	3	-	-	-	-	-	0	4	-	-	4	-	-	-	-	-	-	16	-
5b.1.1.3	Structures below 3' below grade	-	1,713	-	-	-	-	-	257	1,969	-	-	1,969	-	-	-	-	-	-	9,238	-
5b.1.1.4	Turbine	-	1,983	-	-	-	-	-	297	2,280	-	-	2,280	-	-	-	-	-	-	22,040	-
5b.1.1.5	Turbine Pedestal	-	349	-	-	-	-	-	52	402	-	-	402	-	-	-	-	-	-	1,857	-
5b.1.1	Totals	-	8,303	-	-	-	-	-	1,245	9,548	-	-	9,548	-	-	-	-	-	-	77,820	-
Site Closeout Activities																					
5b.1.2	Grade & landscape site	-	431	-	-	-	-	-	65	495	-	-	495	-	-	-	-	-	-	921	-
5b.1.3	Final report to NRC	-	-	-	-	-	-	183	27	211	211	-	-	-	-	-	-	-	-	-	1,560
5b.1	Subtotal Period 5b Activity Costs	-	8,733	-	-	-	-	183	1,337	10,254	211	-	10,044	-	-	-	-	-	-	78,740	1,560
Period 5b Additional Costs																					
5b.2.1	Clean Concrete Disposal	-	2,213	-	-	-	-	3	332	2,549	-	-	2,549	-	-	-	-	-	-	8,386	-
5b.2.2	Intake Structure Cofferdam	-	596	-	-	-	-	-	89	686	-	-	686	-	-	-	-	-	-	5,168	-

Table H-1
Prairie Island Nuclear Generating Plant, Unit 1
SAFSTOR Decommissioning Cost Estimate with DOE Pickup of Industry Spent Fuel Starting in 2025
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 5b Additional Costs (continued)																					
5b.2.3	Construction Debris	-	-	-	-	-	-	10	2	12	-	-	12	-	-	-	-	-	-	-	-
5b.2.4	Backfill	-	2,751	-	-	-	-	-	413	3,164	-	-	3,164	-	-	-	-	-	-	2,904	-
5b.2	Subtotal Period 5b Additional Costs	-	5,560	-	-	-	-	13	836	6,410	-	-	6,410	-	-	-	-	-	-	16,458	-
Period 5b Collateral Costs																					
5b.3.1	Small tool allowance	-	107	-	-	-	-	-	16	123	-	-	123	-	-	-	-	-	-	-	-
5b.3	Subtotal Period 5b Collateral Costs	-	107	-	-	-	-	-	16	123	-	-	123	-	-	-	-	-	-	-	-
Period 5b Period-Dependent Costs																					
5b.4.2	Property taxes	-	-	-	-	-	-	1,712	171	1,883	-	-	1,883	-	-	-	-	-	-	-	-
5b.4.3	Heavy equipment rental	-	6,670	-	-	-	-	-	1,000	7,670	-	-	7,670	-	-	-	-	-	-	-	-
5b.4.4	Plant energy budget	-	-	-	-	-	-	321	48	369	-	-	369	-	-	-	-	-	-	-	-
5b.4.5	Fixed Overhead	-	-	-	-	-	-	990	148	1,138	-	-	1,138	-	-	-	-	-	-	-	-
5b.4.6	Railroad Track Maintenance	-	-	-	-	-	-	122	18	141	-	-	141	-	-	-	-	-	-	-	-
5b.4.7	Security Staff Cost	-	-	-	-	-	-	1,812	272	2,084	-	-	2,084	-	-	-	-	-	-	-	29,221
5b.4.8	DOC Staff Cost	-	-	-	-	-	-	10,467	1,570	12,038	-	-	12,038	-	-	-	-	-	-	-	116,885
5b.4.9	Utility Staff Cost	-	-	-	-	-	-	3,673	551	4,224	-	-	4,224	-	-	-	-	-	-	-	57,340
5b.4	Subtotal Period 5b Period-Dependent Costs	-	6,670	-	-	-	-	19,097	3,779	29,546	-	-	29,546	-	-	-	-	-	-	-	203,445
5b.0	TOTAL PERIOD 5b COST	-	21,070	-	-	-	-	19,294	5,969	46,333	211	-	46,122	-	-	-	-	-	-	95,198	205,005
PERIOD 5 TOTALS		-	21,070	-	-	-	-	19,294	5,969	46,333	211	-	46,122	-	-	-	-	-	-	95,198	205,005
TOTAL COST TO DECOMMISSION		**5,848**	**85,184**	**27,686**	**5,682**	**12,040**	**41,346**	**865,206**	**162,654**	**1,205,645**	**908,226**	**242,850**	**54,569**	**147,532**	**115,740**	**125**	**742**	**3,746**	**15,119,820**	**699,530**	**6,227,724**

TOTAL COST TO DECOMMISSION WITH 15.59% CONTINGENCY:	**$1,205,645**	**thousands of 2017 dollars**
TOTAL NRC LICENSE TERMINATION COST IS 75.33% OR:	**$908,226**	**thousands of 2017 dollars**
SPENT FUEL MANAGEMENT COST IS 20.14% OR:	**$242,850**	**thousands of 2017 dollars**
NON-NUCLEAR DEMOLITION COST IS 4.53% OR:	**$54,569**	**thousands of 2017 dollars**
TOTAL LOW-LEVEL RADIOACTIVE WASTE VOLUME BURIED (EXCLUDING GTCC):	**116,607**	**cubic feet**
TOTAL GREATER THAN CLASS C RADWASTE VOLUME GENERATED:	**3,746**	**cubic feet**
TOTAL SCRAP METAL REMOVED:	**33,003**	**tons**
TOTAL CRAFT LABOR REQUIREMENTS:	**699,530**	**man-hours**

End Notes:
n/a - indicates that this activity not charged as decommissioning expense
a - indicates that this activity performed by decommissioning staff
0 - indicates that this value is less than 0.5 but is non-zero
A cell containing " - " indicates a zero value

Table H-2
Prairie Island Nuclear Generating Plant, Unit 2
SAFSTOR Decommissioning Cost Estimate with DOE Pickup of Industry Spent Fuel Starting in 2025
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
PERIOD 1a - Shutdown through Transition																					
Period 1a Direct Decommissioning Activities																					
1a.1.1	SAFSTOR site characterization survey	-	-	-	-	-	-	571	171	742	742	-	-	-	-	-	-	-	-	-	-
1a.1.2	Prepare preliminary decommissioning cost	-	-	-	-	-	-	65	10	75	75	-	-	-	-	-	-	-	-	-	556
1a.1.3	Notification of Cessation of Operations									a											
1a.1.4	Remove fuel & source material									n/a											
1a.1.5	Notification of Permanent Defueling									a											
1a.1.6	Deactivate plant systems & process waste									a											
1a.1.7	Prepare and submit PSDAR	-	-	-	-	-	-	100	15	115	115	-	-	-	-	-	-	-	-	-	855
1a.1.8	Review plant dwgs & specs.	-	-	-	-	-	-	65	10	75	75	-	-	-	-	-	-	-	-	-	556
1a.1.9	Perform detailed rad survey									a											
1a.1.10	Estimate by-product inventory	-	-	-	-	-	-	50	8	58	58	-	-	-	-	-	-	-	-	-	428
1a.1.11	End product description	-	-	-	-	-	-	50	8	58	58	-	-	-	-	-	-	-	-	-	428
1a.1.12	Detailed by-product inventory	-	-	-	-	-	-	75	11	87	87	-	-	-	-	-	-	-	-	-	641
1a.1.13	Define major work sequence	-	-	-	-	-	-	50	8	58	58	-	-	-	-	-	-	-	-	-	428
1a.1.14	Perform SER and EA	-	-	-	-	-	-	156	23	179	179	-	-	-	-	-	-	-	-	-	1,326
1a.1.15	Prepare/submit Defueled Technical Specifications	-	-	-	-	-	-	376	56	433	433	-	-	-	-	-	-	-	-	-	3,207
1a.1.16	Perform Site-Specific Cost Study	-	-	-	-	-	-	251	38	289	289	-	-	-	-	-	-	-	-	-	2,138
1a.1.17	Prepare/submit Irradiated Fuel Management Plan	-	-	-	-	-	-	50	8	58	58	-	-	-	-	-	-	-	-	-	428
Activity Specifications																					
1a.1.18.1	Prepare plant and facilities for SAFSTOR	-	-	-	-	-	-	247	37	284	284	-	-	-	-	-	-	-	-	-	2,104
1a.1.18.2	Plant systems	-	-	-	-	-	-	209	31	241	241	-	-	-	-	-	-	-	-	-	1,782
1a.1.18.3	Plant structures and buildings	-	-	-	-	-	-	157	23	180	180	-	-	-	-	-	-	-	-	-	1,334
1a.1.18.4	Waste management	-	-	-	-	-	-	100	15	115	115	-	-	-	-	-	-	-	-	-	855
1a.1.18.5	Facility and site dormancy	-	-	-	-	-	-	100	15	115	115	-	-	-	-	-	-	-	-	-	855
1a.1.18	Total	-	-	-	-	-	-	813	122	935	935	-	-	-	-	-	-	-	-	-	6,930
Detailed Work Procedures																					
1a.1.19.1	Plant systems	-	-	-	-	-	-	59	9	68	68	-	-	-	-	-	-	-	-	-	506
1a.1.19.2	Facility closeout & dormancy	-	-	-	-	-	-	60	9	69	69	-	-	-	-	-	-	-	-	-	513
1a.1.19	Total	-	-	-	-	-	-	120	18	138	138	-	-	-	-	-	-	-	-	-	1,019
1a.1.20	Procure vacuum drying system	-	-	-	-	-	-	5	1	6	6	-	-	-	-	-	-	-	-	-	43
1a.1.21	Drain/de-energize non-cont. systems									a											
1a.1.22	Drain & dry NSSS									a											
1a.1.23	Drain/de-energize contaminated systems									a											
1a.1.24	Decon/secure contaminated systems									a											
1a.1	Subtotal Period 1a Activity Costs	-	-	-	-	-	-	2,799	505	3,304	3,304	-	-	-	-	-	-	-	-	-	18,981
Period 1a Collateral Costs																					
1a.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	1,776	266	2,042	-	2,042	-	-	-	-	-	-	-	-	-
1a.3.2	Retention and Severance	-	-	-	-	-	-	8,394	1,259	9,653	9,653	-	-	-	-	-	-	-	-	-	-
1a.3.3	Prairie Island Indian Community Payments	-	-	-	-	-	-	2,281	-	2,281	-	2,281	-	-	-	-	-	-	-	-	-
1a.3	Subtotal Period 1a Collateral Costs	-	-	-	-	-	-	12,450	1,525	13,976	9,653	4,323	-	-	-	-	-	-	-	-	-
Period 1a Period-Dependent Costs																					
1a.4.1	Insurance	-	-	-	-	-	-	1,730	173	1,903	1,903	-	-	-	-	-	-	-	-	-	-
1a.4.2	Property taxes	-	-	-	-	-	-	2,682	268	2,950	2,950	-	-	-	-	-	-	-	-	-	-
1a.4.3	Health physics supplies	-	507	-	-	-	-	-	127	633	633	-	-	-	-	-	-	-	-	-	-
1a.4.4	Heavy equipment rental	-	567	-	-	-	-	-	85	652	652	-	-	-	-	-	-	-	-	-	-
1a.4.5	Disposal of DAW generated	-	-	13	4	-	49	-	14	79	79	-	-	-	597	-	-	-	11,939	19	-
1a.4.6	Plant energy budget	-	-	-	-	-	-	1,515	227	1,742	1,742	-	-	-	-	-	-	-	-	-	-
1a.4.7	NRC Fees	-	-	-	-	-	-	778	78	855	855	-	-	-	-	-	-	-	-	-	-
1a.4.8	Emergency Planning Fees	-	-	-	-	-	-	1,604	160	1,765	-	1,765	-	-	-	-	-	-	-	-	-
1a.4.9	Fixed Overhead	-	-	-	-	-	-	1,470	220	1,690	1,690	-	-	-	-	-	-	-	-	-	-
1a.4.10	Spent Fuel Pool O&M	-	-	-	-	-	-	401	60	461	-	461	-	-	-	-	-	-	-	-	-
1a.4.11	ISFSI Operating Costs	-	-	-	-	-	-	52	8	59	-	59	-	-	-	-	-	-	-	-	-
1a.4.12	Railroad Track Maintenance	-	-	-	-	-	-	58	9	66	66	-	-	-	-	-	-	-	-	-	-
1a.4.13	Security Staff Cost	-	-	-	-	-	-	7,390	1,108	8,498	8,498	-	-	-	-	-	-	-	-	-	122,720
1a.4.14	Utility Staff Cost	-	-	-	-	-	-	24,344	3,652	27,995	27,995	-	-	-	-	-	-	-	-	-	400,523
1a.4	Subtotal Period 1a Period-Dependent Costs	-	1,074	13	4	-	49	42,022	6,189	49,351	47,066	2,286	-	-	597	-	-	-	11,939	19	523,243
1a.0	TOTAL PERIOD 1a COST	-	1,074	13	4	-	49	57,272	8,220	66,631	60,023	6,608	-	-	597	-	-	-	11,939	19	542,224

Table H-2
Prairie Island Nuclear Generating Plant, Unit 2
SAFSTOR Decommissioning Cost Estimate with DOE Pickup of Industry Spent Fuel Starting in 2025
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
PERIOD 1b - SAFSTOR Limited DECON Activities																					
Period 1b Direct Decommissioning Activities																					
Decontamination of Site Buildings																					
1b.1.1.1	Reactor	1,135	-	-	-	-	-	-	568	1,703	1,703	-	-	-	-	-	-	-	17,003	-
1b.1.1.2	Auxiliary	1,177	-	-	-	-	-	-	589	1,766	1,766	-	-	-	-	-	-	-	17,950	-
1b.1.1.3	Drum Transfer & Truck Loading Enclosure	16	-	-	-	-	-	-	8	24	24	-	-	-	-	-	-	-	244	-
1b.1.1.4	LLRW Storage Enclosure	99	-	-	-	-	-	-	50	149	149	-	-	-	-	-	-	-	1,487	-
1b.1.1.5	Radwaste	44	-	-	-	-	-	-	22	66	66	-	-	-	-	-	-	-	669	-
1b.1.1.6	Resin Disposal	13	-	-	-	-	-	-	7	20	20	-	-	-	-	-	-	-	198	-
1b.1.1.7	Fuel Handling of Aux Building	863	-	-	-	-	-	-	431	1,294	1,294	-	-	-	-	-	-	-	12,414	-
1b.1.1	Totals	3,348	-	-	-	-	-	-	1,674	5,022	5,022	-	-	-	-	-	-	-	49,966	-
1b.1	Subtotal Period 1b Activity Costs	3,348	-	-	-	-	-	-	1,674	5,022	5,022	-	-	-	-	-	-	-	49,966	-
Period 1b Additional Costs																					
1b.2.1	Spent fuel pool isolation	-	-	-	-	-	-	7,794	1,169	8,963	8,963	-	-	-	-	-	-	-	-	-	-
1b.2	Subtotal Period 1b Additional Costs	-	-	-	-	-	-	7,794	1,169	8,963	8,963	-	-	-	-	-	-	-	-	-	-
Period 1b Collateral Costs																					
1b.3.1	Decon equipment	973	-	-	-	-	-	-	146	1,119	1,119	-	-	-	-	-	-	-	-	-	-
1b.3.2	Process decommissioning water waste	105	-	68	177	-	277	-	155	781	781	-	-	-	660	-	-	-	39,628	129	-
1b.3.4	Small tool allowance	-	56	-	-	-	-	-	8	64	64	-	-	-	-	-	-	-	-	-	-
1b.3.5	Spent Fuel Capital and Transfer	-	-	-	-	-	-	454	68	522	-	522	-	-	-	-	-	-	-	-	-
1b.3.6	Retention and Severance	-	-	-	-	-	-	2,315	347	2,662	2,662	-	-	-	-	-	-	-	-	-	-
1b.3.7	Prairie Island Indian Community Payments	-	-	-	-	-	-	315	-	315	-	315	-	-	-	-	-	-	-	-	-
1b.3	Subtotal Period 1b Collateral Costs	1,078	56	68	177	-	277	3,083	724	5,462	4,625	837	-	-	660	-	-	-	39,628	129	-
Period 1b Period-Dependent Costs																					
1b.4.1	Decon supplies	1,232	-	-	-	-	-	-	308	1,540	1,540	-	-	-	-	-	-	-	-	-	-
1b.4.2	Insurance	-	-	-	-	-	-	436	44	480	480	-	-	-	-	-	-	-	-	-	-
1b.4.3	Property taxes	-	-	-	-	-	-	675	68	743	743	-	-	-	-	-	-	-	-	-	-
1b.4.4	Health physics supplies	-	369	-	-	-	-	-	92	461	461	-	-	-	-	-	-	-	-	-	-
1b.4.5	Heavy equipment rental	-	143	-	-	-	-	-	21	164	164	-	-	-	-	-	-	-	-	-	-
1b.4.6	Disposal of DAW generated	-	-	14	4	-	52	-	15	85	85	-	-	-	636	-	-	-	12,711	21	-
1b.4.7	Plant energy budget	-	-	-	-	-	-	382	57	439	439	-	-	-	-	-	-	-	-	-	-
1b.4.8	NRC Fees	-	-	-	-	-	-	107	11	118	118	-	-	-	-	-	-	-	-	-	-
1b.4.9	Emergency Planning Fees	-	-	-	-	-	-	404	40	445	-	445	-	-	-	-	-	-	-	-	-
1b.4.10	Fixed Overhead	-	-	-	-	-	-	370	56	426	426	-	-	-	-	-	-	-	-	-	-
1b.4.11	Spent Fuel Pool O&M	-	-	-	-	-	-	101	15	116	-	116	-	-	-	-	-	-	-	-	-
1b.4.12	ISFSI Operating Costs	-	-	-	-	-	-	13	2	15	-	15	-	-	-	-	-	-	-	-	-
1b.4.13	Railroad Track Maintenance	-	-	-	-	-	-	15	2	17	17	-	-	-	-	-	-	-	-	-	-
1b.4.14	Security Staff Cost	-	-	-	-	-	-	1,863	279	2,142	2,142	-	-	-	-	-	-	-	-	-	30,932
1b.4.15	Utility Staff Cost	-	-	-	-	-	-	6,501	975	7,476	7,476	-	-	-	-	-	-	-	-	-	106,428
1b.4	Subtotal Period 1b Period-Dependent Costs	1,232	512	14	4	-	52	10,867	1,986	14,667	14,090	576	-	-	636	-	-	-	12,711	21	137,360
1b.0	TOTAL PERIOD 1b COST	5,657	568	82	181	-	328	21,745	5,553	34,114	32,701	1,413	-	-	1,296	-	-	-	52,338	50,116	137,360
PERIOD 1c - Preparations for SAFSTOR Dormancy																					
Period 1c Direct Decommissioning Activities																					
1c.1.1	Prepare support equipment for storage	-	486	-	-	-	-	-	73	559	559	-	-	-	-	-	-	-	-	3,000	-
1c.1.2	Install containment pressure equal. lines	-	48	-	-	-	-	-	7	55	55	-	-	-	-	-	-	-	-	700	-
1c.1.3	Interim survey prior to dormancy	-	-	-	-	-	-	733	220	953	953	-	-	-	-	-	-	-	-	9,017	-
1c.1.4	Secure building accesses									a											
1c.1.5	Prepare & submit interim report	-	-	-	-	-	-	29	4	34	34	-	-	-	-	-	-	-	-	-	249
1c.1	Subtotal Period 1c Activity Costs	-	534	-	-	-	-	762	304	1,601	1,601	-	-	-	-	-	-	-	-	12,717	249
Period 1c Collateral Costs																					
1c.3.1	Process decommissioning water waste	88	-	58	150	-	234	-	131	661	661	-	-	-	560	-	-	-	33,579	109	-
1c.3.3	Small tool allowance	-	4	-	-	-	-	-	1	5	5	-	-	-	-	-	-	-	-	-	-
1c.3.4	Spent Fuel Capital and Transfer	-	-	-	-	-	-	251	38	289	-	289	-	-	-	-	-	-	-	-	-
1c.3.5	Retention and Severance	-	-	-	-	-	-	1,741	261	2,002	2,002	-	-	-	-	-	-	-	-	-	-
1c.3.6	Prairie Island Indian Community Payments	-	-	-	-	-	-	314	-	314	-	314	-	-	-	-	-	-	-	-	-
1c.3	Subtotal Period 1c Collateral Costs	88	4	58	150	-	234	2,306	430	3,271	2,668	603	-	-	560	-	-	-	33,579	109	-

Table H-2
Prairie Island Nuclear Generating Plant, Unit 2
SAFSTOR Decommissioning Cost Estimate with DOE Pickup of Industry Spent Fuel Starting in 2025
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Period 1c Period-Dependent Costs																					
1c.4.1	Insurance	-	-	-	-	-	-	436	44	480	480	-	-	-	-	-	-	-	-	-	-
1c.4.2	Property taxes	-	-	-	-	-	-	674	67	742	742	-	-	-	-	-	-	-	-	-	-
1c.4.3	Health physics supplies	-	191	-	-	-	-	-	48	239	239	-	-	-	-	-	-	-	-	-	-
1c.4.4	Heavy equipment rental	-	143	-	-	-	-	-	21	164	164	-	-	-	-	-	-	-	-	-	-
1c.4.5	Disposal of DAW generated	-	-	3	1	-	13	-	4	20	20	-	-	-	154	-	-	-	3,073	5	-
1c.4.6	Plant energy budget	-	-	-	-	-	-	382	57	439	439	-	-	-	-	-	-	-	-	-	-
1c.4.7	NRC Fees	-	-	-	-	-	-	107	11	118	118	-	-	-	-	-	-	-	-	-	-
1c.4.8	Emergency Planning Fees	-	-	-	-	-	-	404	40	445	-	445	-	-	-	-	-	-	-	-	-
1c.4.9	Fixed Overhead	-	-	-	-	-	-	370	56	426	426	-	-	-	-	-	-	-	-	-	-
1c.4.10	Spent Fuel Pool O&M	-	-	-	-	-	-	101	15	116	-	116	-	-	-	-	-	-	-	-	-
1c.4.11	ISFSI Operating Costs	-	-	-	-	-	-	13	2	15	-	15	-	-	-	-	-	-	-	-	-
1c.4.12	Railroad Track Maintenance	-	-	-	-	-	-	15	2	17	17	-	-	-	-	-	-	-	-	-	-
1c.4.13	Security Staff Cost	-	-	-	-	-	-	1,863	279	2,142	2,142	-	-	-	-	-	-	-	-	-	30,932
1c.4.14	Utility Staff Cost	-	-	-	-	-	-	6,501	975	7,476	7,476	-	-	-	-	-	-	-	-	-	106,428
1c.4	Subtotal Period 1c Period-Dependent Costs	-	334	3	1	-	13	10,866	1,622	12,839	12,263	576	-	-	154	-	-	-	3,073	5	137,360
1c.0	TOTAL PERIOD 1c COST	88	873	61	151	-	247	13,934	2,357	17,711	16,532	1,179	-	-	713	-	-	-	36,652	12,832	137,609
PERIOD 1 TOTALS		5,746	2,514	156	335	-	624	92,951	16,130	118,456	109,256	9,200	-	-	2,606	-	-	-	100,929	62,967	817,193
PERIOD 2a - SAFSTOR Dormancy with Wet Spent Fuel Storage																					
Period 2a Direct Decommissioning Activities																					
2a.1.1	Quarterly Inspection									a											
2a.1.2	Semi-annual environmental survey									a											
2a.1.3	Prepare reports									a											
2a.1.4	Bituminous roof replacement	-	-	-	-	-	-	309	46	356	356	-	-	-	-	-	-	-	-	-	-
2a.1.5	Maintenance supplies	-	-	-	-	-	-	477	119	596	596	-	-	-	-	-	-	-	-	-	-
2a.1	Subtotal Period 2a Activity Costs	-	-	-	-	-	-	786	166	951	951	-	-	-	-	-	-	-	-	-	-
Period 2a Additional Costs																					
2a.2.1	Security Modifications	-	-	-	-	-	-	4,348	652	5,000	5,000	-	-	-	-	-	-	-	-	-	-
2a.2	Subtotal Period 2a Additional Costs	-	-	-	-	-	-	4,348	652	5,000	5,000	-	-	-	-	-	-	-	-	-	-
Period 2a Collateral Costs																					
2a.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	63,609	9,541	73,151	-	73,151	-	-	-	-	-	-	-	-	-
2a.3.2	Retention and Severance	-	-	-	-	-	-	12,266	1,840	14,106	14,106	-	-	-	-	-	-	-	-	-	-
2a.3.3	Prairie Island Indian Community Payments	-	-	-	-	-	-	4,371	-	4,371	-	4,371	-	-	-	-	-	-	-	-	-
2a.3	Subtotal Period 2a Collateral Costs	-	-	-	-	-	-	80,246	11,381	91,628	14,106	77,522	-	-	-	-	-	-	-	-	-
Period 2a Period-Dependent Costs																					
2a.4.1	Insurance	-	-	-	-	-	-	1,788	179	1,966	1,966	-	-	-	-	-	-	-	-	-	-
2a.4.2	Property taxes	-	-	-	-	-	-	9,379	938	10,317	10,317	-	-	-	-	-	-	-	-	-	-
2a.4.3	Health physics supplies	-	631	-	-	-	-	-	158	789	789	-	-	-	-	-	-	-	-	-	-
2a.4.4	Disposal of DAW generated	-	-	15	4	-	55	-	16	89	89	-	-	-	670	-	-	-	13,402	22	-
2a.4.5	Plant energy budget	-	-	-	-	-	-	1,060	159	1,219	1,219	-	-	-	-	-	-	-	-	-	-
2a.4.6	NRC Fees	-	-	-	-	-	-	819	82	901	901	-	-	-	-	-	-	-	-	-	-
2a.4.7	Emergency Planning Fees	-	-	-	-	-	-	4,492	449	4,941	-	4,941	-	-	-	-	-	-	-	-	-
2a.4.8	Fixed Overhead	-	-	-	-	-	-	5,142	771	5,913	5,913	-	-	-	-	-	-	-	-	-	-
2a.4.9	Spent Fuel Pool O&M	-	-	-	-	-	-	1,404	211	1,615	-	1,615	-	-	-	-	-	-	-	-	-
2a.4.10	ISFSI Operating Costs	-	-	-	-	-	-	181	27	208	-	208	-	-	-	-	-	-	-	-	-
2a.4.11	Railroad Track Maintenance	-	-	-	-	-	-	410	62	472	472	-	-	-	-	-	-	-	-	-	-
2a.4.12	Security Staff Cost	-	-	-	-	-	-	23,761	3,564	27,325	19,456	7,870	-	-	-	-	-	-	-	-	392,966
2a.4.13	Utility Staff Cost	-	-	-	-	-	-	3,341	501	3,842	2,732	1,110	-	-	-	-	-	-	-	-	54,579
2a.4	Subtotal Period 2a Period-Dependent Costs	-	631	15	4	-	55	51,776	7,116	59,597	43,854	15,744	-	-	670	-	-	-	13,402	22	447,545
2a.0	TOTAL PERIOD 2a COST	-	631	15	4	-	55	137,156	19,315	157,176	63,911	93,265	-	-	670	-	-	-	13,402	22	447,545
PERIOD 2b - SAFSTOR Dormancy with Dry Spent Fuel Storage																					
Period 2b Direct Decommissioning Activities																					
2b.1.1	Quarterly Inspection									a											
2b.1.2	Semi-annual environmental survey									a											
2b.1.3	Prepare reports									a											
2b.1.4	Bituminous roof replacement	-	-	-	-	-	-	2,226	334	2,560	2,560	-	-	-	-	-	-	-	-	-	-
2b.1.5	Maintenance supplies	-	-	-	-	-	-	3,433	858	4,291	4,291	-	-	-	-	-	-	-	-	-	-
2b.1	Subtotal Period 2b Activity Costs	-	-	-	-	-	-	5,659	1,192	6,852	6,852	-	-	-	-	-	-	-	-	-	-

Table H-2
Prairie Island Nuclear Generating Plant, Unit 2
SAFSTOR Decommissioning Cost Estimate with DOE Pickup of Industry Spent Fuel Starting in 2025
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 2b Collateral Costs																					
2b.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	20,705	3,106	23,811	-	23,811	-	-	-	-	-	-	-	-	-
2b.3.2	Prairie Island Indian Community Payments	-	-	-	-	-	-	31,469	-	31,469	-	31,469	-	-	-	-	-	-	-	-	-
2b.3	Subtotal Period 2b Collateral Costs	-	-	-	-	-	-	52,174	3,106	55,280	-	55,280	-	-	-	-	-	-	-	-	-
Period 2b Period-Dependent Costs																					
2b.4.1	Insurance	-	-	-	-	-	-	12,873	1,287	14,160	14,160	-	-	-	-	-	-	-	-	-	-
2b.4.2	Property taxes	-	-	-	-	-	-	67,525	6,753	74,278	74,278	-	-	-	-	-	-	-	-	-	-
2b.4.3	Health physics supplies	-	2,403	-	-	-	-	-	601	3,003	3,003	-	-	-	-	-	-	-	-	-	-
2b.4.4	Disposal of DAW generated	-	-	57	17	-	212	-	61	346	346	-	-	-	2,602	-	-	-	52,049	85	-
2b.4.5	Plant energy budget	-	-	-	-	-	-	3,816	572	4,388	4,388	-	-	-	-	-	-	-	-	-	-
2b.4.6	NRC Fees	-	-	-	-	-	-	5,654	565	6,219	6,219	-	-	-	-	-	-	-	-	-	-
2b.4.7	Emergency Planning Fees	-	-	-	-	-	-	1,723	172	1,895	-	1,895	-	-	-	-	-	-	-	-	-
2b.4.8	Fixed Overhead	-	-	-	-	-	-	3,844	577	4,421	4,421	-	-	-	-	-	-	-	-	-	-
2b.4.9	ISFSI Operating Costs	-	-	-	-	-	-	1,301	195	1,496	-	1,496	-	-	-	-	-	-	-	-	-
2b.4.10	Railroad Track Maintenance	-	-	-	-	-	-	1,453	218	1,671	1,671	-	-	-	-	-	-	-	-	-	-
2b.4.11	Security Staff Cost	-	-	-	-	-	-	63,533	9,530	73,063	15,051	58,012	-	-	-	-	-	-	-	-	943,283
2b.4.12	Utility Staff Cost	-	-	-	-	-	-	32,977	4,946	37,923	23,588	14,335	-	-	-	-	-	-	-	-	524,046
2b.4	Subtotal Period 2b Period-Dependent Costs	-	2,403	57	17	-	212	194,698	25,478	222,863	147,126	75,737	-	-	2,602	-	-	-	52,049	85	1,467,329
2b.0	TOTAL PERIOD 2b COST	-	2,403	57	17	-	212	252,531	29,776	284,995	153,978	131,017	-	-	2,602	-	-	-	52,049	85	1,467,329
PERIOD 2c - SAFSTOR Dormancy without Spent Fuel Storage																					
Period 2c Direct Decommissioning Activities																					
2c.1.1	Quarterly Inspection									a											
2c.1.2	Semi-annual environmental survey									a											
2c.1.3	Prepare reports									a											
2c.1.4	Bituminous roof replacement	-	-	-	-	-	-	2,073	311	2,384	2,384	-	-	-	-	-	-	-	-	-	-
2c.1.5	Maintenance supplies	-	-	-	-	-	-	3,197	799	3,997	3,997	-	-	-	-	-	-	-	-	-	-
2c.1	Subtotal Period 2c Activity Costs	-	-	-	-	-	-	5,270	1,110	6,381	6,381	-	-	-	-	-	-	-	-	-	-
Period 2c Period-Dependent Costs																					
2c.4.1	Insurance	-	-	-	-	-	-	11,764	1,176	12,940	12,940	-	-	-	-	-	-	-	-	-	-
2c.4.2	Property taxes	-	-	-	-	-	-	53,045	5,305	58,350	58,350	-	-	-	-	-	-	-	-	-	-
2c.4.3	Health physics supplies	-	2,122	-	-	-	-	-	530	2,652	2,652	-	-	-	-	-	-	-	-	-	-
2c.4.4	Disposal of DAW generated	-	-	49	14	-	183	-	53	300	300	-	-	-	2,254	-	-	-	45,081	74	-
2c.4.5	Plant energy budget	-	-	-	-	-	-	3,554	533	4,087	4,087	-	-	-	-	-	-	-	-	-	-
2c.4.6	NRC Fees	-	-	-	-	-	-	5,051	505	5,556	5,556	-	-	-	-	-	-	-	-	-	-
2c.4.7	Fixed Overhead	-	-	-	-	-	-	3,580	537	4,117	4,117	-	-	-	-	-	-	-	-	-	-
2c.4.8	Railroad Track Maintenance	-	-	-	-	-	-	1,353	203	1,556	1,556	-	-	-	-	-	-	-	-	-	-
2c.4.9	Utility Staff Cost	-	-	-	-	-	-	11,863	1,779	13,642	13,642	-	-	-	-	-	-	-	-	-	195,212
2c.4	Subtotal Period 2c Period-Dependent Costs	-	2,122	49	14	-	183	90,209	10,622	103,200	103,200	-	-	-	2,254	-	-	-	45,081	74	195,212
2c.0	TOTAL PERIOD 2c COST	-	2,122	49	14	-	183	95,480	11,732	109,580	109,580	-	-	-	2,254	-	-	-	45,081	74	195,212
PERIOD 2 TOTALS		-	5,156	120	35	-	450	485,167	60,823	551,751	327,469	224,283	-	-	5,527	-	-	-	110,532	180	2,110,086
PERIOD 3a - Reactivate Site Following SAFSTOR Dormancy																					
Period 3a Direct Decommissioning Activities																					
3a.1.1	Prepare preliminary decommissioning cost	-	-	-	-	-	-	65	10	75	75	-	-	-	-	-	-	-	-	-	556
3a.1.2	Review plant dwgs & specs.	-	-	-	-	-	-	231	35	266	266	-	-	-	-	-	-	-	-	-	1,967
3a.1.3	Perform detailed rad survey									a											
3a.1.4	End product description	-	-	-	-	-	-	50	8	58	58	-	-	-	-	-	-	-	-	-	428
3a.1.5	Detailed by-product inventory	-	-	-	-	-	-	65	10	75	75	-	-	-	-	-	-	-	-	-	556
3a.1.6	Define major work sequence	-	-	-	-	-	-	376	56	433	433	-	-	-	-	-	-	-	-	-	3,207
3a.1.7	Perform SER and EA	-	-	-	-	-	-	156	23	179	179	-	-	-	-	-	-	-	-	-	1,326
3a.1.8	Perform Site-Specific Cost Study	-	-	-	-	-	-	251	38	289	289	-	-	-	-	-	-	-	-	-	2,138
Activity Specifications																					
3a.1.9.1	Re-activate plant & temporary facilities	-	-	-	-	-	-	370	55	425	383	-	43	-	-	-	-	-	-	-	3,151
3a.1.9.2	Plant systems	-	-	-	-	-	-	209	31	241	216	-	24	-	-	-	-	-	-	-	1,782
3a.1.9.3	Reactor internals	-	-	-	-	-	-	356	53	410	410	-	-	-	-	-	-	-	-	-	3,036
3a.1.9.4	Reactor vessel	-	-	-	-	-	-	326	49	375	375	-	-	-	-	-	-	-	-	-	2,779
3a.1.9.5	Biological shield	-	-	-	-	-	-	25	4	29	29	-	-	-	-	-	-	-	-	-	214
3a.1.9.6	Steam generators	-	-	-	-	-	-	157	23	180	180	-	-	-	-	-	-	-	-	-	1,334
3a.1.9.7	Reinforced concrete	-	-	-	-	-	-	80	12	92	46	-	46	-	-	-	-	-	-	-	684

Table H-2
Prairie Island Nuclear Generating Plant, Unit 2
SAFSTOR Decommissioning Cost Estimate with DOE Pickup of Industry Spent Fuel Starting in 2025
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Activity Specifications (continued)																					
3a.1.9.8	Main Turbine	-	-	-	-	-	-	20	3	23	-	-	23	-	-	-	-	-	-	-	171
3a.1.9.9	Main Condensers	-	-	-	-	-	-	20	3	23	-	-	23	-	-	-	-	-	-	-	171
3a.1.9.10	Plant structures & buildings	-	-	-	-	-	-	157	23	180	90	-	90	-	-	-	-	-	-	-	1,334
3a.1.9.11	Waste management	-	-	-	-	-	-	231	35	266	266	-	-	-	-	-	-	-	-	-	1,967
3a.1.9.12	Facility & site closeout	-	-	-	-	-	-	45	7	52	26	-	26	-	-	-	-	-	-	-	385
3a.1.9	Total	-	-	-	-	-	-	1,996	299	2,296	2,021	-	275	-	-	-	-	-	-	-	17,009
Planning & Site Preparations																					
3a.1.10	Prepare dismantling sequence	-	-	-	-	-	-	120	18	139	139	-	-	-	-	-	-	-	-	-	1,026
3a.1.11	Plant prep. & temp. svces	-	-	-	-	-	-	3,300	495	3,795	3,795	-	-	-	-	-	-	-	-	-	-
3a.1.12	Design water clean-up system	-	-	-	-	-	-	70	11	81	81	-	-	-	-	-	-	-	-	-	599
3a.1.13	Rigging/Cont. Cntrl Envlps/tooling/etc.	-	-	-	-	-	-	2,300	345	2,645	2,645	-	-	-	-	-	-	-	-	-	-
3a.1.14	Procure casks/liners & containers	-	-	-	-	-	-	62	9	71	71	-	-	-	-	-	-	-	-	-	526
3a.1	Subtotal Period 3a Activity Costs	-	-	-	-	-	-	9,043	1,357	10,400	10,125	-	275	-	-	-	-	-	-	-	29,336
Period 3a Additional Costs																					
3a.2.1	Site Characterization	-	-	-	-	-	-	1,582	475	2,057	2,057	-	-	-	-	-	-	-	-	8,988	3,563
3a.2.2	Mixed/Hazardous Waste	-	-	326	75	169	-	-	69	639	639	-	-	6,324	-	-	-	-	362,914	2,410	-
3a.2.3	Asbestos Abatement	-	2,364	2	110	-	1,359	-	947	4,782	4,782	-	-	-	12,843	-	-	-	166,959	20,907	-
3a.2	Subtotal Period 3a Additional Costs	-	2,364	328	185	169	1,359	1,582	1,491	7,478	7,478	-	-	6,324	12,843	-	-	-	529,873	32,305	3,563
Period 3a Collateral Costs																					
3a.3.1	Small tool allowance	-	32	-	-	-	-	-	5	37	37	-	-	-	-	-	-	-	-	-	-
3a.3	Subtotal Period 3a Collateral Costs	-	32	-	-	-	-	-	5	37	37	-	-	-	-	-	-	-	-	-	-
Period 3a Period-Dependent Costs																					
3a.4.1	Insurance	-	-	-	-	-	-	501	50	552	552	-	-	-	-	-	-	-	-	-	-
3a.4.2	Property taxes	-	-	-	-	-	-	1,644	164	1,809	1,809	-	-	-	-	-	-	-	-	-	-
3a.4.3	Health physics supplies	-	539	-	-	-	-	-	135	673	673	-	-	-	-	-	-	-	-	-	-
3a.4.4	Heavy equipment rental	-	567	-	-	-	-	-	85	652	652	-	-	-	-	-	-	-	-	-	-
3a.4.5	Disposal of DAW generated	-	-	10	3	-	39	-	11	64	64	-	-	-	481	-	-	-	9,613	16	-
3a.4.6	Plant energy budget	-	-	-	-	-	-	1,515	227	1,742	1,742	-	-	-	-	-	-	-	-	-	-
3a.4.7	NRC Fees	-	-	-	-	-	-	298	30	327	327	-	-	-	-	-	-	-	-	-	-
3a.4.8	Fixed Overhead	-	-	-	-	-	-	1,470	220	1,690	1,690	-	-	-	-	-	-	-	-	-	-
3a.4.9	Railroad Track Maintenance	-	-	-	-	-	-	58	9	66	66	-	-	-	-	-	-	-	-	-	-
3a.4.10	Security Staff Cost	-	-	-	-	-	-	312	47	358	358	-	-	-	-	-	-	-	-	-	6,240
3a.4.11	Utility Staff Cost	-	-	-	-	-	-	11,597	1,740	13,336	13,336	-	-	-	-	-	-	-	-	-	199,680
3a.4	Subtotal Period 3a Period-Dependent Costs	-	1,106	10	3	-	39	17,394	2,718	21,270	21,270	-	-	-	481	-	-	-	9,613	16	205,920
3a.0	TOTAL PERIOD 3a COST	-	3,501	339	188	169	1,398	28,019	5,570	39,184	38,909	-	275	6,324	13,324	-	-	-	539,486	32,320	238,819
PERIOD 3b - Decommissioning Preparations																					
Period 3b Direct Decommissioning Activities																					
Detailed Work Procedures																					
3b.1.1.1	Plant systems	-	-	-	-	-	-	238	36	273	246	-	27	-	-	-	-	-	-	-	2,024
3b.1.1.2	Reactor internals	-	-	-	-	-	-	125	19	144	144	-	-	-	-	-	-	-	-	-	1,069
3b.1.1.3	Remaining buildings	-	-	-	-	-	-	68	10	78	19	-	58	-	-	-	-	-	-	-	577
3b.1.1.4	CRD cooling assembly	-	-	-	-	-	-	50	8	58	58	-	-	-	-	-	-	-	-	-	428
3b.1.1.5	CRD housings & ICI tubes	-	-	-	-	-	-	50	8	58	58	-	-	-	-	-	-	-	-	-	428
3b.1.1.6	Incore instrumentation	-	-	-	-	-	-	50	8	58	58	-	-	-	-	-	-	-	-	-	428
3b.1.1.7	Reactor vessel	-	-	-	-	-	-	182	27	210	210	-	-	-	-	-	-	-	-	-	1,552
3b.1.1.8	Facility closeout	-	-	-	-	-	-	60	9	69	35	-	35	-	-	-	-	-	-	-	513
3b.1.1.9	Missile shields	-	-	-	-	-	-	23	3	26	26	-	-	-	-	-	-	-	-	-	192
3b.1.1.10	Biological shield	-	-	-	-	-	-	60	9	69	69	-	-	-	-	-	-	-	-	-	513
3b.1.1.11	Steam generators	-	-	-	-	-	-	231	35	266	266	-	-	-	-	-	-	-	-	-	1,967
3b.1.1.12	Reinforced concrete	-	-	-	-	-	-	50	8	58	29	-	29	-	-	-	-	-	-	-	428
3b.1.1.13	Main Turbine	-	-	-	-	-	-	78	12	90	-	-	90	-	-	-	-	-	-	-	667
3b.1.1.14	Main Condensers	-	-	-	-	-	-	78	12	90	-	-	90	-	-	-	-	-	-	-	667
3b.1.1.15	Auxiliary building	-	-	-	-	-	-	137	21	158	142	-	16	-	-	-	-	-	-	-	1,167
3b.1.1.16	Reactor building	-	-	-	-	-	-	137	21	158	142	-	16	-	-	-	-	-	-	-	1,167
3b.1.1	Total	-	-	-	-	-	-	1,618	243	1,861	1,500	-	361	-	-	-	-	-	-	-	13,787
3b.1	Subtotal Period 3b Activity Costs	-	-	-	-	-	-	1,618	243	1,861	1,500	-	361	-	-	-	-	-	-	-	13,787

Table H-2
Prairie Island Nuclear Generating Plant, Unit 2
SAFSTOR Decommissioning Cost Estimate with DOE Pickup of Industry Spent Fuel Starting in 2025
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 3b Collateral Costs																					
3b.3.1	Decon equipment	973	-	-	-	-	-	-	146	1,119	1,119	-	-	-	-	-	-	-	-	-	-
3b.3.2	DOC staff relocation expenses	-	-	-	-	-	-	1,189	178	1,367	1,367	-	-	-	-	-	-	-	-	-	-
3b.3.3	Pipe cutting equipment	-	1,200	-	-	-	-	-	180	1,380	1,380	-	-	-	-	-	-	-	-	-	-
3b.3	Subtotal Period 3b Collateral Costs	973	1,200	-	-	-	-	1,189	504	3,866	3,866	-	-	-	-	-	-	-	-	-	-
Period 3b Period-Dependent Costs																					
3b.4.1	Decon supplies	35	-	-	-	-	-	-	9	43	43	-	-	-	-	-	-	-	-	-	-
3b.4.2	Insurance	-	-	-	-	-	-	255	25	280	280	-	-	-	-	-	-	-	-	-	-
3b.4.3	Property taxes	-	-	-	-	-	-	764	76	840	840	-	-	-	-	-	-	-	-	-	-
3b.4.4	Health physics supplies	-	230	-	-	-	-	-	57	287	287	-	-	-	-	-	-	-	-	-	-
3b.4.5	Heavy equipment rental	-	283	-	-	-	-	-	42	325	325	-	-	-	-	-	-	-	-	-	-
3b.4.6	Disposal of DAW generated	-	-	6	2	-	22	-	6	35	35	-	-	-	264	-	-	-	5,286	9	-
3b.4.7	Plant energy budget	-	-	-	-	-	-	755	113	869	869	-	-	-	-	-	-	-	-	-	-
3b.4.8	NRC Fees	-	-	-	-	-	-	148	15	163	163	-	-	-	-	-	-	-	-	-	-
3b.4.9	Fixed Overhead	-	-	-	-	-	-	733	110	843	843	-	-	-	-	-	-	-	-	-	-
3b.4.10	Railroad Track Maintenance	-	-	-	-	-	-	29	4	33	33	-	-	-	-	-	-	-	-	-	-
3b.4.11	Security Staff Cost	-	-	-	-	-	-	155	23	179	179	-	-	-	-	-	-	-	-	-	3,111
3b.4.12	DOC Staff Cost	-	-	-	-	-	-	3,539	531	4,070	4,070	-	-	-	-	-	-	-	-	-	42,523
3b.4.13	Utility Staff Cost	-	-	-	-	-	-	5,782	867	6,650	6,650	-	-	-	-	-	-	-	-	-	99,566
3b.4	Subtotal Period 3b Period-Dependent Costs	35	513	6	2	-	22	12,161	1,881	14,618	14,618	-	-	-	264	-	-	-	5,286	9	145,201
3b.0	TOTAL PERIOD 3b COST	1,008	1,713	6	2	-	22	14,968	2,628	20,345	19,984	-	361	-	264	-	-	-	5,286	9	158,988
PERIOD 3 TOTALS		1,008	5,214	345	189	169	1,420	42,987	8,198	59,529	58,893	-	636	6,324	13,588	-	-	-	544,771	32,329	397,807
PERIOD 4a - Large Component Removal																					
Period 4a Direct Decommissioning Activities																					
Nuclear Steam Supply System Removal																					
4a.1.1.1	Reactor Coolant Piping	11	40	6	5	34	75	-	41	212	212	-	-	144	152	-	-	-	33,380	771	-
4a.1.1.2	Pressurizer Relief Tank	5	18	4	3	23	50	-	24	126	126	-	-	96	101	-	-	-	22,241	347	-
4a.1.1.3	Reactor Coolant Pumps & Motors	13	56	43	76	-	736	-	220	1,143	1,143	-	-	-	2,332	-	-	-	295,800	1,226	80
4a.1.1.4	Pressurizer	10	68	359	82	-	693	-	244	1,456	1,456	-	-	-	2,196	-	-	-	158,199	1,499	750
4a.1.1.5	Steam Generators	47	2,943	1,576	1,614	1,246	3,467	-	2,212	13,104	13,104	-	-	18,672	10,990	-	-	-	1,560,086	10,964	2,250
4a.1.1.6	CRDMs/ICIs/Service Structure Removal	60	243	199	32	169	369	-	233	1,305	1,305	-	-	2,138	2,146	-	-	-	165,025	4,449	-
4a.1.1.7	Reactor Vessel Internals	59	4,189	21,552	1,011	-	7,239	239	12,467	46,756	46,756	-	-	-	757	-	673	-	166,167	19,373	933
4a.1.1.8	Vessel & Internals GTCC Disposal	-	-	-	-	-	8,689	-	1,303	9,992	9,992	-	-	-	-	-	-	3,746	837,596	-	-
4a.1.1.9	Reactor Vessel	-	5,439	1,328	198	-	1,804	239	5,398	14,406	14,406	-	-	-	5,719	-	-	-	569,974	19,373	933
4a.1.1	Totals	204	12,996	25,067	3,022	1,471	23,120	478	22,142	88,499	88,499	-	-	21,050	24,393	-	673	3,746	3,808,467	58,003	4,947
Removal of Major Equipment																					
4a.1.2	Main Turbine/Generator	-	269	128	27	287	-	-	127	838	838	-	-	2,243	-	-	-	-	134,601	4,116	-
4a.1.3	Main Condensers	-	2,269	87	26	383	-	-	637	3,403	3,403	-	-	4,000	-	-	-	-	180,000	34,978	-
Cascading Costs from Clean Building Demolition																					
4a.1.4.1	Reactor	-	728	-	-	-	-	-	109	837	837	-	-	-	-	-	-	-	-	7,589	-
4a.1.4.2	Auxiliary	-	210	-	-	-	-	-	32	242	242	-	-	-	-	-	-	-	-	1,309	-
4a.1.4.3	Radwaste	-	8	-	-	-	-	-	1	9	9	-	-	-	-	-	-	-	-	65	-
4a.1.4	Totals	-	946	-	-	-	-	-	142	1,088	1,088	-	-	-	-	-	-	-	-	8,963	-
Disposal of Plant Systems																					
4a.1.5.1	Admin Bldg Ventilation	-	6	-	-	-	-	-	1	6	-	-	6	-	-	-	-	-	-	90	-
4a.1.5.2	Air Removal	-	25	-	-	-	-	-	4	29	-	-	29	-	-	-	-	-	-	422	-
4a.1.5.3	Auxiliary Feedwater	-	40	-	-	-	-	-	6	46	-	-	46	-	-	-	-	-	-	676	-
4a.1.5.4	Auxiliary Feedwater - RCA	-	36	0	1	15	-	-	12	65	65	-	-	178	-	-	-	-	7,214	486	-
4a.1.5.5	Bleed Steam	-	78	-	-	-	-	-	12	90	-	-	90	-	-	-	-	-	-	1,331	-
4a.1.5.6	Caustic Addition - RCA	-	38	0	1	21	-	-	13	74	74	-	-	240	-	-	-	-	9,761	468	-
4a.1.5.7	Chemical Feed	-	15	-	-	-	-	-	2	17	-	-	17	-	-	-	-	-	-	261	-
4a.1.5.8	Chemical Feed - RCA	-	3	0	0	1	-	-	1	5	5	-	-	16	-	-	-	-	634	31	-
4a.1.5.9	Circulating Water	-	24	-	-	-	-	-	4	28	-	-	28	-	-	-	-	-	-	401	-
4a.1.5.10	Condensate	-	459	-	-	-	-	-	69	527	-	-	527	-	-	-	-	-	-	7,537	-
4a.1.5.11	Condensate Polishing	-	181	-	-	-	-	-	27	209	-	-	209	-	-	-	-	-	-	2,987	-
4a.1.5.12	Condensate Polishing - RCA	-	36	1	3	42	-	-	16	98	98	-	-	483	-	-	-	-	19,616	493	-
4a.1.5.13	Electro-Hydraulic	-	8	-	-	-	-	-	1	10	-	-	10	-	-	-	-	-	-	143	-
4a.1.5.14	External Circulating Water	-	23	-	-	-	-	-	3	26	-	-	26	-	-	-	-	-	-	385	-
4a.1.5.15	External Circulating Water - RCA	-	70	1	4	62	-	-	28	165	165	-	-	721	-	-	-	-	29,284	938	-

Table H-2
Prairie Island Nuclear Generating Plant, Unit 2
SAFSTOR Decommissioning Cost Estimate with DOE Pickup of Industry Spent Fuel Starting in 2025
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Disposal of Plant Systems (continued)																					
4a.1.5.16	Feedwater	-	111	-	-	-	-	-	17	128	-	-	128	-	-	-	-	-	-	1,840	-
4a.1.5.17	Feedwater - RCA	-	236	7	24	359	-	-	117	744	744	-	-	4,147	-	-	-	-	168,414	3,377	-
4a.1.5.18	Gland Seal	-	29	-	-	-	-	-	4	34	-	-	34	-	-	-	-	-	-	504	-
4a.1.5.19	Heater Drain	-	334	-	-	-	-	-	50	384	-	-	384	-	-	-	-	-	-	5,638	-
4a.1.5.20	Hypobromous Acid Feed	-	5	-	-	-	-	-	1	6	-	-	6	-	-	-	-	-	-	86	-
4a.1.5.21	Hypobromous Acid Feed - RCA	-	1	0	0	0	-	-	0	1	1	-	-	2	-	-	-	-	100	12	-
4a.1.5.22	Internal Circ Water & CDSR	-	22	-	-	-	-	-	3	25	-	-	25	-	-	-	-	-	-	366	-
4a.1.5.23	Main Gen/Exciter/Transformer	-	0	-	-	-	-	-	0	0	-	-	0	-	-	-	-	-	-	5	-
4a.1.5.24	Main Steam	-	88	-	-	-	-	-	13	101	-	-	101	-	-	-	-	-	-	1,482	-
4a.1.5.25	Main Steam - RCA	-	364	9	30	447	-	-	163	1,013	1,013	-	-	5,166	-	-	-	-	209,799	5,146	-
4a.1.5.26	Repairable Spare Snubbers	-	6	0	0	1	-	-	2	8	8	-	-	12	-	-	-	-	490	82	-
4a.1.5.27	Steam Exclusion	-	2	-	-	-	-	-	0	2	-	-	2	-	-	-	-	-	-	32	-
4a.1.5.28	Steam Exclusion - RCA	-	4	0	0	2	-	-	1	8	8	-	-	24	-	-	-	-	966	47	-
4a.1.5.29	Steam Generator Blowdown	-	362	20	21	165	179	-	165	911	911	-	-	1,906	631	-	-	-	119,126	5,179	-
4a.1.5.30	Steam Generators	-	5	-	-	-	-	-	1	5	-	-	5	-	-	-	-	-	-	75	-
4a.1.5.31	Turbine & Moisture Separators	-	329	-	-	-	-	-	49	379	-	-	379	-	-	-	-	-	-	5,472	-
4a.1.5.32	Turbine Oil Purification	-	46	-	-	-	-	-	7	53	-	-	53	-	-	-	-	-	-	757	-
4a.1.5.33	Water Treatment	-	394	-	-	-	-	-	59	453	-	-	453	-	-	-	-	-	-	6,677	-
4a.1.5.34	Water Treatment - RCA	-	19	0	1	10	-	-	6	37	37	-	-	115	-	-	-	-	4,652	252	-
4a.1.5	Totals	-	3,400	39	85	1,125	179	-	858	5,687	3,128	-	2,559	13,010	631	-	-	-	570,056	53,681	-
4a.1.6	Scaffolding in support of decommissioning	-	2,682	24	8	97	25	-	695	3,532	3,532	-	-	1,012	89	-	-	-	51,445	23,719	-
4a.1	Subtotal Period 4a Activity Costs	204	22,563	25,345	3,168	3,363	23,325	478	24,601	103,048	100,489	-	2,559	41,316	25,114	-	673	3,746	4,744,569	183,459	4,947
Period 4a Additional Costs																					
4a.2.1	Remedial Action Surveys	-	-	-	-	-	-	1,516	455	1,971	1,971	-	-	-	-	-	-	-	-	19,818	-
4a.2.2	Retired RPV upper internals package	1	659	785	107	-	1,439	-	1,437	4,427	4,427	-	-	-	2,097	125	-	-	205,890	2,175	87
4a.2	Subtotal Period 4a Additional Costs	1	659	785	107	-	1,439	1,516	1,892	6,398	6,398	-	-	-	2,097	125	-	-	205,890	21,993	87
Period 4a Collateral Costs																					
4a.3.1	Process decommissioning water waste	2	-	4	11	-	17	-	7	42	42	-	-	-	40	-	-	-	2,403	8	-
4a.3.3	Small tool allowance	-	220	-	-	-	-	-	33	254	228	-	25	-	-	-	-	-	-	-	-
4a.3	Subtotal Period 4a Collateral Costs	2	220	4	11	-	17	-	41	295	270	-	25	-	40	-	-	-	2,403	8	-
Period 4a Period-Dependent Costs																					
4a.4.1	Decon supplies	79	-	-	-	-	-	-	20	98	98	-	-	-	-	-	-	-	-	-	-
4a.4.2	Insurance	-	-	-	-	-	-	578	58	636	636	-	-	-	-	-	-	-	-	-	-
4a.4.3	Property taxes	-	-	-	-	-	-	1,698	170	1,868	1,868	-	-	-	-	-	-	-	-	-	-
4a.4.4	Health physics supplies	-	1,556	-	-	-	-	-	389	1,945	1,945	-	-	-	-	-	-	-	-	-	-
4a.4.5	Heavy equipment rental	-	2,484	-	-	-	-	-	373	2,857	2,857	-	-	-	-	-	-	-	-	-	-
4a.4.6	Disposal of DAW generated	-	-	73	21	-	274	-	79	449	449	-	-	-	3,371	-	-	-	67,420	110	-
4a.4.7	Plant energy budget	-	-	-	-	-	-	1,628	244	1,872	1,872	-	-	-	-	-	-	-	-	-	-
4a.4.8	NRC Fees	-	-	-	-	-	-	430	43	473	473	-	-	-	-	-	-	-	-	-	-
4a.4.9	Fixed Overhead	-	-	-	-	-	-	1,401	210	1,611	1,611	-	-	-	-	-	-	-	-	-	-
4a.4.10	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	458	69	527	527	-	-	-	-	-	-	-	-	-	-
4a.4.11	Railroad Track Maintenance	-	-	-	-	-	-	65	10	75	75	-	-	-	-	-	-	-	-	-	-
4a.4.12	Security Staff Cost	-	-	-	-	-	-	4,348	652	5,000	5,000	-	-	-	-	-	-	-	-	-	73,548
4a.4.13	DOC Staff Cost	-	-	-	-	-	-	13,997	2,100	16,097	16,097	-	-	-	-	-	-	-	-	-	162,394
4a.4.14	Utility Staff Cost	-	-	-	-	-	-	18,027	2,704	20,731	20,731	-	-	-	-	-	-	-	-	-	294,192
4a.4	Subtotal Period 4a Period-Dependent Costs	79	4,040	73	21	-	274	42,631	7,120	54,239	54,239	-	-	-	3,371	-	-	-	67,420	110	530,134
4a.0	TOTAL PERIOD 4a COST	286	27,483	26,207	3,307	3,363	25,055	44,625	33,653	163,980	161,395	-	2,585	41,316	30,622	125	673	3,746	5,020,282	205,570	535,167
PERIOD 4b - Site Decontamination																					
Period 4b Direct Decommissioning Activities																					
4b.1.1	Remove spent fuel racks	297	32	94	32	-	595	-	319	1,369	1,369	-	-	-	2,092	-	-	-	138,298	576	-
Disposal of Plant Systems																					
4b.1.2.1	ADT & Misc Ventilation	-	21	0	1	13	3	-	8	47	47	-	-	153	9	-	-	-	6,814	325	-
4b.1.2.2	Aux Bldg Normal Ventilation	-	60	2	5	60	11	-	28	165	165	-	-	692	39	-	-	-	30,671	906	-
4b.1.2.3	Aux Bldg Special Ventilation	-	12	0	0	6	2	-	4	25	25	-	-	70	6	-	-	-	3,243	176	-
4b.1.2.4	Battery Rm Special Ventilation	-	1	-	-	-	-	-	0	2	-	-	2	-	-	-	-	-	-	24	-
4b.1.2.5	Boron Recycle	-	3	0	0	0	3	-	2	8	8	-	-	3	9	-	-	-	709	45	-
4b.1.2.6	Chemical & Volume Control	-	822	59	44	204	560	-	388	2,075	2,075	-	-	2,356	1,977	-	-	-	225,854	11,575	-
4b.1.2.7	Cold Chemical Lab Ventilation	-	1	-	-	-	-	-	0	1	-	-	1	-	-	-	-	-	-	9	-

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Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Disposal of Plant Systems (continued)																					
4b.1.2.8	Component Cooling - RCA	-	617	21	70	1,038	-	-	322	2,068	2,068	-	-	11,996	-	-	-	-	487,169	8,583	-
4b.1.2.9	Containment Cooling	-	31	-	-	-	-	-	5	35	-	-	35	-	-	-	-	-	-	502	-
4b.1.2.10	Containment Cooling - RCA	-	288	5	16	237	-	-	110	656	656	-	-	2,743	-	-	-	-	111,390	3,949	-
4b.1.2.11	Containment Hydrogen Control - RCA	-	35	0	1	12	-	-	11	60	60	-	-	141	-	-	-	-	5,742	494	-
4b.1.2.12	Containment Spray - RCA	-	186	3	8	126	-	-	67	389	389	-	-	1,453	-	-	-	-	59,019	2,617	-
4b.1.2.13	Containment Ventilation	-	201	23	38	408	205	-	171	1,047	1,047	-	-	4,721	722	-	-	-	239,450	3,016	-
4b.1.2.14	Control/Relay/Cmptr Rm Vent	-	27	1	2	23	6	-	12	70	70	-	-	260	20	-	-	-	11,915	406	-
4b.1.2.15	Cooling Water	-	139	-	-	-	-	-	21	160	-	-	160	-	-	-	-	-	-	2,344	-
4b.1.2.16	Cooling Water - RCA	-	456	15	49	730	-	-	232	1,482	1,482	-	-	8,442	-	-	-	-	342,822	6,311	-
4b.1.2.17	Cranes/Hoists/Elevators - RCA	-	3	0	1	9	-	-	2	15	15	-	-	103	-	-	-	-	4,184	48	-
4b.1.2.18	D3 Emergency Diesel	-	9	-	-	-	-	-	1	10	-	-	10	-	-	-	-	-	-	141	-
4b.1.2.19	D4 Emergency Diesel	-	9	-	-	-	-	-	1	10	-	-	10	-	-	-	-	-	-	141	-
4b.1.2.20	D5 Emergency Diesel	-	0	-	-	-	-	-	0	0	-	-	0	-	-	-	-	-	-	5	-
4b.1.2.21	Electrical - Clean	-	1,502	-	-	-	-	-	225	1,727	-	-	1,727	-	-	-	-	-	-	24,276	-
4b.1.2.22	Electrical - Contaminated	-	417	5	13	173	21	-	138	767	767	-	-	1,997	75	-	-	-	86,080	5,813	-
4b.1.2.23	Electrical - Contaminated - Fuel Pool	-	178	2	6	75	9	-	59	329	329	-	-	864	33	-	-	-	37,250	2,488	-
4b.1.2.24	Electrical - Decontaminated	-	2,866	33	109	1,622	-	-	980	5,610	5,610	-	-	18,753	-	-	-	-	761,569	38,423	-
4b.1.2.25	Electrical - Decontaminated - Fuel Pool	-	1,230	14	47	698	-	-	421	2,410	2,410	-	-	8,069	-	-	-	-	327,668	16,495	-
4b.1.2.26	Filter Rm Ventilation	-	4	0	0	2	0	-	1	8	8	-	-	24	1	-	-	-	1,020	61	-
4b.1.2.27	Fire Protection & Detection	-	178	-	-	-	-	-	27	205	-	-	205	-	-	-	-	-	-	3,009	-
4b.1.2.28	Fire Protection & Detection - RCA	-	236	3	11	158	-	-	85	492	492	-	-	1,828	-	-	-	-	74,245	3,134	-
4b.1.2.29	Fire Protection & Detection - RCA Fuel P	-	36	1	2	25	-	-	13	76	76	-	-	286	-	-	-	-	11,622	476	-
4b.1.2.30	Fuel Handling	-	64	1	2	17	14	-	22	121	121	-	-	200	49	-	-	-	11,396	983	-
4b.1.2.31	Fuel Oil	-	1	-	-	-	-	-	0	1	-	-	1	-	-	-	-	-	-	9	-
4b.1.2.32	HVAC - Clean	-	132	-	-	-	-	-	20	151	-	-	151	-	-	-	-	-	-	2,373	-
4b.1.2.33	HVAC - Contaminated	-	1,102	26	69	929	115	-	457	2,699	2,699	-	-	10,745	405	-	-	-	463,144	14,282	-
4b.1.2.34	HVAC - Contaminated - Fuel Pool	-	495	12	31	418	52	-	205	1,212	1,212	-	-	4,828	182	-	-	-	208,080	6,417	-
4b.1.2.35	Heating	-	279	-	-	-	-	-	42	321	-	-	321	-	-	-	-	-	-	4,804	-
4b.1.2.36	Heating - RCA	-	323	3	11	165	-	-	107	609	609	-	-	1,907	-	-	-	-	77,458	4,086	-
4b.1.2.37	Hot Lab & Sample Rm Ventilation	-	17	0	1	9	1	-	6	34	34	-	-	107	4	-	-	-	4,632	255	-
4b.1.2.38	Incore Instrumentation	-	26	1	1	5	16	-	12	62	62	-	-	60	58	-	-	-	6,264	412	-
4b.1.2.39	Misc Drains & Vents	-	203	12	9	40	121	-	90	475	475	-	-	458	426	-	-	-	46,850	2,841	-
4b.1.2.40	Misc Lab & Service Areas Vent	-	113	8	6	32	70	-	52	280	280	-	-	370	244	-	-	-	31,186	1,537	-
4b.1.2.41	Miscellaneous Gas	-	63	-	-	-	-	-	9	72	-	-	72	-	-	-	-	-	-	1,073	-
4b.1.2.42	Miscellaneous Gas - RCA	-	129	1	3	52	-	-	41	226	226	-	-	600	-	-	-	-	24,378	1,636	-
4b.1.2.43	Radiation Monitoring	-	6	-	-	-	-	-	1	7	-	-	7	-	-	-	-	-	-	111	-
4b.1.2.44	Radiation Monitoring - RCA	-	62	1	2	27	-	-	20	112	112	-	-	316	-	-	-	-	12,826	782	-
4b.1.2.45	Reactor Coolant	-	207	20	12	20	208	-	110	577	577	-	-	229	730	-	-	-	57,672	2,891	-
4b.1.2.46	Reactor Hot Sampling	-	112	10	5	5	89	-	53	273	273	-	-	54	312	-	-	-	22,919	1,499	-
4b.1.2.47	Reactor Makeup	-	36	-	-	-	-	-	5	41	-	-	41	-	-	-	-	-	-	583	-
4b.1.2.48	Reactor Makeup - RCA	-	4	0	0	2	-	-	1	8	8	-	-	28	-	-	-	-	1,148	47	-
4b.1.2.49	Reactor Vessel	-	16	0	0	2	4	-	5	28	28	-	-	22	14	-	-	-	1,826	225	-
4b.1.2.50	Residual Heat Removal	-	338	84	66	247	924	-	371	2,029	2,029	-	-	2,853	3,244	-	-	-	330,651	5,039	-
4b.1.2.51	Safeguards Chilled Water	-	4	-	-	-	-	-	1	5	-	-	5	-	-	-	-	-	-	75	-
4b.1.2.52	Safeguards Chilled Water - RCA	-	4	0	0	2	-	-	1	8	8	-	-	26	-	-	-	-	1,045	51	-
4b.1.2.53	Safety Injection	-	758	40	56	577	329	-	371	2,131	2,131	-	-	6,676	1,161	-	-	-	347,600	11,029	-
4b.1.2.54	Sampling	-	46	3	2	3	27	-	19	100	100	-	-	37	93	-	-	-	7,697	645	-
4b.1.2.55	Service Bldg & New Cmptr Vent	-	0	-	-	-	-	-	0	0	-	-	0	-	-	-	-	-	-	6	-
4b.1.2.56	Shield Bldg Ventilation	-	103	13	19	175	138	-	91	539	539	-	-	2,028	484	-	-	-	114,378	1,555	-
4b.1.2.57	Spent Fuel Pool Cooling	-	32	3	2	3	30	-	17	87	87	-	-	39	107	-	-	-	8,635	427	-
4b.1.2.58	Spent Fuel Pool Normal Ventilation	-	23	1	2	23	3	-	10	62	62	-	-	265	12	-	-	-	11,532	352	-
4b.1.2.59	Station & Instrument Air	-	140	-	-	-	-	-	21	161	-	-	161	-	-	-	-	-	-	2,424	-
4b.1.2.60	Station & Instrument Air - RCA	-	288	3	9	141	-	-	95	535	535	-	-	1,625	-	-	-	-	65,986	3,638	-
4b.1.2.61	Turbine Bldg Traps & Drains	-	26	-	-	-	-	-	4	30	-	-	30	-	-	-	-	-	-	462	-
4b.1.2.62	Turbine Bldg Traps & Drains - RCA	-	28	0	1	16	-	-	10	55	55	-	-	180	-	-	-	-	7,321	344	-
4b.1.2.63	Turbine Bldg Ventilation	-	40	-	-	-	-	-	6	46	-	-	46	-	-	-	-	-	-	655	-
4b.1.2.64	Unit Coolers	-	20	-	-	-	-	-	3	23	-	-	23	-	-	-	-	-	-	332	-
4b.1.2.65	Unit Coolers - RCA	-	54	0	1	20	-	-	17	93	93	-	-	232	-	-	-	-	9,413	690	-
4b.1.2.66	Waste Gas Disposal	-	417	40	35	212	381	-	241	1,327	1,327	-	-	2,453	1,358	-	-	-	188,334	5,879	-
4b.1.2.67	Waste Liquid Disposal	-	1,581	108	76	316	1,019	-	720	3,819	3,819	-	-	3,655	3,594	-	-	-	385,370	22,011	-
4b.1.2.68	Waste Solid Disposal	-	127	11	8	34	112	-	67	358	358	-	-	389	393	-	-	-	41,732	1,781	-
4b.1.2	Totals	-	16,987	591	852	9,112	4,472	-	6,657	38,670	35,660	-	3,010	105,339	15,761	-	-	-	5,317,908	240,033	-
4b.1.3	Scaffolding in support of decommissioning	-	4,024	36	12	146	38	-	1,043	5,298	5,298	-	-	1,518	134	-	-	-	77,168	35,578	-

Xcel Energy

Table H-2
Prairie Island Nuclear Generating Plant, Unit 2
SAFSTOR Decommissioning Cost Estimate with DOE Pickup of Industry Spent Fuel Starting in 2025
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Decontamination of Site Buildings																					
4b.1.4.1	Reactor	1,037	2,361	118	833	193	6,373	-	2,868	13,784	13,784	-	-	2,230	36,903	-	-	-	3,286,751	45,596	-
4b.1.4.2	Auxiliary	1,105	356	12	80	92	582	-	814	3,040	3,040	-	-	1,060	3,355	-	-	-	332,498	21,222	-
4b.1.4.3	Backwash Waste Receiving Tank	-	24	1	11	-	87	-	30	154	154	-	-	-	507	-	-	-	43,896	264	-
4b.1.4.4	Drum Transfer & Truck Loading Enclosure	15	7	0	2	2	13	-	13	52	52	-	-	19	74	-	-	-	7,118	328	-
4b.1.4.5	LLRW Storage Enclosure	105	45	1	11	3	87	-	88	341	341	-	-	38	502	-	-	-	44,971	2,149	-
4b.1.4.6	Radwaste	47	20	1	5	4	39	-	40	155	155	-	-	42	225	-	-	-	21,136	963	-
4b.1.4.7	Resin Disposal	14	10	0	2	7	12	-	14	60	60	-	-	83	69	-	-	-	9,271	340	-
4b.1.4.8	Fuel Handling of Aux Building	875	966	9	32	209	173	-	759	3,024	3,024	-	-	2,417	944	-	-	-	177,818	27,141	-
4b.1.4	Totals	3,199	3,791	143	977	509	7,366	-	4,626	20,611	20,611	-	-	5,889	42,580	-	-	-	3,923,460	98,004	-
4b.1.5	Prepare/submit License Termination Plan	-	-	-	-	-	-	206	31	236	236	-	-	-	-	-	-	-	-	-	1,751
4b.1.6	Receive NRC approval of termination plan									a											
4b.1	Subtotal Period 4b Activity Costs	3,496	24,833	864	1,872	9,767	12,471	206	12,675	66,184	63,174	-	3,010	112,746	60,568	-	-	-	9,456,834	374,192	1,751
Period 4b Additional Costs																					
4b.2.1	License Termination Survey Planning	-	-	-	-	-	-	845	253	1,098	1,098	-	-	-	-	-	-	-	-	-	6,240
4b.2.2	Remedial Action Surveys	-	-	-	-	-	-	2,832	849	3,681	3,681	-	-	-	-	-	-	-	-	37,017	-
4b.2.3	Excavation of Underground Services	-	811	-	-	-	-	520	200	1,531	-	-	1,531	-	-	-	-	-	-	7,407	-
4b.2.4	Operational Equipment	-	-	9	29	312	-	-	52	402	402	-	-	5,855	-	-	-	-	146,375	16	-
4b.2.5	License Termination ISFSI	-	37	2	211	-	2,157	1,158	891	4,456	4,456	-	-	-	7,458	-	-	-	1,071,985	3,403	5,284
4b.2.6	Demolition and Site Restoration ISFSI	-	399	-	-	-	-	87	73	558	-	-	558	-	-	-	-	-	-	1,900	160
4b.2	Subtotal Period 4b Additional Costs	-	1,246	11	240	312	2,157	5,441	2,319	11,726	9,637	-	2,089	5,855	7,458	-	-	-	1,218,360	49,742	11,684
Period 4b Collateral Costs																					
4b.3.1	Process decommissioning water waste	7	-	11	29	-	46	-	20	113	113	-	-	-	109	-	-	-	6,546	21	-
4b.3.3	Small tool allowance	-	417	-	-	-	-	-	63	480	480	-	-	-	-	-	-	-	-	-	-
4b.3.4	Decommissioning Equipment Disposition	-	-	144	55	575	150	-	147	1,071	1,071	-	-	6,000	529	-	-	-	304,968	88	-
4b.3.5	On-site survey and release of 0.437 tons clean metallic waste	-	-	-	-	-	-	1	0	1	1	-	-	-	-	-	-	-	-	-	-
4b.3	Subtotal Period 4b Collateral Costs	7	417	155	84	575	196	1	229	1,664	1,664	-	-	6,000	638	-	-	-	311,514	109	-
Period 4b Period-Dependent Costs																					
4b.4.1	Decon supplies	1,338	-	-	-	-	-	-	335	1,673	1,673	-	-	-	-	-	-	-	-	-	-
4b.4.2	Insurance	-	-	-	-	-	-	910	91	1,001	1,001	-	-	-	-	-	-	-	-	-	-
4b.4.3	Property taxes	-	-	-	-	-	-	2,554	255	2,809	2,809	-	-	-	-	-	-	-	-	-	-
4b.4.4	Health physics supplies	-	2,897	-	-	-	-	-	724	3,621	3,621	-	-	-	-	-	-	-	-	-	-
4b.4.5	Heavy equipment rental	-	4,021	-	-	-	-	-	603	4,624	4,624	-	-	-	-	-	-	-	-	-	-
4b.4.6	Disposal of DAW generated	-	-	128	37	-	476	-	137	778	778	-	-	-	5,849	-	-	-	116,984	191	-
4b.4.7	Plant energy budget	-	-	-	-	-	-	2,023	303	2,326	2,326	-	-	-	-	-	-	-	-	-	-
4b.4.8	NRC Fees	-	-	-	-	-	-	677	68	745	745	-	-	-	-	-	-	-	-	-	-
4b.4.9	Fixed Overhead	-	-	-	-	-	-	2,205	331	2,535	2,535	-	-	-	-	-	-	-	-	-	-
4b.4.10	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	721	108	829	829	-	-	-	-	-	-	-	-	-	-
4b.4.11	Railroad Track Maintenance	-	-	-	-	-	-	103	15	118	118	-	-	-	-	-	-	-	-	-	-
4b.4.12	Security Staff Cost	-	-	-	-	-	-	6,843	1,026	7,870	7,870	-	-	-	-	-	-	-	-	-	115,753
4b.4.13	DOC Staff Cost	-	-	-	-	-	-	21,571	3,236	24,806	24,806	-	-	-	-	-	-	-	-	-	248,175
4b.4.14	Utility Staff Cost	-	-	-	-	-	-	26,893	4,034	30,927	30,927	-	-	-	-	-	-	-	-	-	437,085
4b.4	Subtotal Period 4b Period-Dependent Costs	1,338	6,917	128	37	-	476	64,499	11,267	84,662	84,662	-	-	-	5,849	-	-	-	116,984	191	801,014
4b.0	TOTAL PERIOD 4b COST	4,841	33,414	1,158	2,234	10,654	15,300	70,147	26,490	164,237	159,138	-	5,099	124,601	74,513	-	-	-	11,103,690	424,234	814,449
PERIOD 4f - License Termination																					
Period 4f Direct Decommissioning Activities																					
4f.1.1	ORISE confirmatory survey	-	-	-	-	-	-	176	53	229	229	-	-	-	-	-	-	-	-	-	-
4f.1.2	Terminate license									a											
4f.1	Subtotal Period 4f Activity Costs	-	-	-	-	-	-	176	53	229	229	-	-	-	-	-	-	-	-	-	-
Period 4f Additional Costs																					
4f.2.1	License Termination Survey	-	-	-	-	-	-	7,406	2,222	9,628	9,628	-	-	-	-	-	-	-	-	102,642	3,120
4f.2	Subtotal Period 4f Additional Costs	-	-	-	-	-	-	7,406	2,222	9,628	9,628	-	-	-	-	-	-	-	-	102,642	3,120
Period 4f Collateral Costs																					
4f.3.1	DOC staff relocation expenses	-	-	-	-	-	-	1,189	178	1,367	1,367	-	-	-	-	-	-	-	-	-	-
4f.3	Subtotal Period 4f Collateral Costs	-	-	-	-	-	-	1,189	178	1,367	1,367	-	-	-	-	-	-	-	-	-	-

Table H-2
Prairie Island Nuclear Generating Plant, Unit 2
SAFSTOR Decommissioning Cost Estimate with DOE Pickup of Industry Spent Fuel Starting in 2025
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Period 4f Period-Dependent Costs																					
4f.4.1	Insurance	-	-	-	-	-	-	382	38	420	420	-	-	-	-	-	-	-	-	-	-
4f.4.2	Property taxes	-	-	-	-	-	-	1,002	100	1,102	1,102	-	-	-	-	-	-	-	-	-	-
4f.4.3	Health physics supplies	-	600	-	-	-	-	-	150	750	750	-	-	-	-	-	-	-	-	-	-
4f.4.4	Disposal of DAW generated	-	-	7	2	-	27	-	8	44	44	-	-	-	332	-	-	-	6,649	11	-
4f.4.5	Plant energy budget	-	-	-	-	-	-	227	34	261	261	-	-	-	-	-	-	-	-	-	-
4f.4.6	NRC Fees	-	-	-	-	-	-	272	27	299	299	-	-	-	-	-	-	-	-	-	-
4f.4.7	Fixed Overhead	-	-	-	-	-	-	926	139	1,065	1,065	-	-	-	-	-	-	-	-	-	-
4f.4.8	Railroad Track Maintenance	-	-	-	-	-	-	43	6	50	50	-	-	-	-	-	-	-	-	-	-
4f.4.9	Security Staff Cost	-	-	-	-	-	-	707	106	813	813	-	-	-	-	-	-	-	-	-	11,668
4f.4.10	DOC Staff Cost	-	-	-	-	-	-	4,101	615	4,716	4,716	-	-	-	-	-	-	-	-	-	46,283
4f.4.11	Utility Staff Cost	-	-	-	-	-	-	3,630	544	4,174	4,174	-	-	-	-	-	-	-	-	-	56,395
4f.4	Subtotal Period 4f Period-Dependent Costs	-	600	7	2	-	27	11,289	1,768	13,695	13,695	-	-	-	332	-	-	-	6,649	11	114,346
4f.0	TOTAL PERIOD 4f COST	-	600	7	2	-	27	20,061	4,222	24,919	24,919	-	-	-	332	-	-	-	6,649	102,652	117,466
PERIOD 4 TOTALS		5,126	61,497	27,372	5,543	14,017	40,383	134,832	64,365	353,136	345,452	-	7,684	165,917	105,467	125	673	3,746	16,130,620	732,456	1,467,082
PERIOD 5b - Site Restoration																					
Period 5b Direct Decommissioning Activities																					
Demolition of Remaining Site Buildings																					
5b.1.1.1	Reactor	-	4,256	-	-	-	-	-	638	4,895	-	-	4,895	-	-	-	-	-	-	44,679	-
5b.1.1.2	Auxiliary	-	1,897	-	-	-	-	-	285	2,182	-	-	2,182	-	-	-	-	-	-	11,902	-
5b.1.1.3	Condensate Storage Tank Foundation	-	6	-	-	-	-	-	1	7	-	-	7	-	-	-	-	-	-	33	-
5b.1.1.4	Construction Warehouse & Fab Shop	-	118	-	-	-	-	-	18	135	-	-	135	-	-	-	-	-	-	1,405	-
5b.1.1.5	D3/D4 Emergency Generator	-	13	-	-	-	-	-	2	15	-	-	15	-	-	-	-	-	-	84	-
5b.1.1.6	Drum Transfer & Truck Loading Enclosure	-	19	-	-	-	-	-	3	21	-	-	21	-	-	-	-	-	-	221	-
5b.1.1.7	Hydrogen House	-	6	-	-	-	-	-	1	7	-	-	7	-	-	-	-	-	-	47	-
5b.1.1.8	LLRW Storage Enclosure	-	121	-	-	-	-	-	18	139	-	-	139	-	-	-	-	-	-	853	-
5b.1.1.9	Misc Structures 2017	-	1,391	-	-	-	-	-	209	1,599	-	-	1,599	-	-	-	-	-	-	12,939	-
5b.1.1.10	Radwaste	-	165	-	-	-	-	-	25	190	-	-	190	-	-	-	-	-	-	1,400	-
5b.1.1.11	Resin Disposal	-	13	-	-	-	-	-	2	15	-	-	15	-	-	-	-	-	-	120	-
5b.1.1.12	Structures below 3' below grade	-	1,713	-	-	-	-	-	257	1,969	-	-	1,969	-	-	-	-	-	-	9,238	-
5b.1.1.13	Sulfuric Acid Tank Enclosure	-	3	-	-	-	-	-	0	3	-	-	3	-	-	-	-	-	-	35	-
5b.1.1.14	Turbine	-	1,983	-	-	-	-	-	298	2,281	-	-	2,281	-	-	-	-	-	-	22,052	-
5b.1.1.15	Turbine Pedestal	-	349	-	-	-	-	-	52	402	-	-	402	-	-	-	-	-	-	1,857	-
5b.1.1.16	Warehouse #2	-	22	-	-	-	-	-	3	25	-	-	25	-	-	-	-	-	-	213	-
5b.1.1.17	Waste Neutralizing Tank House	-	7	-	-	-	-	-	1	8	-	-	8	-	-	-	-	-	-	56	-
5b.1.1.18	Waste Oil Storage	-	8	-	-	-	-	-	1	10	-	-	10	-	-	-	-	-	-	70	-
5b.1.1.19	Water Treatment	-	303	-	-	-	-	-	46	349	-	-	349	-	-	-	-	-	-	2,690	-
5b.1.1.20	Fuel Handling of Aux Building	-	1,032	-	-	-	-	-	155	1,186	-	-	1,186	-	-	-	-	-	-	8,240	-
5b.1.1	Totals	-	13,424	-	-	-	-	-	2,014	15,438	-	-	15,438	-	-	-	-	-	-	118,134	-
Site Closeout Activities																					
5b.1.2	Remove Rubble	-	1,492	-	-	-	-	-	224	1,716	-	-	1,716	-	-	-	-	-	-	7,408	-
5b.1.3	Grade & landscape site	-	431	-	-	-	-	-	65	495	-	-	495	-	-	-	-	-	-	921	-
5b.1.4	Final report to NRC	-	-	-	-	-	-	78	12	90	90	-	-	-	-	-	-	-	-	-	667
5b.1	Subtotal Period 5b Activity Costs	-	15,347	-	-	-	-	78	2,314	17,740	90	-	17,650	-	-	-	-	-	-	126,463	667
Period 5b Additional Costs																					
5b.2.1	Clean Concrete Disposal	-	3,313	-	-	-	-	8	498	3,818	-	-	3,818	-	-	-	-	-	-	12,824	-
5b.2.2	Intake Structure Cofferdam	-	423	-	-	-	-	-	63	486	-	-	486	-	-	-	-	-	-	3,552	-
5b.2.3	Construction Debris	-	-	-	-	-	-	463	69	532	-	-	532	-	-	-	-	-	-	-	-
5b.2.4	Backfill	-	8,465	-	-	-	-	-	1,270	9,735	-	-	9,735	-	-	-	-	-	-	9,327	-
5b.2	Subtotal Period 5b Additional Costs	-	12,201	-	-	-	-	471	1,901	14,572	-	-	14,572	-	-	-	-	-	-	25,703	-
Period 5b Collateral Costs																					
5b.3.1	Small tool allowance	-	169	-	-	-	-	-	25	194	-	-	194	-	-	-	-	-	-	-	-
5b.3	Subtotal Period 5b Collateral Costs	-	169	-	-	-	-	-	25	194	-	-	194	-	-	-	-	-	-	-	-
Period 5b Period-Dependent Costs																					
5b.4.2	Property taxes	-	-	-	-	-	-	526	53	579	-	-	579	-	-	-	-	-	-	-	-
5b.4.3	Heavy equipment rental	-	6,670	-	-	-	-	-	1,000	7,670	-	-	7,670	-	-	-	-	-	-	-	-
5b.4.4	Plant energy budget	-	-	-	-	-	-	321	48	369	-	-	369	-	-	-	-	-	-	-	-
5b.4.5	Fixed Overhead	-	-	-	-	-	-	990	148	1,138	-	-	1,138	-	-	-	-	-	-	-	-
5b.4.6	Railroad Track Maintenance	-	-	-	-	-	-	122	18	141	-	-	141	-	-	-	-	-	-	-	-

Table H-2
Prairie Island Nuclear Generating Plant, Unit 2
SAFSTOR Decommissioning Cost Estimate with DOE Pickup of Industry Spent Fuel Starting in 2025
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 5b Period-Dependent Costs (continued)																					
5b.4.7	Security Staff Cost	-	-	-	-	-	-	1,812	272	2,084	-	-	2,084	-	-	-	-	-	-	-	29,221
5b.4.8	DOC Staff Cost	-	-	-	-	-	-	10,467	1,570	12,038	-	-	12,038	-	-	-	-	-	-	-	116,885
5b.4.9	Utility Staff Cost	-	-	-	-	-	-	3,673	551	4,224	-	-	4,224	-	-	-	-	-	-	-	57,340
5b.4	Subtotal Period 5b Period-Dependent Costs	-	6,670	-	-	-	-	17,912	3,661	28,242	-	-	28,242	-	-	-	-	-	-	-	203,445
5b.0	TOTAL PERIOD 5b COST	-	34,387	-	-	-	-	18,461	7,901	60,748	90	-	60,658	-	-	-	-	-	-	152,166	204,112
PERIOD 5 TOTALS		-	34,387	-	-	-	-	18,461	7,901	60,748	90	-	60,658	-	-	-	-	-	-	152,166	204,112
TOTAL COST TO DECOMMISSION		**11,879**	**108,769**	**27,994**	**6,103**	**14,186**	**42,876**	**774,398**	**157,417**	**1,143,621**	**841,160**	**233,483**	**68,978**	**172,241**	**127,188**	**125**	**673**	**3,746**	**16,886,860**	**980,098**	**4,996,280**

TOTAL COST TO DECOMMISSION WITH 15.96% CONTINGENCY:	**$1,143,621**	**thousands of 2017 dollars**
TOTAL NRC LICENSE TERMINATION COST IS 73.55% OR:	**$841,160**	**thousands of 2017 dollars**
SPENT FUEL MANAGEMENT COST IS 20.42% OR:	**$233,483**	**thousands of 2017 dollars**
NON-NUCLEAR DEMOLITION COST IS 6.03% OR:	**$68,978**	**thousands of 2017 dollars**
TOTAL LOW-LEVEL RADIOACTIVE WASTE VOLUME BURIED (EXCLUDING GTCC):	**127,986**	**cubic feet**
TOTAL GREATER THAN CLASS C RADWASTE VOLUME GENERATED:	**3,746**	**cubic feet**
TOTAL SCRAP METAL REMOVED:	**41,593**	**tons**
TOTAL CRAFT LABOR REQUIREMENTS:	**980,098**	**man-hours**

End Notes:
n/a - indicates that this activity not charged as decommissioning expense
a - indicates that this activity performed by decommissioning staff
0 - indicates that this value is less than 0.5 but is non-zero
A cell containing " - " indicates a zero value

APPENDIX I

DETAILED COST ANALYSIS

SCENARIO 7: SAFSTOR with 60 Year DFS

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Prairie Island Nuclear Generating Plant, Unit 1 ..... I-2

Prairie Island Nuclear Generating Plant, Unit 2 ..... I-11

Table I-1
Prairie Island Nuclear Generating Plant, Unit 1
SAFSTOR Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
PERIOD 1a - Shutdown through Transition																					
Period 1a Direct Decommissioning Activities																					
1a.1.1	SAFSTOR site characterization survey	-	-	-	-	-	-	571	171	742	742	-	-	-	-	-	-	-	-	-	-
1a.1.2	Prepare preliminary decommissioning cost	-	-	-	-	-	-	153	23	175	175	-	-	-	-	-	-	-	-	-	1,300
1a.1.3	Notification of Cessation of Operations									a											
1a.1.4	Remove fuel & source material									n/a											
1a.1.5	Notification of Permanent Defueling									a											
1a.1.6	Deactivate plant systems & process waste									a											
1a.1.7	Prepare and submit PSDAR	-	-	-	-	-	-	235	35	270	270	-	-	-	-	-	-	-	-	-	2,000
1a.1.8	Review plant dwgs & specs.	-	-	-	-	-	-	153	23	175	175	-	-	-	-	-	-	-	-	-	1,300
1a.1.9	Perform detailed rad survey									a											
1a.1.10	Estimate by-product inventory	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1a.1.11	End product description	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1a.1.12	Detailed by-product inventory	-	-	-	-	-	-	176	26	202	202	-	-	-	-	-	-	-	-	-	1,500
1a.1.13	Define major work sequence	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
1a.1.14	Perform SER and EA	-	-	-	-	-	-	364	55	418	418	-	-	-	-	-	-	-	-	-	3,100
1a.1.15	Prepare/submit Defueled Technical Specifications	-	-	-	-	-	-	880	132	1,012	1,012	-	-	-	-	-	-	-	-	-	7,500
1a.1.16	Perform Site-Specific Cost Study	-	-	-	-	-	-	587	88	675	675	-	-	-	-	-	-	-	-	-	5,000
1a.1.17	Prepare/submit Irradiated Fuel Management Plan	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
Activity Specifications																					
1a.1.18.1	Prepare plant and facilities for SAFSTOR	-	-	-	-	-	-	578	87	664	664	-	-	-	-	-	-	-	-	-	4,920
1a.1.18.2	Plant systems	-	-	-	-	-	-	489	73	562	562	-	-	-	-	-	-	-	-	-	4,167
1a.1.18.3	Plant structures and buildings	-	-	-	-	-	-	366	55	421	421	-	-	-	-	-	-	-	-	-	3,120
1a.1.18.4	Waste management	-	-	-	-	-	-	235	35	270	270	-	-	-	-	-	-	-	-	-	2,000
1a.1.18.5	Facility and site dormancy	-	-	-	-	-	-	235	35	270	270	-	-	-	-	-	-	-	-	-	2,000
1a.1.18	Total	-	-	-	-	-	-	1,902	285	2,188	2,188	-	-	-	-	-	-	-	-	-	16,207
Detailed Work Procedures																					
1a.1.19.1	Plant systems	-	-	-	-	-	-	139	21	160	160	-	-	-	-	-	-	-	-	-	1,183
1a.1.19.2	Facility closeout & dormancy	-	-	-	-	-	-	141	21	162	162	-	-	-	-	-	-	-	-	-	1,200
1a.1.19	Total	-	-	-	-	-	-	280	42	322	322	-	-	-	-	-	-	-	-	-	2,383
1a.1.20	Procure vacuum drying system	-	-	-	-	-	-	12	2	13	13	-	-	-	-	-	-	-	-	-	100
1a.1.21	Drain/de-energize non-cont. systems									a											
1a.1.22	Drain & dry NSSS									a											
1a.1.23	Drain/de-energize contaminated systems									a											
1a.1.24	Decon/secure contaminated systems									a											
1a.1	Subtotal Period 1a Activity Costs	-	-	-	-	-	-	5,781	953	6,734	6,734	-	-	-	-	-	-	-	-	-	44,390
Period 1a Collateral Costs																					
1a.3.1	Prairie Island Indian Community Payments	-	-	-	-	-	-	2,003	-	2,003	-	2,003	-	-	-	-	-	-	-	-	-
1a.3	Subtotal Period 1a Collateral Costs	-	-	-	-	-	-	2,003	-	2,003	-	2,003	-	-	-	-	-	-	-	-	-
Period 1a Period-Dependent Costs																					
1a.4.1	Insurance	-	-	-	-	-	-	1,730	173	1,903	1,903	-	-	-	-	-	-	-	-	-	-
1a.4.2	Property taxes	-	-	-	-	-	-	2,682	268	2,950	2,950	-	-	-	-	-	-	-	-	-	-
1a.4.3	Health physics supplies	-	515	-	-	-	-	-	129	644	644	-	-	-	-	-	-	-	-	-	-
1a.4.4	Heavy equipment rental	-	567	-	-	-	-	-	85	652	652	-	-	-	-	-	-	-	-	-	-
1a.4.5	Disposal of DAW generated	-	-	13	4	-	50	-	14	81	81	-	-	-	610	-	-	-	12,190	20	-
1a.4.6	Plant energy budget	-	-	-	-	-	-	1,515	227	1,742	1,742	-	-	-	-	-	-	-	-	-	-
1a.4.7	NRC Fees	-	-	-	-	-	-	1,110	111	1,221	1,221	-	-	-	-	-	-	-	-	-	-
1a.4.8	Emergency Planning Fees	-	-	-	-	-	-	1,604	160	1,765	-	1,765	-	-	-	-	-	-	-	-	-
1a.4.9	Fixed Overhead	-	-	-	-	-	-	1,470	220	1,690	1,690	-	-	-	-	-	-	-	-	-	-
1a.4.10	Spent Fuel Pool O&M	-	-	-	-	-	-	401	60	461	-	461	-	-	-	-	-	-	-	-	-
1a.4.11	ISFSI Operating Costs	-	-	-	-	-	-	52	8	59	-	59	-	-	-	-	-	-	-	-	-
1a.4.12	Railroad Track Maintenance	-	-	-	-	-	-	58	9	66	66	-	-	-	-	-	-	-	-	-	-
1a.4.13	Security Staff Cost	-	-	-	-	-	-	7,390	1,108	8,498	8,498	-	-	-	-	-	-	-	-	-	122,720
1a.4.14	Utility Staff Cost	-	-	-	-	-	-	25,791	3,869	29,660	29,660	-	-	-	-	-	-	-	-	-	422,240
1a.4	Subtotal Period 1a Period-Dependent Costs	-	1,083	13	4	-	50	43,802	6,442	51,394	49,108	2,286	-	-	610	-	-	-	12,190	20	544,960
1a.0	TOTAL PERIOD 1a COST	-	1,083	13	4	-	50	51,587	7,395	60,131	55,842	4,289	-	-	610	-	-	-	12,190	20	589,350

Table I-1
Prairie Island Nuclear Generating Plant, Unit 1
SAFSTOR Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
PERIOD 1b - SAFSTOR Limited DECON Activities																					
Period 1b Direct Decommissioning Activities																					
Decontamination of Site Buildings																					
1b.1.1.1	Reactor	1,135	-	-	-	-	-	-	568	1,703	1,703	-	-	-	-	-	-	-	-	17,003	-
1b.1.1	Totals	1,135	-	-	-	-	-	-	568	1,703	1,703	-	-	-	-	-	-	-	-	17,003	-
1b.1	Subtotal Period 1b Activity Costs	1,135	-	-	-	-	-	-	568	1,703	1,703	-	-	-	-	-	-	-	-	17,003	-
Period 1b Additional Costs																					
1b.2.1	Spent fuel pool isolation	-	-	-	-	-	-	11,691	1,754	13,445	13,445	-	-	-	-	-	-	-	-	-	-
1b.2	Subtotal Period 1b Additional Costs	-	-	-	-	-	-	11,691	1,754	13,445	13,445	-	-	-	-	-	-	-	-	-	-
Period 1b Collateral Costs																					
1b.3.1	Decon equipment	973	-	-	-	-	-	-	146	1,119	1,119	-	-	-	-	-	-	-	-	-	-
1b.3.2	Process decommissioning water waste	77	-	50	130	-	204	-	114	575	575	-	-	-	486	-	-	-	29,184	95	-
1b.3.4	Small tool allowance	-	19	-	-	-	-	-	3	22	22	-	-	-	-	-	-	-	-	-	-
1b.3.5	Prairie Island Indian Community Payments	-	-	-	-	-	-	315	-	315	-	315	-	-	-	-	-	-	-	-	-
1b.3	Subtotal Period 1b Collateral Costs	1,050	19	50	130	-	204	315	263	2,031	1,716	315	-	-	486	-	-	-	29,184	95	-
Period 1b Period-Dependent Costs																					
1b.4.1	Decon supplies	415	-	-	-	-	-	-	104	518	518	-	-	-	-	-	-	-	-	-	-
1b.4.2	Insurance	-	-	-	-	-	-	436	44	480	480	-	-	-	-	-	-	-	-	-	-
1b.4.3	Property taxes	-	-	-	-	-	-	676	68	744	744	-	-	-	-	-	-	-	-	-	-
1b.4.4	Health physics supplies	-	212	-	-	-	-	-	53	264	264	-	-	-	-	-	-	-	-	-	-
1b.4.5	Heavy equipment rental	-	143	-	-	-	-	-	21	164	164	-	-	-	-	-	-	-	-	-	-
1b.4.6	Disposal of DAW generated	-	-	7	2	-	27	-	8	43	43	-	-	-	326	-	-	-	6,519	11	-
1b.4.7	Plant energy budget	-	-	-	-	-	-	382	57	439	439	-	-	-	-	-	-	-	-	-	-
1b.4.8	NRC Fees	-	-	-	-	-	-	161	16	178	178	-	-	-	-	-	-	-	-	-	-
1b.4.9	Emergency Planning Fees	-	-	-	-	-	-	404	40	445	-	445	-	-	-	-	-	-	-	-	-
1b.4.10	Fixed Overhead	-	-	-	-	-	-	370	56	426	426	-	-	-	-	-	-	-	-	-	-
1b.4.11	Spent Fuel Pool O&M	-	-	-	-	-	-	101	15	116	-	116	-	-	-	-	-	-	-	-	-
1b.4.12	ISFSI Operating Costs	-	-	-	-	-	-	13	2	15	-	15	-	-	-	-	-	-	-	-	-
1b.4.13	Railroad Track Maintenance	-	-	-	-	-	-	15	2	17	17	-	-	-	-	-	-	-	-	-	-
1b.4.14	Security Staff Cost	-	-	-	-	-	-	1,863	279	2,142	2,142	-	-	-	-	-	-	-	-	-	30,932
1b.4.15	Utility Staff Cost	-	-	-	-	-	-	6,501	975	7,476	7,476	-	-	-	-	-	-	-	-	-	106,428
1b.4	Subtotal Period 1b Period-Dependent Costs	415	355	7	2	-	27	10,922	1,740	13,467	12,891	576	-	-	326	-	-	-	6,519	11	137,360
1b.0	TOTAL PERIOD 1b COST	2,600	373	57	132	-	230	22,929	4,324	30,645	29,754	891	-	-	812	-	-	-	35,703	17,108	137,360
PERIOD 1c - Preparations for SAFSTOR Dormancy																					
Period 1c Direct Decommissioning Activities																					
1c.1.1	Prepare support equipment for storage	-	486	-	-	-	-	-	73	559	559	-	-	-	-	-	-	-	-	3,000	-
1c.1.2	Install containment pressure equal. lines	-	48	-	-	-	-	-	7	55	55	-	-	-	-	-	-	-	-	700	-
1c.1.3	Interim survey prior to dormancy	-	-	-	-	-	-	733	220	953	953	-	-	-	-	-	-	-	-	9,017	-
1c.1.4	Secure building accesses									a											
1c.1.5	Prepare & submit interim report	-	-	-	-	-	-	68	10	79	79	-	-	-	-	-	-	-	-	-	583
1c.1	Subtotal Period 1c Activity Costs	-	534	-	-	-	-	801	310	1,646	1,646	-	-	-	-	-	-	-	-	12,717	583
Period 1c Collateral Costs																					
1c.3.1	Process decommissioning water waste	88	-	58	150	-	234	-	131	661	661	-	-	-	560	-	-	-	33,579	109	-
1c.3.3	Small tool allowance	-	4	-	-	-	-	-	1	5	5	-	-	-	-	-	-	-	-	-	-
1c.3.4	Spent Fuel Capital and Transfer	-	-	-	-	-	-	159	24	183	-	183	-	-	-	-	-	-	-	-	-
1c.3.5	Retention and Severance	-	-	-	-	-	-	1,088	163	1,251	1,251	-	-	-	-	-	-	-	-	-	-
1c.3.6	Prairie Island Indian Community Payments	-	-	-	-	-	-	315	-	315	-	315	-	-	-	-	-	-	-	-	-
1c.3	Subtotal Period 1c Collateral Costs	88	4	58	150	-	234	1,562	319	2,415	1,917	498	-	-	560	-	-	-	33,579	109	-
Period 1c Period-Dependent Costs																					
1c.4.1	Insurance	-	-	-	-	-	-	436	44	480	480	-	-	-	-	-	-	-	-	-	-
1c.4.2	Property taxes	-	-	-	-	-	-	676	68	744	744	-	-	-	-	-	-	-	-	-	-
1c.4.3	Health physics supplies	-	191	-	-	-	-	-	48	239	239	-	-	-	-	-	-	-	-	-	-
1c.4.4	Heavy equipment rental	-	143	-	-	-	-	-	21	164	164	-	-	-	-	-	-	-	-	-	-
1c.4.5	Disposal of DAW generated	-	-	3	1	-	13	-	4	20	20	-	-	-	154	-	-	-	3,073	5	-
1c.4.6	Plant energy budget	-	-	-	-	-	-	382	57	439	439	-	-	-	-	-	-	-	-	-	-

Xcel Energy

Table I-1
Prairie Island Nuclear Generating Plant, Unit 1
SAFSTOR Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 1c Period-Dependent Costs (continued)																					
1c.4.7	NRC Fees	-	-	-	-	-	-	161	16	178	178	-	-	-	-	-	-	-	-	-	-
1c.4.8	Emergency Planning Fees	-	-	-	-	-	-	404	40	445	-	445	-	-	-	-	-	-	-	-	-
1c.4.9	Fixed Overhead	-	-	-	-	-	-	370	56	426	426	-	-	-	-	-	-	-	-	-	-
1c.4.10	Spent Fuel Pool O&M	-	-	-	-	-	-	101	15	116	-	116	-	-	-	-	-	-	-	-	-
1c.4.11	ISFSI Operating Costs	-	-	-	-	-	-	13	2	15	-	15	-	-	-	-	-	-	-	-	-
1c.4.12	Railroad Track Maintenance	-	-	-	-	-	-	15	2	17	17	-	-	-	-	-	-	-	-	-	-
1c.4.13	Security Staff Cost	-	-	-	-	-	-	1,863	279	2,142	2,142	-	-	-	-	-	-	-	-	-	30,932
1c.4.14	Utility Staff Cost	-	-	-	-	-	-	6,501	975	7,476	7,476	-	-	-	-	-	-	-	-	-	106,428
1c.4	Subtotal Period 1c Period-Dependent Costs	-	334	3	1	-	13	10,922	1,627	12,900	12,324	576	-	-	154	-	-	-	3,073	5	137,360
1c.0	TOTAL PERIOD 1c COST	88	873	61	151	-	247	13,285	2,256	16,961	15,887	1,074	-	-	713	-	-	-	36,652	12,832	137,943
PERIOD 1 TOTALS		2,688	2,329	132	287	-	527	87,801	13,975	107,738	101,484	6,254	-	-	2,135	-	-	-	84,545	29,960	864,653
PERIOD 2a - SAFSTOR Dormancy with Wet Spent Fuel Storage																					
Period 2a Direct Decommissioning Activities																					
2a.1.1	Quarterly Inspection									a											
2a.1.2	Semi-annual environmental survey									a											
2a.1.3	Prepare reports									a											
2a.1.4	Bituminous roof replacement	-	-	-	-	-	-	68	10	78	78	-	-	-	-	-	-	-	-	-	-
2a.1.5	Maintenance supplies	-	-	-	-	-	-	643	161	804	804	-	-	-	-	-	-	-	-	-	-
2a.1	Subtotal Period 2a Activity Costs	-	-	-	-	-	-	711	171	882	882	-	-	-	-	-	-	-	-	-	-
Period 2a Additional Costs																					
2a.2.1	Security Modifications	-	-	-	-	-	-	4,348	652	5,000	5,000	-	-	-	-	-	-	-	-	-	-
2a.2	Subtotal Period 2a Additional Costs	-	-	-	-	-	-	4,348	652	5,000	5,000	-	-	-	-	-	-	-	-	-	-
Period 2a Collateral Costs																					
2a.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	73,811	11,072	84,883	-	84,883	-	-	-	-	-	-	-	-	-
2a.3.2	Retention and Severance	-	-	-	-	-	-	23,628	3,544	27,172	27,172	-	-	-	-	-	-	-	-	-	-
2a.3.3	Prairie Island Indian Community Payments	-	-	-	-	-	-	5,897	-	5,897	-	5,897	-	-	-	-	-	-	-	-	-
2a.3	Subtotal Period 2a Collateral Costs	-	-	-	-	-	-	103,336	14,616	117,952	27,172	90,780	-	-	-	-	-	-	-	-	-
Period 2a Period-Dependent Costs																					
2a.4.1	Insurance	-	-	-	-	-	-	2,412	241	2,653	2,653	-	-	-	-	-	-	-	-	-	-
2a.4.2	Property taxes	-	-	-	-	-	-	12,654	1,265	13,919	13,919	-	-	-	-	-	-	-	-	-	-
2a.4.3	Health physics supplies	-	898	-	-	-	-	-	224	1,122	1,122	-	-	-	-	-	-	-	-	-	-
2a.4.4	Disposal of DAW generated	-	-	21	6	-	79	-	23	129	129	-	-	-	972	-	-	-	19,431	32	-
2a.4.5	Plant energy budget	-	-	-	-	-	-	1,430	214	1,644	1,644	-	-	-	-	-	-	-	-	-	-
2a.4.6	NRC Fees	-	-	-	-	-	-	1,211	121	1,332	1,332	-	-	-	-	-	-	-	-	-	-
2a.4.7	Emergency Planning Fees	-	-	-	-	-	-	6,061	606	6,667	-	6,667	-	-	-	-	-	-	-	-	-
2a.4.8	Fixed Overhead	-	-	-	-	-	-	6,938	1,041	7,979	7,979	-	-	-	-	-	-	-	-	-	-
2a.4.9	Spent Fuel Pool O&M	-	-	-	-	-	-	1,894	284	2,178	-	2,178	-	-	-	-	-	-	-	-	-
2a.4.10	ISFSI Operating Costs	-	-	-	-	-	-	244	37	280	-	280	-	-	-	-	-	-	-	-	-
2a.4.11	Railroad Track Maintenance	-	-	-	-	-	-	481	72	553	553	-	-	-	-	-	-	-	-	-	-
2a.4.12	Security Staff Cost	-	-	-	-	-	-	32,791	4,919	37,709	26,849	10,860	-	-	-	-	-	-	-	-	542,920
2a.4.13	Utility Staff Cost	-	-	-	-	-	-	11,657	1,748	13,405	9,531	3,874	-	-	-	-	-	-	-	-	190,075
2a.4	Subtotal Period 2a Period-Dependent Costs	-	898	21	6	-	79	77,772	10,796	89,573	65,713	23,860	-	-	972	-	-	-	19,431	32	732,995
2a.0	TOTAL PERIOD 2a COST	-	898	21	6	-	79	186,168	26,235	213,407	98,767	114,640	-	-	972	-	-	-	19,431	32	732,995
PERIOD 2b - SAFSTOR Dormancy with Dry Spent Fuel Storage																					
Period 2b Direct Decommissioning Activities																					
2b.1.1	Quarterly Inspection									a											
2b.1.2	Semi-annual environmental survey									a											
2b.1.3	Prepare reports									a											
2b.1.4	Bituminous roof replacement	-	-	-	-	-	-	549	82	631	631	-	-	-	-	-	-	-	-	-	-
2b.1.5	Maintenance supplies	-	-	-	-	-	-	5,206	1,301	6,507	6,507	-	-	-	-	-	-	-	-	-	-
2b.1	Subtotal Period 2b Activity Costs	-	-	-	-	-	-	5,754	1,384	7,138	7,138	-	-	-	-	-	-	-	-	-	-
Period 2b Collateral Costs																					
2b.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	29,940	4,491	34,431	-	34,431	-	-	-	-	-	-	-	-	-
2b.3.2	Prairie Island Indian Community Payments	-	-	-	-	-	-	47,719	-	47,719	-	47,719	-	-	-	-	-	-	-	-	-
2b.3	Subtotal Period 2b Collateral Costs	-	-	-	-	-	-	77,660	4,491	82,151	-	82,151	-	-	-	-	-	-	-	-	-

Xcel Energy

Table I-1
Prairie Island Nuclear Generating Plant, Unit 1
SAFSTOR Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 2b Period-Dependent Costs																					
2b.4.1	Insurance	-	-	-	-	-	-	19,520	1,952	21,472	21,472	-	-	-	-	-	-	-	-	-	-
2b.4.2	Property taxes	-	-	-	-	-	-	102,394	10,239	112,633	112,633	-	-	-	-	-	-	-	-	-	-
2b.4.3	Health physics supplies	-	3,643	-	-	-	-	-	911	4,554	4,554	-	-	-	-	-	-	-	-	-	-
2b.4.4	Disposal of DAW generated	-	-	86	25	-	321	-	93	525	525	-	-	-	3,946	-	-	-	78,923	129	-
2b.4.5	Plant energy budget	-	-	-	-	-	-	5,786	868	6,654	6,654	-	-	-	-	-	-	-	-	-	-
2b.4.6	NRC Fees	-	-	-	-	-	-	9,312	931	10,244	10,244	-	-	-	-	-	-	-	-	-	-
2b.4.7	Emergency Planning Fees	-	-	-	-	-	-	2,612	261	2,873	-	2,873	-	-	-	-	-	-	-	-	-
2b.4.8	Fixed Overhead	-	-	-	-	-	-	5,829	874	6,703	6,703	-	-	-	-	-	-	-	-	-	-
2b.4.9	ISFSI Operating Costs	-	-	-	-	-	-	1,972	296	2,268	-	2,268	-	-	-	-	-	-	-	-	-
2b.4.10	Railroad Track Maintenance	-	-	-	-	-	-	2,203	330	2,534	2,534	-	-	-	-	-	-	-	-	-	-
2b.4.11	Security Staff Cost	-	-	-	-	-	-	96,335	14,450	110,786	22,822	87,964	-	-	-	-	-	-	-	-	1,430,311
2b.4.12	Utility Staff Cost	-	-	-	-	-	-	50,003	7,500	57,503	35,767	21,736	-	-	-	-	-	-	-	-	794,617
2b.4	Subtotal Period 2b Period-Dependent Costs	-	3,643	86	25	-	321	295,966	38,707	338,748	223,907	114,842	-	-	3,946	-	-	-	78,923	129	2,224,928
2b.0	TOTAL PERIOD 2b COST	-	3,643	86	25	-	321	379,380	44,581	428,037	231,045	196,992	-	-	3,946	-	-	-	78,923	129	2,224,928
PERIOD 2c - SAFSTOR Dormancy without Spent Fuel Storage																					
Period 2c Direct Decommissioning Activities																					
2c.1.1	Quarterly Inspection									a											
2c.1.2	Semi-annual environmental survey									a											
2c.1.3	Prepare reports									a											
2c.1.4	Bituminous roof replacement	-	-	-	-	-	-	141	21	162	162	-	-	-	-	-	-	-	-	-	-
2c.1.5	Maintenance supplies	-	-	-	-	-	-	1,337	334	1,671	1,671	-	-	-	-	-	-	-	-	-	-
2c.1	Subtotal Period 2c Activity Costs	-	-	-	-	-	-	1,478	355	1,833	1,833	-	-	-	-	-	-	-	-	-	-
Period 2c Period-Dependent Costs																					
2c.4.1	Insurance	-	-	-	-	-	-	4,919	492	5,411	5,411	-	-	-	-	-	-	-	-	-	-
2c.4.2	Property taxes	-	-	-	-	-	-	17,059	1,706	18,764	18,764	-	-	-	-	-	-	-	-	-	-
2c.4.3	Health physics supplies	-	925	-	-	-	-	-	231	1,157	1,157	-	-	-	-	-	-	-	-	-	-
2c.4.4	Disposal of DAW generated	-	-	22	6	-	81	-	23	133	133	-	-	-	999	-	-	-	19,973	33	-
2c.4.5	Plant energy budget	-	-	-	-	-	-	1,486	223	1,709	1,709	-	-	-	-	-	-	-	-	-	-
2c.4.6	NRC Fees	-	-	-	-	-	-	2,182	218	2,400	2,400	-	-	-	-	-	-	-	-	-	-
2c.4.7	Fixed Overhead	-	-	-	-	-	-	1,497	225	1,721	1,721	-	-	-	-	-	-	-	-	-	-
2c.4.8	Railroad Track Maintenance	-	-	-	-	-	-	566	85	651	651	-	-	-	-	-	-	-	-	-	-
2c.4.9	Security Staff Cost	-	-	-	-	-	-	21,142	3,171	24,313	24,313	-	-	-	-	-	-	-	-	-	306,102
2c.4.10	Utility Staff Cost	-	-	-	-	-	-	10,901	1,635	12,536	12,536	-	-	-	-	-	-	-	-	-	178,560
2c.4	Subtotal Period 2c Period-Dependent Costs	-	925	22	6	-	81	59,751	8,009	68,795	68,795	-	-	-	999	-	-	-	19,973	33	484,661
2c.0	TOTAL PERIOD 2c COST	-	925	22	6	-	81	61,229	8,365	70,628	70,628	-	-	-	999	-	-	-	19,973	33	484,661
PERIOD 2 TOTALS		-	5,466	129	38	-	482	626,776	79,181	712,072	400,440	311,632	-	-	5,916	-	-	-	118,328	193	3,442,584
PERIOD 3a - Reactivate Site Following SAFSTOR Dormancy																					
Period 3a Direct Decommissioning Activities																					
3a.1.1	Prepare preliminary decommissioning cost	-	-	-	-	-	-	153	23	175	175	-	-	-	-	-	-	-	-	-	1,300
3a.1.2	Review plant dwgs & specs.	-	-	-	-	-	-	540	81	621	621	-	-	-	-	-	-	-	-	-	4,600
3a.1.3	Perform detailed rad survey									a											
3a.1.4	End product description	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
3a.1.5	Detailed by-product inventory	-	-	-	-	-	-	153	23	175	175	-	-	-	-	-	-	-	-	-	1,300
3a.1.6	Define major work sequence	-	-	-	-	-	-	880	132	1,012	1,012	-	-	-	-	-	-	-	-	-	7,500
3a.1.7	Perform SER and EA	-	-	-	-	-	-	364	55	418	418	-	-	-	-	-	-	-	-	-	3,100
3a.1.8	Perform Site-Specific Cost Study	-	-	-	-	-	-	587	88	675	675	-	-	-	-	-	-	-	-	-	5,000
Activity Specifications																					
3a.1.9.1	Re-activate plant & temporary facilities	-	-	-	-	-	-	865	130	995	895	-	99	-	-	-	-	-	-	-	7,370
3a.1.9.2	Plant systems	-	-	-	-	-	-	489	73	562	506	-	56	-	-	-	-	-	-	-	4,167
3a.1.9.3	Reactor internals	-	-	-	-	-	-	833	125	958	958	-	-	-	-	-	-	-	-	-	7,100
3a.1.9.4	Reactor vessel	-	-	-	-	-	-	763	114	877	877	-	-	-	-	-	-	-	-	-	6,500
3a.1.9.5	Biological shield	-	-	-	-	-	-	59	9	67	67	-	-	-	-	-	-	-	-	-	500
3a.1.9.6	Steam generators	-	-	-	-	-	-	366	55	421	421	-	-	-	-	-	-	-	-	-	3,120
3a.1.9.7	Reinforced concrete	-	-	-	-	-	-	188	28	216	108	-	108	-	-	-	-	-	-	-	1,600
3a.1.9.8	Main Turbine	-	-	-	-	-	-	47	7	54	-	-	54	-	-	-	-	-	-	-	400
3a.1.9.9	Main Condensers	-	-	-	-	-	-	47	7	54	-	-	54	-	-	-	-	-	-	-	400
3a.1.9.10	Plant structures & buildings	-	-	-	-	-	-	366	55	421	211	-	211	-	-	-	-	-	-	-	3,120
3a.1.9.11	Waste management	-	-	-	-	-	-	540	81	621	621	-	-	-	-	-	-	-	-	-	4,600

Table I-1
Prairie Island Nuclear Generating Plant, Unit 1
SAFSTOR Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Activity Specifications (continued)																					
3a.1.9.12	Facility & site closeout	-	-	-	-	-	-	106	16	121	61	-	61	-	-	-	-	-	-	-	900
3a.1.9	Total	-	-	-	-	-	-	4,669	700	5,369	4,726	-	643	-	-	-	-	-	-	-	39,777
Planning & Site Preparations																					
3a.1.10	Prepare dismantling sequence	-	-	-	-	-	-	282	42	324	324	-	-	-	-	-	-	-	-	-	2,400
3a.1.11	Plant prep. & temp. svces	-	-	-	-	-	-	3,300	495	3,795	3,795	-	-	-	-	-	-	-	-	-	-
3a.1.12	Design water clean-up system	-	-	-	-	-	-	164	25	189	189	-	-	-	-	-	-	-	-	-	1,400
3a.1.13	Rigging/Cont. Cntrl Envlps/tooling/etc.	-	-	-	-	-	-	2,300	345	2,645	2,645	-	-	-	-	-	-	-	-	-	-
3a.1.14	Procure casks/liners & containers	-	-	-	-	-	-	144	22	166	166	-	-	-	-	-	-	-	-	-	1,230
3a.1	Subtotal Period 3a Activity Costs	-	-	-	-	-	-	13,653	2,048	15,701	15,058	-	643	-	-	-	-	-	-	-	68,607
Period 3a Additional Costs																					
3a.2.1	Site Characterization	-	-	-	-	-	-	3,700	1,110	4,810	4,810	-	-	-	-	-	-	-	-	21,020	8,332
3a.2.2	Mixed/Hazardous Waste	-	-	318	75	164	-	-	68	624	624	-	-	6,133	-	-	-	-	351,986	2,361	-
3a.2.3	Asbestos Abatement	-	2,364	2	110	-	1,359	-	947	4,782	4,782	-	-	-	12,843	-	-	-	166,959	20,907	-
3a.2	Subtotal Period 3a Additional Costs	-	2,364	320	185	164	1,359	3,700	2,125	10,216	10,216	-	-	6,133	12,843	-	-	-	518,945	44,288	8,332
Period 3a Collateral Costs																					
3a.3.1	Small tool allowance	-	32	-	-	-	-	-	5	37	37	-	-	-	-	-	-	-	-	-	-
3a.3	Subtotal Period 3a Collateral Costs	-	32	-	-	-	-	-	5	37	37	-	-	-	-	-	-	-	-	-	-
Period 3a Period-Dependent Costs																					
3a.4.1	Insurance	-	-	-	-	-	-	501	50	552	552	-	-	-	-	-	-	-	-	-	-
3a.4.2	Property taxes	-	-	-	-	-	-	1,736	174	1,909	1,909	-	-	-	-	-	-	-	-	-	-
3a.4.3	Health physics supplies	-	562	-	-	-	-	-	140	702	702	-	-	-	-	-	-	-	-	-	-
3a.4.4	Heavy equipment rental	-	567	-	-	-	-	-	85	652	652	-	-	-	-	-	-	-	-	-	-
3a.4.5	Disposal of DAW generated	-	-	11	3	-	42	-	12	68	68	-	-	-	514	-	-	-	10,287	17	-
3a.4.6	Plant energy budget	-	-	-	-	-	-	1,515	227	1,742	1,742	-	-	-	-	-	-	-	-	-	-
3a.4.7	NRC Fees	-	-	-	-	-	-	341	34	376	376	-	-	-	-	-	-	-	-	-	-
3a.4.8	Fixed Overhead	-	-	-	-	-	-	1,470	220	1,690	1,690	-	-	-	-	-	-	-	-	-	-
3a.4.9	Railroad Track Maintenance	-	-	-	-	-	-	58	9	66	66	-	-	-	-	-	-	-	-	-	-
3a.4.10	Security Staff Cost	-	-	-	-	-	-	3,843	576	4,419	4,419	-	-	-	-	-	-	-	-	-	65,000
3a.4.11	Utility Staff Cost	-	-	-	-	-	-	15,819	2,373	18,191	18,191	-	-	-	-	-	-	-	-	-	257,920
3a.4	Subtotal Period 3a Period-Dependent Costs	-	1,129	11	3	-	42	25,282	3,901	30,368	30,368	-	-	-	514	-	-	-	10,287	17	322,920
3a.0	TOTAL PERIOD 3a COST	-	3,524	331	188	164	1,401	42,635	8,078	56,321	55,678	-	643	6,133	13,357	-	-	-	529,232	44,305	399,859
PERIOD 3b - Decommissioning Preparations																					
Period 3b Direct Decommissioning Activities																					
Detailed Work Procedures																					
3b.1.1.1	Plant systems	-	-	-	-	-	-	556	83	639	575	-	64	-	-	-	-	-	-	-	4,733
3b.1.1.2	Reactor internals	-	-	-	-	-	-	293	44	337	337	-	-	-	-	-	-	-	-	-	2,500
3b.1.1.3	Remaining buildings	-	-	-	-	-	-	158	24	182	46	-	137	-	-	-	-	-	-	-	1,350
3b.1.1.4	CRD cooling assembly	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
3b.1.1.5	CRD housings & ICI tubes	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
3b.1.1.6	Incore instrumentation	-	-	-	-	-	-	117	18	135	135	-	-	-	-	-	-	-	-	-	1,000
3b.1.1.7	Reactor vessel	-	-	-	-	-	-	426	64	490	490	-	-	-	-	-	-	-	-	-	3,630
3b.1.1.8	Facility closeout	-	-	-	-	-	-	141	21	162	81	-	81	-	-	-	-	-	-	-	1,200
3b.1.1.9	Missile shields	-	-	-	-	-	-	53	8	61	61	-	-	-	-	-	-	-	-	-	450
3b.1.1.10	Biological shield	-	-	-	-	-	-	141	21	162	162	-	-	-	-	-	-	-	-	-	1,200
3b.1.1.11	Steam generators	-	-	-	-	-	-	540	81	621	621	-	-	-	-	-	-	-	-	-	4,600
3b.1.1.12	Reinforced concrete	-	-	-	-	-	-	117	18	135	67	-	67	-	-	-	-	-	-	-	1,000
3b.1.1.13	Main Turbine	-	-	-	-	-	-	183	27	211	-	-	211	-	-	-	-	-	-	-	1,560
3b.1.1.14	Main Condensers	-	-	-	-	-	-	183	27	211	-	-	211	-	-	-	-	-	-	-	1,560
3b.1.1.15	Auxiliary building	-	-	-	-	-	-	320	48	369	332	-	37	-	-	-	-	-	-	-	2,730
3b.1.1.16	Reactor building	-	-	-	-	-	-	320	48	369	332	-	37	-	-	-	-	-	-	-	2,730
3b.1.1	Total	-	-	-	-	-	-	3,785	568	4,352	3,508	-	844	-	-	-	-	-	-	-	32,243
3b.1	Subtotal Period 3b Activity Costs	-	-	-	-	-	-	3,785	568	4,352	3,508	-	844	-	-	-	-	-	-	-	32,243
Period 3b Collateral Costs																					
3b.3.1	Decon equipment	973	-	-	-	-	-	-	146	1,119	1,119	-	-	-	-	-	-	-	-	-	-
3b.3.2	DOC staff relocation expenses	-	-	-	-	-	-	1,189	178	1,367	1,367	-	-	-	-	-	-	-	-	-	-
3b.3.3	Pipe cutting equipment	-	1,200	-	-	-	-	-	180	1,380	1,380	-	-	-	-	-	-	-	-	-	-
3b.3	Subtotal Period 3b Collateral Costs	973	1,200	-	-	-	-	1,189	504	3,866	3,866	-	-	-	-	-	-	-	-	-	-

Table I-1
Prairie Island Nuclear Generating Plant, Unit 1
SAFSTOR Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 3b Period-Dependent Costs																					
3b.4.1	Decon supplies	35	-	-	-	-	-	-	9	43	43	-	-	-	-	-	-	-	-	-	-
3b.4.2	Insurance	-	-	-	-	-	-	255	25	280	280	-	-	-	-	-	-	-	-	-	-
3b.4.3	Property taxes	-	-	-	-	-	-	804	80	884	884	-	-	-	-	-	-	-	-	-	-
3b.4.4	Health physics supplies	-	248	-	-	-	-	-	62	309	309	-	-	-	-	-	-	-	-	-	-
3b.4.5	Heavy equipment rental	-	283	-	-	-	-	-	42	325	325	-	-	-	-	-	-	-	-	-	-
3b.4.6	Disposal of DAW generated	-	-	6	2	-	24	-	7	39	39	-	-	-	290	-	-	-	5,802	9	-
3b.4.7	Plant energy budget	-	-	-	-	-	-	755	113	869	869	-	-	-	-	-	-	-	-	-	-
3b.4.8	NRC Fees	-	-	-	-	-	-	170	17	187	187	-	-	-	-	-	-	-	-	-	-
3b.4.9	Fixed Overhead	-	-	-	-	-	-	733	110	843	843	-	-	-	-	-	-	-	-	-	-
3b.4.10	Railroad Track Maintenance	-	-	-	-	-	-	29	4	33	33	-	-	-	-	-	-	-	-	-	-
3b.4.11	Security Staff Cost	-	-	-	-	-	-	1,916	287	2,204	2,204	-	-	-	-	-	-	-	-	-	32,411
3b.4.12	DOC Staff Cost	-	-	-	-	-	-	5,123	769	5,892	5,892	-	-	-	-	-	-	-	-	-	58,080
3b.4.13	Utility Staff Cost	-	-	-	-	-	-	7,888	1,183	9,071	9,071	-	-	-	-	-	-	-	-	-	128,607
3b.4	Subtotal Period 3b Period-Dependent Costs	35	530	6	2	-	24	17,673	2,709	20,979	20,979	-	-	-	290	-	-	-	5,802	9	219,098
3b.0	TOTAL PERIOD 3b COST	1,008	1,730	6	2	-	24	22,646	3,781	29,197	28,353	-	844	-	290	-	-	-	5,802	9	251,341
PERIOD 3 TOTALS		1,008	5,254	338	190	164	1,425	65,281	11,860	85,519	84,032	-	1,487	6,133	13,647	-	-	-	535,034	44,314	651,200
PERIOD 4a - Large Component Removal																					
Period 4a Direct Decommissioning Activities																					
Nuclear Steam Supply System Removal																					
4a.1.1.1	Reactor Coolant Piping	11	40	6	5	34	75	-	41	212	212	-	-	144	152	-	-	-	33,380	771	-
4a.1.1.2	Pressurizer Relief Tank	5	18	4	3	23	50	-	24	126	126	-	-	96	101	-	-	-	22,241	347	-
4a.1.1.3	Reactor Coolant Pumps & Motors	13	56	43	76	-	736	-	220	1,143	1,143	-	-	-	2,332	-	-	-	295,800	1,226	80
4a.1.1.4	Pressurizer	10	68	359	82	-	693	-	244	1,456	1,456	-	-	-	2,196	-	-	-	158,199	1,499	750
4a.1.1.5	Steam Generators	47	2,943	1,576	1,614	1,246	3,467	-	2,212	13,104	13,104	-	-	18,672	10,990	-	-	-	1,560,086	10,964	2,250
4a.1.1.6	CRDMs/ICIs/Service Structure Removal	60	243	199	32	169	369	-	233	1,305	1,305	-	-	2,138	2,146	-	-	-	165,025	4,449	-
4a.1.1.7	Reactor Vessel Internals	61	4,189	21,537	971	-	7,954	239	12,812	47,763	47,763	-	-	-	757	-	742	-	166,435	19,373	933
4a.1.1.8	Vessel & Internals GTCC Disposal	-	-	-	-	-	8,689	-	1,303	9,992	9,992	-	-	-	-	-	-	3,746	837,596	-	-
4a.1.1.9	Reactor Vessel	-	5,439	1,328	198	-	1,804	239	5,398	14,406	14,406	-	-	-	5,719	-	-	-	569,974	19,373	933
4a.1.1	Totals	206	12,996	25,052	2,982	1,471	23,836	478	22,487	89,506	89,506	-	-	21,050	24,393	-	742	3,746	3,808,735	58,003	4,947
Removal of Major Equipment																					
4a.1.2	Main Turbine/Generator	-	269	128	27	287	-	-	127	838	838	-	-	2,243	-	-	-	-	134,601	4,116	-
4a.1.3	Main Condensers	-	2,269	87	26	383	-	-	637	3,403	3,403	-	-	4,000	-	-	-	-	180,000	34,978	-
Cascading Costs from Clean Building Demolition																					
4a.1.4.1	Reactor	-	728	-	-	-	-	-	109	837	837	-	-	-	-	-	-	-	-	7,589	-
4a.1.4	Totals	-	728	-	-	-	-	-	109	837	837	-	-	-	-	-	-	-	-	7,589	-
Disposal of Plant Systems																					
4a.1.5.1	Air Removal	-	27	-	-	-	-	-	4	31	-	-	31	-	-	-	-	-	-	452	-
4a.1.5.2	Auxiliary Feedwater	-	40	-	-	-	-	-	6	46	-	-	46	-	-	-	-	-	-	670	-
4a.1.5.3	Auxiliary Feedwater - RCA	-	45	0	1	19	-	-	14	79	79	-	-	215	-	-	-	-	8,722	601	-
4a.1.5.4	Bleed Steam	-	78	-	-	-	-	-	12	90	-	-	90	-	-	-	-	-	-	1,335	-
4a.1.5.5	Caustic Addition - RCA	-	36	0	1	20	-	-	12	71	71	-	-	233	-	-	-	-	9,453	444	-
4a.1.5.6	Chemical Feed	-	17	-	-	-	-	-	3	20	-	-	20	-	-	-	-	-	-	304	-
4a.1.5.7	Chemical Feed - RCA	-	1	0	0	1	-	-	0	2	2	-	-	6	-	-	-	-	243	12	-
4a.1.5.8	Circulating Water	-	37	-	-	-	-	-	6	42	-	-	42	-	-	-	-	-	-	619	-
4a.1.5.9	Condensate	-	414	-	-	-	-	-	62	476	-	-	476	-	-	-	-	-	-	6,837	-
4a.1.5.10	Condensate Polishing	-	205	-	-	-	-	-	31	236	-	-	236	-	-	-	-	-	-	3,420	-
4a.1.5.11	Condensate Polishing - RCA	-	176	4	12	180	-	-	73	444	444	-	-	2,078	-	-	-	-	84,395	2,329	-
4a.1.5.12	Electro-hydraulic	-	8	-	-	-	-	-	1	9	-	-	9	-	-	-	-	-	-	127	-
4a.1.5.13	Feedwater	-	133	-	-	-	-	-	20	153	-	-	153	-	-	-	-	-	-	2,215	-
4a.1.5.14	Feedwater - RCA	-	186	6	19	278	-	-	91	579	579	-	-	3,208	-	-	-	-	130,294	2,651	-
4a.1.5.15	Gland Seal	-	29	-	-	-	-	-	4	34	-	-	34	-	-	-	-	-	-	505	-
4a.1.5.16	Heater Drain	-	349	-	-	-	-	-	52	401	-	-	401	-	-	-	-	-	-	5,881	-
4a.1.5.17	Internal Circ Water & CDSR	-	23	-	-	-	-	-	3	27	-	-	27	-	-	-	-	-	-	389	-
4a.1.5.18	Main Gen/Exciter/Transformer	-	0	-	-	-	-	-	0	0	-	-	0	-	-	-	-	-	-	5	-
4a.1.5.19	Main Steam	-	101	-	-	-	-	-	15	116	-	-	116	-	-	-	-	-	-	1,690	-
4a.1.5.20	Main Steam - RCA	-	350	9	29	436	-	-	158	983	983	-	-	5,044	-	-	-	-	204,825	4,956	-
4a.1.5.21	Steam Generator Blowdown	-	416	21	22	176	195	-	185	1,014	1,014	-	-	2,031	686	-	-	-	127,773	5,974	-
4a.1.5.22	Steam Generators	-	5	-	-	-	-	-	1	5	-	-	5	-	-	-	-	-	-	75	-
4a.1.5.23	Turbine & Moisture Separators	-	337	-	-	-	-	-	51	388	-	-	388	-	-	-	-	-	-	5,609	-

Table I-1
Prairie Island Nuclear Generating Plant, Unit 1
SAFSTOR Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Burial Volumes Class B Cu. Feet	Burial Volumes Class C Cu. Feet	Burial Volumes GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Disposal of Plant Systems (continued)																					
4a.1.5.24	Turbine Oil Purification	-	61	-	-	-	-	-	9	71	-	-	71	-	-	-	-	-	-	1,003	-
4a.1.5	Totals	-	3,075	40	85	1,108	195	-	814	5,317	3,172	-	2,145	12,815	686	-	-	-	565,705	48,101	-
4a.1.6	Scaffolding in support of decommissioning	-	833	3	1	13	3	-	212	1,066	1,066	-	-	138	12	-	-	-	7,016	6,020	-
4a.1	Subtotal Period 4a Activity Costs	206	20,170	25,310	3,121	3,263	24,034	478	24,386	100,967	98,823	-	2,145	40,246	25,091	-	742	3,746	4,696,057	158,807	4,947
Period 4a Additional Costs																					
4a.2.1	Remedial Action Surveys	-	-	-	-	-	-	1,865	559	2,424	2,424	-	-	-	-	-	-	-	-	24,374	-
4a.2.2	Retired RPV upper internals package	1	659	785	107	-	1,439	-	1,437	4,427	4,427	-	-	-	2,097	125	-	-	205,890	2,175	87
4a.2	Subtotal Period 4a Additional Costs	1	659	785	107	-	1,439	1,865	1,996	6,851	6,851	-	-	-	2,097	125	-	-	205,890	26,549	87
Period 4a Collateral Costs																					
4a.3.1	Process decommissioning water waste	2	-	4	10	-	16	-	7	40	40	-	-	-	39	-	-	-	2,329	8	-
4a.3.3	Small tool allowance	-	195	-	-	-	-	-	29	224	201	-	22	-	-	-	-	-	-	-	-
4a.3	Subtotal Period 4a Collateral Costs	2	195	4	10	-	16	-	36	264	242	-	22	-	39	-	-	-	2,329	8	-
Period 4a Period-Dependent Costs																					
4a.4.1	Decon supplies	82	-	-	-	-	-	-	20	102	102	-	-	-	-	-	-	-	-	-	-
4a.4.2	Insurance	-	-	-	-	-	-	599	60	659	659	-	-	-	-	-	-	-	-	-	-
4a.4.3	Property taxes	-	-	-	-	-	-	1,782	178	1,960	1,960	-	-	-	-	-	-	-	-	-	-
4a.4.4	Health physics supplies	-	1,476	-	-	-	-	-	369	1,846	1,846	-	-	-	-	-	-	-	-	-	-
4a.4.5	Heavy equipment rental	-	2,575	-	-	-	-	-	386	2,961	2,961	-	-	-	-	-	-	-	-	-	-
4a.4.6	Disposal of DAW generated	-	-	61	18	-	228	-	66	373	373	-	-	-	2,802	-	-	-	56,048	91	-
4a.4.7	Plant energy budget	-	-	-	-	-	-	1,687	253	1,940	1,940	-	-	-	-	-	-	-	-	-	-
4a.4.8	NRC Fees	-	-	-	-	-	-	653	65	719	719	-	-	-	-	-	-	-	-	-	-
4a.4.9	Fixed Overhead	-	-	-	-	-	-	1,452	218	1,670	1,670	-	-	-	-	-	-	-	-	-	-
4a.4.10	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	475	71	546	546	-	-	-	-	-	-	-	-	-	-
4a.4.11	Railroad Track Maintenance	-	-	-	-	-	-	68	10	78	78	-	-	-	-	-	-	-	-	-	-
4a.4.12	Security Staff Cost	-	-	-	-	-	-	3,359	504	3,863	3,863	-	-	-	-	-	-	-	-	-	57,436
4a.4.13	DOC Staff Cost	-	-	-	-	-	-	14,349	2,152	16,501	16,501	-	-	-	-	-	-	-	-	-	166,833
4a.4.14	Utility Staff Cost	-	-	-	-	-	-	17,900	2,685	20,586	20,586	-	-	-	-	-	-	-	-	-	295,394
4a.4	Subtotal Period 4a Period-Dependent Costs	82	4,051	61	18	-	228	42,324	7,038	53,802	53,802	-	-	-	2,802	-	-	-	56,048	91	519,664
4a.0	TOTAL PERIOD 4a COST	290	25,075	26,160	3,256	3,263	25,717	44,667	33,457	161,884	159,717	-	2,167	40,246	30,029	125	742	3,746	4,960,324	185,455	524,697
PERIOD 4b - Site Decontamination																					
Period 4b Direct Decommissioning Activities																					
4b.1.1	Remove spent fuel racks	297	32	94	32	-	595	-	319	1,369	1,369	-	-	-	2,092	-	-	-	138,298	576	-
Disposal of Plant Systems																					
4b.1.2.1	Aux Bldg Normal Ventilation	-	2	0	0	0	-	-	0	3	3	-	-	3	-	-	-	-	140	26	-
4b.1.2.2	Battery Rm Special Ventilation	-	0	-	-	-	-	-	0	0	-	-	0	-	-	-	-	-	-	6	-
4b.1.2.3	Buildings Maintenance	-	4	-	-	-	-	-	1	5	-	-	5	-	-	-	-	-	-	65	-
4b.1.2.4	Chemical & Volume Control	-	1,210	83	69	389	802	-	580	3,134	3,134	-	-	4,498	2,846	-	-	-	369,246	17,235	-
4b.1.2.5	Component Cooling - RCA	-	821	22	72	1,075	-	-	379	2,369	2,369	-	-	12,427	-	-	-	-	504,675	11,242	-
4b.1.2.6	Containment Cooling	-	65	-	-	-	-	-	10	74	-	-	74	-	-	-	-	-	-	1,086	-
4b.1.2.7	Containment Cooling - RCA	-	290	6	20	294	-	-	120	730	730	-	-	3,400	-	-	-	-	138,090	3,971	-
4b.1.2.8	Containment Hydrogen Control - RCA	-	29	0	1	9	-	-	9	48	48	-	-	105	-	-	-	-	4,278	401	-
4b.1.2.9	Containment Spray - RCA	-	90	2	5	75	-	-	35	206	206	-	-	868	-	-	-	-	35,249	1,217	-
4b.1.2.10	Containment Ventilation	-	219	24	40	428	209	-	180	1,100	1,100	-	-	4,951	737	-	-	-	249,786	3,278	-
4b.1.2.11	Cooling Water	-	142	-	-	-	-	-	21	163	-	-	163	-	-	-	-	-	-	2,396	-
4b.1.2.12	Cooling Water - RCA	-	629	14	45	668	-	-	266	1,622	1,622	-	-	7,728	-	-	-	-	313,832	8,594	-
4b.1.2.13	D1 Emergency Diesel	-	44	-	-	-	-	-	7	50	-	-	50	-	-	-	-	-	-	730	-
4b.1.2.14	D2 Emergency Diesel	-	31	-	-	-	-	-	5	36	-	-	36	-	-	-	-	-	-	522	-
4b.1.2.15	Diesel Rooms Ventilation	-	8	-	-	-	-	-	1	10	-	-	10	-	-	-	-	-	-	135	-
4b.1.2.16	Electrical - Clean	-	1,669	-	-	-	-	-	250	1,919	-	-	1,919	-	-	-	-	-	-	26,981	-
4b.1.2.17	Electrical - Contaminated	-	536	6	16	219	27	-	177	980	980	-	-	2,527	95	-	-	-	108,935	7,488	-
4b.1.2.18	Electrical - Contaminated - Fuel Pool	-	133	2	4	53	7	-	44	242	242	-	-	615	23	-	-	-	26,508	1,857	-
4b.1.2.19	Electrical - Decontaminated	-	3,674	41	137	2,037	-	-	1,249	7,138	7,138	-	-	23,551	-	-	-	-	956,401	49,378	-
4b.1.2.20	Electrical - Decontaminated - Fuel Pool	-	918	10	34	510	-	-	312	1,785	1,785	-	-	5,893	-	-	-	-	239,327	12,340	-
4b.1.2.21	Fuel Handling	-	104	6	9	79	62	-	55	314	314	-	-	908	218	-	-	-	51,280	1,595	-
4b.1.2.22	Fuel Oil	-	106	-	-	-	-	-	16	122	-	-	122	-	-	-	-	-	-	1,697	-
4b.1.2.23	HVAC - Clean	-	105	-	-	-	-	-	16	121	-	-	121	-	-	-	-	-	-	1,891	-
4b.1.2.24	HVAC - Contaminated	-	335	8	21	282	35	-	139	819	819	-	-	3,261	123	-	-	-	140,573	4,335	-
4b.1.2.25	HVAC - Contaminated - Fuel Pool	-	143	3	9	121	15	-	59	351	351	-	-	1,398	53	-	-	-	60,246	1,858	-

Table I-1
Prairie Island Nuclear Generating Plant, Unit 1
SAFSTOR Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Disposal of Plant Systems (continued)																					
4b.1.2.26	Incore Instrumentation	-	24	1	1	5	16	-	11	59	59	-	-	60	57	-	-	-	6,177	382	-
4b.1.2.27	Misc Drains & Vents	-	203	14	10	34	146	-	95	503	503	-	-	390	514	-	-	-	49,900	2,764	-
4b.1.2.28	Reactor Coolant	-	271	21	14	30	221	-	132	689	689	-	-	344	777	-	-	-	65,413	3,865	-
4b.1.2.29	Reactor Hot Sampling	-	120	11	6	6	98	-	57	297	297	-	-	66	342	-	-	-	25,347	1,611	-
4b.1.2.30	Reactor Makeup	-	64	-	-	-	-	-	10	73	-	-	73	-	-	-	-	-	-	1,042	-
4b.1.2.31	Reactor Vessel	-	18	1	0	2	4	-	6	31	31	-	-	26	14	-	-	-	2,011	260	-
4b.1.2.32	Residual Heat Removal	-	360	85	66	250	926	-	377	2,065	2,065	-	-	2,895	3,252	-	-	-	332,849	5,374	-
4b.1.2.33	Safeguards Chilled Water	-	15	-	-	-	-	-	2	18	-	-	18	-	-	-	-	-	-	259	-
4b.1.2.34	Safeguards Chilled Water - RCA	-	82	1	3	43	-	-	27	155	155	-	-	495	-	-	-	-	20,100	1,019	-
4b.1.2.35	Safety Injection	-	774	40	57	587	327	-	376	2,161	2,161	-	-	6,788	1,156	-	-	-	351,793	11,276	-
4b.1.2.36	Sampling	-	53	4	2	5	31	-	22	116	116	-	-	59	107	-	-	-	9,505	731	-
4b.1.2.37	Shield Bldg Ventilation	-	120	14	20	186	139	-	97	576	576	-	-	2,152	491	-	-	-	119,838	1,811	-
4b.1.2.38	Spent Fuel Pool Cooling	-	311	34	25	70	377	-	190	1,006	1,006	-	-	806	1,325	-	-	-	120,439	4,400	-
4b.1.2.39	Station & Instrument Air	-	17	-	-	-	-	-	3	20	-	-	20	-	-	-	-	-	-	300	-
4b.1.2.40	Station & Instrument Air - RCA	-	79	1	2	29	-	-	24	135	135	-	-	332	-	-	-	-	13,496	1,053	-
4b.1.2.41	Station & Instrument Air - RCA Fuel Pool	-	20	0	0	7	-	-	6	34	34	-	-	83	-	-	-	-	3,374	263	-
4b.1.2.42	Turbine Bldg Traps & Drains	-	44	-	-	-	-	-	7	50	-	-	50	-	-	-	-	-	-	767	-
4b.1.2.43	Unit Coolers	-	37	-	-	-	-	-	6	42	-	-	42	-	-	-	-	-	-	611	-
4b.1.2.44	Unit Coolers - RCA	-	53	0	1	20	-	-	16	91	91	-	-	230	-	-	-	-	9,348	683	-
4b.1.2	Totals	-	13,970	453	689	7,514	3,443	-	5,394	31,463	28,759	-	2,704	86,861	12,129	-	-	-	4,328,159	198,796	-
4b.1.3	Scaffolding in support of decommissioning	-	1,250	5	2	20	5	-	317	1,599	1,599	-	-	207	18	-	-	-	10,524	9,030	-
Decontamination of Site Buildings																					
4b.1.4.1	Reactor	1,037	2,360	118	833	193	6,372	-	2,868	13,781	13,781	-	-	2,230	36,899	-	-	-	3,286,398	45,584	-
4b.1.4.2	Backwash Waste Receiving Tank	-	24	1	11	-	87	-	30	154	154	-	-	-	507	-	-	-	43,896	264	-
4b.1.4	Totals	1,037	2,385	119	845	193	6,460	-	2,897	13,936	13,936	-	-	2,230	37,406	-	-	-	3,330,294	45,848	-
4b.1.5	Prepare/submit License Termination Plan	-	-	-	-	-	-	481	72	553	553	-	-	-	-	-	-	-	-	-	4,096
4b.1.6	Receive NRC approval of termination plan									a											
4b.1	Subtotal Period 4b Activity Costs	1,334	17,637	671	1,567	7,726	10,503	481	9,000	48,919	46,215	-	2,704	89,298	51,645	-	-	-	7,807,274	254,251	4,096
Period 4b Additional Costs																					
4b.2.1	License Termination Survey Planning	-	-	-	-	-	-	845	253	1,098	1,098	-	-	-	-	-	-	-	-	-	6,240
4b.2.2	Remedial Action Surveys	-	-	-	-	-	-	2,832	849	3,681	3,681	-	-	-	-	-	-	-	-	37,017	-
4b.2.3	Excavation of Underground Services	-	811	-	-	-	-	520	200	1,531	-	-	1,531	-	-	-	-	-	-	7,407	-
4b.2.4	Operational Equipment	-	-	9	29	312	-	-	52	402	402	-	-	5,855	-	-	-	-	146,375	16	-
4b.2.5	License Termination ISFSI	-	37	2	211	-	2,157	1,186	898	4,491	4,491	-	-	-	7,458	-	-	-	1,071,985	3,670	5,284
4b.2.6	Demolition and Site Restoration ISFSI	-	495	-	-	-	-	87	87	669	-	-	669	-	-	-	-	-	-	2,308	160
4b.2	Subtotal Period 4b Additional Costs	-	1,342	11	240	312	2,157	5,469	2,340	11,872	9,672	-	2,200	5,855	7,458	-	-	-	1,218,360	50,417	11,684
Period 4b Collateral Costs																					
4b.3.1	Process decommissioning water waste	5	-	9	23	-	36	-	16	88	88	-	-	-	85	-	-	-	5,086	17	-
4b.3.3	Small tool allowance	-	288	-	-	-	-	-	43	331	331	-	-	-	-	-	-	-	-	-	-
4b.3.4	Decommissioning Equipment Disposition	-	-	144	55	575	150	-	147	1,071	1,071	-	-	6,000	529	-	-	-	304,968	88	-
4b.3	Subtotal Period 4b Collateral Costs	5	288	152	78	575	186	-	205	1,490	1,490	-	-	6,000	614	-	-	-	310,054	105	-
Period 4b Period-Dependent Costs																					
4b.4.1	Decon supplies	521	-	-	-	-	-	-	130	651	651	-	-	-	-	-	-	-	-	-	-
4b.4.2	Insurance	-	-	-	-	-	-	910	91	1,001	1,001	-	-	-	-	-	-	-	-	-	-
4b.4.3	Property taxes	-	-	-	-	-	-	2,610	261	2,872	2,872	-	-	-	-	-	-	-	-	-	-
4b.4.4	Health physics supplies	-	2,248	-	-	-	-	-	562	2,810	2,810	-	-	-	-	-	-	-	-	-	-
4b.4.5	Heavy equipment rental	-	4,021	-	-	-	-	-	603	4,624	4,624	-	-	-	-	-	-	-	-	-	-
4b.4.6	Disposal of DAW generated	-	-	85	25	-	318	-	92	520	520	-	-	-	3,905	-	-	-	78,097	127	-
4b.4.7	Plant energy budget	-	-	-	-	-	-	2,023	303	2,326	2,326	-	-	-	-	-	-	-	-	-	-
4b.4.8	NRC Fees	-	-	-	-	-	-	992	99	1,092	1,092	-	-	-	-	-	-	-	-	-	-
4b.4.9	Fixed Overhead	-	-	-	-	-	-	2,205	331	2,535	2,535	-	-	-	-	-	-	-	-	-	-
4b.4.10	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	721	108	829	829	-	-	-	-	-	-	-	-	-	-
4b.4.11	Railroad Track Maintenance	-	-	-	-	-	-	103	15	118	118	-	-	-	-	-	-	-	-	-	-
4b.4.12	Security Staff Cost	-	-	-	-	-	-	1,017	153	1,170	1,170	-	-	-	-	-	-	-	-	-	20,373
4b.4.13	DOC Staff Cost	-	-	-	-	-	-	14,220	2,133	16,353	16,353	-	-	-	-	-	-	-	-	-	174,093
4b.4.14	Utility Staff Cost	-	-	-	-	-	-	18,286	2,743	21,029	21,029	-	-	-	-	-	-	-	-	-	311,145
4b.4	Subtotal Period 4b Period-Dependent Costs	521	6,269	85	25	-	318	43,087	7,625	57,929	57,929	-	-	-	3,905	-	-	-	78,097	127	505,611
4b.0	TOTAL PERIOD 4b COST	1,860	25,537	919	1,910	8,613	13,164	49,037	19,170	120,210	115,306	-	4,904	101,153	63,622	-	-	-	9,413,785	304,901	521,391

Table I-1
Prairie Island Nuclear Generating Plant, Unit 1
SAFSTOR Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
PERIOD 4e - Delay before License Termination																					
Period 4e Period-Dependent Costs																					
4e.4.1	Insurance	-	-	-	-	-	-	308	31	339	339	-	-	-	-	-	-	-	-	-	-
4e.4.2	Property taxes	-	-	-	-	-	-	846	85	930	930	-	-	-	-	-	-	-	-	-	-
4e.4.3	Health physics supplies	-	56	-	-	-	-	-	14	70	70	-	-	-	-	-	-	-	-	-	-
4e.4.4	Disposal of DAW generated	-	-	1	0	-	5	-	1	8	8	-	-	-	60	-	-	-	1,202	2	-
4e.4.6	NRC Fees	-	-	-	-	-	-	134	13	147	147	-	-	-	-	-	-	-	-	-	-
4e.4.7	Fixed Overhead	-	-	-	-	-	-	746	112	858	858	-	-	-	-	-	-	-	-	-	-
4e.4.8	Railroad Track Maintenance	-	-	-	-	-	-	35	5	40	40	-	-	-	-	-	-	-	-	-	-
4e.4.9	Utility Staff Cost	-	-	-	-	-	-	536	80	616	616	-	-	-	-	-	-	-	-	-	8,776
4e.4	Subtotal Period 4e Period-Dependent Costs	-	56	1	0	-	5	2,604	342	3,009	3,009	-	-	-	60	-	-	-	1,202	2	8,776
4e.0	TOTAL PERIOD 4e COST	-	56	1	0	-	5	2,604	342	3,009	3,009	-	-	-	60	-	-	-	1,202	2	8,776
PERIOD 4f - License Termination																					
Period 4f Direct Decommissioning Activities																					
4f.1.1	ORISE confirmatory survey	-	-	-	-	-	-	176	53	229	229	-	-	-	-	-	-	-	-	-	-
4f.1.2	Terminate license									a											
4f.1	Subtotal Period 4f Activity Costs	-	-	-	-	-	-	176	53	229	229	-	-	-	-	-	-	-	-	-	-
Period 4f Additional Costs																					
4f.2.1	License Termination Survey	-	-	-	-	-	-	3,217	965	4,182	4,182	-	-	-	-	-	-	-	-	40,172	3,120
4f.2	Subtotal Period 4f Additional Costs	-	-	-	-	-	-	3,217	965	4,182	4,182	-	-	-	-	-	-	-	-	40,172	3,120
Period 4f Collateral Costs																					
4f.3.1	DOC staff relocation expenses	-	-	-	-	-	-	1,189	178	1,367	1,367	-	-	-	-	-	-	-	-	-	-
4f.3	Subtotal Period 4f Collateral Costs	-	-	-	-	-	-	1,189	178	1,367	1,367	-	-	-	-	-	-	-	-	-	-
Period 4f Period-Dependent Costs																					
4f.4.1	Insurance	-	-	-	-	-	-	382	38	420	420	-	-	-	-	-	-	-	-	-	-
4f.4.2	Property taxes	-	-	-	-	-	-	1,002	100	1,102	1,102	-	-	-	-	-	-	-	-	-	-
4f.4.3	Health physics supplies	-	418	-	-	-	-	-	105	523	523	-	-	-	-	-	-	-	-	-	-
4f.4.4	Disposal of DAW generated	-	-	7	2	-	27	-	8	44	44	-	-	-	332	-	-	-	6,649	11	-
4f.4.5	Plant energy budget	-	-	-	-	-	-	227	34	261	261	-	-	-	-	-	-	-	-	-	-
4f.4.6	NRC Fees	-	-	-	-	-	-	417	42	459	459	-	-	-	-	-	-	-	-	-	-
4f.4.7	Fixed Overhead	-	-	-	-	-	-	926	139	1,065	1,065	-	-	-	-	-	-	-	-	-	-
4f.4.8	Railroad Track Maintenance	-	-	-	-	-	-	43	6	50	50	-	-	-	-	-	-	-	-	-	-
4f.4.9	Security Staff Cost	-	-	-	-	-	-	707	106	813	813	-	-	-	-	-	-	-	-	-	11,668
4f.4.10	DOC Staff Cost	-	-	-	-	-	-	4,101	615	4,716	4,716	-	-	-	-	-	-	-	-	-	46,283
4f.4.11	Utility Staff Cost	-	-	-	-	-	-	3,630	544	4,174	4,174	-	-	-	-	-	-	-	-	-	56,395
4f.4	Subtotal Period 4f Period-Dependent Costs	-	418	7	2	-	27	11,435	1,738	13,627	13,627	-	-	-	332	-	-	-	6,649	11	114,346
4f.0	TOTAL PERIOD 4f COST	-	418	7	2	-	27	16,016	2,934	19,405	19,405	-	-	-	332	-	-	-	6,649	40,183	117,466
PERIOD 4 TOTALS		2,150	51,086	27,088	5,168	11,876	38,913	112,324	55,902	304,508	297,436	-	7,071	141,399	94,043	125	742	3,746	14,381,960	530,540	1,172,330
PERIOD 5b - Site Restoration																					
Period 5b Direct Decommissioning Activities																					
Demolition of Remaining Site Buildings																					
5b.1.1.1	Reactor	-	4,255	-	-	-	-	-	638	4,894	-	-	4,894	-	-	-	-	-	-	44,669	-
5b.1.1.2	Condensate Storage Tank Foundation	-	3	-	-	-	-	-	0	4	-	-	4	-	-	-	-	-	-	16	-
5b.1.1.3	Structures below 3' below grade	-	1,713	-	-	-	-	-	257	1,969	-	-	1,969	-	-	-	-	-	-	9,238	-
5b.1.1.4	Turbine	-	1,983	-	-	-	-	-	297	2,280	-	-	2,280	-	-	-	-	-	-	22,040	-
5b.1.1.5	Turbine Pedestal	-	349	-	-	-	-	-	52	402	-	-	402	-	-	-	-	-	-	1,857	-
5b.1.1	Totals	-	8,303	-	-	-	-	-	1,245	9,548	-	-	9,548	-	-	-	-	-	-	77,820	-
Site Closeout Activities																					
5b.1.2	Grade & landscape site	-	431	-	-	-	-	-	65	495	-	-	495	-	-	-	-	-	-	921	-
5b.1.3	Final report to NRC	-	-	-	-	-	-	183	27	211	211	-	-	-	-	-	-	-	-	-	1,560
5b.1	Subtotal Period 5b Activity Costs	-	8,733	-	-	-	-	183	1,337	10,254	211	-	10,044	-	-	-	-	-	-	78,740	1,560
Period 5b Additional Costs																					
5b.2.1	Clean Concrete Disposal	-	2,213	-	-	-	-	3	332	2,549	-	-	2,549	-	-	-	-	-	-	8,386	-
5b.2.2	Intake Structure Cofferdam	-	596	-	-	-	-	-	89	686	-	-	686	-	-	-	-	-	-	5,168	-

Table I-1
Prairie Island Nuclear Generating Plant, Unit 1
SAFSTOR Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 5b Additional Costs (continued)																					
5b.2.3	Construction Debris	-	-	-	-	-	-	10	2	12	-	-	12	-	-	-	-	-	-	-	-
5b.2.4	Backfill	-	2,751	-	-	-	-	-	413	3,164	-	-	3,164	-	-	-	-	-	-	2,904	-
5b.2	Subtotal Period 5b Additional Costs	-	5,560	-	-	-	-	13	836	6,410	-	-	6,410	-	-	-	-	-	-	16,458	-
Period 5b Collateral Costs																					
5b.3.1	Small tool allowance	-	107	-	-	-	-	-	16	123	-	-	123	-	-	-	-	-	-	-	-
5b.3	Subtotal Period 5b Collateral Costs	-	107	-	-	-	-	-	16	123	-	-	123	-	-	-	-	-	-	-	-
Period 5b Period-Dependent Costs																					
5b.4.2	Property taxes	-	-	-	-	-	-	1,712	171	1,883	-	-	1,883	-	-	-	-	-	-	-	-
5b.4.3	Heavy equipment rental	-	6,670	-	-	-	-	-	1,000	7,670	-	-	7,670	-	-	-	-	-	-	-	-
5b.4.4	Plant energy budget	-	-	-	-	-	-	321	48	369	-	-	369	-	-	-	-	-	-	-	-
5b.4.5	Fixed Overhead	-	-	-	-	-	-	990	148	1,138	-	-	1,138	-	-	-	-	-	-	-	-
5b.4.6	Railroad Track Maintenance	-	-	-	-	-	-	122	18	141	-	-	141	-	-	-	-	-	-	-	-
5b.4.7	Security Staff Cost	-	-	-	-	-	-	1,812	272	2,084	-	-	2,084	-	-	-	-	-	-	-	29,221
5b.4.8	DOC Staff Cost	-	-	-	-	-	-	10,467	1,570	12,038	-	-	12,038	-	-	-	-	-	-	-	116,885
5b.4.9	Utility Staff Cost	-	-	-	-	-	-	3,673	551	4,224	-	-	4,224	-	-	-	-	-	-	-	57,340
5b.4	Subtotal Period 5b Period-Dependent Costs	-	6,670	-	-	-	-	19,097	3,779	29,546	-	-	29,546	-	-	-	-	-	-	-	203,445
5b.0	TOTAL PERIOD 5b COST	-	21,070	-	-	-	-	19,294	5,969	46,333	211	-	46,122	-	-	-	-	-	-	95,198	205,005
PERIOD 5 TOTALS		-	21,070	-	-	-	-	19,294	5,969	46,333	211	-	46,122	-	-	-	-	-	-	95,198	205,005
TOTAL COST TO DECOMMISSION		**5,846**	**85,205**	**27,686**	**5,682**	**12,040**	**41,346**	**911,476**	**166,888**	**1,256,169**	**883,602**	**317,887**	**54,680**	**147,532**	**115,742**	**125**	**742**	**3,746**	**15,119,870**	**700,205**	**6,335,772**

TOTAL COST TO DECOMMISSION WITH 15.32% CONTINGENCY:	**$1,256,169**	**thousands of 2017 dollars**
TOTAL NRC LICENSE TERMINATION COST IS 70.34% OR:	**$883,602**	**thousands of 2017 dollars**
SPENT FUEL MANAGEMENT COST IS 25.31% OR:	**$317,887**	**thousands of 2017 dollars**
NON-NUCLEAR DEMOLITION COST IS 4.35% OR:	**$54,680**	**thousands of 2017 dollars**
TOTAL LOW-LEVEL RADIOACTIVE WASTE VOLUME BURIED (EXCLUDING GTCC):	**116,610**	**cubic feet**
TOTAL GREATER THAN CLASS C RADWASTE VOLUME GENERATED:	**3,746**	**cubic feet**
TOTAL SCRAP METAL REMOVED:	**33,003**	**tons**
TOTAL CRAFT LABOR REQUIREMENTS:	**700,205**	**man-hours**

End Notes:
n/a - indicates that this activity not charged as decommissioning expense
a - indicates that this activity performed by decommissioning staff
0 - indicates that this value is less than 0.5 but is non-zero
A cell containing " - " indicates a zero value

Table I-2
Prairie Island Nuclear Generating Plant, Unit 2
SAFSTOR Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
PERIOD 1a - Shutdown through Transition																					
Period 1a Direct Decommissioning Activities																					
1a.1.1	SAFSTOR site characterization survey	-	-	-	-	-	-	571	171	742	742	-	-	-	-	-	-	-	-	-	-
1a.1.2	Prepare preliminary decommissioning cost	-	-	-	-	-	-	65	10	75	75	-	-	-	-	-	-	-	-	-	556
1a.1.3	Notification of Cessation of Operations									a											
1a.1.4	Remove fuel & source material									n/a											
1a.1.5	Notification of Permanent Defueling									a											
1a.1.6	Deactivate plant systems & process waste									a											
1a.1.7	Prepare and submit PSDAR	-	-	-	-	-	-	100	15	115	115	-	-	-	-	-	-	-	-	-	855
1a.1.8	Review plant dwgs & specs.	-	-	-	-	-	-	65	10	75	75	-	-	-	-	-	-	-	-	-	556
1a.1.9	Perform detailed rad survey									a											
1a.1.10	Estimate by-product inventory	-	-	-	-	-	-	50	8	58	58	-	-	-	-	-	-	-	-	-	428
1a.1.11	End product description	-	-	-	-	-	-	50	8	58	58	-	-	-	-	-	-	-	-	-	428
1a.1.12	Detailed by-product inventory	-	-	-	-	-	-	75	11	87	87	-	-	-	-	-	-	-	-	-	641
1a.1.13	Define major work sequence	-	-	-	-	-	-	50	8	58	58	-	-	-	-	-	-	-	-	-	428
1a.1.14	Perform SER and EA	-	-	-	-	-	-	156	23	179	179	-	-	-	-	-	-	-	-	-	1,326
1a.1.15	Prepare/submit Defueled Technical Specifications	-	-	-	-	-	-	376	56	433	433	-	-	-	-	-	-	-	-	-	3,207
1a.1.16	Perform Site-Specific Cost Study	-	-	-	-	-	-	251	38	289	289	-	-	-	-	-	-	-	-	-	2,138
1a.1.17	Prepare/submit Irradiated Fuel Management Plan	-	-	-	-	-	-	50	8	58	58	-	-	-	-	-	-	-	-	-	428
Activity Specifications																					
1a.1.18.1	Prepare plant and facilities for SAFSTOR	-	-	-	-	-	-	247	37	284	284	-	-	-	-	-	-	-	-	-	2,104
1a.1.18.2	Plant systems	-	-	-	-	-	-	209	31	241	241	-	-	-	-	-	-	-	-	-	1,782
1a.1.18.3	Plant structures and buildings	-	-	-	-	-	-	157	23	180	180	-	-	-	-	-	-	-	-	-	1,334
1a.1.18.4	Waste management	-	-	-	-	-	-	100	15	115	115	-	-	-	-	-	-	-	-	-	855
1a.1.18.5	Facility and site dormancy	-	-	-	-	-	-	100	15	115	115	-	-	-	-	-	-	-	-	-	855
1a.1.18	Total	-	-	-	-	-	-	813	122	935	935	-	-	-	-	-	-	-	-	-	6,930
Detailed Work Procedures																					
1a.1.19.1	Plant systems	-	-	-	-	-	-	59	9	68	68	-	-	-	-	-	-	-	-	-	506
1a.1.19.2	Facility closeout & dormancy	-	-	-	-	-	-	60	9	69	69	-	-	-	-	-	-	-	-	-	513
1a.1.19	Total	-	-	-	-	-	-	120	18	138	138	-	-	-	-	-	-	-	-	-	1,019
1a.1.20	Procure vacuum drying system	-	-	-	-	-	-	5	1	6	6	-	-	-	-	-	-	-	-	-	43
1a.1.21	Drain/de-energize non-cont. systems									a											
1a.1.22	Drain & dry NSSS									a											
1a.1.23	Drain/de-energize contaminated systems									a											
1a.1.24	Decon/secure contaminated systems									a											
1a.1	Subtotal Period 1a Activity Costs	-	-	-	-	-	-	2,799	505	3,304	3,304	-	-	-	-	-	-	-	-	-	18,981
Period 1a Collateral Costs																					
1a.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	1,227	184	1,411	-	1,411	-	-	-	-	-	-	-	-	-
1a.3.2	Retention and Severance	-	-	-	-	-	-	8,394	1,259	9,653	9,653	-	-	-	-	-	-	-	-	-	-
1a.3.3	Prairie Island Indian Community Payments	-	-	-	-	-	-	2,281	-	2,281	-	2,281	-	-	-	-	-	-	-	-	-
1a.3	Subtotal Period 1a Collateral Costs	-	-	-	-	-	-	11,902	1,443	13,345	9,653	3,692	-	-	-	-	-	-	-	-	-
Period 1a Period-Dependent Costs																					
1a.4.1	Insurance	-	-	-	-	-	-	1,730	173	1,903	1,903	-	-	-	-	-	-	-	-	-	-
1a.4.2	Property taxes	-	-	-	-	-	-	2,682	268	2,950	2,950	-	-	-	-	-	-	-	-	-	-
1a.4.3	Health physics supplies	-	507	-	-	-	-	-	127	633	633	-	-	-	-	-	-	-	-	-	-
1a.4.4	Heavy equipment rental	-	567	-	-	-	-	-	85	652	652	-	-	-	-	-	-	-	-	-	-
1a.4.5	Disposal of DAW generated	-	-	13	4	-	49	-	14	79	79	-	-	-	597	-	-	-	11,939	19	-
1a.4.6	Plant energy budget	-	-	-	-	-	-	1,515	227	1,742	1,742	-	-	-	-	-	-	-	-	-	-
1a.4.7	NRC Fees	-	-	-	-	-	-	778	78	855	855	-	-	-	-	-	-	-	-	-	-
1a.4.8	Emergency Planning Fees	-	-	-	-	-	-	1,604	160	1,765	-	1,765	-	-	-	-	-	-	-	-	-
1a.4.9	Fixed Overhead	-	-	-	-	-	-	1,470	220	1,690	1,690	-	-	-	-	-	-	-	-	-	-
1a.4.10	Spent Fuel Pool O&M	-	-	-	-	-	-	401	60	461	-	461	-	-	-	-	-	-	-	-	-
1a.4.11	ISFSI Operating Costs	-	-	-	-	-	-	52	8	59	-	59	-	-	-	-	-	-	-	-	-
1a.4.12	Railroad Track Maintenance	-	-	-	-	-	-	58	9	66	66	-	-	-	-	-	-	-	-	-	-
1a.4.13	Security Staff Cost	-	-	-	-	-	-	7,390	1,108	8,498	8,498	-	-	-	-	-	-	-	-	-	122,720
1a.4.14	Utility Staff Cost	-	-	-	-	-	-	24,344	3,652	27,995	27,995	-	-	-	-	-	-	-	-	-	400,523
1a.4	Subtotal Period 1a Period-Dependent Costs	-	1,074	13	4	-	49	42,022	6,189	49,351	47,066	2,286	-	-	597	-	-	-	11,939	19	523,243
1a.0	TOTAL PERIOD 1a COST	-	1,074	13	4	-	49	56,723	8,138	66,000	60,023	5,977	-	-	597	-	-	-	11,939	19	542,224

Table I-2
Prairie Island Nuclear Generating Plant, Unit 2
SAFSTOR Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
PERIOD 1b - SAFSTOR Limited DECON Activities																					
Period 1b Direct Decommissioning Activities																					
Decontamination of Site Buildings																					
1b.1.1.1	Reactor	1,135	-	-	-	-	-	-	568	1,703	1,703	-	-	-	-	-	-	-	17,003	-	
1b.1.1.2	Auxiliary	1,177	-	-	-	-	-	-	589	1,766	1,766	-	-	-	-	-	-	-	17,950	-	
1b.1.1.3	Drum Transfer & Truck Loading Enclosure	16	-	-	-	-	-	-	8	24	24	-	-	-	-	-	-	-	244	-	
1b.1.1.4	LLRW Storage Enclosure	99	-	-	-	-	-	-	50	149	149	-	-	-	-	-	-	-	1,487	-	
1b.1.1.5	Radwaste	44	-	-	-	-	-	-	22	66	66	-	-	-	-	-	-	-	669	-	
1b.1.1.6	Resin Disposal	13	-	-	-	-	-	-	7	20	20	-	-	-	-	-	-	-	198	-	
1b.1.1.7	Fuel Handling of Aux Building	863	-	-	-	-	-	-	431	1,294	1,294	-	-	-	-	-	-	-	12,414	-	
1b.1.1	Totals	3,348	-	-	-	-	-	-	1,674	5,022	5,022	-	-	-	-	-	-	-	49,966	-	
1b.1	Subtotal Period 1b Activity Costs	3,348	-	-	-	-	-	-	1,674	5,022	5,022	-	-	-	-	-	-	-	49,966	-	
Period 1b Additional Costs																					
1b.2.1	Spent fuel pool isolation	-	-	-	-	-	-	7,794	1,169	8,963	8,963	-	-	-	-	-	-	-	-	-	
1b.2	Subtotal Period 1b Additional Costs	-	-	-	-	-	-	7,794	1,169	8,963	8,963	-	-	-	-	-	-	-	-	-	
Period 1b Collateral Costs																					
1b.3.1	Decon equipment	973	-	-	-	-	-	-	146	1,119	1,119	-	-	-	-	-	-	-	-	-	
1b.3.2	Process decommissioning water waste	105	-	68	177	-	277	-	155	781	781	-	-	-	660	-	-	-	39,628	129	
1b.3.4	Small tool allowance	-	56	-	-	-	-	-	8	64	64	-	-	-	-	-	-	-	-	-	
1b.3.5	Spent Fuel Capital and Transfer	-	-	-	-	-	-	286	43	329	-	329	-	-	-	-	-	-	-	-	
1b.3.6	Retention and Severance	-	-	-	-	-	-	2,315	347	2,662	2,662	-	-	-	-	-	-	-	-	-	
1b.3.7	Prairie Island Indian Community Payments	-	-	-	-	-	-	315	-	315	-	315	-	-	-	-	-	-	-	-	
1b.3	Subtotal Period 1b Collateral Costs	1,078	56	68	177	-	277	2,916	699	5,269	4,625	644	-	-	660	-	-	-	39,628	129	-
Period 1b Period-Dependent Costs																					
1b.4.1	Decon supplies	1,232	-	-	-	-	-	-	308	1,540	1,540	-	-	-	-	-	-	-	-	-	
1b.4.2	Insurance	-	-	-	-	-	-	436	44	480	480	-	-	-	-	-	-	-	-	-	
1b.4.3	Property taxes	-	-	-	-	-	-	675	68	743	743	-	-	-	-	-	-	-	-	-	
1b.4.4	Health physics supplies	-	369	-	-	-	-	-	92	461	461	-	-	-	-	-	-	-	-	-	
1b.4.5	Heavy equipment rental	-	143	-	-	-	-	-	21	164	164	-	-	-	-	-	-	-	-	-	
1b.4.6	Disposal of DAW generated	-	-	14	4	-	52	-	15	85	85	-	-	-	636	-	-	-	12,711	21	
1b.4.7	Plant energy budget	-	-	-	-	-	-	382	57	439	439	-	-	-	-	-	-	-	-	-	
1b.4.8	NRC Fees	-	-	-	-	-	-	107	11	118	118	-	-	-	-	-	-	-	-	-	
1b.4.9	Emergency Planning Fees	-	-	-	-	-	-	404	40	445	-	445	-	-	-	-	-	-	-	-	
1b.4.10	Fixed Overhead	-	-	-	-	-	-	370	56	426	426	-	-	-	-	-	-	-	-	-	
1b.4.11	Spent Fuel Pool O&M	-	-	-	-	-	-	101	15	116	-	116	-	-	-	-	-	-	-	-	
1b.4.12	ISFSI Operating Costs	-	-	-	-	-	-	13	2	15	-	15	-	-	-	-	-	-	-	-	
1b.4.13	Railroad Track Maintenance	-	-	-	-	-	-	15	2	17	17	-	-	-	-	-	-	-	-	-	
1b.4.14	Security Staff Cost	-	-	-	-	-	-	1,863	279	2,142	2,142	-	-	-	-	-	-	-	-	30,932	
1b.4.15	Utility Staff Cost	-	-	-	-	-	-	6,501	975	7,476	7,476	-	-	-	-	-	-	-	-	106,428	
1b.4	Subtotal Period 1b Period-Dependent Costs	1,232	512	14	4	-	52	10,867	1,986	14,667	14,090	576	-	-	636	-	-	-	12,711	21	137,360
1b.0	TOTAL PERIOD 1b COST	5,657	568	82	181	-	328	21,577	5,528	33,921	32,701	1,220	-	-	1,296	-	-	-	52,338	50,116	137,360
PERIOD 1c - Preparations for SAFSTOR Dormancy																					
Period 1c Direct Decommissioning Activities																					
1c.1.1	Prepare support equipment for storage	-	486	-	-	-	-	-	73	559	559	-	-	-	-	-	-	-	-	3,000	-
1c.1.2	Install containment pressure equal. lines	-	48	-	-	-	-	-	7	55	55	-	-	-	-	-	-	-	-	700	-
1c.1.3	Interim survey prior to dormancy	-	-	-	-	-	-	733	220	953	953	-	-	-	-	-	-	-	-	9,017	-
1c.1.4	Secure building accesses									a											
1c.1.5	Prepare & submit interim report	-	-	-	-	-	-	29	4	34	34	-	-	-	-	-	-	-	-	-	249
1c.1	Subtotal Period 1c Activity Costs	-	534	-	-	-	-	762	304	1,601	1,601	-	-	-	-	-	-	-	-	12,717	249
Period 1c Collateral Costs																					
1c.3.1	Process decommissioning water waste	88	-	58	150	-	234	-	131	661	661	-	-	-	560	-	-	-	33,579	109	-
1c.3.3	Small tool allowance	-	4	-	-	-	-	-	1	5	5	-	-	-	-	-	-	-	-	-	-
1c.3.4	Spent Fuel Capital and Transfer	-	-	-	-	-	-	84	13	96	-	96	-	-	-	-	-	-	-	-	-
1c.3.5	Retention and Severance	-	-	-	-	-	-	1,741	261	2,002	2,002	-	-	-	-	-	-	-	-	-	-
1c.3.6	Prairie Island Indian Community Payments	-	-	-	-	-	-	314	-	314	-	314	-	-	-	-	-	-	-	-	-
1c.3	Subtotal Period 1c Collateral Costs	88	4	58	150	-	234	2,139	405	3,079	2,668	411	-	-	560	-	-	-	33,579	109	-

Table I-2
Prairie Island Nuclear Generating Plant, Unit 2
SAFSTOR Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Period 1c Period-Dependent Costs																					
1c.4.1	Insurance	-	-	-	-	-	-	436	44	480	480	-	-	-	-	-	-	-	-	-	-
1c.4.2	Property taxes	-	-	-	-	-	-	674	67	742	742	-	-	-	-	-	-	-	-	-	-
1c.4.3	Health physics supplies	-	191	-	-	-	-	-	48	239	239	-	-	-	-	-	-	-	-	-	-
1c.4.4	Heavy equipment rental	-	143	-	-	-	-	-	21	164	164	-	-	-	-	-	-	-	-	-	-
1c.4.5	Disposal of DAW generated	-	-	3	1	-	13	-	4	20	20	-	-	-	154	-	-	-	3,073	5	-
1c.4.6	Plant energy budget	-	-	-	-	-	-	382	57	439	439	-	-	-	-	-	-	-	-	-	-
1c.4.7	NRC Fees	-	-	-	-	-	-	107	11	118	118	-	-	-	-	-	-	-	-	-	-
1c.4.8	Emergency Planning Fees	-	-	-	-	-	-	404	40	445	-	445	-	-	-	-	-	-	-	-	-
1c.4.9	Fixed Overhead	-	-	-	-	-	-	370	56	426	426	-	-	-	-	-	-	-	-	-	-
1c.4.10	Spent Fuel Pool O&M	-	-	-	-	-	-	101	15	116	-	116	-	-	-	-	-	-	-	-	-
1c.4.11	ISFSI Operating Costs	-	-	-	-	-	-	13	2	15	-	15	-	-	-	-	-	-	-	-	-
1c.4.12	Railroad Track Maintenance	-	-	-	-	-	-	15	2	17	17	-	-	-	-	-	-	-	-	-	-
1c.4.13	Security Staff Cost	-	-	-	-	-	-	1,863	279	2,142	2,142	-	-	-	-	-	-	-	-	-	30,932
1c.4.14	Utility Staff Cost	-	-	-	-	-	-	6,501	975	7,476	7,476	-	-	-	-	-	-	-	-	-	106,428
1c.4	Subtotal Period 1c Period-Dependent Costs	-	334	3	1	-	13	10,866	1,622	12,839	12,263	576	-	-	154	-	-	-	3,073	5	137,360
1c.0	TOTAL PERIOD 1c COST	88	873	61	151	-	247	13,767	2,331	17,518	16,532	987	-	-	713	-	-	-	36,652	12,832	137,609
PERIOD 1 TOTALS		5,746	2,514	156	335	-	624	92,067	15,997	117,440	109,256	8,184	-	-	2,606	-	-	-	100,929	62,967	817,193
PERIOD 2a - SAFSTOR Dormancy with Wet Spent Fuel Storage																					
Period 2a Direct Decommissioning Activities																					
2a.1.1	Quarterly Inspection									a											
2a.1.2	Semi-annual environmental survey									a											
2a.1.3	Prepare reports									a											
2a.1.4	Bituminous roof replacement	-	-	-	-	-	-	309	46	356	356	-	-	-	-	-	-	-	-	-	-
2a.1.5	Maintenance supplies	-	-	-	-	-	-	477	119	596	596	-	-	-	-	-	-	-	-	-	-
2a.1	Subtotal Period 2a Activity Costs	-	-	-	-	-	-	786	166	951	951	-	-	-	-	-	-	-	-	-	-
Period 2a Additional Costs																					
2a.2.1	Security Modifications	-	-	-	-	-	-	4,348	652	5,000	5,000	-	-	-	-	-	-	-	-	-	-
2a.2	Subtotal Period 2a Additional Costs	-	-	-	-	-	-	4,348	652	5,000	5,000	-	-	-	-	-	-	-	-	-	-
Period 2a Collateral Costs																					
2a.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	72,373	10,856	83,229	-	83,229	-	-	-	-	-	-	-	-	-
2a.3.2	Retention and Severance	-	-	-	-	-	-	12,266	1,840	14,106	14,106	-	-	-	-	-	-	-	-	-	-
2a.3.3	Prairie Island Indian Community Payments	-	-	-	-	-	-	4,371	-	4,371	-	4,371	-	-	-	-	-	-	-	-	-
2a.3	Subtotal Period 2a Collateral Costs	-	-	-	-	-	-	89,010	12,696	101,706	14,106	87,600	-	-	-	-	-	-	-	-	-
Period 2a Period-Dependent Costs																					
2a.4.1	Insurance	-	-	-	-	-	-	1,788	179	1,966	1,966	-	-	-	-	-	-	-	-	-	-
2a.4.2	Property taxes	-	-	-	-	-	-	9,379	938	10,317	10,317	-	-	-	-	-	-	-	-	-	-
2a.4.3	Health physics supplies	-	631	-	-	-	-	-	158	789	789	-	-	-	-	-	-	-	-	-	-
2a.4.4	Disposal of DAW generated	-	-	15	4	-	55	-	16	89	89	-	-	-	670	-	-	-	13,402	22	-
2a.4.5	Plant energy budget	-	-	-	-	-	-	1,060	159	1,219	1,219	-	-	-	-	-	-	-	-	-	-
2a.4.6	NRC Fees	-	-	-	-	-	-	819	82	901	901	-	-	-	-	-	-	-	-	-	-
2a.4.7	Emergency Planning Fees	-	-	-	-	-	-	4,492	449	4,941	-	4,941	-	-	-	-	-	-	-	-	-
2a.4.8	Fixed Overhead	-	-	-	-	-	-	5,142	771	5,913	5,913	-	-	-	-	-	-	-	-	-	-
2a.4.9	Spent Fuel Pool O&M	-	-	-	-	-	-	1,404	211	1,615	-	1,615	-	-	-	-	-	-	-	-	-
2a.4.10	ISFSI Operating Costs	-	-	-	-	-	-	181	27	208	-	208	-	-	-	-	-	-	-	-	-
2a.4.11	Railroad Track Maintenance	-	-	-	-	-	-	410	62	472	472	-	-	-	-	-	-	-	-	-	-
2a.4.12	Security Staff Cost	-	-	-	-	-	-	23,761	3,564	27,325	19,456	7,870	-	-	-	-	-	-	-	-	392,966
2a.4.13	Utility Staff Cost	-	-	-	-	-	-	3,341	501	3,842	2,732	1,110	-	-	-	-	-	-	-	-	54,579
2a.4	Subtotal Period 2a Period-Dependent Costs	-	631	15	4	-	55	51,776	7,116	59,597	43,854	15,744	-	-	670	-	-	-	13,402	22	447,545
2a.0	TOTAL PERIOD 2a COST	-	631	15	4	-	55	145,920	20,630	167,255	63,911	103,344	-	-	670	-	-	-	13,402	22	447,545
PERIOD 2b - SAFSTOR Dormancy with Dry Spent Fuel Storage																					
Period 2b Direct Decommissioning Activities																					
2b.1.1	Quarterly Inspection									a											
2b.1.2	Semi-annual environmental survey									a											
2b.1.3	Prepare reports									a											
2b.1.4	Bituminous roof replacement	-	-	-	-	-	-	3,376	506	3,882	3,882	-	-	-	-	-	-	-	-	-	-
2b.1.5	Maintenance supplies	-	-	-	-	-	-	5,206	1,301	6,507	6,507	-	-	-	-	-	-	-	-	-	-
2b.1	Subtotal Period 2b Activity Costs	-	-	-	-	-	-	8,581	1,808	10,389	10,389	-	-	-	-	-	-	-	-	-	-

Table I-2
Prairie Island Nuclear Generating Plant, Unit 2
SAFSTOR Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 2b Collateral Costs																					
2b.3.1	Spent Fuel Capital and Transfer	-	-	-	-	-	-	29,940	4,491	34,431	-	34,431	-	-	-	-	-	-	-	-	-
2b.3.2	Prairie Island Indian Community Payments	-	-	-	-	-	-	47,719	-	47,719	-	47,719	-	-	-	-	-	-	-	-	-
2b.3	Subtotal Period 2b Collateral Costs	-	-	-	-	-	-	77,660	4,491	82,151	-	82,151	-	-	-	-	-	-	-	-	-
Period 2b Period-Dependent Costs																					
2b.4.1	Insurance	-	-	-	-	-	-	19,520	1,952	21,472	21,472	-	-	-	-	-	-	-	-	-	-
2b.4.2	Property taxes	-	-	-	-	-	-	102,394	10,239	112,633	112,633	-	-	-	-	-	-	-	-	-	-
2b.4.3	Health physics supplies	-	3,643	-	-	-	-	-	911	4,554	4,554	-	-	-	-	-	-	-	-	-	-
2b.4.4	Disposal of DAW generated	-	-	86	25	-	321	-	93	525	525	-	-	-	3,946	-	-	-	78,923	129	-
2b.4.5	Plant energy budget	-	-	-	-	-	-	5,786	868	6,654	6,654	-	-	-	-	-	-	-	-	-	-
2b.4.6	NRC Fees	-	-	-	-	-	-	8,573	857	9,430	9,430	-	-	-	-	-	-	-	-	-	-
2b.4.7	Emergency Planning Fees	-	-	-	-	-	-	2,612	261	2,873	-	2,873	-	-	-	-	-	-	-	-	-
2b.4.8	Fixed Overhead	-	-	-	-	-	-	5,829	874	6,703	6,703	-	-	-	-	-	-	-	-	-	-
2b.4.9	ISFSI Operating Costs	-	-	-	-	-	-	1,972	296	2,268	-	2,268	-	-	-	-	-	-	-	-	-
2b.4.10	Railroad Track Maintenance	-	-	-	-	-	-	2,203	330	2,534	2,534	-	-	-	-	-	-	-	-	-	-
2b.4.11	Security Staff Cost	-	-	-	-	-	-	96,335	14,450	110,786	22,822	87,964	-	-	-	-	-	-	-	-	1,430,311
2b.4.12	Utility Staff Cost	-	-	-	-	-	-	50,003	7,500	57,503	35,767	21,736	-	-	-	-	-	-	-	-	794,617
2b.4	Subtotal Period 2b Period-Dependent Costs	-	3,643	86	25	-	321	295,227	38,633	337,935	223,094	114,842	-	-	3,946	-	-	-	78,923	129	2,224,928
2b.0	TOTAL PERIOD 2b COST	-	3,643	86	25	-	321	381,468	44,931	430,475	233,483	196,992	-	-	3,946	-	-	-	78,923	129	2,224,928
PERIOD 2c - SAFSTOR Dormancy without Spent Fuel Storage																					
Period 2c Direct Decommissioning Activities																					
2c.1.1	Quarterly Inspection									a											
2c.1.2	Semi-annual environmental survey									a											
2c.1.3	Prepare reports									a											
2c.1.4	Bituminous roof replacement	-	-	-	-	-	-	940	141	1,080	1,080	-	-	-	-	-	-	-	-	-	-
2c.1.5	Maintenance supplies	-	-	-	-	-	-	1,449	362	1,811	1,811	-	-	-	-	-	-	-	-	-	-
2c.1	Subtotal Period 2c Activity Costs	-	-	-	-	-	-	2,388	503	2,892	2,892	-	-	-	-	-	-	-	-	-	-
Period 2c Period-Dependent Costs																					
2c.4.1	Insurance	-	-	-	-	-	-	5,331	533	5,864	5,864	-	-	-	-	-	-	-	-	-	-
2c.4.2	Property taxes	-	-	-	-	-	-	18,485	1,849	20,334	20,334	-	-	-	-	-	-	-	-	-	-
2c.4.3	Health physics supplies	-	962	-	-	-	-	-	240	1,202	1,202	-	-	-	-	-	-	-	-	-	-
2c.4.4	Disposal of DAW generated	-	-	22	7	-	83	-	24	136	136	-	-	-	1,021	-	-	-	20,430	33	-
2c.4.5	Plant energy budget	-	-	-	-	-	-	1,610	242	1,852	1,852	-	-	-	-	-	-	-	-	-	-
2c.4.6	NRC Fees	-	-	-	-	-	-	2,289	229	2,518	2,518	-	-	-	-	-	-	-	-	-	-
2c.4.7	Fixed Overhead	-	-	-	-	-	-	1,622	243	1,866	1,866	-	-	-	-	-	-	-	-	-	-
2c.4.8	Railroad Track Maintenance	-	-	-	-	-	-	613	92	705	705	-	-	-	-	-	-	-	-	-	-
2c.4.9	Utility Staff Cost	-	-	-	-	-	-	5,376	806	6,182	6,182	-	-	-	-	-	-	-	-	-	88,466
2c.4	Subtotal Period 2c Period-Dependent Costs	-	962	22	7	-	83	35,327	4,258	40,659	40,659	-	-	-	1,021	-	-	-	20,430	33	88,466
2c.0	TOTAL PERIOD 2c COST	-	962	22	7	-	83	37,716	4,761	43,551	43,551	-	-	-	1,021	-	-	-	20,430	33	88,466
PERIOD 2 TOTALS		-	5,236	123	36	-	459	565,104	70,323	641,280	340,944	300,336	-	-	5,638	-	-	-	112,755	184	2,760,938
PERIOD 3a - Reactivate Site Following SAFSTOR Dormancy																					
Period 3a Direct Decommissioning Activities																					
3a.1.1	Prepare preliminary decommissioning cost	-	-	-	-	-	-	65	10	75	75	-	-	-	-	-	-	-	-	-	556
3a.1.2	Review plant dwgs & specs.	-	-	-	-	-	-	231	35	266	266	-	-	-	-	-	-	-	-	-	1,967
3a.1.3	Perform detailed rad survey									a											
3a.1.4	End product description	-	-	-	-	-	-	50	8	58	58	-	-	-	-	-	-	-	-	-	428
3a.1.5	Detailed by-product inventory	-	-	-	-	-	-	65	10	75	75	-	-	-	-	-	-	-	-	-	556
3a.1.6	Define major work sequence	-	-	-	-	-	-	376	56	433	433	-	-	-	-	-	-	-	-	-	3,207
3a.1.7	Perform SER and EA	-	-	-	-	-	-	156	23	179	179	-	-	-	-	-	-	-	-	-	1,326
3a.1.8	Perform Site-Specific Cost Study	-	-	-	-	-	-	251	38	289	289	-	-	-	-	-	-	-	-	-	2,138
Activity Specifications																					
3a.1.9.1	Re-activate plant & temporary facilities	-	-	-	-	-	-	370	55	425	383	-	43	-	-	-	-	-	-	-	3,151
3a.1.9.2	Plant systems	-	-	-	-	-	-	209	31	241	216	-	24	-	-	-	-	-	-	-	1,782
3a.1.9.3	Reactor internals	-	-	-	-	-	-	356	53	410	410	-	-	-	-	-	-	-	-	-	3,036
3a.1.9.4	Reactor vessel	-	-	-	-	-	-	326	49	375	375	-	-	-	-	-	-	-	-	-	2,779
3a.1.9.5	Biological shield	-	-	-	-	-	-	25	4	29	29	-	-	-	-	-	-	-	-	-	214
3a.1.9.6	Steam generators	-	-	-	-	-	-	157	23	180	180	-	-	-	-	-	-	-	-	-	1,334
3a.1.9.7	Reinforced concrete	-	-	-	-	-	-	80	12	92	46	-	46	-	-	-	-	-	-	-	684

Table I-2
Prairie Island Nuclear Generating Plant, Unit 2
SAFSTOR Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Activity Specifications (continued)																					
3a.1.9.8	Main Turbine	-	-	-	-	-	-	20	3	23	-	-	23	-	-	-	-	-	-	-	171
3a.1.9.9	Main Condensers	-	-	-	-	-	-	20	3	23	-	-	23	-	-	-	-	-	-	-	171
3a.1.9.10	Plant structures & buildings	-	-	-	-	-	-	157	23	180	90	-	90	-	-	-	-	-	-	-	1,334
3a.1.9.11	Waste management	-	-	-	-	-	-	231	35	266	266	-	-	-	-	-	-	-	-	-	1,967
3a.1.9.12	Facility & site closeout	-	-	-	-	-	-	45	7	52	26	-	26	-	-	-	-	-	-	-	385
3a.1.9	Total	-	-	-	-	-	-	1,996	299	2,296	2,021	-	275	-	-	-	-	-	-	-	17,009
Planning & Site Preparations																					
3a.1.10	Prepare dismantling sequence	-	-	-	-	-	-	120	18	139	139	-	-	-	-	-	-	-	-	-	1,026
3a.1.11	Plant prep. & temp. svces	-	-	-	-	-	-	3,300	495	3,795	3,795	-	-	-	-	-	-	-	-	-	-
3a.1.12	Design water clean-up system	-	-	-	-	-	-	70	11	81	81	-	-	-	-	-	-	-	-	-	599
3a.1.13	Rigging/Cont. Cntrl Envlps/tooling/etc.	-	-	-	-	-	-	2,300	345	2,645	2,645	-	-	-	-	-	-	-	-	-	-
3a.1.14	Procure casks/liners & containers	-	-	-	-	-	-	62	9	71	71	-	-	-	-	-	-	-	-	-	526
3a.1	Subtotal Period 3a Activity Costs	-	-	-	-	-	-	9,043	1,357	10,400	10,125	-	275	-	-	-	-	-	-	-	29,336
Period 3a Additional Costs																					
3a.2.1	Site Characterization	-	-	-	-	-	-	1,582	475	2,057	2,057	-	-	-	-	-	-	-	-	8,988	3,563
3a.2.2	Mixed/Hazardous Waste	-	-	326	75	169	-	-	69	639	639	-	-	6,324	-	-	-	-	362,914	2,410	-
3a.2.3	Asbestos Abatement	-	2,364	2	110	-	1,359	-	947	4,782	4,782	-	-	-	12,843	-	-	-	166,959	20,907	-
3a.2	Subtotal Period 3a Additional Costs	-	2,364	328	185	169	1,359	1,582	1,491	7,478	7,478	-	-	6,324	12,843	-	-	-	529,873	32,305	3,563
Period 3a Collateral Costs																					
3a.3.1	Small tool allowance	-	32	-	-	-	-	-	5	37	37	-	-	-	-	-	-	-	-	-	-
3a.3	Subtotal Period 3a Collateral Costs	-	32	-	-	-	-	-	5	37	37	-	-	-	-	-	-	-	-	-	-
Period 3a Period-Dependent Costs																					
3a.4.1	Insurance	-	-	-	-	-	-	501	50	552	552	-	-	-	-	-	-	-	-	-	-
3a.4.2	Property taxes	-	-	-	-	-	-	1,608	161	1,769	1,769	-	-	-	-	-	-	-	-	-	-
3a.4.3	Health physics supplies	-	539	-	-	-	-	-	135	673	673	-	-	-	-	-	-	-	-	-	-
3a.4.4	Heavy equipment rental	-	567	-	-	-	-	-	85	652	652	-	-	-	-	-	-	-	-	-	-
3a.4.5	Disposal of DAW generated	-	-	10	3	-	39	-	11	64	64	-	-	-	481	-	-	-	9,613	16	-
3a.4.6	Plant energy budget	-	-	-	-	-	-	1,515	227	1,742	1,742	-	-	-	-	-	-	-	-	-	-
3a.4.7	NRC Fees	-	-	-	-	-	-	298	30	327	327	-	-	-	-	-	-	-	-	-	-
3a.4.8	Fixed Overhead	-	-	-	-	-	-	1,470	220	1,690	1,690	-	-	-	-	-	-	-	-	-	-
3a.4.9	Railroad Track Maintenance	-	-	-	-	-	-	58	9	66	66	-	-	-	-	-	-	-	-	-	-
3a.4.10	Security Staff Cost	-	-	-	-	-	-	312	47	358	358	-	-	-	-	-	-	-	-	-	6,240
3a.4.11	Utility Staff Cost	-	-	-	-	-	-	11,597	1,740	13,336	13,336	-	-	-	-	-	-	-	-	-	199,680
3a.4	Subtotal Period 3a Period-Dependent Costs	-	1,106	10	3	-	39	17,358	2,714	21,230	21,230	-	-	-	481	-	-	-	9,613	16	205,920
3a.0	TOTAL PERIOD 3a COST	-	3,501	339	188	169	1,398	27,983	5,567	39,145	38,870	-	275	6,324	13,324	-	-	-	539,486	32,320	238,819
PERIOD 3b - Decommissioning Preparations																					
Period 3b Direct Decommissioning Activities																					
Detailed Work Procedures																					
3b.1.1.1	Plant systems	-	-	-	-	-	-	238	36	273	246	-	27	-	-	-	-	-	-	-	2,024
3b.1.1.2	Reactor internals	-	-	-	-	-	-	125	19	144	144	-	-	-	-	-	-	-	-	-	1,069
3b.1.1.3	Remaining buildings	-	-	-	-	-	-	68	10	78	19	-	58	-	-	-	-	-	-	-	577
3b.1.1.4	CRD cooling assembly	-	-	-	-	-	-	50	8	58	58	-	-	-	-	-	-	-	-	-	428
3b.1.1.5	CRD housings & ICI tubes	-	-	-	-	-	-	50	8	58	58	-	-	-	-	-	-	-	-	-	428
3b.1.1.6	Incore instrumentation	-	-	-	-	-	-	50	8	58	58	-	-	-	-	-	-	-	-	-	428
3b.1.1.7	Reactor vessel	-	-	-	-	-	-	182	27	210	210	-	-	-	-	-	-	-	-	-	1,552
3b.1.1.8	Facility closeout	-	-	-	-	-	-	60	9	69	35	-	35	-	-	-	-	-	-	-	513
3b.1.1.9	Missile shields	-	-	-	-	-	-	23	3	26	26	-	-	-	-	-	-	-	-	-	192
3b.1.1.10	Biological shield	-	-	-	-	-	-	60	9	69	69	-	-	-	-	-	-	-	-	-	513
3b.1.1.11	Steam generators	-	-	-	-	-	-	231	35	266	266	-	-	-	-	-	-	-	-	-	1,967
3b.1.1.12	Reinforced concrete	-	-	-	-	-	-	50	8	58	29	-	29	-	-	-	-	-	-	-	428
3b.1.1.13	Main Turbine	-	-	-	-	-	-	78	12	90	-	-	90	-	-	-	-	-	-	-	667
3b.1.1.14	Main Condensers	-	-	-	-	-	-	78	12	90	-	-	90	-	-	-	-	-	-	-	667
3b.1.1.15	Auxiliary building	-	-	-	-	-	-	137	21	158	142	-	16	-	-	-	-	-	-	-	1,167
3b.1.1.16	Reactor building	-	-	-	-	-	-	137	21	158	142	-	16	-	-	-	-	-	-	-	1,167
3b.1.1	Total	-	-	-	-	-	-	1,618	243	1,861	1,500	-	361	-	-	-	-	-	-	-	13,787
3b.1	Subtotal Period 3b Activity Costs	-	-	-	-	-	-	1,618	243	1,861	1,500	-	361	-	-	-	-	-	-	-	13,787

Table I-2
Prairie Island Nuclear Generating Plant, Unit 2
SAFSTOR Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 3b Collateral Costs																					
3b.3.1	Decon equipment	973	-	-	-	-	-	-	146	1,119	1,119	-	-	-	-	-	-	-	-	-	-
3b.3.2	DOC staff relocation expenses	-	-	-	-	-	-	1,189	178	1,367	1,367	-	-	-	-	-	-	-	-	-	-
3b.3.3	Pipe cutting equipment	-	1,200	-	-	-	-	-	180	1,380	1,380	-	-	-	-	-	-	-	-	-	-
3b.3	Subtotal Period 3b Collateral Costs	973	1,200	-	-	-	-	1,189	504	3,866	3,866	-	-	-	-	-	-	-	-	-	-
Period 3b Period-Dependent Costs																					
3b.4.1	Decon supplies	35	-	-	-	-	-	-	9	43	43	-	-	-	-	-	-	-	-	-	-
3b.4.2	Insurance	-	-	-	-	-	-	255	25	280	280	-	-	-	-	-	-	-	-	-	-
3b.4.3	Property taxes	-	-	-	-	-	-	760	76	836	836	-	-	-	-	-	-	-	-	-	-
3b.4.4	Health physics supplies	-	230	-	-	-	-	-	57	287	287	-	-	-	-	-	-	-	-	-	-
3b.4.5	Heavy equipment rental	-	283	-	-	-	-	-	42	325	325	-	-	-	-	-	-	-	-	-	-
3b.4.6	Disposal of DAW generated	-	-	6	2	-	22	-	6	35	35	-	-	-	264	-	-	-	5,286	9	-
3b.4.7	Plant energy budget	-	-	-	-	-	-	755	113	869	869	-	-	-	-	-	-	-	-	-	-
3b.4.8	NRC Fees	-	-	-	-	-	-	148	15	163	163	-	-	-	-	-	-	-	-	-	-
3b.4.9	Fixed Overhead	-	-	-	-	-	-	733	110	843	843	-	-	-	-	-	-	-	-	-	-
3b.4.10	Railroad Track Maintenance	-	-	-	-	-	-	29	4	33	33	-	-	-	-	-	-	-	-	-	-
3b.4.11	Security Staff Cost	-	-	-	-	-	-	155	23	179	179	-	-	-	-	-	-	-	-	-	3,111
3b.4.12	DOC Staff Cost	-	-	-	-	-	-	3,539	531	4,070	4,070	-	-	-	-	-	-	-	-	-	42,523
3b.4.13	Utility Staff Cost	-	-	-	-	-	-	5,782	867	6,650	6,650	-	-	-	-	-	-	-	-	-	99,566
3b.4	Subtotal Period 3b Period-Dependent Costs	35	513	6	2	-	22	12,157	1,880	14,614	14,614	-	-	-	264	-	-	-	5,286	9	145,201
3b.0	TOTAL PERIOD 3b COST	1,008	1,713	6	2	-	22	14,964	2,627	20,341	19,980	-	361	-	264	-	-	-	5,286	9	158,988
PERIOD 3 TOTALS		1,008	5,214	345	189	169	1,420	42,947	8,194	59,485	58,850	-	636	6,324	13,588	-	-	-	544,771	32,329	397,807
PERIOD 4a - Large Component Removal																					
Period 4a Direct Decommissioning Activities																					
Nuclear Steam Supply System Removal																					
4a.1.1.1	Reactor Coolant Piping	11	40	6	5	34	75	-	41	212	212	-	-	144	152	-	-	-	33,380	771	-
4a.1.1.2	Pressurizer Relief Tank	5	18	4	3	23	50	-	24	126	126	-	-	96	101	-	-	-	22,241	347	-
4a.1.1.3	Reactor Coolant Pumps & Motors	13	56	43	76	-	736	-	220	1,143	1,143	-	-	-	2,332	-	-	-	295,800	1,226	80
4a.1.1.4	Pressurizer	10	68	359	82	-	693	-	244	1,456	1,456	-	-	-	2,196	-	-	-	158,199	1,499	750
4a.1.1.5	Steam Generators	47	2,943	1,576	1,614	1,246	3,467	-	2,212	13,104	13,104	-	-	18,672	10,990	-	-	-	1,560,086	10,964	2,250
4a.1.1.6	CRDMs/ICIs/Service Structure Removal	60	243	199	32	169	369	-	233	1,305	1,305	-	-	2,138	2,146	-	-	-	165,025	4,449	-
4a.1.1.7	Reactor Vessel Internals	59	4,189	21,552	1,011	-	7,239	239	12,467	46,756	46,756	-	-	-	757	-	673	-	166,167	19,373	933
4a.1.1.8	Vessel & Internals GTCC Disposal	-	-	-	-	-	8,689	-	1,303	9,992	9,992	-	-	-	-	-	-	3,746	837,596	-	-
4a.1.1.9	Reactor Vessel	-	5,439	1,328	198	-	1,804	239	5,398	14,406	14,406	-	-	-	5,719	-	-	-	569,974	19,373	933
4a.1.1	Totals	204	12,996	25,067	3,022	1,471	23,120	478	22,142	88,499	88,499	-	-	21,050	24,393	-	673	3,746	3,808,467	58,003	4,947
Removal of Major Equipment																					
4a.1.2	Main Turbine/Generator	-	269	128	27	287	-	-	127	838	838	-	-	2,243	-	-	-	-	134,601	4,116	-
4a.1.3	Main Condensers	-	2,269	87	26	383	-	-	637	3,403	3,403	-	-	4,000	-	-	-	-	180,000	34,978	-
Cascading Costs from Clean Building Demolition																					
4a.1.4.1	Reactor	-	728	-	-	-	-	-	109	837	837	-	-	-	-	-	-	-	-	7,589	-
4a.1.4.2	Auxiliary	-	210	-	-	-	-	-	32	242	242	-	-	-	-	-	-	-	-	1,309	-
4a.1.4.3	Radwaste	-	8	-	-	-	-	-	1	9	9	-	-	-	-	-	-	-	-	65	-
4a.1.4	Totals	-	946	-	-	-	-	-	142	1,088	1,088	-	-	-	-	-	-	-	-	8,963	-
Disposal of Plant Systems																					
4a.1.5.1	Admin Bldg Ventilation	-	6	-	-	-	-	-	1	6	-	-	6	-	-	-	-	-	-	90	-
4a.1.5.2	Air Removal	-	25	-	-	-	-	-	4	29	-	-	29	-	-	-	-	-	-	422	-
4a.1.5.3	Auxiliary Feedwater	-	40	-	-	-	-	-	6	46	-	-	46	-	-	-	-	-	-	676	-
4a.1.5.4	Auxiliary Feedwater - RCA	-	36	0	1	15	-	-	12	65	65	-	-	178	-	-	-	-	7,214	486	-
4a.1.5.5	Bleed Steam	-	78	-	-	-	-	-	12	90	-	-	90	-	-	-	-	-	-	1,331	-
4a.1.5.6	Caustic Addition - RCA	-	38	0	1	21	-	-	13	74	74	-	-	240	-	-	-	-	9,761	468	-
4a.1.5.7	Chemical Feed	-	15	-	-	-	-	-	2	17	-	-	17	-	-	-	-	-	-	261	-
4a.1.5.8	Chemical Feed - RCA	-	3	0	0	1	-	-	1	5	5	-	-	16	-	-	-	-	634	31	-
4a.1.5.9	Circulating Water	-	24	-	-	-	-	-	4	28	-	-	28	-	-	-	-	-	-	401	-
4a.1.5.10	Condensate	-	459	-	-	-	-	-	69	527	-	-	527	-	-	-	-	-	-	7,537	-
4a.1.5.11	Condensate Polishing	-	181	-	-	-	-	-	27	209	-	-	209	-	-	-	-	-	-	2,987	-
4a.1.5.12	Condensate Polishing - RCA	-	36	1	3	42	-	-	16	98	98	-	-	483	-	-	-	-	19,616	493	-
4a.1.5.13	Electro-Hydraulic	-	8	-	-	-	-	-	1	10	-	-	10	-	-	-	-	-	-	143	-
4a.1.5.14	External Circulating Water	-	23	-	-	-	-	-	3	26	-	-	26	-	-	-	-	-	-	385	-
4a.1.5.15	External Circulating Water - RCA	-	70	1	4	62	-	-	28	165	165	-	-	721	-	-	-	-	29,284	938	-

Table I-2
Prairie Island Nuclear Generating Plant, Unit 2
SAFSTOR Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Disposal of Plant Systems (continued)																					
4a.1.5.16	Feedwater	-	111	-	-	-	-	-	17	128	-	-	128	-	-	-	-	-	-	1,840	-
4a.1.5.17	Feedwater - RCA	-	236	7	24	359	-	-	117	744	744	-	-	4,147	-	-	-	-	168,414	3,377	-
4a.1.5.18	Gland Seal	-	29	-	-	-	-	-	4	34	-	-	34	-	-	-	-	-	-	504	-
4a.1.5.19	Heater Drain	-	334	-	-	-	-	-	50	384	-	-	384	-	-	-	-	-	-	5,638	-
4a.1.5.20	Hypobromous Acid Feed	-	5	-	-	-	-	-	1	6	-	-	6	-	-	-	-	-	-	86	-
4a.1.5.21	Hypobromous Acid Feed - RCA	-	1	0	0	0	-	-	0	1	1	-	-	2	-	-	-	-	100	12	-
4a.1.5.22	Internal Circ Water & CDSR	-	22	-	-	-	-	-	3	25	-	-	25	-	-	-	-	-	-	366	-
4a.1.5.23	Main Gen/Exciter/Transformer	-	0	-	-	-	-	-	0	0	-	-	0	-	-	-	-	-	-	5	-
4a.1.5.24	Main Steam	-	88	-	-	-	-	-	13	101	-	-	101	-	-	-	-	-	-	1,482	-
4a.1.5.25	Main Steam - RCA	-	364	9	30	447	-	-	163	1,013	1,013	-	-	5,166	-	-	-	-	209,799	5,146	-
4a.1.5.26	Repairable Spare Snubbers	-	6	0	0	1	-	-	2	8	8	-	-	12	-	-	-	-	490	82	-
4a.1.5.27	Steam Exclusion	-	2	-	-	-	-	-	0	2	-	-	2	-	-	-	-	-	-	32	-
4a.1.5.28	Steam Exclusion - RCA	-	4	0	0	2	-	-	1	8	8	-	-	24	-	-	-	-	966	47	-
4a.1.5.29	Steam Generator Blowdown	-	362	20	21	165	179	-	165	911	911	-	-	1,906	631	-	-	-	119,126	5,179	-
4a.1.5.30	Steam Generators	-	5	-	-	-	-	-	1	5	-	-	5	-	-	-	-	-	-	75	-
4a.1.5.31	Turbine & Moisture Separators	-	329	-	-	-	-	-	49	379	-	-	379	-	-	-	-	-	-	5,472	-
4a.1.5.32	Turbine Oil Purification	-	46	-	-	-	-	-	7	53	-	-	53	-	-	-	-	-	-	757	-
4a.1.5.33	Water Treatment	-	394	-	-	-	-	-	59	453	-	-	453	-	-	-	-	-	-	6,677	-
4a.1.5.34	Water Treatment - RCA	-	19	0	1	10	-	-	6	37	37	-	-	115	-	-	-	-	4,652	252	-
4a.1.5	Totals	-	3,400	39	85	1,125	179	-	858	5,687	3,128	-	2,559	13,010	631	-	-	-	570,056	53,681	-
4a.1.6	Scaffolding in support of decommissioning	-	2,682	24	8	97	25	-	695	3,532	3,532	-	-	1,012	89	-	-	-	51,445	23,719	-
4a.1	Subtotal Period 4a Activity Costs	204	22,563	25,345	3,168	3,363	23,325	478	24,601	103,048	100,489	-	2,559	41,316	25,114	-	673	3,746	4,744,569	183,459	4,947
Period 4a Additional Costs																					
4a.2.1	Remedial Action Surveys	-	-	-	-	-	-	1,516	455	1,971	1,971	-	-	-	-	-	-	-	-	19,818	-
4a.2.2	Retired RPV upper internals package	1	659	785	107	-	1,439	-	1,437	4,427	4,427	-	-	-	2,097	125	-	-	205,890	2,175	87
4a.2	Subtotal Period 4a Additional Costs	1	659	785	107	-	1,439	1,516	1,892	6,398	6,398	-	-	-	2,097	125	-	-	205,890	21,993	87
Period 4a Collateral Costs																					
4a.3.1	Process decommissioning water waste	2	-	4	11	-	17	-	7	42	42	-	-	-	40	-	-	-	2,403	8	-
4a.3.3	Small tool allowance	-	220	-	-	-	-	-	33	254	228	-	25	-	-	-	-	-	-	-	-
4a.3	Subtotal Period 4a Collateral Costs	2	220	4	11	-	17	-	41	295	270	-	25	-	40	-	-	-	2,403	8	-
Period 4a Period-Dependent Costs																					
4a.4.1	Decon supplies	66	-	-	-	-	-	-	17	83	83	-	-	-	-	-	-	-	-	-	-
4a.4.2	Insurance	-	-	-	-	-	-	487	49	536	536	-	-	-	-	-	-	-	-	-	-
4a.4.3	Property taxes	-	-	-	-	-	-	1,429	143	1,572	1,572	-	-	-	-	-	-	-	-	-	-
4a.4.4	Health physics supplies	-	1,465	-	-	-	-	-	366	1,832	1,832	-	-	-	-	-	-	-	-	-	-
4a.4.5	Heavy equipment rental	-	2,093	-	-	-	-	-	314	2,407	2,407	-	-	-	-	-	-	-	-	-	-
4a.4.6	Disposal of DAW generated	-	-	71	21	-	266	-	77	434	434	-	-	-	3,264	-	-	-	65,288	106	-
4a.4.7	Plant energy budget	-	-	-	-	-	-	1,372	206	1,578	1,578	-	-	-	-	-	-	-	-	-	-
4a.4.8	NRC Fees	-	-	-	-	-	-	363	36	399	399	-	-	-	-	-	-	-	-	-	-
4a.4.9	Fixed Overhead	-	-	-	-	-	-	1,180	177	1,357	1,357	-	-	-	-	-	-	-	-	-	-
4a.4.10	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	386	58	444	444	-	-	-	-	-	-	-	-	-	-
4a.4.11	Railroad Track Maintenance	-	-	-	-	-	-	55	8	63	63	-	-	-	-	-	-	-	-	-	-
4a.4.12	Security Staff Cost	-	-	-	-	-	-	3,664	550	4,213	4,213	-	-	-	-	-	-	-	-	-	61,973
4a.4.13	DOC Staff Cost	-	-	-	-	-	-	11,794	1,769	13,563	13,563	-	-	-	-	-	-	-	-	-	136,836
4a.4.14	Utility Staff Cost	-	-	-	-	-	-	15,190	2,278	17,468	17,468	-	-	-	-	-	-	-	-	-	247,890
4a.4	Subtotal Period 4a Period-Dependent Costs	66	3,559	71	21	-	266	35,920	6,048	45,950	45,950	-	-	-	3,264	-	-	-	65,288	106	446,699
4a.0	TOTAL PERIOD 4a COST	273	27,002	26,205	3,306	3,363	25,047	37,914	32,581	155,691	153,106	-	2,585	41,316	30,515	125	673	3,746	5,018,150	205,566	451,732
PERIOD 4b - Site Decontamination																					
Period 4b Direct Decommissioning Activities																					
4b.1.1	Remove spent fuel racks	297	32	94	32	-	595	-	319	1,369	1,369	-	-	-	2,092	-	-	-	138,298	576	-
Disposal of Plant Systems																					
4b.1.2.1	ADT & Misc Ventilation	-	21	0	1	13	3	-	8	47	47	-	-	153	9	-	-	-	6,814	325	-
4b.1.2.2	Aux Bldg Normal Ventilation	-	60	2	5	60	11	-	28	165	165	-	-	692	39	-	-	-	30,671	906	-
4b.1.2.3	Aux Bldg Special Ventilation	-	12	0	0	6	2	-	4	25	25	-	-	70	6	-	-	-	3,243	176	-
4b.1.2.4	Battery Rm Special Ventilation	-	1	-	-	-	-	-	0	2	-	-	2	-	-	-	-	-	-	24	-
4b.1.2.5	Boron Recycle	-	3	0	0	0	3	-	2	8	8	-	-	3	9	-	-	-	709	45	-
4b.1.2.6	Chemical & Volume Control	-	822	59	44	204	560	-	388	2,075	2,075	-	-	2,356	1,977	-	-	-	225,854	11,575	-
4b.1.2.7	Cold Chemical Lab Ventilation	-	1	-	-	-	-	-	0	1	-	-	1	-	-	-	-	-	-	9	-

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(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Disposal of Plant Systems (continued)																					
4b.1.2.8	Component Cooling - RCA	-	617	21	70	1,038	-	-	322	2,068	2,068	-	-	11,996	-	-	-	-	487,169	8,583	-
4b.1.2.9	Containment Cooling	-	31	-	-	-	-	-	5	35	-	-	35	-	-	-	-	-	-	502	-
4b.1.2.10	Containment Cooling - RCA	-	288	5	16	237	-	-	110	656	656	-	-	2,743	-	-	-	-	111,390	3,949	-
4b.1.2.11	Containment Hydrogen Control - RCA	-	35	0	1	12	-	-	11	60	60	-	-	141	-	-	-	-	5,742	494	-
4b.1.2.12	Containment Spray - RCA	-	186	3	8	126	-	-	67	389	389	-	-	1,453	-	-	-	-	59,019	2,617	-
4b.1.2.13	Containment Ventilation	-	201	23	38	408	205	-	171	1,047	1,047	-	-	4,721	722	-	-	-	239,450	3,016	-
4b.1.2.14	Control/Relay/Cmptr Rm Vent	-	27	1	2	23	6	-	12	70	70	-	-	260	20	-	-	-	11,915	406	-
4b.1.2.15	Cooling Water	-	139	-	-	-	-	-	21	160	-	-	160	-	-	-	-	-	-	2,344	-
4b.1.2.16	Cooling Water - RCA	-	456	15	49	730	-	-	232	1,482	1,482	-	-	8,442	-	-	-	-	342,822	6,311	-
4b.1.2.17	Cranes/Hoists/Elevators - RCA	-	3	0	1	9	-	-	2	15	15	-	-	103	-	-	-	-	4,184	48	-
4b.1.2.18	D3 Emergency Diesel	-	9	-	-	-	-	-	1	10	-	-	10	-	-	-	-	-	-	141	-
4b.1.2.19	D4 Emergency Diesel	-	9	-	-	-	-	-	1	10	-	-	10	-	-	-	-	-	-	141	-
4b.1.2.20	D5 Emergency Diesel	-	0	-	-	-	-	-	0	0	-	-	0	-	-	-	-	-	-	5	-
4b.1.2.21	Electrical - Clean	-	1,502	-	-	-	-	-	225	1,727	-	-	1,727	-	-	-	-	-	-	24,276	-
4b.1.2.22	Electrical - Contaminated	-	417	5	13	173	21	-	138	767	767	-	-	1,997	75	-	-	-	86,080	5,813	-
4b.1.2.23	Electrical - Contaminated - Fuel Pool	-	178	2	6	75	9	-	59	329	329	-	-	864	33	-	-	-	37,250	2,488	-
4b.1.2.24	Electrical - Decontaminated	-	2,866	33	109	1,622	-	-	980	5,610	5,610	-	-	18,753	-	-	-	-	761,569	38,423	-
4b.1.2.25	Electrical - Decontaminated - Fuel Pool	-	1,230	14	47	698	-	-	421	2,410	2,410	-	-	8,069	-	-	-	-	327,668	16,495	-
4b.1.2.26	Filter Rm Ventilation	-	4	0	0	2	0	-	1	8	8	-	-	24	1	-	-	-	1,020	61	-
4b.1.2.27	Fire Protection & Detection	-	178	-	-	-	-	-	27	205	-	-	205	-	-	-	-	-	-	3,009	-
4b.1.2.28	Fire Protection & Detection - RCA	-	236	3	11	158	-	-	85	492	492	-	-	1,828	-	-	-	-	74,245	3,134	-
4b.1.2.29	Fire Protection & Detection - RCA Fuel P	-	36	1	2	25	-	-	13	76	76	-	-	286	-	-	-	-	11,622	476	-
4b.1.2.30	Fuel Handling	-	64	1	2	17	14	-	22	121	121	-	-	200	49	-	-	-	11,396	983	-
4b.1.2.31	Fuel Oil	-	1	-	-	-	-	-	0	1	-	-	1	-	-	-	-	-	-	9	-
4b.1.2.32	HVAC - Clean	-	132	-	-	-	-	-	20	151	-	-	151	-	-	-	-	-	-	2,373	-
4b.1.2.33	HVAC - Contaminated	-	1,102	26	69	929	115	-	457	2,699	2,699	-	-	10,745	405	-	-	-	463,144	14,282	-
4b.1.2.34	HVAC - Contaminated - Fuel Pool	-	495	12	31	418	52	-	205	1,212	1,212	-	-	4,828	182	-	-	-	208,080	6,417	-
4b.1.2.35	Heating	-	279	-	-	-	-	-	42	321	-	-	321	-	-	-	-	-	-	4,804	-
4b.1.2.36	Heating - RCA	-	323	3	11	165	-	-	107	609	609	-	-	1,907	-	-	-	-	77,458	4,086	-
4b.1.2.37	Hot Lab & Sample Rm Ventilation	-	17	0	1	9	1	-	6	34	34	-	-	107	4	-	-	-	4,632	255	-
4b.1.2.38	Incore Instrumentation	-	26	1	1	5	16	-	12	62	62	-	-	60	58	-	-	-	6,264	412	-
4b.1.2.39	Misc Drains & Vents	-	203	12	9	40	121	-	90	475	475	-	-	458	426	-	-	-	46,850	2,841	-
4b.1.2.40	Misc Lab & Service Areas Vent	-	113	8	6	32	70	-	52	280	280	-	-	370	244	-	-	-	31,186	1,537	-
4b.1.2.41	Miscellaneous Gas	-	63	-	-	-	-	-	9	72	-	-	72	-	-	-	-	-	-	1,073	-
4b.1.2.42	Miscellaneous Gas - RCA	-	129	1	3	52	-	-	41	226	226	-	-	600	-	-	-	-	24,378	1,636	-
4b.1.2.43	Radiation Monitoring	-	6	-	-	-	-	-	1	7	-	-	7	-	-	-	-	-	-	111	-
4b.1.2.44	Radiation Monitoring - RCA	-	62	1	2	27	-	-	20	112	112	-	-	316	-	-	-	-	12,826	782	-
4b.1.2.45	Reactor Coolant	-	207	20	12	20	208	-	110	577	577	-	-	229	730	-	-	-	57,672	2,891	-
4b.1.2.46	Reactor Hot Sampling	-	112	10	5	5	89	-	53	273	273	-	-	54	312	-	-	-	22,919	1,499	-
4b.1.2.47	Reactor Makeup	-	36	-	-	-	-	-	5	41	-	-	41	-	-	-	-	-	-	583	-
4b.1.2.48	Reactor Makeup - RCA	-	4	0	0	2	-	-	1	8	8	-	-	28	-	-	-	-	1,148	47	-
4b.1.2.49	Reactor Vessel	-	16	0	0	2	4	-	5	28	28	-	-	22	14	-	-	-	1,826	225	-
4b.1.2.50	Residual Heat Removal	-	338	84	66	247	924	-	371	2,029	2,029	-	-	2,853	3,244	-	-	-	330,651	5,039	-
4b.1.2.51	Safeguards Chilled Water	-	4	-	-	-	-	-	1	5	-	-	5	-	-	-	-	-	-	75	-
4b.1.2.52	Safeguards Chilled Water - RCA	-	4	0	0	2	-	-	1	8	8	-	-	26	-	-	-	-	1,045	51	-
4b.1.2.53	Safety Injection	-	758	40	56	577	329	-	371	2,131	2,131	-	-	6,676	1,161	-	-	-	347,600	11,029	-
4b.1.2.54	Sampling	-	46	3	2	3	27	-	19	100	100	-	-	37	93	-	-	-	7,697	645	-
4b.1.2.55	Service Bldg & New Cmptr Vent	-	0	-	-	-	-	-	0	0	-	-	0	-	-	-	-	-	-	6	-
4b.1.2.56	Shield Bldg Ventilation	-	103	13	19	175	138	-	91	539	539	-	-	2,028	484	-	-	-	114,378	1,555	-
4b.1.2.57	Spent Fuel Pool Cooling	-	32	3	2	3	30	-	17	87	87	-	-	39	107	-	-	-	8,635	427	-
4b.1.2.58	Spent Fuel Pool Normal Ventilation	-	23	1	2	23	3	-	10	62	62	-	-	265	12	-	-	-	11,532	352	-
4b.1.2.59	Station & Instrument Air	-	140	-	-	-	-	-	21	161	-	-	161	-	-	-	-	-	-	2,424	-
4b.1.2.60	Station & Instrument Air - RCA	-	288	3	9	141	-	-	95	535	535	-	-	1,625	-	-	-	-	65,986	3,638	-
4b.1.2.61	Turbine Bldg Traps & Drains	-	26	-	-	-	-	-	4	30	-	-	30	-	-	-	-	-	-	462	-
4b.1.2.62	Turbine Bldg Traps & Drains - RCA	-	28	0	1	16	-	-	10	55	55	-	-	180	-	-	-	-	7,321	344	-
4b.1.2.63	Turbine Bldg Ventilation	-	40	-	-	-	-	-	6	46	-	-	46	-	-	-	-	-	-	655	-
4b.1.2.64	Unit Coolers	-	20	-	-	-	-	-	3	23	-	-	23	-	-	-	-	-	-	332	-
4b.1.2.65	Unit Coolers - RCA	-	54	0	1	20	-	-	17	93	93	-	-	232	-	-	-	-	9,413	690	-
4b.1.2.66	Waste Gas Disposal	-	417	40	35	212	381	-	241	1,327	1,327	-	-	2,453	1,358	-	-	-	188,334	5,879	-
4b.1.2.67	Waste Liquid Disposal	-	1,581	108	76	316	1,019	-	720	3,819	3,819	-	-	3,655	3,594	-	-	-	385,370	22,011	-
4b.1.2.68	Waste Solid Disposal	-	127	11	8	34	112	-	67	358	358	-	-	389	393	-	-	-	41,732	1,781	-
4b.1.2	Totals	-	16,987	591	852	9,112	4,472	-	6,657	38,670	35,660	-	3,010	105,339	15,761	-	-	-	5,317,908	240,033	-
4b.1.3	Scaffolding in support of decommissioning	-	4,024	36	12	146	38	-	1,043	5,298	5,298	-	-	1,518	134	-	-	-	77,168	35,578	-

Table I-2
Prairie Island Nuclear Generating Plant, Unit 2
SAFSTOR Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Decontamination of Site Buildings																					
4b.1.4.1	Reactor	1,037	2,361	118	833	193	6,373	-	2,868	13,784	13,784	-	-	2,230	36,903	-	-	-	3,286,751	45,596	-
4b.1.4.2	Auxiliary	1,105	356	12	80	92	582	-	814	3,040	3,040	-	-	1,060	3,355	-	-	-	332,498	21,222	-
4b.1.4.3	Backwash Waste Receiving Tank	-	24	1	11	-	87	-	30	154	154	-	-	-	507	-	-	-	43,896	264	-
4b.1.4.4	Drum Transfer & Truck Loading Enclosure	15	7	0	2	2	13	-	13	52	52	-	-	19	74	-	-	-	7,118	328	-
4b.1.4.5	LLRW Storage Enclosure	105	45	1	11	3	87	-	88	341	341	-	-	38	502	-	-	-	44,971	2,149	-
4b.1.4.6	Radwaste	47	20	1	5	4	39	-	40	155	155	-	-	42	225	-	-	-	21,136	963	-
4b.1.4.7	Resin Disposal	14	10	0	2	7	12	-	14	60	60	-	-	83	69	-	-	-	9,271	340	-
4b.1.4.8	Fuel Handling of Aux Building	875	966	9	32	209	173	-	759	3,024	3,024	-	-	2,417	944	-	-	-	177,818	27,141	-
4b.1.4	Totals	3,199	3,791	143	977	509	7,366	-	4,626	20,611	20,611	-	-	5,889	42,580	-	-	-	3,923,460	98,004	-
4b.1.5	Prepare/submit License Termination Plan	-	-	-	-	-	-	206	31	236	236	-	-	-	-	-	-	-	-	-	1,751
4b.1.6	Receive NRC approval of termination plan									a											
4b.1	Subtotal Period 4b Activity Costs	3,496	24,833	864	1,872	9,767	12,471	206	12,675	66,184	63,174	-	3,010	112,746	60,568	-	-	-	9,456,834	374,192	1,751
Period 4b Additional Costs																					
4b.2.1	License Termination Survey Planning	-	-	-	-	-	-	845	253	1,098	1,098	-	-	-	-	-	-	-	-	-	6,240
4b.2.2	Remedial Action Surveys	-	-	-	-	-	-	2,832	849	3,681	3,681	-	-	-	-	-	-	-	-	37,017	-
4b.2.3	Excavation of Underground Services	-	811	-	-	-	-	520	200	1,531	-	-	1,531	-	-	-	-	-	-	7,407	-
4b.2.4	Operational Equipment	-	-	9	29	312	-	-	52	402	402	-	-	5,855	-	-	-	-	146,375	16	-
4b.2.5	License Termination ISFSI	-	37	2	211	-	2,157	1,186	898	4,491	4,491	-	-	-	7,458	-	-	-	1,071,985	3,670	5,284
4b.2.6	Demolition and Site Restoration ISFSI	-	495	-	-	-	-	87	87	669	-	-	669	-	-	-	-	-	-	2,308	160
4b.2	Subtotal Period 4b Additional Costs	-	1,342	11	240	312	2,157	5,469	2,340	11,872	9,672	-	2,200	5,855	7,458	-	-	-	1,218,360	50,417	11,684
Period 4b Collateral Costs																					
4b.3.1	Process decommissioning water waste	7	-	11	29	-	46	-	20	113	113	-	-	-	109	-	-	-	6,546	21	-
4b.3.3	Small tool allowance	-	418	-	-	-	-	-	63	481	481	-	-	-	-	-	-	-	-	-	-
4b.3.4	Decommissioning Equipment Disposition	-	-	144	55	575	150	-	147	1,071	1,071	-	-	6,000	529	-	-	-	304,968	88	-
4b.3.5	On-site survey and release of 0.437 tons clean metallic waste	-	-	-	-	-	-	1	0	1	1	-	-	-	-	-	-	-	-	-	-
4b.3	Subtotal Period 4b Collateral Costs	7	418	155	84	575	196	1	229	1,665	1,665	-	-	6,000	638	-	-	-	311,514	109	-
Period 4b Period-Dependent Costs																					
4b.4.1	Decon supplies	1,338	-	-	-	-	-	-	335	1,673	1,673	-	-	-	-	-	-	-	-	-	-
4b.4.2	Insurance	-	-	-	-	-	-	910	91	1,001	1,001	-	-	-	-	-	-	-	-	-	-
4b.4.3	Property taxes	-	-	-	-	-	-	2,554	255	2,809	2,809	-	-	-	-	-	-	-	-	-	-
4b.4.4	Health physics supplies	-	2,900	-	-	-	-	-	725	3,625	3,625	-	-	-	-	-	-	-	-	-	-
4b.4.5	Heavy equipment rental	-	4,021	-	-	-	-	-	603	4,624	4,624	-	-	-	-	-	-	-	-	-	-
4b.4.6	Disposal of DAW generated	-	-	128	37	-	476	-	137	778	778	-	-	-	5,849	-	-	-	116,984	191	-
4b.4.7	Plant energy budget	-	-	-	-	-	-	2,023	303	2,326	2,326	-	-	-	-	-	-	-	-	-	-
4b.4.8	NRC Fees	-	-	-	-	-	-	677	68	745	745	-	-	-	-	-	-	-	-	-	-
4b.4.9	Fixed Overhead	-	-	-	-	-	-	2,205	331	2,535	2,535	-	-	-	-	-	-	-	-	-	-
4b.4.10	Liquid Radwaste Processing Equipment/Services	-	-	-	-	-	-	721	108	829	829	-	-	-	-	-	-	-	-	-	-
4b.4.11	Railroad Track Maintenance	-	-	-	-	-	-	103	15	118	118	-	-	-	-	-	-	-	-	-	-
4b.4.12	Security Staff Cost	-	-	-	-	-	-	6,843	1,026	7,870	7,870	-	-	-	-	-	-	-	-	-	115,753
4b.4.13	DOC Staff Cost	-	-	-	-	-	-	21,571	3,236	24,806	24,806	-	-	-	-	-	-	-	-	-	248,175
4b.4.14	Utility Staff Cost	-	-	-	-	-	-	26,893	4,034	30,927	30,927	-	-	-	-	-	-	-	-	-	437,085
4b.4	Subtotal Period 4b Period-Dependent Costs	1,338	6,921	128	37	-	476	64,499	11,268	84,667	84,667	-	-	-	5,849	-	-	-	116,984	191	801,014
4b.0	TOTAL PERIOD 4b COST	4,841	33,514	1,158	2,234	10,654	15,300	70,175	26,513	164,387	159,178	-	5,210	124,601	74,513	-	-	-	11,103,690	424,909	814,449
PERIOD 4f - License Termination																					
Period 4f Direct Decommissioning Activities																					
4f.1.1	ORISE confirmatory survey	-	-	-	-	-	-	176	53	229	229	-	-	-	-	-	-	-	-	-	-
4f.1.2	Terminate license									a											
4f.1	Subtotal Period 4f Activity Costs	-	-	-	-	-	-	176	53	229	229	-	-	-	-	-	-	-	-	-	-
Period 4f Additional Costs																					
4f.2.1	License Termination Survey	-	-	-	-	-	-	7,406	2,222	9,628	9,628	-	-	-	-	-	-	-	-	102,642	3,120
4f.2	Subtotal Period 4f Additional Costs	-	-	-	-	-	-	7,406	2,222	9,628	9,628	-	-	-	-	-	-	-	-	102,642	3,120
Period 4f Collateral Costs																					
4f.3.1	DOC staff relocation expenses	-	-	-	-	-	-	1,189	178	1,367	1,367	-	-	-	-	-	-	-	-	-	-
4f.3	Subtotal Period 4f Collateral Costs	-	-	-	-	-	-	1,189	178	1,367	1,367	-	-	-	-	-	-	-	-	-	-

Table I-2
Prairie Island Nuclear Generating Plant, Unit 2
SAFSTOR Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes				Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
															Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet			
Period 4f Period-Dependent Costs																					
4f.4.1	Insurance	-	-	-	-	-	-	382	38	420	420	-	-	-	-	-	-	-	-	-	-
4f.4.2	Property taxes	-	-	-	-	-	-	1,002	100	1,102	1,102	-	-	-	-	-	-	-	-	-	-
4f.4.3	Health physics supplies	-	600	-	-	-	-	-	150	750	750	-	-	-	-	-	-	-	-	-	-
4f.4.4	Disposal of DAW generated	-	-	7	2	-	27	-	8	44	44	-	-	-	332	-	-	-	6,649	11	-
4f.4.5	Plant energy budget	-	-	-	-	-	-	227	34	261	261	-	-	-	-	-	-	-	-	-	-
4f.4.6	NRC Fees	-	-	-	-	-	-	272	27	299	299	-	-	-	-	-	-	-	-	-	-
4f.4.7	Fixed Overhead	-	-	-	-	-	-	926	139	1,065	1,065	-	-	-	-	-	-	-	-	-	-
4f.4.8	Railroad Track Maintenance	-	-	-	-	-	-	43	6	50	50	-	-	-	-	-	-	-	-	-	-
4f.4.9	Security Staff Cost	-	-	-	-	-	-	707	106	813	813	-	-	-	-	-	-	-	-	-	11,668
4f.4.10	DOC Staff Cost	-	-	-	-	-	-	4,101	615	4,716	4,716	-	-	-	-	-	-	-	-	-	46,283
4f.4.11	Utility Staff Cost	-	-	-	-	-	-	3,630	544	4,174	4,174	-	-	-	-	-	-	-	-	-	56,395
4f.4	Subtotal Period 4f Period-Dependent Costs	-	600	7	2	-	27	11,289	1,768	13,695	13,695	-	-	-	332	-	-	-	6,649	11	114,346
4f.0	TOTAL PERIOD 4f COST	-	600	7	2	-	27	20,061	4,222	24,919	24,919	-	-	-	332	-	-	-	6,649	102,652	117,466
PERIOD 4 TOTALS		5,114	61,116	27,370	5,542	14,017	40,374	128,149	63,315	344,997	337,203	-	7,794	165,917	105,360	125	673	3,746	16,128,490	733,128	1,383,647
PERIOD 5b - Site Restoration																					
Period 5b Direct Decommissioning Activities																					
Demolition of Remaining Site Buildings																					
5b.1.1.1	Reactor	-	4,256	-	-	-	-	-	638	4,895	-	-	4,895	-	-	-	-	-	-	44,679	-
5b.1.1.2	Auxiliary	-	1,897	-	-	-	-	-	285	2,182	-	-	2,182	-	-	-	-	-	-	11,902	-
5b.1.1.3	Condensate Storage Tank Foundation	-	6	-	-	-	-	-	1	7	-	-	7	-	-	-	-	-	-	33	-
5b.1.1.4	Construction Warehouse & Fab Shop	-	118	-	-	-	-	-	18	135	-	-	135	-	-	-	-	-	-	1,405	-
5b.1.1.5	D3/D4 Emergency Generator	-	13	-	-	-	-	-	2	15	-	-	15	-	-	-	-	-	-	84	-
5b.1.1.6	Drum Transfer & Truck Loading Enclosure	-	19	-	-	-	-	-	3	21	-	-	21	-	-	-	-	-	-	221	-
5b.1.1.7	Hydrogen House	-	6	-	-	-	-	-	1	7	-	-	7	-	-	-	-	-	-	47	-
5b.1.1.8	LLRW Storage Enclosure	-	121	-	-	-	-	-	18	139	-	-	139	-	-	-	-	-	-	853	-
5b.1.1.9	Misc Structures 2017	-	1,391	-	-	-	-	-	209	1,599	-	-	1,599	-	-	-	-	-	-	12,939	-
5b.1.1.10	Radwaste	-	165	-	-	-	-	-	25	190	-	-	190	-	-	-	-	-	-	1,400	-
5b.1.1.11	Resin Disposal	-	13	-	-	-	-	-	2	15	-	-	15	-	-	-	-	-	-	120	-
5b.1.1.12	Structures below 3' below grade	-	1,713	-	-	-	-	-	257	1,969	-	-	1,969	-	-	-	-	-	-	9,238	-
5b.1.1.13	Sulfuric Acid Tank Enclosure	-	3	-	-	-	-	-	0	3	-	-	3	-	-	-	-	-	-	35	-
5b.1.1.14	Turbine	-	1,983	-	-	-	-	-	298	2,281	-	-	2,281	-	-	-	-	-	-	22,052	-
5b.1.1.15	Turbine Pedestal	-	349	-	-	-	-	-	52	402	-	-	402	-	-	-	-	-	-	1,857	-
5b.1.1.16	Warehouse #2	-	22	-	-	-	-	-	3	25	-	-	25	-	-	-	-	-	-	213	-
5b.1.1.17	Waste Neutralizing Tank House	-	7	-	-	-	-	-	1	8	-	-	8	-	-	-	-	-	-	56	-
5b.1.1.18	Waste Oil Storage	-	8	-	-	-	-	-	1	10	-	-	10	-	-	-	-	-	-	70	-
5b.1.1.19	Water Treatment	-	303	-	-	-	-	-	46	349	-	-	349	-	-	-	-	-	-	2,690	-
5b.1.1.20	Fuel Handling of Aux Building	-	1,032	-	-	-	-	-	155	1,186	-	-	1,186	-	-	-	-	-	-	8,240	-
5b.1.1	Totals	-	13,424	-	-	-	-	-	2,014	15,438	-	-	15,438	-	-	-	-	-	-	118,134	-
Site Closeout Activities																					
5b.1.2	Remove Rubble	-	1,492	-	-	-	-	-	224	1,716	-	-	1,716	-	-	-	-	-	-	7,408	-
5b.1.3	Grade & landscape site	-	431	-	-	-	-	-	65	495	-	-	495	-	-	-	-	-	-	921	-
5b.1.4	Final report to NRC	-	-	-	-	-	-	78	12	90	90	-	-	-	-	-	-	-	-	-	667
5b.1	Subtotal Period 5b Activity Costs	-	15,347	-	-	-	-	78	2,314	17,740	90	-	17,650	-	-	-	-	-	-	126,463	667
Period 5b Additional Costs																					
5b.2.1	Clean Concrete Disposal	-	3,313	-	-	-	-	8	498	3,818	-	-	3,818	-	-	-	-	-	-	12,824	-
5b.2.2	Intake Structure Cofferdam	-	423	-	-	-	-	-	63	486	-	-	486	-	-	-	-	-	-	3,552	-
5b.2.3	Construction Debris	-	-	-	-	-	-	463	69	532	-	-	532	-	-	-	-	-	-	-	-
5b.2.4	Backfill	-	8,465	-	-	-	-	-	1,270	9,735	-	-	9,735	-	-	-	-	-	-	9,327	-
5b.2	Subtotal Period 5b Additional Costs	-	12,201	-	-	-	-	471	1,901	14,572	-	-	14,572	-	-	-	-	-	-	25,703	-
Period 5b Collateral Costs																					
5b.3.1	Small tool allowance	-	169	-	-	-	-	-	25	194	-	-	194	-	-	-	-	-	-	-	-
5b.3	Subtotal Period 5b Collateral Costs	-	169	-	-	-	-	-	25	194	-	-	194	-	-	-	-	-	-	-	-
Period 5b Period-Dependent Costs																					
5b.4.2	Property taxes	-	-	-	-	-	-	526	53	579	-	-	579	-	-	-	-	-	-	-	-
5b.4.3	Heavy equipment rental	-	6,670	-	-	-	-	-	1,000	7,670	-	-	7,670	-	-	-	-	-	-	-	-
5b.4.4	Plant energy budget	-	-	-	-	-	-	321	48	369	-	-	369	-	-	-	-	-	-	-	-
5b.4.5	Fixed Overhead	-	-	-	-	-	-	990	148	1,138	-	-	1,138	-	-	-	-	-	-	-	-
5b.4.6	Railroad Track Maintenance	-	-	-	-	-	-	122	18	141	-	-	141	-	-	-	-	-	-	-	-

Table I-2
Prairie Island Nuclear Generating Plant, Unit 2
SAFSTOR Decommissioning Cost Estimate with 60 Years of Spent Fuel Storage
(thousands of 2017 dollars)

Activity Index	Activity Description	Decon Cost	Removal Cost	Packaging Costs	Transport Costs	Off-Site Processing Costs	LLRW Disposal Costs	Other Costs	Total Contingency	Total Costs	NRC Lic. Term. Costs	Spent Fuel Management Costs	Site Restoration Costs	Processed Volume Cu. Feet	Burial Volumes Class A Cu. Feet	Class B Cu. Feet	Class C Cu. Feet	GTCC Cu. Feet	Burial / Processed Wt., Lbs.	Craft Manhours	Utility and Contractor Manhours
Period 5b Period-Dependent Costs (continued)																					
5b.4.7	Security Staff Cost	-	-	-	-	-	-	1,812	272	2,084	-	-	2,084	-	-	-	-	-	-	-	29,221
5b.4.8	DOC Staff Cost	-	-	-	-	-	-	10,467	1,570	12,038	-	-	12,038	-	-	-	-	-	-	-	116,885
5b.4.9	Utility Staff Cost	-	-	-	-	-	-	3,673	551	4,224	-	-	4,224	-	-	-	-	-	-	-	57,340
5b.4	Subtotal Period 5b Period-Dependent Costs	-	6,670	-	-	-	-	17,912	3,661	28,242	-	-	28,242	-	-	-	-	-	-	-	203,445
5b.0	TOTAL PERIOD 5b COST	-	34,387	-	-	-	-	18,461	7,901	60,748	90	-	60,658	-	-	-	-	-	-	152,166	204,112
PERIOD 5 TOTALS		-	34,387	-	-	-	-	18,461	7,901	60,748	90	-	60,658	-	-	-	-	-	-	152,166	204,112
TOTAL COST TO DECOMMISSION		**11,867**	**108,467**	**27,994**	**6,103**	**14,186**	**42,876**	**846,728**	**165,730**	**1,223,951**	**846,342**	**308,520**	**69,089**	**172,241**	**127,192**	**125**	**673**	**3,746**	**16,886,950**	**980,773**	**5,563,697**

TOTAL COST TO DECOMMISSION WITH 15.66% CONTINGENCY:	**$1,223,951**	**thousands of 2017 dollars**
TOTAL NRC LICENSE TERMINATION COST IS 69.15% OR:	**$846,342**	**thousands of 2017 dollars**
SPENT FUEL MANAGEMENT COST IS 25.21% OR:	**$308,520**	**thousands of 2017 dollars**
NON-NUCLEAR DEMOLITION COST IS 5.64% OR:	**$69,089**	**thousands of 2017 dollars**
TOTAL LOW-LEVEL RADIOACTIVE WASTE VOLUME BURIED (EXCLUDING GTCC):	**127,991**	**cubic feet**
TOTAL GREATER THAN CLASS C RADWASTE VOLUME GENERATED:	**3,746**	**cubic feet**
TOTAL SCRAP METAL REMOVED:	**41,593**	**tons**
TOTAL CRAFT LABOR REQUIREMENTS:	**980,773**	**man-hours**

End Notes:
n/a - indicates that this activity not charged as decommissioning expense
a - indicates that this activity performed by decommissioning staff
0 - indicates that this value is less than 0.5 but is non-zero
A cell containing " - " indicates a zero value

APPENDIX J

ISFSI DECOMMISSIONING

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Table J-1
Prairie Island Nuclear Generating Plant
Scenarios 1 & 6
ISFSI Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Description	Removal Costs	Packaging Costs	Transport Costs	LLRW Disposal Costs	Other Costs	Total Costs	Burial Volume Class A (cubic feet)	Craft Manhours	Oversight and Contractor Manhours
Decommissioning Contractor									
Planning (characterization, specs and procedures)	-	-	-	-	200	200	-	-	1,000
Decontamination (activated disposition)	73	3	422	4,315	-	4,813	14,916	526	-
License Termination (radiological surveys)	-	-	-	-	808	808	-	6,279	-
Subtotal	**73**	**3**	**422**	**4,315**	**1,008**	**5,821**	**14,916**	**6,805**	**1,000**
Supporting Costs									
NRC and NRC Contractor Fees and Costs					357	357	-	-	776
Insurance					193	193	-	-	-
Property taxes					51	51	-	-	-
Site O&M Cost					101	101	-	-	-
Railroad Track Maintenance					38	38	-	-	-
Security Staff Cost					308	308	-	-	4,999
Oversight Staff Cost					260	260	-	-	3,792
Subtotal	**-**	**-**	**-**	**-**	**1,308**	**1,308**	**-**	**-**	**9,568**
Total (w/o contingency)	**73**	**3**	**422**	**4,315**	**2,316**	**7,129**	**14,916**	**6,805**	**10,568**
Total (w/25% contingency)						**8,912**			

The application of contingency (25%) is consistent with the evaluation criteria referenced by the NRC in NUREG-1757 ("Consolidated Decommissioning Guidance, Financial Assurance, Recordkeeping, and Timeliness," U.S. NRC's Office of Nuclear Material Safety and Safeguards, NUREG-1757, Vol. 3, Rev. 1, February 2012)

Table J-2
Prairie Island Nuclear Generating Plant
Scenarios 2 & 7
ISFSI Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Description	Removal Costs	Packaging Costs	Transport Costs	LLRW Disposal Costs	Other Costs	Total Costs	Burial Volume Class A (cubic feet)	Craft Manhours	Oversight and Contractor Manhours
Decommissioning Contractor									
Planning (characterization, specs and procedures)	-	-	-	-	200	200	-	-	1,000
Decontamination (activated disposition)	73	3	422	4,315	-	4,813	14,916	526	-
License Termination (radiological surveys)	-	-	-	-	865	865	-	6,813	-
Subtotal	73	3	422	4,315	**1,065**	**5,878**	14,916	7,339	1,000
Supporting Costs									
NRC and NRC Contractor Fees and Costs					356	356	-	-	776
Insurance					193	193	-	-	-
Property taxes					51	51	-	-	-
Site O&M Cost					101	101	-	-	-
Railroad Track Maintenance					38	38	-	-	-
Security Staff Cost					308	308	-	-	4,999
Oversight Staff Cost					260	260	-	-	3,792
Subtotal	-	-	-	-	**1,307**	**1,307**	**-**	**-**	**9,568**
Total (w/o contingency)	**73**	**3**	**422**	**4,315**	**2,372**	**7,185**	**14,916**	**7,339**	**10,568**
Total (w/25% contingency)						**8,982**			

The application of contingency (25%) is consistent with the evaluation criteria referenced by the NRC in NUREG-1757 ("Consolidated Decommissioning Guidance, Financial Assurance, Recordkeeping, and Timeliness," U.S. NRC's Office of Nuclear Material Safety and Safeguards, NUREG-1757, Vol. 3, Rev. 1, February 2012)

Table J-3
Prairie Island Nuclear Generating Plant
Scenario 3 & 4
ISFSI Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Description	Decon Costs	Removal Costs	Packaging Costs	Transport Costs	LLRW Disposal Costs	Other Costs	Total Costs	Burial Volume Class A (cubic feet)	Craft Manhours	Oversight and Contractor Manhours
Decommissioning Contractor										
Planning (characterization, specs and procedures)	-	-	-	-	-	296	296	-	-	1,168
Decontamination (activated disposition)	30	2	1	5	38	-	76	254	365	-
License Termination (radiological surveys)	-	-	-	-	-	1,288	1,288	-	10,842	-
Subtotal	**30**	**2**	**1**	**5**	**38**	**1,584**	**1,660**	**254**	**11,207**	**1,168**
Supporting Costs										
NRC and NRC Contractor Fees and Costs						357	357	-	-	776
Insurance						193	193	-	-	-
Property taxes						51	51	-	-	-
Site O&M Cost						101	101	-	-	-
Railroad Track Maintenance						38	38	-	-	-
Security Staff Cost						308	308	-	-	4,999
Oversight Staff Cost						260	260	-	-	3,792
Subtotal	**-**	**-**	**-**	**-**	**-**	**1,308**	**1,308**	**-**	**-**	**4,396**
Total (w/o contingency)	**30**	**2**	**1**	**5**	**38**	**2,892**	**2,968**	**254**	**11,207**	**5,564**
Total (w/25% contingency)							**3,711**			

The application of contingency (25%) is consistent with the evaluation criteria referenced by the NRC in NUREG-1757 ("Consolidated Decommissioning Guidance, Financial Assurance, Recordkeeping, and Timeliness," U.S. NRC's Office of Nuclear Material Safety and Safeguards, NUREG-1757, Vol. 3, Rev. 1, February 2012)

Table J-4
Prairie Island Nuclear Generating Plant
Scenario 5
ISFSI Decommissioning Cost Estimate
(thousands of 2017 dollars)

Activity Description	Decon Costs	Removal Costs	Packaging Costs	Transport Costs	LLRW Disposal Costs	Other Costs	Total Costs	Burial Volume Class A (cubic feet)	Craft Manhours	Oversight and Contractor Manhours
Decommissioning Contractor										
Planning (characterization, specs and procedures)	-	-	-	-	-	241	241	-	-	1,072
Decontamination (activated disposition)	30	96	4	427	4,579	-	5,136	16,457	1,123	-
License Termination (radiological surveys)	-	-	-	-	-	1,136	1,136	-	9,412	-
Subtotal	**30**	**96**	**4**	**427**	**4,579**	**1,377**	**6,513**	**16,457**	**10,535**	**1,072**
Supporting Costs										
NRC and NRC Contractor Fees and Costs						357	357	-	-	776
Insurance						193	193	-	-	-
Property taxes						51	51	-	-	-
Fixed Overhead						101	101	-	-	-
Railroad Track Maintenance						38	38	-	-	-
Security Staff Cost						308	308	-	-	4,999
Oversight Staff Cost						260	260	-	-	3,792
Subtotal	**-**	**-**	**-**	**-**	**-**	**476**	**1,308**	**-**	**-**	**8,792**
Total (w/o contingency)	**30**	**96**	**4**	**427**	**4,579**	**1,853**	**7,821**	**16,457**	**10,535**	**9,864**
Total (w/25% contingency)							**9,777**			

The application of contingency (25%) is consistent with the evaluation criteria referenced by the NRC in NUREG-1757 ("Consolidated Decommissioning Guidance, Financial Assurance, Recordkeeping, and Timeliness," U.S. NRC's Office of Nuclear Material Safety and Safeguards, NUREG-1757, Vol. 3, Rev. 1, February 2012)

APPENDIX N10 – NUCLEAR WORKER TRANSITION PLAN

I. INTRODUCTION

Minn. Stat. § 3.8851, subd. 4 requires Northern States Power Company, doing business as Xcel Energy, to submit to the Minnesota Public Utilities Commission updates periodically, with the resource plan filing, of the Worker Transition Plan (WTP) required under Minn. Stat. § 116C.772, subd. 3. The WTP is required to address the event of a shutdown of Prairie Island nuclear generating plant for longer than six months.

The 1995 WTP (the original filing of this plan) reported that the conditions that could lead to a short lead-time reactive worker transition due to an unplanned immediate shutdown were not typical of the scenario facing Minnesota. Minnesota's Monticello and Prairie Island Nuclear generating plants have a long history of being well-maintained resulting in safe, reliable and economic operations. The WTP described in 1995 assumed a long lead-time, proactive approach. Monticello and Prairie Island Units 1 and 2 continue to have strong operating records and are expected to operate until at least 2030, 2033 and 2034 respectively. This update continues to assume the long lead-time proactive approach to a WTP.

II. TRANSITION PLAN PHILOSOPHY

Monticello will reach the end of its current operating license in 11 years, or 2030. As part of our preferred plan, we are proposing to extend Monticello operations through 2040 or 21 years from now. Prairie Island Unit 1 will reach the end of its current operating license in 14 years, or 2033, and Prairie Island Unit 2 will reach the end of its current operating license in 15 years, or 2034. These extended operating periods and Xcel Energy's commitment to employees affords the opportunity to plan for employee transition resulting from a planned plant closure. Xcel Energy will continue to base staffing decisions on operational excellence and Nuclear Regulatory Commission (NRC) requirements that may result in changed staff assignments and levels.

Monticello and Prairie Island nuclear generating plants are operated by dedicated nuclear professionals. The extended plant lives, the fact that many workers will reach retirement age well before the extended licenses will expire, and a strong management commitment are critical to the success of the Xcel Energy Worker Transition Plan. This strategy provides employees the opportunity to develop their skills inventories so they are congruent with the changing needs of the company and the marketplace.

The proactive approach to managing human resources produces a workforce that is motivated, cross-functional and flexible. This approach greatly reduces the need for reactive planning.

Should Prairie Island or Monticello close, there are four transition paths available. They are:

1. Stay with Xcel Energy in a similar job/career path.
2. Stay with Xcel Energy in a different job/career path.
3. Retire.
4. Leave Xcel Energy for outside employment opportunities.

The proactive strategy for managing human resources allows employees to prepare for each path, and thus position themselves for a number of potential outcomes. Xcel Energy acknowledges that a proactive transition requires prior planning, total management support, complete understanding and support throughout all levels of the corporation and a comprehensive guiding process.

Xcel Energy values its employees and recognizes that they make the nuclear operations excellent. Xcel Energy has an obligation to help employees plan for the future. The result of effective planning is a partnership that yields strong nuclear operations and satisfied employees. Approximately 1,150 permanent, skilled positions would be eliminated or restructured should Monticello and Prairie Island close. Providing these employees with avenues to enhance their skills prior to plant closing will make the transition to new jobs (inside or outside of Xcel Energy) easier, but not painless. Xcel Energy's objective is to structure and develop its work force to meet the challenges inherent in a competitive business environment. That objective will be accomplished by:

1. Establishing Business Plan workforce effectiveness goals.
2. Translating those goals into an effective Human Asset Plan.
3. Producing employee development plans.

A breakdown of the number of employees that work at Monticello and Prairie Island appears in Table 1 below.

Table 1: Nuclear Employee Breakdown

	Nuclear Department		Total
	Bargaining	Non-bargaining	
Monticello	185	325	510
Prairie Island	335	311	646
Total	520	636	1,156

III. XCEL ENERGY TRANSITION PROCESSES

The transition processes described below apply to both non-bargaining and bargaining unit employees at Monticello and Prairie Island. For bargaining unit employees the transition plan is in accordance with the collective bargaining agreement and Xcel Energy programs and processes as described below.

IV. INTERNAL PLACEMENT

A. Job Opportunity Bulletin

Xcel Energy provides online notification of employment and career development opportunities in all new or replacement positions. This process, in accordance with our collective bargaining agreement, is used prior to outside hiring.

B. Leadership Essentials

Xcel Energy has a program to identify employees interested in becoming a member of the Xcel Energy management team, and provides assessment and development to them. Leadership Essentials is an on-line resource designed to help both beginning and experienced leaders learn, and continue to develop various leadership skills. All union employees are invited to participate.

C. Corporate Training Programs

Xcel Energy offers employees training and development courses for skills needed to stay current in their present job and development courses to prepare them for future positions. This training covers technical, computer and business skills.

D. Apprenticeship Training Programs

An apprentice is a person engaged in training for one of the skill areas covered in the current labor agreement. Programs are State of Minnesota registered and provide on-the-job training and related instruction in all areas of the apprenticeship being served.

E. Tuition Reimbursement

The Tuition Reimbursement Program gives employees financial assistance to take courses offered by accredited schools and institutions of higher learning to complete a degree program.

F. Severance

1. The severance pay agreement for bargaining unit employees is covered in the current labor agreements with IBEW locals 160 and 949.
2. The Company has a severance plan for non-bargaining employees which covers regular, full-time or part-time employees of the Company not covered by a current labor agreement. To be eligible for severance, certain eligibility requirements must be met.

V. SUMMARY

The foundation for this type of worker transition program is based on the availability of long-term planning. If a premature closure of Prairie Island or Monticello were to occur, the results would be less favorable. In that case, employees would be afforded less time to prepare themselves for other employment within Xcel Energy or for careers outside of the company. No amount of prior planning can alleviate employees' personal hardships should a valuable and efficient plant be forced to close prematurely. Such an occurrence would be highly speculative, and it would not be cost-effective to prepare contingencies based on scenarios that are not likely to occur.

VI. CONCLUSIONS

1. Xcel Energy is committed to its employees. That commitment is reflected in the scope of resources available to employees. Xcel Energy will continue to invest heavily in employees' training and development so that the transition to a business environment will be proactive.
2. Xcel Energy's commitment to excellence in operations is unequivocal, as is the Company's commitment to operate Monticello and Prairie Island

Units 1 and 2 until 2030, 2033 and 2034, respectively. In addition, as part of our preferred plan we are proposing to extend Monticello another 10 years through 2040.

3. The long lead-time prior to potential plant closings affords Xcel Energy and its employees an opportunity to plan for the transition.
4. An orderly transition is possible through Business and Human Asset Planning as performed by Xcel Energy.

VII. COMMITMENTS

1. Xcel Energy will continue to account for changes in the workforce through business planning and Human Asset Planning.
2. Xcel Energy will continue to work with affected unions to promote the retention and training of its highly skilled and dedicated workforce.

APPENDIX O1 – SUMMARY OF IRP STAKEHOLDER ENGAGEMENT

Our plans for the future of our integrated system impact five states, millions of customers, thousands of employees, and hundreds of communities. We understand the interest and desire for stakeholders to be involved and help shape the future of our system. In light of this interest, we developed our Integrated Resource Plan through a robust external stakeholder process. This includes holding stakeholder workshops, engaging third party consultants, participating in studies that evaluate the impact of plant retirements on host communities, and working with the labor unions to ensure smooth transitions for our impacted employees. Below we discuss our stakeholder work to date in more detail.

I. STAKEHOLDER WORKSHOPS

The Company made a concerted effort to work with stakeholders in developing the Resource Plan, through both workshops and one-on-one meetings. We sent email invitations to over 300 individual stakeholders or organizations and held 13 public workshops that provided a forum for productive dialogue and education. Our goal was to educate stakeholders on the resource planning process and our Upper Midwest system – as well as gather stakeholder feedback and perspectives for incorporation into our Resource Plan. We also wanted to increase accessibility to our subject matter experts and the supporting data while enhancing collaboration. The meetings also revealed stakeholders' desire for additional, deeper discussions about our system, our Resource Plan, and the broader context of statewide decarbonization pathways.

Our meetings covered a variety of topics and featured external speakers and stakeholders including Chris Clack with Vibrant Clean Energy, Jesse Jenkins with Massachusetts Institute of Technology,[1] MISO, the Center for Energy and Environment, the Coalition of Host Communities, and Community Power. Table 1 below lists the Workshops we hosted.

[1] Now at the Harvard University Center for the Environment.

Table 1: Stakeholder Workshops

Workshop Topic	Date
The Evolving Integrated Planning Process	6/26/19
The Evolving Electric System - Part 1	8/22/18
The Evolving Electric System - Part 2	8/28/18
Economic and Technical Considerations – Part 1	9/10/18
Economic and Technical Considerations – Part 2	9/24/18
Recap 9/10 Workshop Webinar (Economic and Technical Considerations – Part 1)	10/5/18
Preliminary Results – Part 1	10/22/18
Preliminary Results – Part 2	10/23/18
Demand-Side Management, Storage and Q&A Panel	12/14/18
Modeling Inputs & Assumptions Webinar	2/11/19
Host Community Considerations	2/12/19
Xcel Energy Non-Technical Overview Session	4/2/19
E3 Modeling Results	4/17/19
Xcel Energy Preliminary Preferred Plan	5/20/19

We also filed all supporting documents and presentations from the workshops in Docket No. E002/RP-15-21.

As this Resource Plan contemplates the long-term resource mix for five states, as discussed in the Planning Landscape section, we have also had discussions with various regulatory agencies in multiple jurisdictions to hear and understand their needs and concerns and incorporate those where possible.

As a result of all of this stakeholder collaboration, we made changes to several inputs and modeling approaches and also kept this in mind as we prepared the narrative supporting our proposed plan. For instance, in response to input from energy efficiency stakeholders and using the results from the *Minnesota Energy Efficiency Potential Study*,[2] we modeled energy efficiency as a supply side resource for the first time in this Resource Plan, an innovation that led to significantly more energy efficiency being selected than in prior plans. We also changed the source for our renewable pricing assumptions in response to stakeholder feedback. And in response to stakeholders' strong interest in electrification as a possible pathway to accelerate progress on the State's greenhouse gas goals, we created a load forecast sensitivity exploring the potential energy and peak demand impacts on our system of a scenario with aggressive electrification of transportation, water heating and space heating. We

[2] *Minnesota Energy Efficiency Potential Study: 2020–2029*. Conservation Applied Research and Development (CARD) FINAL Report. Prepared for the Minnesota Department of Commerce, Division of Energy Resources, by Center for Energy and Environment, Optimal Energy and Seventhwave. December 2018.

appreciate the time and input stakeholders have provided to date and believe the proposed plan—and this filing— has benefitted from it. We look forward to continued discussions as this process progresses.

II. EXTERNAL CONSULTANTS

We engaged a national expert on energy policy and economics, Dr. Susan Tierney with Analysis Group, to facilitate and host our Resource Plan stakeholder workshops as well as several smaller stakeholder meetings. Dr. Tierney not only brought a national perspective into the conversation but was also an independent third party that helped facilitate engaging and productive dialogue with stakeholders.

We also retained a consultant, Energy and Environmental Economics, Inc. (E3), to perform independent modeling and analysis of our system in order to ensure transparent work and access to the data and models for stakeholders. E3 is a recognized industry-leading firm based in San Francisco and consults extensively with utilities, developers, government agencies, and environmental groups on clean energy issues. E3's experience analyzing the impacts of deep decarbonization on utility systems in other parts of the country was very valuable to us in evaluating the impacts of decarbonizing our Upper Midwest System. E3 used three types of models to provide perspective on our Resource Plan:

- The RESOLVE model, which evaluates and optimizes the least-cost portfolios of resources to meet system demand considering carbon and other constraints,
- The RECAP model, which evaluates the reliability of electric energy and system capacity of the optimized resource portfolios over thousands of simulated weather years, and
- The PATHWAYS model, an economy-wide representation of infrastructure, energy use, and emissions within a specific jurisdiction used to create emissions accounting scenarios and model energy and climate policies. PATHWAYS was used in this project to evaluate scenarios for meeting Minnesota's statutory goal of 80 percent economy-wide reduction in greenhouse gases below 2005 levels by 2050.

E3's independent modeling results, which were generally consistent and supportive of our Strategist modeling results, were presented to, and discussed with, stakeholders in a workshop, and the results were made publicly available via the eDockets filing system after the stakeholder workshops. In addition, their completed RESOLVE and RECAP reports are also included with this Resource Plan submission as Appendix P2.

Working with E3 on their PATHWAYS to model scenarios to achieve Minnesota's 80 percent economy-wide greenhouse gas reduction goal provided a broader context for our Resource Plan, exploring the potential not only to decarbonize the statewide electricity system but also spread the benefit of low-carbon electricity to other economic sectors. E3's PATHWAYS Report is provided as Appendix P3. E3 modeled two mitigation scenarios – High Electrification and High Biofuels – and three sensitivities, as summarized in Appendix F4. Stakeholder feedback, both in the September 23 and October 24, 2018 stakeholder workshops and in individual meetings, informed the assumptions and modeling approach. In addition, the Company and E3 met with the Minnesota Pollution Control Agency (PCA) and Minnesota Department of Transportation (MnDOT) during the modeling process to acquire state-specific emissions, transportation, and econometric data, discuss assumptions and methodology, and present results. We offered to make the PATHWAYS model, now calibrated for Minnesota, available to the State for future analyses supporting the statewide greenhouse gas goals. As an immediate outgrowth of this effort, MnDOT is now working with E3 in the Pathways to Decarbonizing Transportation project, where E3 is using PATHWAYS to model strategies for reducing greenhouse gas emissions from the transportation sector.[3] Analyses for other sectors may follow.

III. HOST COMMUNITY WORK

The Company is participating in a study overseen by the Center for Energy and Environment (CEE) that will examine the impacts of the large baseload generation plants in Minnesota on the host communities. The other participants in the study include the Coalition of Utility Cities, Minnesota Power, and the Prairie Island Indian Community. The study will consist of a quantitative and qualitative component. The quantitative component of the study is similar to the study we conducted for Sherco 1 and 2 in our last IRP. For the qualitative component, CEE will engage with host community residents and business to gauge awareness, opinions and concerns around potential power plant closures. Efforts on both components are underway and we will supplement this IRP filing when each component is completed. As this docket progresses, we expect to be able to incorporate further findings and hold additional discussions incorporating the finalized report outcomes. Further discussion of the scope and status of this study is included as Appendix O2.

In addition, we also worked with the Nuclear Energy Institute (NEI) to evaluate the impact of our nuclear fleet on the Minnesota Economy. Our nuclear plants employ approximately 1,400 staff in and around the Monticello and Redwing communities,

[3] See http://www.dot.state.mn.us/sustainability/pathways.html.

which translates into an estimated 4,200 additional jobs in other industries across Minnesota. The plants are also important sources of tax base for their host communities, resulting in a combined total of approximately $42 million in state and local taxes annually. In total, Xcel Energy's nuclear operations contribute approximately $1 billion in annual economic benefits throughout the state. These and other benefits area summarized in NEI's April 2017 report titled "The Impact of Xcel Energy's Fleet on the Minnesota Economy," which looked at data from 2014-2016[4] and is attached as Appendix O3.

We acknowledge the role our plants play in the communities in which they are located and look forward to working with these stakeholders on transition plans as this Resource Plan progresses and plant closure dates draw nearer.

IV. LABOR

We are also working closely with labor unions and that work has resulted in support from the Infrastructure Union (LIUNA) for our preferred plan. LIUNA has stated that they appreciate and acknowledge that Xcel Energy has provided high-quality jobs that have sustained families and communities for generations and appreciate our commitment to supporting communities and employees through this energy transition.

Moving forward we will continue to work with local unions and set a course to negotiate multiskilling for the plants that are impacted by this Resource Plan. This skill set will position our employees for other job opportunities within Xcel Energy. As we get closer to plant closure dates, temporary work force will be utilized to back-fill impacted employees who have moved to other positions within the Company. This strategy lessens the burden and stress for impacted employees to find positions, as plant near closure dates.

In addition, plant management, Work Force Relations and Human Resources will work together with other business organizations within Xcel Energy to help coordinate interviews for affected employees.

[4] The 1,400 staff and $42 million in state and local taxes referenced above reflects updated information as through 2018.

V. CONCLUSION

We understand the interest and desire for our stakeholders to be involved and help shape the future of our system. We have put forward a concerted effort to engage these stakeholders at the outset and believe we have done a good job at doing so—but this work is just beginning. As this process unfolds and the plant closure dates approach, we will continue our successful track record of engaging parties, transitioning our workforce, looking for new investments, creating new jobs, and working with impacted communities and employees on transition plans.

APPENDIX O2 – SCOPE & OUTLINE: CENTER FOR ENERGY & ENVIRONMENT STUDY

The Company is participating in a study overseen by the Center for Energy and Environment (CEE) that will examine the impacts of the large baseload generation plants in Minnesota on the host communities. The other participants in the study include the Coalition of Utility Cities (CUCs), Minnesota Power, and the Prairie Island Indian Community. The CUCs are a coalition of communities that host large baseload generation plants in Minnesota and include: Becker, Monticello, Red Wing, Oak Park Heights and Cohasset. With the support of the McKnight Foundation, the Just Transition Fund, and the Initiative Foundations of Minnesota, the CUCs contracted with CEE to oversee a study on the direct and indirect financial and social impacts of hosting a baseload power plant on the host communities.

A portion of the host community impact study will be similar to the study conducted for Sherco 1 and 2 in our last Resource Plan. The study will evaluate alternative retirement and replacement scenarios for our remaining baseload facilities. The study will also evaluate the impacts of Minnesota Power's Boswell plant on the Cohasset area. In addition, the study will provide a qualitative component that will include interviews and surveys of key stakeholders in the local area of each plant. The independent oversight of CEE and the direct participation of impacted communities are important components that we believe will lend additional credibility to the study. On February 12, 2019, we hosted a workshop as part of the Resource Plan process on the scope of this study as part of our outreach efforts in advance of our July 1 filing. At that workshop, the CUC presented on issues facing host communities and included individual presentations by representatives from Becker, Oak Park Heights, Red Wing, Monticello, and the Prairie Island Indian Community. The study scope and process was well received by attendees of the workshop.

The study will consist of a quantitative and qualitative component. Efforts on both components are underway and we will supplement this Resource Plan filing when each component is complete. We expect to provide a supplement on the quantitative component within the next 60 days. A report on the qualitative component is expected to be completed in November.

To support the quantitative effort, CEE has contracted with the University of Colorado to conduct economic modeling of the local and statewide impacts of the retirement of the baseload generation plants in Minnesota. The Company retained the University of Colorado to conduct the study for Sherco 1 and 2 in our last IRP. The Business Research Division (BRD) of the Leeds School of Business at the University of Colorado Boulder will analyze the economic impact of alternative plant

retirement scenarios on their respective host communities. The purpose of this part of study is to provide third-party research examining the economic positive and negative effects of different scenarios. The scenarios analyzed will reflect five plant retirement scenarios as summarized below, including our preferred plan.

Scenarios to be Analyzed in the Host Community Impact Study								
Strategist Scenario	**Description**	**Coal Retirements**				**Nuclear**		
		Sherco 1	Sherco 2	Sherco 3	AS King	Monticello	Prairie Island 1	Prairie Island 2
1	**Reference**	2026	2023	2040	2037	2030	2033	2034
2	**Early King**	2026	2023	2040	2028	2030	2033	2034
4	**Early Coal**	2026	2023	2030	2028	2030	2033	2034
9 Pref. Plan	**Early Coal; Extend Monti**	2026	2023	2030	2028	2040	2033	2034
10	**Early King; Extend Monti**	2026	2023	2040	2028	2040	2033	2034
12	**Early Coal; Extend All Nuclear**	2026	2023	2030	2028	2040	2043	2044

This quantitative analysis will examine the baseload retirement scenarios, above, and the added resources based on the resource expansion plans in each scenario, which correspond to scenarios analyzed using the Strategist model. The analysis will consider operating expenditures, capital expenditures, and consumer rate costs for each scenario above relative to the reference scenario.

The research analysis method to be used for this study is the Regional Economic Models, Incorporated's (REMI) input-output, general equilibrium, econometric, and economic geography model, using state and national economic and demographic data, as well as data from the Company including capital expenditures, operating expenditures, and revenue requirements for each scenario. The study will look at near-term, mid-term, and long-term impacts and will capture the economic activity related to decommissioning and the construction of replacement generation.

While the specific location of replacement generation is unknown, a portion of the replacement generation will be assumed to be constructed within Minnesota and the study will examine impacts on the State of Minnesota. The REMI modeling will analyze the economic impacts on each host county and well as the state of Minnesota. The model allows for the analysis of changes in spending, investment, and employment in each region. We will supplement our IRP filing with the report from the BRD as soon as it is available.

The Host Community Impact study will also contain a qualitative component. CEE will collect responses to a questionnaire from community residents to gauge awareness, opinions and concerns around potential power plant closures. CEE will also conduct interviews with community members and leaders in each affected community, key stakeholders representing labor, and other impacted stakeholders. CEE will develop a report that identifies overarching themes and findings including issues that may be unique for specific communities. We will supplement our Resource Plan filing with the qualitative report once it is available.

We are grateful to CEE for overseeing this study and to the study participants for engaging in this constructive exercise. As we move forward with our carbon reduction goals, we are cognizant that phasing out some of our legacy generation has a significant impact not only on our energy mix, but on the economies of communities where those plants are located and the employees who work in those plants. We are dedicated to working with our employees, communities, and stakeholders to manage community impacts throughout our clean energy transition. Our baseload generation plants are prominent places of employment and contributors to the property tax base in the host communities. This is why we make efforts to spur economic development in locations where our current units will eventually be phased out.

For example, since our most recent Resource Plan, where we proposed to retire the Sherco 1 and 2 coal units in Becker, we have worked extensively with the local government, community stakeholders, and the state to draw new development to support the local economy. This includes a planned combined cycle generating unit at the Sherco site, the Northern Metal Recycling facility, and, prospectively a new Google data center with energy matched by a wind facility. Some of that activity (e.g. the Google data center) is also anticipated to spur new renewable energy development on our system.

In addition to the community impacts, we are also aware that these plant closures impact our employees and their families. With this in mind, and consistent with our past practices, we will work with these impacted employees to transition them to other Xcel Energy plants or areas of the company. In the past, when plants have been closed or converted (and impacted headcount) we have provided résumé writing services, support for interview practice, job training, and job shadowing opportunities. Through natural attrition and job re-locations, we have been able to successfully "re-home" nearly all impacted employees from plant closures and conversions to date.

As we continue toward achievement of our aggressive carbon goals, we will continue to make significant investments in clean energy in the states we serve. As we do so, we will look for opportunities to create fair access to clean energy programs, jobs and economic development opportunities. The Host Community Impact study will provide further context and opportunities for engagement with our communities, employees, and stakeholder as we continue to work together on the clean energy transition.

The Impact of Xcel Energy's Nuclear Fleet on the Minnesota Economy

An Analysis by the Nuclear Energy Institute

April 2017

NUCLEAR ENERGY INSTITUTE

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Executive Summary

Xcel Energy Inc. (Xcel Energy) owns and operates two nuclear energy facilities, including three reactors, in Minnesota and has its headquarters in Minneapolis, Minnesota. The two nuclear energy facilities are:

- Monticello Nuclear Generating Plant in Monticello, Minnesota
- Prairie Island Nuclear Generating Plant in Red Wing, Minnesota

Almost 6,100 jobs in Minnesota result from Xcel Energy's nuclear operations.

The two nuclear facilities have been an integral part of the region's clean energy portfolio and economic fabric since the 1970s. They have generated reliable emission-free electricity, thousands of jobs, and billions of dollars of economic activity while Xcel Energy has been deeply involved in its local communities, proving the plants' value as economic contributors to Minnesota and the Upper Midwest.

To quantify the employment and economic impact of these facilities, the Nuclear Energy Institute (NEI) conducted an independent analysis. Based on data provided by Xcel Energy on employment, operating expenditures, revenues and tax payments, NEI conducted the analysis using a nationally recognized model to estimate the facilities' economic impacts on the Minnesota economy. Regional Economic Models, Inc. (REMI) developed the Policy Insight Plus (PI+) economic impact modeling system, the methodology employed in this analysis. (See section 5 of this report for more information on the REMI methodology.)

Key Findings

Xcel Energy's nuclear operations support:

Xcel Energy's nuclear operations are estimated to generate $1 billion of total economic output annually in Minnesota.

Economic stimulus. Xcel Energy's nuclear operations are estimated to generate $1 billion of total economic output annually, which contributes $600 million to Minnesota's gross state product each year. This study finds that for every dollar of output from Xcel Energy's nuclear operations, the state economy produces $1.98.

Tax impacts. NEI estimates that Xcel Energy's nuclear facilities in Minnesota contribute about $33 million in state and local taxes annually. In 2015, Xcel Energy reported over $34.5 million in state and local taxes paid. Xcel Energy is the largest property tax payer in Minnesota. NEI estimates that Xcel Energy's nuclear facilities contribute over $113 million in federal taxes each year.

Thousands of high-skilled jobs. Approximately 1,700 jobs exist at Xcel Energy's nuclear energy facilities, which includes 140 nuclear support positions at its headquarters in Minneapolis. This direct employment creates about 4,200 additional jobs in other industries in Minnesota. A total of

nearly 6,100 jobs in Minnesota are a result of Xcel Energy's nuclear operations.

Xcel Energy's nuclear operations result in a total tax impact of approximately $146 million to the local, state and federal governments each year.

Clean electricity for Minnesota. Xcel Energy's nuclear facilities generate about 21 percent of Minnesota's electricity and about 54 percent of the state's carbon-free electricity. Without the carbon-free electricity produced by these nuclear plants, an estimated 12 million metric tons of carbon dioxide would be released annually, the equivalent of putting more than 2.6 million additional cars on Minnesota's roadways each year, or double the number of passenger cars in all of Minnesota. By 2030, these nuclear plants will have provided almost $9 billion in avoided emissions benefits.

Reliability leaders. During full-power operations, the three reactors provide 1,770 megawatts of around-the-clock electricity for Minnesota homes and businesses. Over the last 10 years, the facilities have operated at approximately 85 percent of capacity, which is significantly higher than all other forms of electric generation. This reliable production helps offset potential price volatility of other energy sources (e.g., natural gas) and the intermittency of renewable electricity sources. Nuclear energy provides reliable electricity to businesses and consumers and helps prevent power disruptions which could lead to lost economic output, higher business costs, potential loss of jobs, and losses to consumers.

Without the carbon-free electricity produced by these nuclear plants, an additional 12 million metric tons of carbon dioxide would be released annually, the equivalent of the emissions from over 2 million cars each year.

Community and environmental leadership. Xcel Energy is a corporate leader in its neighboring communities, supporting education initiatives, environmental and conservation projects, and numerous charitable organizations.

Section 1
Background and Generation History

Monticello Nuclear Generating Plant

Dates of commercial operation
1971

Location
40 miles northwest of the Twin Cities

License Expiration Year
2030

Reactor Type
Boiling water

Total Electrical Capacity (Megawatts)
671

Prairie Island Nuclear Generating Plant

Dates of commercial operation
Prairie Island 1 - 1973
Prairie Island 2 - 1974

Location
40 Miles southeast of the Twin Cities

License Expiration Years
Prairie Island 1 - 2033
Prairie Island 2 - 2034

Reactor Type
Pressurized water

Total Electrical Capacity (Megawatts)
Prairie Island 1 - 550
Prairie Island 2 - 550

The Monticello Nuclear Generating Plant (Monticello) is located on 215-acre site in Monticello, Minnesota. It consists of a single, Boiling Water Reactor (BWR) that produces 671 MW of non-emitting baseload power.

The Prairie Island Nuclear Generating Plant (Prairie Island) is located on a 575-acre site in Red Wing, Minnesota. It consists of two Pressurized Water Reactors (PWRs) that together produce 1,100 MW of non-emitting base-load power.

Reliable Electricity Generation

Over the past decade, the three reactors operated at an average capacity factor of 85 percent. Capacity factor, a measure of electricity production availability, is the ratio of actual electricity generated to the maximum possible electric generation during the year.

Xcel Energy's nuclear plants typically generate nearly over 13 million megawatt-hours of electricity ever year. In 2015, Xcel Energy's reactors generated over 20 percent of the electricity in Minnesota. The three reactors provide enough electricity for approximately 1.4 million Minnesota households (if all of the electricity went to the residential sector).

Monticello and Prairie Island operate in the Midcontinent Independent System Operator (MISO) region, which stretches from Louisiana to Canada which covers portions of 15 states and Manitoba. Along with 14 other nuclear reactors in that operate in MISO, nuclear power keeps wholesale prices 9 percent lower in MISO than they would be without nuclear power.[1]

Thousands of High-Skilled, Well-Paying Local Jobs

Xcel Energy's nuclear operations employ nearly 1,600 full-time workers at the plants, and 140 support and executive positions at its Minneapolis headquarters. This employment supports an additional 4,200 jobs in other economic sectors in Minnesota. In total, these plants support 6,100 jobs across Minnesota (including those at the plant). The annual payroll for the direct jobs is approximately $240 million. Most jobs at nuclear power plants require technical training and are typically among the highest-paying jobs in the area. Nationwide, nuclear energy jobs pay 36 percent more than average salaries in a plant's local area according to an NEI analysis.[2]

[1] *The Nuclear Industry's Contribution to the U.S. Economy*, The Brattle Group, July 2015.

[2] *NEI Factsheet: Job Creation and Economic Benefits of Nuclear Energy*.

Safe and Clean for the Environment

Nuclear facilities generate large amounts of electricity without emitting greenhouse gases or other air pollutants. State and federal policymakers recognize nuclear energy as an essential source of safe, reliable electricity that meets both our environmental needs and the state's demand for electricity.

In 2015, the operation of these three reactors prevented the emission of 12 million metric tons of carbon dioxide,[3] about the same amount emitted by over 2 million cars each year. Overall, Minnesota's electric sector emits more than 32 million metric tons of carbon dioxide annually. The three reactors also prevent the emission of more than 11,100 tons of nitrogen oxide, equivalent to that released by 1.2 million cars, and 16,800 tons of sulfur dioxide. Sulfur dioxide and nitrogen oxide are precursors to acid rain and urban smog.

[3] Emissions prevented are calculated using regional fossil fuel emission rates from the U.S. Environmental Protection Agency and plant generation data from the U.S. Energy Information Administration.

Section 2

Economic Benefits in Minnesota

NEI used the REMI PI+ model to analyze economic and expenditure data provided by the plants to develop estimates of their economic benefits (more information on REMI can be found in Section 5).

The economic impacts of the Monticello and Prairie Island plants and the nuclear operations at Xcel Energy headquarters consist of direct and secondary impacts. The main variables used to analyze these impacts are:

Output
The direct output is the value of power produced by the Xcel Energy facilities. In the case of Xcel Energy's headquarters, it is the value of the nuclear support operations. The secondary output is the additional economic activity created as a consequence of the electricity generation. The direct output will impact the economic activity in other industries and how those employed at the facilities influence the demand for goods and services within the community.

Employment
The direct employment is the number of jobs at the Xcel Energy facilities. Secondary employment is the number of jobs in the other industries supported as a result of Xcel Energy's operations.

Gross State Product
Gross state product is the value of goods and services produced by labor and property at the Xcel Energy facilities—e.g., sales (i.e., output) minus intermediate goods. In the REMI model, operations is the final good from an Xcel Energy nuclear plant. Intermediate goods are the components purchased to make that electricity due to projected increases in electricity prices.

Xcel Energy's nuclear facilities are predicted to provide nearly $16 billion in economic benefits and $3.5 billion in disposable personal income benefits over the next 15 years.

Disposable Personal Income
Disposable personal income is the total after-tax income that residents in the analyzed region would receive. This value is available for purchases on groceries and clothing or for saving and investing for the future in things like college education, retirement or a mortgage.

Substantial Economic Drivers

The direct output in 2016 of the Xcel Energy nuclear facilities were estimated to total $531 million (the value of the electricity produced at the plants), with a total economic output on the state of $1.05 billion. In other words, for every dollar of output, the state economy produced $1.98. By 2030, the total economic output is estimated to increase to $1.11 billion.

In 2016, Xcel Energy's nuclear facilities were estimated to contribute $595 million to Minnesota's gross state product (GSP) and, by 2030, the GSP stays constant at almost $600 million.

Figure 2.0
Xcel Energy Nuclear Operations' Total Output and Gross State Product Contributions to Minnesota
*(dollars in 2015 billions)**

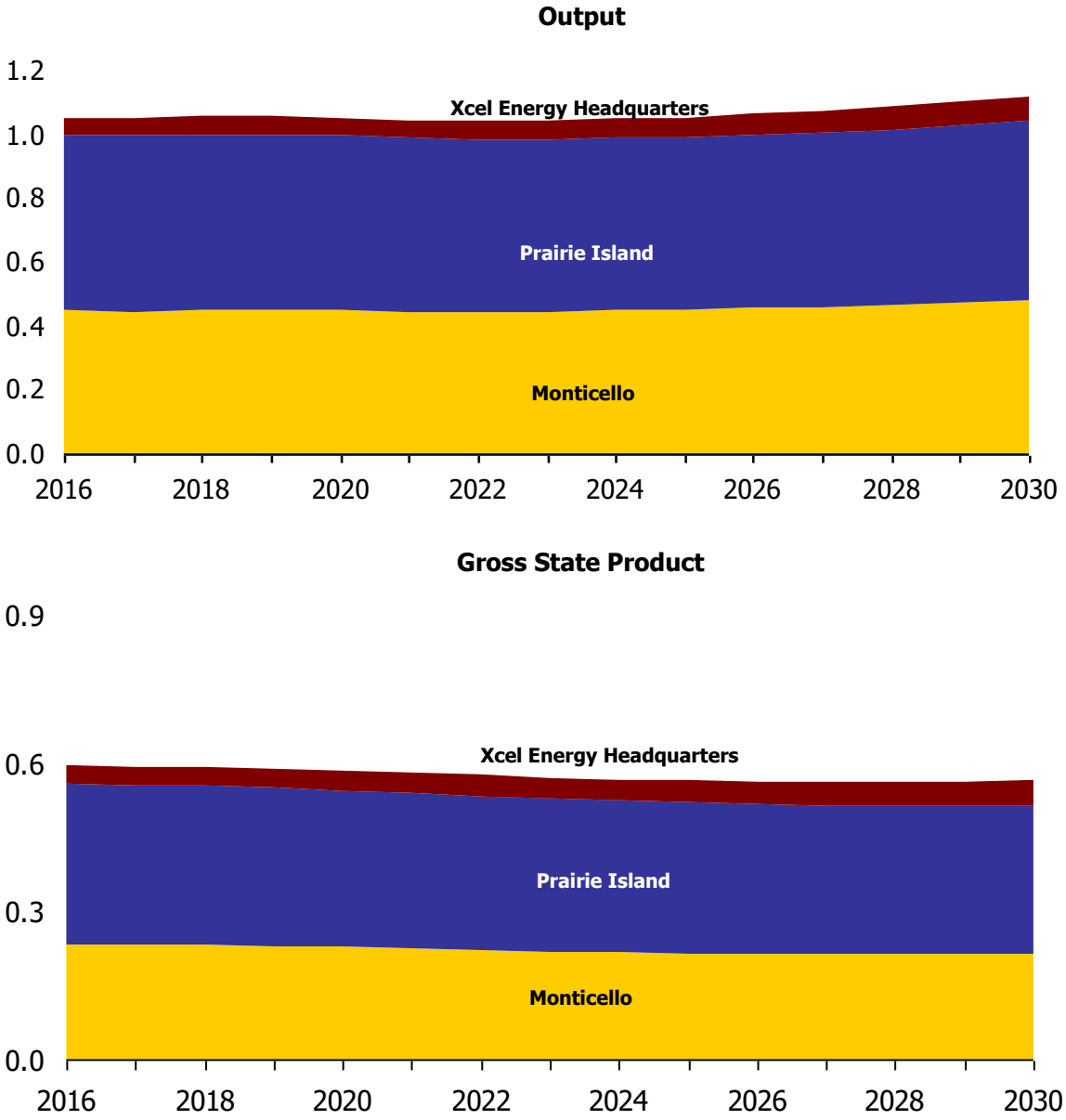


Figure 2.0 shows the value of total output and contributions to GSP from the operation of Xcel Energy's nuclear facilities through 2030, using spending data provided by Xcel Energy.

The three reactors' largest impacts are on the utilities sector, while the headquarters' greatest impact is on the corporate management sector. Xcel Energy's facilities have a substantial impact on the professional, scientific, and technical services sector—because of the volume of specialized services required to operate and maintain a nuclear power plant. Finally, there are beneficial impacts in Minnesota on the manufacturing and administrative and waste management sectors. Other sectors that benefit from the facilities' operations in Minnesota include finance and insurance, health care, retail trade, and real estate.
A full depiction of the sectors in Minnesota that benefit from the facilities is in Table 2.0.

Table 2.0
Estimated Total Output of Xcel Nuclear Operations on Minnesota's Economic Sectors in 2016 *(in millions of 2015 dollars)*

Sector Description	Monticello	Prairie Island	Xcel Energy HQ	Total
Utilities	220	311	0	531
Professional, Scientific, and Technical Services	51	52	3	106
Manufacturing	33	34	2	69
Administrative and Waste Management Services	32	32	1	65
Other Services, except Public Administration	27	28	1	56
Finance and Insurance	18	20	4	42
Management of Companies and Enterprises	3	4	31	38
Retail Trade	12	13	2	27
Health Care and Social Assistance	11	13	2	26
Real Estate and Rental and Leasing	11	12	3	26
All Other Industries	29	31	5	65
Total	**447**	**550**	**54**	**1,051**

Job Diversity and Creation

Xcel Energy's nuclear business activities stimulate the state's labor income and employment. Over 1,600 people work at Xcel Energy's nuclear plants and 140 more are employed at its Minneapolis headquarters for nuclear operations. These jobs stimulate another 4,200 jobs in other sectors in the state. All told, Xcel Energy's operations support nearly 6,100 jobs in Minnesota.

Table 2.1
Xcel Energy's Estimated Support in Direct and Secondary Jobs in Minnesota in 2016

Occupation	Monticello	Prairie Island	Xcel Energy HQ	Total
Utilities	807	870	1	1,678
Administrative and Waste Management Services	474	479	14	967
Professional, Scientific, and Technical Services	396	400	24	820
Other Services, except Public Administration	351	365	21	737
Retail Trade	159	185	33	377
Health Care and Social Assistance	133	154	25	312
Finance and Insurance	80	87	18	185
Management of Companies and Enterprises	16	17	147	180
Manufacturing	85	87	4	176
Accommodation and Food Services	64	73	16	153
Construction	66	66	2	134
Arts, Entertainment, and Recreation	34	38	9	81
Wholesale Trade	30	33	5	68
Transportation and Warehousing	28	30	4	62
Real Estate and Rental and Leasing	23	25	6	54
All Other Industries	31	37	9	77
Total	**2,777**	**2,946**	**338**	**6,061**

As discussed earlier in Section 2, the types of jobs supported by Xcel Energy's nuclear operations are diverse. Jobs supported range from office jobs in the professional, scientific, and technical services, finance and insurance, and public administration jobs to blue-collar jobs in construction and manufacturing to life-saving jobs in healthcare.

Table 2.1 details the numbers and types of jobs that Xcel Energy are supported in 2016. Xcel Energy's workers are included in the occupation categories in the table.

Economic Stimulus Through Taxes

Xcel Energy's nuclear operations resulted in an estimated annual total tax impact of $146 million to the local, state and federal governments. This includes the direct impact and secondary impacts, because plant expenditures increase economic activity, leading to additional income and value creation and, therefore, to additional tax revenue from other sectors.

Xcel Energy's impacts on the state economy are substantial. In addition to the $595 million in gross state product, the company is estimated to generate over $33 million in taxes from the plants and their activities for Minnesota and its local governments. See Table 2.2.

Extra Income for Residents

The economic activity and low-cost electricity the plants create, to which Xcel Energy's nuclear operations at its headquarters contributes, also provide a boost to incomes of residents of Minnesota. In a consumer-driven economy, this is of the utmost importance. This boost is estimated to be $237 million annually in disposable personal income greater than if the plants and headquarters did not exist. This extra income provides Minnesotans with extra money to purchase necessities such as groceries and clothing for their families or save for college or retirement. More detail of this contribution to disposable personal income is in Table 2.3.

Large Multiplier Effects for Economic Activity and Jobs

By producing affordable, reliable electricity, Xcel Energy's nuclear operations are hubs of economic activity for Minnesota. Table 2.4 provides the multipliers and summarizes the total effects from each plant. The multipliers show that for every dollar of output generated, the plants stimulate between $2.03 and $2.30 in economic output in the state, while Xcel Energy headquarters produces $1.74 for every dollar. Minnesota employment multipliers range between 3.39 and 3.44 at the plants and 2.49 at Xcel Energy headquarters.

Table 2.2
Estimated Total Tax Impacts in 2016
*(in 2015 millions of dollars)**

Facility	State and Local	Federal	Total
Monticello	12	44	56
Prairie Island	18	62	80
Xcel Energy HQ	2	7	9
Total Taxes	**33**	**113**	**146**

** Calculated based on a percentage of gross state product.*

Table 2.3
Estimated Total Personal Disposable Income Impacts in 2016
(in 2015 millions of dollars)

Facility	Total
Monticello	96
Prairie Island	116
Xcel Energy HQ	25
Total	**237**

Table 2.4
Xcel Energy's Impacts on the Minnesota Economy in 2016 *(in 2015 millions of dollars)*

Facility (Description)	Direct	Secondary	Total	Multiplier
Monticello				
Output (Utilities)	$220	$227	$447	2.03
Employment	807	1,970	2,777	3.44
Gross State Product			$232	
Prairie Island				
Output (Utilities)	$311	$239	$550	2.30
Employment	870	2,076	2,946	3.39
Gross State Product			$326	
Xcel Energy Headquarters				
Output (Management of Companies and Enterprises)	$31	$23	$54	1.74
Employment	136	202	338	2.49
Gross State Product			$37	

Section 3
Protecting the Environment

Like all nuclear power plants, Monticello and Prairie Island produce carbon-free electricity. Nuclear power produces 62 percent of the United States' carbon-free electricity and nearly 20 percent of total electricity generated. Hydro, wind and solar produce 19, 15, and 2 percent of carbon-free electricity, respectively. Nuclear power plants avoided 564 million metric tons of carbon dioxide in 2015, while hydro, wind and solar avoided 327 million metric tons combined. Annually, the avoided emissions from nuclear power is similar to adding 128 million cars to the nation's roads. Nuclear power plants also avoided hundreds of thousands of tons of nitrogen oxide and sulfur dioxide. The Environmental Protection Agency estimates that the Clean Power Plan will reduce carbon emissions by 414 million tons annually by 2030, or 73 percent of current carbon avoidance of the nuclear industry.

Xcel Energy employee holding a Peregrine Falcon chick.

Xcel Energy's Nuclear Plants Contribution

In 2015, the operation of these three reactors prevented the emission of 12 million metric tons of carbon dioxide, about the same amount emitted by over 2 million cars each year. According to the Minnesota Pollution Control Agency's most recent data from 2012, Minnesota's electric sector emitted 47.6 million tons of carbon dioxide. The three reactors also prevent the emission of more than 11,100 tons of nitrogen oxide, equivalent to that released by 1.2 million cars, and 16,800 tons of sulfur dioxide. Sulfur dioxide and nitrogen oxide are precursors to acid rain and urban smog.

Clean Air Benefits of Xcel Energy Nuclear

Monticello and Prairie Island are the two largest carbon-free sources of generation in Xcel Energy's portfolio. In 2015, Monticello and Prairie Island produced over 12 million megawatt hours of electricity which avoided the emission of 11.6 million metric tons of carbon dioxide. They also prevent the release of thousands of tons of Nitrogen Oxide and Sulfur Dioxide.

In August 2016, the U.S. Court of Appeals for the Seventh Circuit validated the Social Cost of Carbon as a legitimate method to place a value on the benefits of carbon reduction.[1] Between 2016 and 2030, assuming Monticello and Prairie Island avoid the emission of 11.6 million metric tons of CO2 every year, these avoided emissions would represent an $8.67 billion in cumulative benefits. NEI calculated this value using the Social Cost of Carbon values from the Interagency Working Group Technical Support Document that was revised in July 2015. The values are in 2007 dollars and were inflated using the GDP deflator to 2015 dollars. The calculation is based on the 2015 carbon intensity of electricity generation in NERC's Midwest Reliability Organization.[2]

[1] *Zero Zone, Inc., et al., v. U.S. Department of Energy*

[2] *The Minnesota Public Utilities Commission is currently updating its CO2 externality range. Therefore, NEI has used the federal Social Cost of Carbon values as the Commission has not yet finalized its decision. The specific reference to the docket is: In the Matter of the Further Investigation into Environmental and Socioeconomic Costs Under Minn. Stat. § 216B.2422, Subd. 3. Minnesota Public Utilities Commission Docket No. E-999/CI-14-643.*

Section 4

Community Leadership and Environmental Protection

In addition to the economic benefits that Xcel Energy's nuclear operations contribute to Minnesota in the form of jobs, income and taxes, the company and its employees contribute to local communities in many other beneficial ways. Xcel Energy strengthens Minnesota communities through hiring veterans, charitable contributions, educational programs that teach and promote the benefits of nuclear energy, environmental programs that improve the quality of the environment, and civic engagement activities that build trust and goodwill.

Children using Monticello mobile simulator at open house event.

Corporate Citizenship

At a corporate level, Xcel Energy contributes significant time and resources to charitable endeavors. Over the past 10 years, Xcel Energy has raised $2.5 million annually for the United Way. Xcel Energy matches this amount, which means over $50 million has been contributed to local communities in the past decade. This annual campaign raises money with various events such as chili cook-offs and sporting tournaments. Each year, employees, contractors and retirees continue the tradition of giving, advocating and volunteering in the community.

The 2016 United Way campaign broke all previous records with the highest combined total of donations, surpassing the goal of $3 million. The result will be more than $5.6 million in matched contributions.

Prairie Island employees volunteering at Red Wing Memorial Park.

Below are further examples of contributions of Xcel Energy and its employees:

- In September 2015, more than 3,500 volunteers pitched in and spent 10,300 hours painting, sorting, planting and otherwise supporting 80 local non-profits during Xcel Energy's fifth annual Day of Service, making it the company's largest event ever.
- The Xcel Energy Foundation awarded $3.8 million in grants to nearly 430 non-profits benefitting four community focus areas that include STEM education, economic sustainability, environmental stewardship and access to arts and culture.
- Even after they retire, former Xcel Energy employees are giving back. The Pioneers in Public Service (PIPS) retiree volunteer program has been operating for over 30 years. PIPS members have dedicated more than 80,000 volunteer hours serving in communities.

Environmental Stewardship

Xcel energy generates 55 percent of its Upper Midwest electricity using carbon-free generation. Thirty percent of that generation is from its two nuclear plants in Minnesota, 15 percent is from wind energy, and 10 percent is from a combination of hydro/biomass/solar sources. Beyond its nuclear program, Xcel Energy has been the number one utility provider of wind energy for 12 straight years.

Xcel Energy employees volunteering for Habitat for Humanity.

In 2016, the U.S. Environmental Protection Agency awarded Xcel Energy the Climate Leadership Award for achieving its self-identified goal of 20 percent reduction in carbon by 2020 (which it achieved in 2014). Xcel Energy achieved these reductions through increasing renewable energy investment, modernizing its generation fleet, and offering incentives for customers to save energy.

Employment of Veterans

In 2016, Xcel Energy set a goal of hiring veterans as 15 percent of new hires. The company exceeded this goal. Military Times Magazine rated Xcel Energy as a top company for hiring veterans. Xcel Energy was listed among the Top 100 Military Friendly Employers by GI Jobs Magazine and ranked number 8 on Monster and Miltary.com's list of best companies for veteran hiring. Also, in 2016, the Minnesota Employer Support of the Guard and Reserve recognized Xcel Energy with the Pro Patria and Above and Beyond Awards for providing beneficial leave and support rules for military members required to perform military duties.

Contributions & Sponsorships

Xcel Energy nuclear plant employees volunteer and contribute to numerous community and local organizations and events. For example, Prairie Island engages in an annual golf tournament that benefits the United Way and a Make-A-Wish summer series. Both plants support Habitat for Humanity and both the Boy and Girl Scouts of America.

Section 5

Xcel Energy Nuclear Operations and the U.S. Nuclear Energy Industry

The three reactors play a vital role in helping Minnesota meet its demand for affordable, reliable and sustainable energy.

In 2015, electricity production from U.S. nuclear power plants was about 800 billion kilowatt-hours—nearly 20 percent of America's electricity supply. In Minnesota, nuclear energy generates approximately 21 percent of the state's electricity, and Xcel Energy's three reactors generated about 13 billion kilowatt-hours of electricity, which is approximately 54 percent of Minnesota's carbon-free electricity generation.

Xcel Energy's nuclear plants provide 54 percent of the carbon-free electricity generation in Minnesota.

Over the past 25 years, America's nuclear power plants have increased output and improved performance significantly. Since 1990, the industry has increased total output equivalent to that of 26 additional 1,000-MWe nuclear power plants, when in fact only five new reactors have come online. This is due to the fact that in 1990, U.S. nuclear plants were operating approximately 66 percent of the time compared to achieving a record capacity factor of over 92 percent in 2015.

Nuclear Energy's Value Proposition

Nuclear energy's role in the nation's electricity portfolio was especially valuable during the 2014 "polar vortex," when record cold temperatures gripped the United States and other sources of electricity were forced off the grid. Nuclear power plants nationwide operated at an average capacity factor of 96 percent during the period of extreme cold temperatures. During that time, supply volatility drove natural gas prices in many markets to record highs and much of that gas was diverted from use in the electric sector so that it could be used for home heating.

Some of America's electricity markets, however, are structured in ways that place some nuclear energy facilities at risk of premature retirement, despite excellent operations. It is imperative that policymakers and markets appropriately recognize the full strategic value of nuclear energy in a diverse energy portfolio.

That value proposition starts with the safe and reliable production of large quantities of electricity around the clock.

One of nuclear energy's key benefits is the availability of low-cost fuel (which does not need to be delivered continuously and the ability to produce electricity under virtually all weather conditions. Renewable energy, an emerging part of the energy mix, is intermittent (the sun doesn't always shine and the wind

doesn't always blow when generation is needed) and therefore cannot be readily dispatched to meet demand; natural gas-fired generation depends on fuel being available (both physically and at a reasonable price); and on-site coal piles can freeze.

Nuclear power plants also provide clean-air compliance value. Minnesota's Next Generation Energy Act of 2007 set a goal that would reduce greenhouse gas emissions 15 percent below the 2005 level in 2015, and 30 and 80 percent below that level in 2025 and 2050, respectively.

Nuclear plants provide voltage support to the grid, helping to maintain grid stability. They have portfolio value, contributing to fuel and technology diversity. And they provide a tremendous local and regional economic development opportunity, including large numbers of high-paying jobs and significant contributions to the local and state economies and tax base.

Based on more than 50 years of experience, the nuclear industry is one of the safest industrial working environments in the nation.

Stable Prices for Consumers

In addition to increasing electricity production at existing nuclear energy facilities, power from these facilities is affordable and stable for consumers. Compared to the cost of electricity produced using fossil fuels—which are heavily dependent on market fuel prices—nuclear plants' fuel costs are relatively stable, making consumers' electric bills more predictable. Uranium fuel is only about one-third of the production cost of nuclear energy, while fuel costs have historically made up between 75-85 percent of coal-fired and natural gas production costs. Production costs for a nuclear plant have historically been $0.03/kWh or lower. Natural gas production costs are currently historically low at $0.03/kWh, but have been over $0.08/kWh in 2000, 2001, 2005 and 2008.

Safety and Security

Safety is the highest priority for the nuclear energy industry. Based on more than 50 years of experience, the industry is one of the safest industrial working environments in the nation. Through rigorous training of plant workers and increased communication and cooperation among nuclear plants and federal, state and local regulating bodies, the industry is keeping the nation's 99 nuclear plants safe for their communities and the environment.

The U.S. Nuclear Regulatory Commission (NRC) provides independent federal oversight of the industry and tracks data on the number of "significant events" at each nuclear plant. (A significant event is any occurrence that challenges a plant's safety systems.) The average number of significant events per reactor declined from 0.45 per year in 1990 to 0.01 in 2014, illustrating the emphasis on safety throughout the nuclear industry.

General worker safety is also excellent at nuclear power plants—far safer than in the manufacturing sector. U.S. Bureau of Labor Statistics data show that, in 2013, nuclear energy facilities achieved an incidence rate of 0.3 per 200,000

work hours, compared to 1.8 for fossil-fuel power plants, 1.8 for electric utilities and 4.0 for the manufacturing industry.

All American nuclear plants are designed and operated with public safety first and foremost in mind. The plants have redundant and diverse safety systems which are backed by multiple power sources.

U.S. nuclear plants also have over 9,000 highly trained paramilitary personnel protecting the plants from external threats. These plants also maintain emergency response plans that are reviewed and approved by the Nuclear Regulatory Commission and coordinated with the Federal Emergency Management Agency. In order to maintain this high level of safety and security within its community, each plant coordinates with its local police, fire, and EMS departments.

Industry Trends: License Renewal and New Plants

The excellent economic and safety performance of U.S. nuclear power plants has demonstrated the value of nuclear energy to the electric industry, the financial community and policymakers. This is evidenced by the increasing number of facilities seeking license renewals from the NRC.

Of the currently operating reactors nationwide, 84 out of 99 have received license renewal. The Nuclear Regulatory Commission found no technical limitations to prevent a nuclear plant from operating for 80 years.

Originally licensed to operate for 40 years, nuclear energy facilities can operate safely for longer. The NRC granted the first 20-year license renewal to the Calvert Cliffs plants in Maryland in 2000. As of March 2017, 84 currently operating reactors had received license extensions, and operators of 13 additional reactors either had submitted applications or announced that they will seek renewal. License renewal is an attractive alternative to building new electric capacity because of nuclear energy's low production costs and the return on investment provided by extending a plant's operational life.

The Nuclear Regulatory Commission has found that there are no technical reasons to prevent a nuclear plant from operating for 80 years. In 2014, the Nuclear Regulatory Commission found that its current regulatory structure regarding initial license renewal is suitable for second license renewal. In 2015, Dominion announced that it will apply in 2019 for a second license renewal for its Surry Power Station in Virginia. If granted, this will allow the plant to operate for an additional 20 years (80 years in total). Exelon announced in June 2016 that it will pursue second license renewal for its Peach Bottom plant.

Besides relicensing nuclear plants, energy companies are building new, advanced-design reactors. Georgia Power and South Carolina Electric & Gas are building two advanced reactors each, near Augusta, Ga., and Columbia, S.C. These facilities are nearly halfway through their construction programs. These projects employ more than 5,000 workers each now that construction is peaking. In addition, Tennessee Valley Authority began operation of the Watts Bar 2 reactor in Tennessee in June 2016.

Section 6

Economic Impact Analysis Methodology

This analysis uses the REMI model to estimate the economic and fiscal impacts of Xcel Energy's nuclear facilities.

Regional Economic Models, Inc. (REMI)

REMI is a modeling firm specializing in services related to economic impacts and policy analysis, headquartered in Amherst, Mass. It provides software, support services, and issue-based expertise and consulting in almost every state, the District of Columbia, and other countries in North America, Europe, Latin America, the Middle East and Asia.

REMI's software has two main purposes: forecasting and analysis of alternatives. All models have a "baseline" forecast of the future of a regional economy at the county level. Using "policy variables," in REMI terminology, provides scenarios based on different situations. The ability to model policy variables makes it a powerful tool for conveying the economic "story" behind policy. The model translates various considerations into understandable concepts like GDP and jobs.

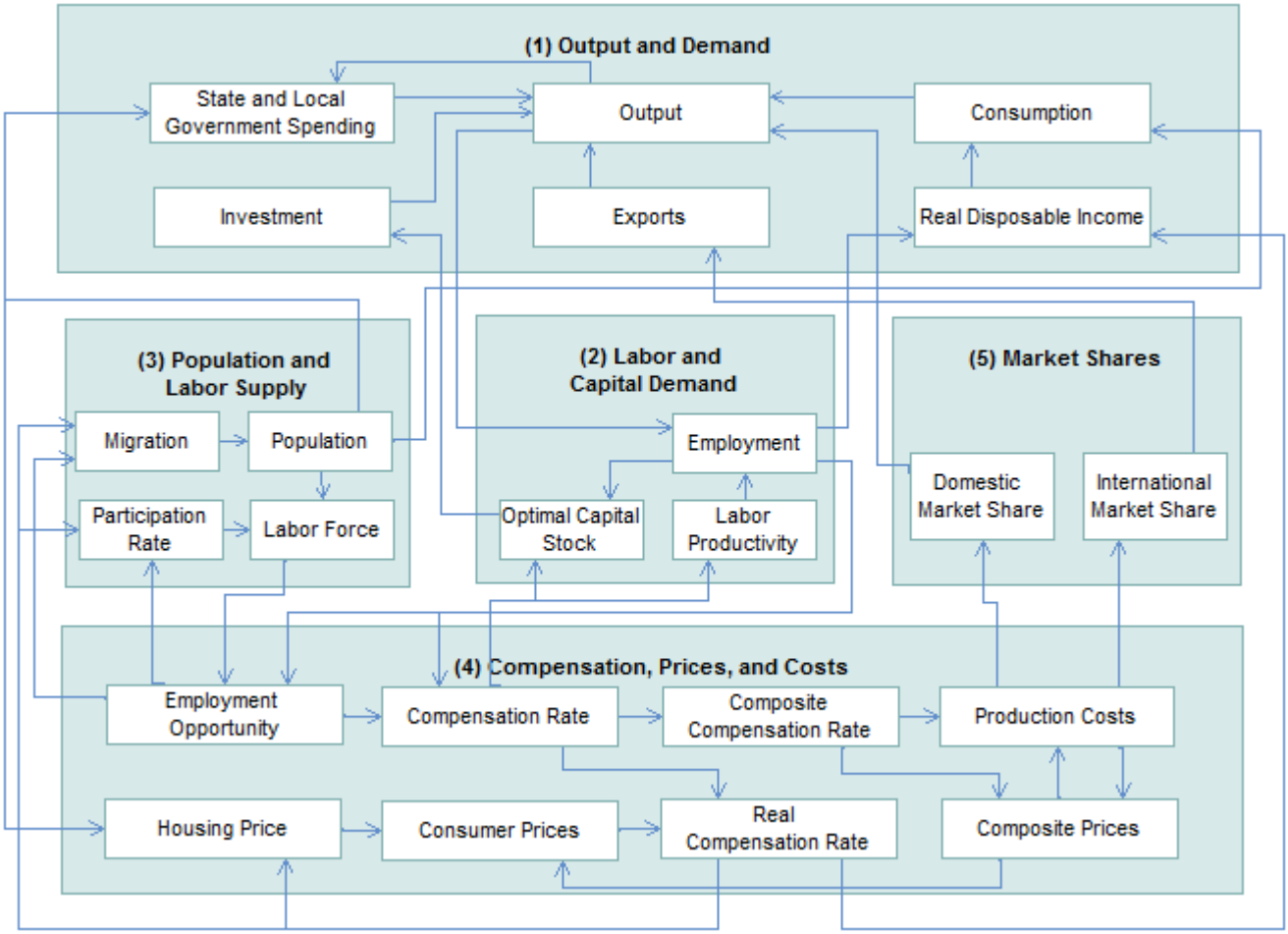
REMI relies on data from public sources, including the Bureau of Economic Analysis, Bureau of Labor Statistics, Energy Information Administration and the Census Bureau. Forecasts for future macroeconomic conditions in REMI come from a combination of resources, including the Research Seminar in Quantitative Economics at the University of Michigan and the Bureau of Labor Statistics. These sources serve as the main framework for the software model needed to perform simulations.

Policy Insight Plus (PI+)

REMI's PI+ is a computerized, multiregional, dynamic model of the states or other sub-national units of the United States economy. PI+ relies on four quantitative methodologies to guide its approach to economic modeling:

1. Input/output tabulation (IO)—IO models, sometimes called "social accounting matrices" (SAM), quantify the interrelation of industries and households in a computational sense. It models the flow of goods between firms in supply-chains, wages paid to households, and final consumption by households, government and the international market. These channels create the "multiplier" effect of $1 going farther than when accounting for its impact on enabling subsequent value..
2. Computable general equilibrium (CGE)—CGE modeling adds market concepts to the IO structure. This includes how those structures evolve over time and how they respond to alternative policies. CGE incorporates con-

Figure 6.0



This diagram represents the structure and linkages of the regional economy in PI+. Each rectangle is a discrete, quantifiable concept or rate, and each arrow represents an equation linking the two of them. Some are complex econometric relationships, such as the one for migrant, while some are rather simple, such as the one for labor force, which is the population times the participation rate. The change of one relationship causes a change throughout the rest of the structure because different parts move and react to incentives at different points. At the top, Block 1 represents the macroeconomic whole of a region with final demand and final production concepts behind GDP, such as consumption, investments, net exports and government spending. Block 2 forms the "business perspective": An amount of sales orders arrive from Block 1, and firms maximize profits by minimizing costs when making optimal decisions about hiring (labor) and investment (capital). Block 3 is a full demographic model. It has births and deaths, migration within the United States to labor market conditions, and international immigration. It interacts with Block 1 through consumer and government spending levels and Block 4 through labor supply. Block 4 is the CGE portion of the model, where markets for housing, consumer goods, labor and business inputs interact. Block 5 is a quantification of competitiveness. It is literally regional purchase coefficients (RPCs) in modeling and proportional terms, which show the ability of a region to keep imports away while exporting its goods to other places and nations.

cepts on markets for labor, housing, consumer goods, imports and the importance of competitiveness to fostering economic growth over time. Changing one of these will influence the others—for instance, a new knife factory would improve the labor market and then bring it to a head by increasing migration into the area, driving housing and rent prices higher, and inducing the market to create a new subdivision to return to "market clearing" conditions.

3. Econometrics—REMI uses statistical parameters and historical data to populate the numbers inside the IO and CGE portions. The estimation of the different parameters, elasticity terms and figures gives the strength of various responses. It also gives the "time-lags" from the beginning of a policy to the point where markets have had a chance to clear.

4. New economic geography—Economic geography provides REMI a sense of economies of scale and agglomeration. This is the quantification of the strength of clusters in an area and their influence on productivity. One example would include the technology and research industries in Seattle. The labor in the area specializes to serve firms like Amazon and Microsoft and, thus, their long-term productivity grows more quickly than that of smaller regions with no proclivity towards software development (such as Helena, Mont.). The same is true on the manufacturing side with physical inputs, such as with the supply-chain for Boeing and Paccar in Washington in the production of transportation equipment. Final assembly will have a close relationship and a high degree of proximity to its suppliers of parts, repairs, transportation and other professional services, which show up in clusters in the state.

Conclusion

The estimated total economic impacts (direct and secondary) to Minnesota from Xcel Energy's nuclear operations at its three reactors and support operations at Xcel Energy headquarters are over $1 billion in output and approximately $600 million in gross state product every year. These operations also contribute $240 million in after-tax income to residents of Minnesota. The nuclear operations and their secondary effects also account for over 6,000 jobs in Minnesota.

The plant's economic benefits—on taxes and through wages and purchases of supplies and services—are considerable. In addition, plant employees further stimulate the local economy by purchasing goods and services from businesses around the area, supporting many small businesses throughout the region.

The facilities generated nearly 13 billion kilowatt-hours of emission-free electricity in 2015, enough to serve the yearly needs for 1.4 million homes. This low-cost, reliable electricity helped keep electricity prices in check in Minnesota.

Xcel Energy's nuclear plants are leaders economically, fiscally, environmentally and socially within Minnesota.

APPENDIX P1 – E3 SUMMARY

I. OVERVIEW OF ANALYSIS CONDUCTED BY ENERGY AND ENVIRONMENTAL ECONOMICS

We retained Energy and Environmental Economics, Inc. (E3) to provide analysis to inform our Resource Plan. E3 is a recognized industry-leading firm based in San Francisco and consults extensively with utilities, developers, government agencies, and environmental groups on clean energy issues. E3's experience analyzing the impacts of economy-wide decarbonization and the impacts of decarbonization on utility systems in other parts of the country was very valuable to us in evaluating the impacts of decarbonizing our Upper Midwest System and developing our Preferred Plan.

E3's analysis is provided in two reports. The first report provides their analysis on decarbonizing our Upper Midwest System (System Study). For this analysis, E3 performed an electricity portfolio optimization analysis that identifies a range of strategies to meet our greenhouse gas reductions goals. The second report provides E3's analysis on achieving the Minnesota economy-wide goal of an 80 percent reduction in greenhouse gases below 2005 levels by 2050 (Pathways Study). E3 presented its analysis at stakeholder workshops in September and October of 2018 and April 2019.

A. Upper Midwest System Study

For the System Study, E3 performed independent modeling and analysis of our system to inform our Resource Plan using two models:

- The RESOLVE model, which evaluates and optimizes the least-cost portfolios of resources to meet system demand considering carbon and other constraints,
- The RECAP model, which evaluates the reliability of electric energy and system capacity of the optimized resource portfolios over thousands of simulated weather years.

E3 used scenario analysis to examine the impacts of achieving deep carbon reductions in our generation portfolio in accordance with our long-term goals. Each scenario examined was designed to achieve carbon reduction milestones of 85% below 2005 levels by 2030 and 95% below 2005 levels by 2045. As discussed in detail in the report, these scenarios varied assumptions on the retirement of our nuclear and coal plants and the ability to add new gas-fired resources, the impacts of high electrification, gas prices, technology costs, and the ability to sell surplus generation into the MISO market.

The System Study contains several key findings that inform our Resource Plan:

1. **The study suggests that we can achieve substantial reductions in carbon emissions from our Upper Midwest portfolio at relatively low cost.** Across the 21 scenarios examined in this study that achieve deep carbon reductions during the study horizon, the lowest-cost scenarios reduce carbon at a levelized cost of $15-20 per ton. The ability to achieve such large emissions reductions at such a relatively low cost results from several converging factors: (1) low natural gas prices, which enable low-cost fuel switching from coal to gas; (2) the relatively low (and falling) costs of new wind and solar resources due to technology improvements over the past decade; (3) a potential to increase deployment of energy efficiency and other demand-side programs to manage load growth; and (4) anticipated reductions in future battery storage costs, which enable integration of high penetrations of renewable generation.
2. **The lowest-cost near-term opportunity to reduce carbon in Xcel's Upper Midwest system is to replace coal generation with a combination of renewables, storage, natural gas and efficiency.** E3's analysis suggests that accelerating the retirement of our remaining coal plants and replacing them with a portfolio of efficiency, renewables, storage, and natural gas generation provides the least-cost pathway to reducing emissions consistent with our 2030 goals.
3. **A diverse portfolio of resources—including nuclear—offers the least-cost long-term pathway to deep carbon reductions.** The scenario analysis conducted in this study suggests that under most circumstances, extending the licenses of both Monticello and Prairie Island to allow continued operation provides a least-cost option to meeting long-term carbon goals. This is due not only to the plants' ability to generate carbon-free electricity at relatively low cost but also, and perhaps more significantly, to the fact that nuclear generation (unlike wind, solar, or energy storage), as a "firm" resource, can generate at its full nameplate capacity for sustained periods when needed to meet reliability needs. This unique combination of characteristics makes existing nuclear plants inherently valuable to meeting our long-term carbon goals. All else equal, levelized cost of carbon abatement was higher in scenarios that did not allow nuclear relicensing.
4. **While new resources like wind, solar, and storage will play a central role in supplying carbon-free energy to Xcel's customers, these resources alone cannot meet Xcel's resource adequacy needs at reasonable costs.** The reliability analysis conducted in the study highlights the limitations of renewable and storage resources to meet resource adequacy needs: due to

variability of renewable generation and limits on duration of energy storage with today's technologies, these resources offer less capacity value than firm resources that can produce at full capacity when needed. Further, because their marginal capacity value declines with increasing penetration, wind, solar, and storage offer a relatively poor substitute for traditional firm capacity resources in meeting reliability needs at scale. Taken to an extreme, this study shows that a system designed to rely solely on renewables and storage to meet reliability needs would require prohibitively large investments. These findings underscore the need for an evolving approach to resource adequacy as the system as a whole incorporates greater amounts of renewables and storage. Such an approach would ensure that sufficient resources are available even when variable renewables and storage alone cannot produce sufficient levels of generation to meet load.

5. **Natural gas plants will be useful to ensure a reliable system but will operate at low capacity factors.** Some form of firm, dispatchable capacity is likely necessary to complement large anticipated investments in efficiency, renewables, and storage that will be necessary to decarbonize Xcel's energy supply. **Error! Reference source not found.** shows that among all low-carbon scenarios considered in this study, the least-cost options rely heavily on firm capacity resources to meet resource adequacy needs. In Xcel's case, investing in 2,000 to 4,000 MW of new gas generation capacity will lower the costs of achieving long-term carbon goals. All else equal, the levelized cost of carbon abatement was higher in scenarios that did not allow new gas. In the extreme, providing reliable electricity in a scenario with no dispatchable gas was modeled to require 36 GW of wind and solar, 24 GW of storage, and impose $4.4 billion per year in incremental fixed costs. As technology continues to improve, some of the electricity system values provided by gas generation may be able to be provided by a combination of longer-duration storage, demand response, and carbon-free dispatchable technologies that are not commercial today.

B. PATHWAYS Study

For the PATHWAYS study, E3 developed a set of long-term economy-wide, deep decarbonization scenarios for the state of Minnesota. These scenarios provide an exploration of the cross-sectoral implications of meeting economy-wide carbon reduction goals, and highlight the role of Xcel Energy, and the electric sector as a whole, in meeting the state's economy-wide carbon goal. The PATHWAYS study highlights the central role of the electric sector in reducing economy-wide greenhouse gas emissions by supplying clean energy to new loads as more fossil-fueled end uses convert to electricity.

Key finds from the PATHWAYS study include:

1. **Electrification and low-carbon electricity are necessary (but not sufficient) to reach statewide goals.** The analysis demonstrates how increased reliance on low-carbon electricity enables emission reductions by avoiding direct combustion of fossil fuels in households, businesses, and vehicles across a number of scenarios. Under a high electrification scenario, switching multiple end uses to very low-carbon electricity could enable an estimated 35 million tons of CO_2 reductions per year in other sectors by 2050, in addition to reductions in the electric sector itself.
2. **Buildings and transportation have significant potential to drive load growth, especially after 2025.** The analysis also highlights the significant potential for adoption of new electric appliances and vehicles, and the potential impact on total electricity requirements for Minnesota utilities. Transportation and building electrification drive electric load growth, especially after 2030, particularly in a future with constraints on bioenergy. Electrification of space heating has a particularly large impact on both total load (MWh) and peak demand (MW), primarily due to two factors: cold-climate efficiency challenges with electric air source heat pumps, and the greater difficulty (compared to electrified transportation or water heating) of limiting heating loads to off-peak hours.
3. R**easonable electric rates and low costs for new electric devices are essential for electrification.** The levels of electrification modeled in buildings and transportation are dependent on consumer adoption, which will benefit from reductions in capital costs and reasonable electric rates, even as the electric grid continues to decarbonize.

C. Relation to the Company's Resource Plan Analysis

By design, the scope of analysis conducted in E3's System Study overlaps considerably with the internal analysis conducted to develop our Preferred Plan. Wherever possible, the E3 studies relied on the same numerical inputs and assumptions as used to develop our Preferred Plan, supplemented by publicly available data sources where necessary. This approach was chosen to test the hypothesis that Xcel's internal analysis should generally align with the results obtained by an unbiased third-party using rigorous industry-standard approaches.

The PATHWAYS study provides context for the role of the electricity sector in reducing statewide carbon emissions. The PATHWAYS study explores scenarios that

could achieve an 80 percent reduction in economy-wide greenhouse gas emissions, but it is not a least-cost optimization. As discussed in Appendix F4, the PATHWAYS study was also used to develop a high electrification load forecast sensitivity that was analyzed in E3's System Study and our Strategist modeling.

Xcel Energy Low Carbon Scenario Analysis

Decarbonizing the Generation Portfolio of Xcel Energy's Upper Midwest System

July 2019

Energy+Environmental Economics

Xcel Energy Low Carbon Scenario Analysis

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Xcel Energy Low Carbon Scenario Analysis

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Acknowledgements & Disclaimer

The authors of this study would like to acknowledge the contributions of the staff of Xcel Energy's Upper Midwest branch, who throughout this effort provided timely input, data, and perspectives. The willing contributions of the Xcel Energy staff were crucial to the development of both methods and results in this study that reflect the unique nature of the electricity system in the region. While the Xcel Energy staff provided crucial inputs and played an important role in scoping the study, the analysis completed here and the conclusions reached thereupon are solely reflective of E3's views and perspectives.

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Acronyms

AEO	Annual Energy Outlook
ATB	Annual Technologies Baseline
CAGR	Compound annual growth rate
CCGT	Combined cycle gas turbine
CHP	Combined heat & power
CT	Combustion turbine
DR	Demand response
EE	Energy efficiency
EIA	Energy Information Administration
ELCC	Effective load carrying capability
EV	Electric vehicle
ICE	Internal combustion engine
IPCC	Intergovernmental Panel on Climate Change
IRP	Integrated resource plan
LCOE	Levelized cost of energy
LOLE	Loss of load expectation
LOLP	Loss of load probability
MISO	Midcontinent Independent System Operator
MTEP	MISO Transmission Expansion Plan
NREL	National Renewable Energy Laboratory
PPA	Power purchase agreement
PRM	Planning reserve margin
PV	Photovoltaic
RPS	Renewables Portfolio Standard
RTO	Regional transmission organization

Executive Summary

Study Overview

Across the United States, the electricity sector is in a rapid state of transition, driven by multiple factors:

- An increasing preference for "clean" energy resources and interest in decarbonization of electricity supply at the state, utility, and customer levels;
- Significant realized cost reductions of renewable resources such as wind and solar, coupled with the emergence of new technologies such as battery storage; and
- Aging generation infrastructure leading to plant retirements and a corresponding need for investment in new generation resources.

These trends, and the elevated levels of investment in new renewable generation they have prompted throughout the country in the past decade, are likely to continue.

Since 2005, Xcel Energy's Upper Midwest system, which serves customers in Minnesota and four neighboring states, has made significant progress toward decarbonizing its energy supply. The company's conversion of its High Bridge and Riverside coal plants, achievement of energy efficiency consistent with state standards, and investment in a total of over 3,000 MW of wind generation have led to a collective shift towards carbon-free generation resources, which are expected to represent approximately 60% of the Upper Midwest system's generation mix by 2020. The expected annual generation mix for the Upper Midwest system in 2020 is shown in Figure i.

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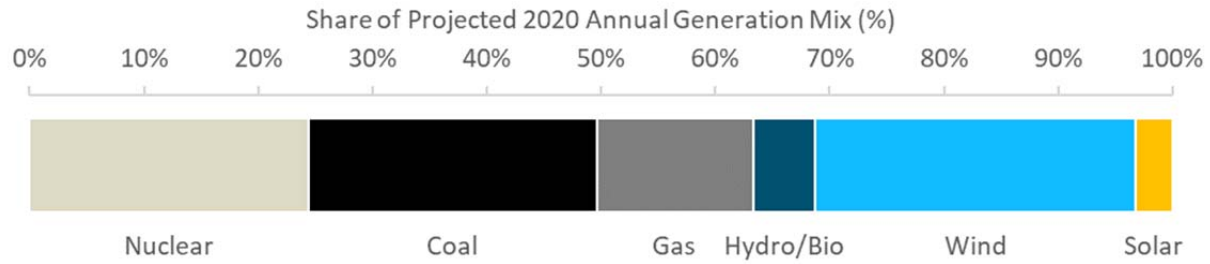
Figure i. Projected annual generation mix in 2020



This shift has enabled significant carbon reductions in the Upper Midwest portfolio, whose 2017 emissions were roughly 30% below a 2005 benchmark level. Xcel also recently established notable forward-looking goals that imply significant continued effort in this area over the long term:

- Xcel's 2015 Upper Midwest Integrated Resource Plan established plans to retire two coal plants and meet 60% of customer loads with carbon-free resources by 2030; and
- In December 2018, Xcel announced a company-wide goal to reduce emissions by 80% by 2030 and to be 100% carbon-free by 2050, a first-of-its-kind target among U.S. utilities.

Achieving these ambitious goals will require careful and strategic approaches to planning, procurement, and utility operations. While low-cost wind, solar and energy storage resources will make up the bulk of investments needed to meet Xcel's goals, additional capabilities will be needed to supplement these resources whose availability depends on uncontrollable meteorological phenomena. Balancing load and generation instantaneously and ensuring resource adequacy under all conditions (e.g., during periods of high load and low wind and solar output) requires an evolution in today's operational and planning practices. Designing a low-cost resource portfolio that simultaneously meets future reliability standards and clean energy objectives has become one of the principal long-term planning challenges for utilities today.

This report, commissioned of E3 by Xcel Energy addresses several key questions implied by the company's aggressive carbon targets:

- What would be the composition of the Upper Midwest system portfolio—and what are its corresponding greenhouse gas emissions—under a "Reference Case" scenario reflecting a business-as-usual, least-cost approach to meeting future energy and capacity needs?
- What are Xcel's options—and what are the corresponding costs—for achieving steep emission reductions consistent with near- and long-term goals?
- What are the reliability implications of relying heavily on renewable and storage resources? Could an electric system achieve 100% emissions reductions using only today's commercially available technologies while maintaining reliability?

To answer these questions, this study uses scenario analysis to design and characterize a range of different portfolios that each achieve aggressive levels of decarbonization relative to a Reference Case. The portfolios are constructed from different assumptions about potential coal and nuclear plant retirements and future investments in natural gas resources, which in turn determine the quantity and timing of future renewables and storage additions and investments in demand-side resources needed to meet long-term carbon reduction goals.

By design, the scope of analysis conducted in this study overlaps considerably with the internal analysis conducted by Xcel Energy in the development of its preferred plan as filed in its Integrated Resource Plan. Wherever possible, this study relies on the same numerical inputs and assumptions as used by Xcel's IRP team, supplemented by publicly available data sources where necessary. This approach was chosen to ensure that the results of Xcel's internal analysis align with the rigorous, industry-standard approaches.

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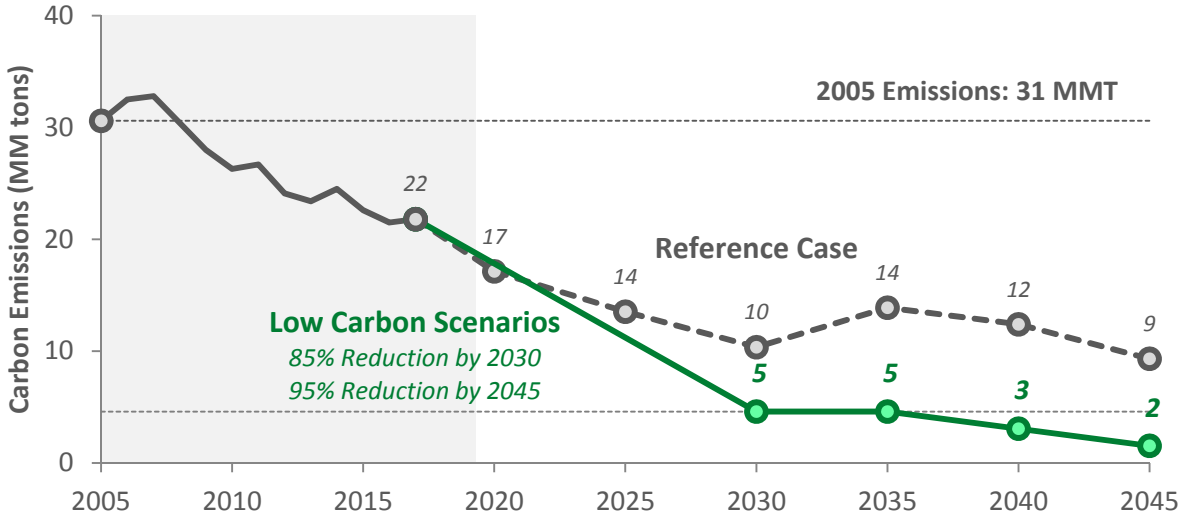
Methods and Assumptions

This study uses scenario analysis to examine the impacts of achieving deep carbon reductions in Xcel's portfolio in accordance with the company's long-term goals. Keeping in mind the breadth of resource options available to meet Xcel's future energy and capacity needs, and consequently the many different pathways to achieve the company's targeted carbon reductions, this analysis designs and evaluates a range of different plausible portfolios. Each scenario examined in this study (with the exception of a counterfactual Reference Case) is designed to achieve carbon reduction milestones of 85% below 2005 levels by 2030 and 95% below 2005 levels by 2045. The trajectory of carbon reductions that each scenario is designed to achieve is shown in Figure ii.

Figure ii. Future Upper Midwest carbon reduction pathway as modeled in this study compared to counterfactual Reference Case



While all scenarios are consistent with the carbon reduction trajectory above, each scenario achieves the desired level of carbon reductions with a unique combination of resource options (i.e., nuclear, fossil, renewable, storage, and demand-side resources). Figure iii shows the range of assumptions used

in this study about each of those resources. Overall, this study compares 21 distinct scenarios against a Reference Case that provides a benchmark against which costs and emissions reductions are measured. The purpose of constructing scenarios in this way is to highlight tradeoffs implied by Xcel's key strategic decisions as it transitions toward a low-carbon future:

- What is the long-term role of nuclear generation in Xcel's portfolio?
- How would the continued operation of Xcel's coal resources impact its efforts to decarbonize?
- What role, if any, should new natural gas play in meeting long-term resource adequacy needs?
- What renewables, storage, and demand-side resources are needed to meet carbon goals?

Figure iii. Range of assumptions about Xcel's resource options captured in scenario analysis

Resource	Scenario Options			
Nuclear	Retire upon license expiry	Relicense Monticello only	Relicense both nuclear plants	Retire Prairie Island by 2030
Coal	Retire all plants at end of useful life	Retire AS King by 2030	Retire all coal by 2030	
Gas	Allow investment in new gas	Limit new gas additions to Sherco CC	Prohibit all new gas investment	
Wind	Add new wind to meet energy, capacity, and clean energy goals			
Solar	Add new solar to meet energy, capacity, and clean energy goals			
Storage	Add new storage to meet capacity & flexibility needs			
DR	Add new DR to meet capacity needs			
Efficiency	Deploy energy efficiency to meet energy, capacity & clean energy needs			

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This study utilizes two resource planning models developed to analyze electric systems at high penetrations of renewable generation:

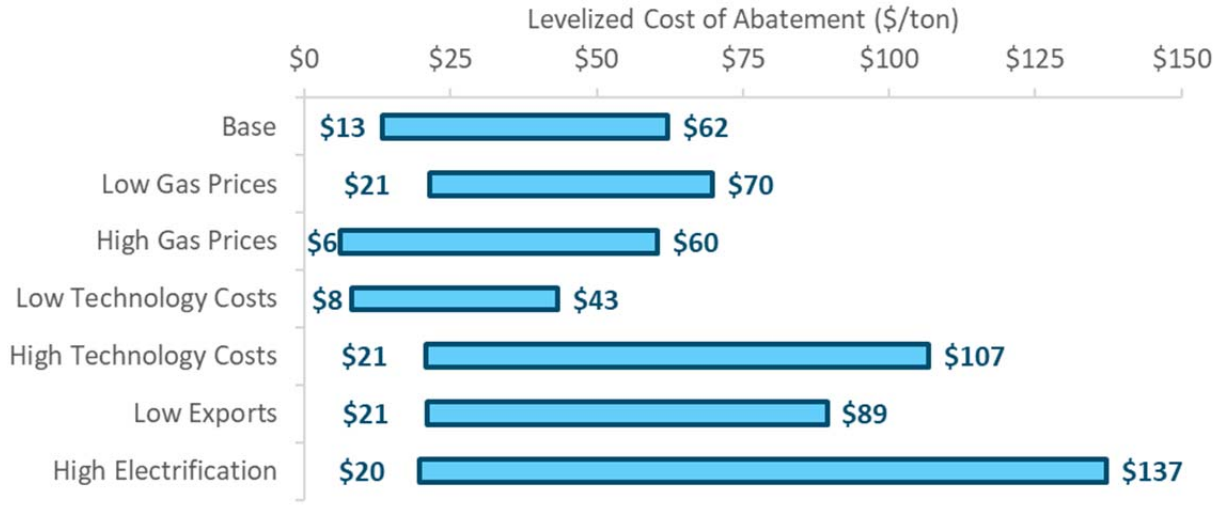
- **E3's Renewable Energy Capacity (RECAP) model**, a loss-of-load-probability model that provides a detailed and statistically robust perspective on the reliability of electric systems with conventional, renewable, storage, and demand-side resources; and
- **E3's Renewable Energy Solutions (RESOLVE) model**, a capacity expansion model that uses optimization techniques to identify a least-cost portfolio of resource investments to meet future reliability and clean energy objectives while also simulating electric system operations on an hourly basis.

These tools complement one another and jointly provide a strong foundation for analyzing and understanding the implications of a long-term transition towards low-carbon and carbon-free resource portfolios. In this study, RECAP provides a rigorous, data-driven perspective on the future reliability needs of the Xcel portfolio and the ability of wind, solar, and storage to meet those needs; RESOLVE builds on this analysis to design least-cost portfolios that achieve reliability objectives while meeting clean energy goals, balancing large quantities of variable resources, and minimizing costs.

Key Findings

First—and perhaps most significantly—this study suggests that Xcel Energy can achieve substantial reductions in carbon emissions from its Upper Midwest portfolio at relatively low cost. Across the 21 scenarios examined in this study that achieve deep carbon reductions during the study horizon, the lowest-cost scenarios reduce carbon at a levelized cost of $15-20 per ton. The ability to achieve such large emissions reductions at such a relatively low cost results from several converging factors: (1) low natural gas prices, which enable low-cost fuel switching from coal to gas; (2) the relatively low (and falling) costs of new wind and solar resources due to technology improvements over the past decade; (3) a potential to increase deployment of energy efficiency and other demand-side programs to manage load growth; and (4) anticipated reductions in future battery storage costs, which enable integration of high penetrations of renewable generation.

Figure iv. Range of carbon abatement costs across all scenarios and sensitivities.



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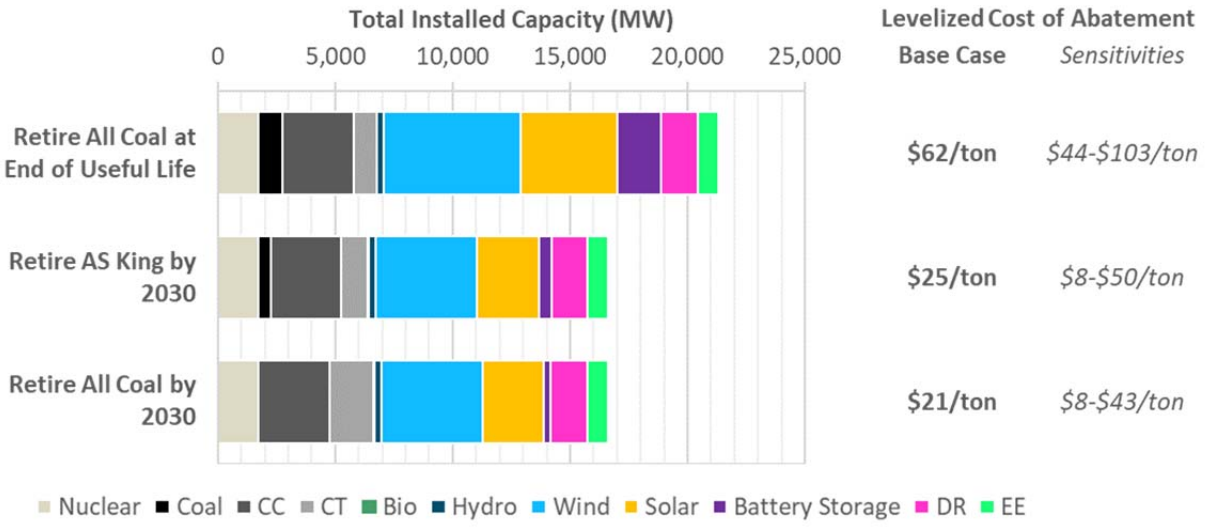
The lowest-cost near-term opportunity to reduce carbon in Xcel's Upper Midwest system is to replace coal generation with a combination of renewables, storage, efficiency, and natural gas generation. The four coal plants owned by Xcel produce approximately 85% of the Upper Midwest system's greenhouse gas emissions in the 2020 Reference Case; while Xcel has already established plans to retire two of these plants prior to 2030, this analysis suggests that accelerating the retirement of its remaining two plants and replacing them with a portfolio of efficiency, renewables, storage, and natural gas generation provides the least-cost pathway to reducing emissions consistent with Xcel's 2030 goals (see Figure v).

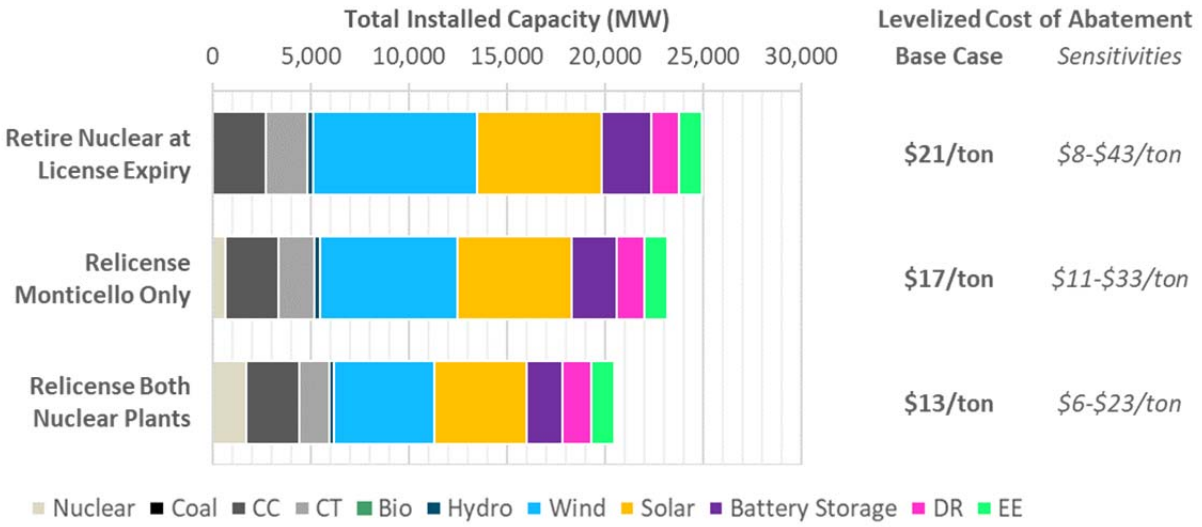
Figure v. Xcel resource portfolios that achieve 85% carbon reductions in 2030



A diverse portfolio of resources—including nuclear—offers the least-cost long-term pathway to deep carbon reductions. Beyond 2030, meeting Xcel's long-term carbon goals will require continued development of new carbon-free energy resources. At the same time, the expiration of existing licenses at both of Xcel's nuclear facilities in the early 2030s raises questions about the role of nuclear in Xcel's long-term generation portfolio. The scenario analysis conducted in this study suggests that under most

circumstances, extending the licenses of both Monticello and Prairie Island to allow continued operation provides a least-cost option to meeting long-term carbon goals (Figure vi). This is due not only to the plants' ability to generate carbon-free electricity at relatively low cost but also, and perhaps more significantly, to the fact that nuclear generation (unlike wind, solar, or energy storage) operates as a "firm" resource that can generate at its full nameplate capacity for sustained periods when needed to meet Xcel's reliability needs. This unique combination of characteristics makes Xcel's existing nuclear plants inherently valuable to meeting Xcel's long-term carbon goals.

Figure vi. Xcel resource portfolios that achieve 95% carbon reductions in 2045



While new resources like wind, solar, and storage will play a central role in supplying carbon-free energy to Xcel's customers, these resources alone cannot meet Xcel's resource adequacy needs at reasonable costs. The reliability analysis conducted in this study highlights the limitations of renewable and storage resources to meet resource adequacy needs: due to variability and limits on duration, these resources offer less capacity value than firm resources that can produce at full capacity when needed. Further, because their marginal capacity value declines with increasing penetration, wind, solar, and

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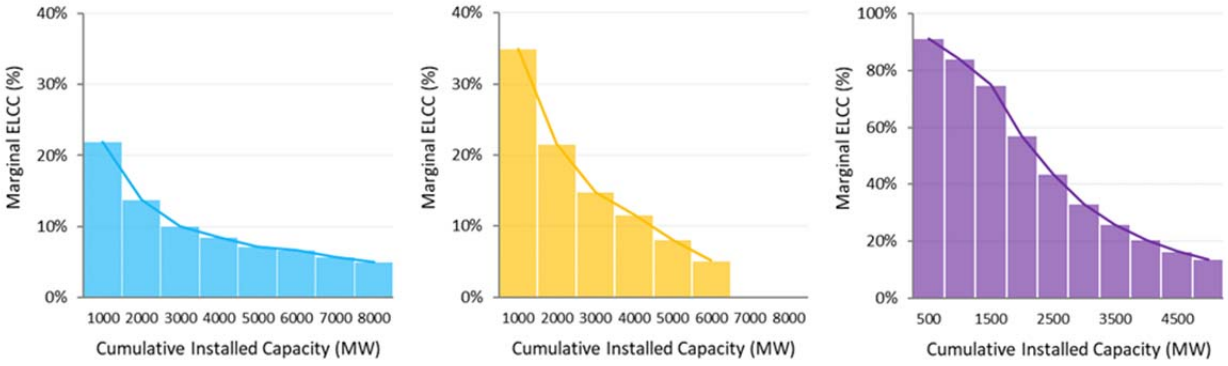
storage offer a relatively poor substitute for traditional firm capacity resources in meeting reliability needs at scale (see Figure vii). Taken to an extreme, this study shows that a system designed to rely solely on renewables and storage to meet reliability needs would require prohibitively large investments. These findings underscore the need for an evolving approach to resource adequacy—by both Xcel and MISO—as renewables and storage reach greater levels of penetration. Such an approach is critical to ensure that sufficient resources are available even when variable renewables and storage alone cannot produce sufficient levels of generation to meet load.

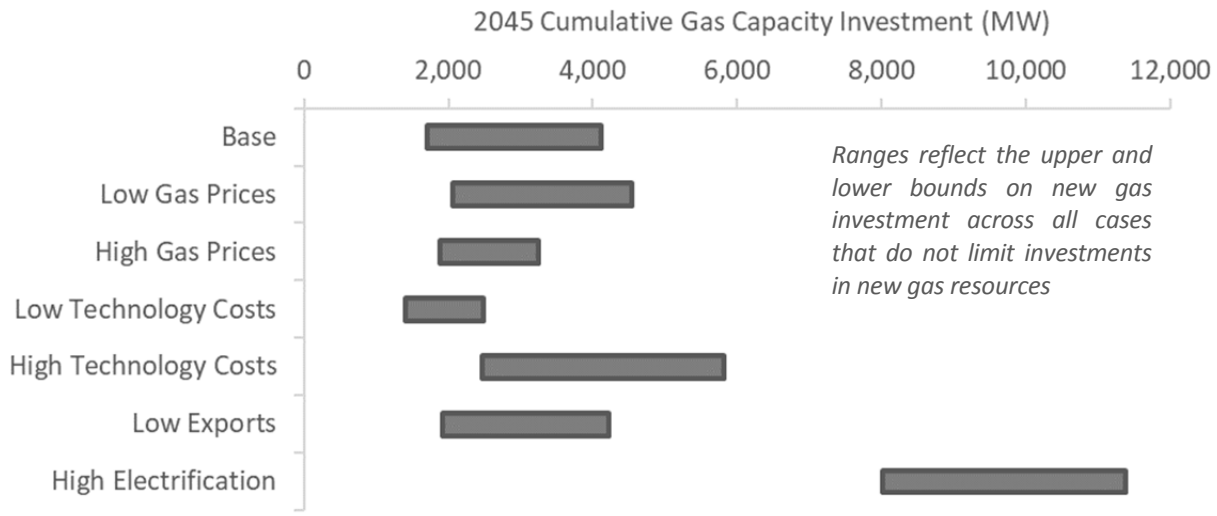
Figure vii. Marginal capacity values of wind, solar, and storage resources in Xcel's 2030 portfolio



Natural gas plants will be critically important to ensure a reliable system but will operate at low capacity factors. Because of the inherent limitations of renewables and storage resources to satisfy resource adequacy needs alone, some form of firm, dispatchable capacity will be needed to complement large anticipated investments in efficiency, renewables, and storage that needed to decarbonize Xcel's energy supply. While Xcel's existing nuclear plants are highly valuable because of their firm attributes, they alone are not sufficient to satisfy the need for firm capacity; natural gas resources will continue to play a crucial role in meeting system reliability. Figure viii shows the range of new investments in natural gas resources across all the cases and sensitivities that allowed gas investment as part of the least-cost plan. Under Base Case assumptions, the level of new gas

investments needed by 2045 spans a range from 2,000 to 4,000 MW (depending on whether existing nuclear plants are relicensed); among most other sensitivities, a similar range is observed. One sensitivity stands out for its outsized effect: in the High Electrification sensitivity, due to large new loads that increase winter peak significantly, the level of investment in new gas resources in least-cost portfolios is dramatically higher—8,000 to 11,000 MW. Collectively, these observations point to a more general finding: investment in new natural gas resources to meet capacity needs enables a low-cost pathway to decarbonize electricity and to facilitate levels of electrification needed to meet economy-wide carbon reduction goals.

Figure viii. Range of investments in new natural gas capacity resources by 2045 as part of a least-cost plan to achieve deep carbon reductions



Finally, while this study identifies a number of promising pathways towards Xcel's long-term carbon goals, the cost of achieving carbon reductions remains highly uncertain and subject to impacts of factors beyond the company's control. Even in the scenario that this study identifies as a least-cost plan—one that combined nuclear relicensing, accelerated coal retirements, and investments in

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renewables, storage, efficiency, and gas to meet long-term goals—the potential costs calculated at the study's endpoint in 2045 spans a broad range from 150% above to 125% below the costs under Base Case assumptions. The largest potential sources of risk identified in this study result from uncertainty on the future cost of new renewable and storage resources and the uncertainty of how the changing generation mix in the broader MISO system will impact Xcel's opportunities to manage costs through market transactions. The exposure of Xcel's portfolio to such uncertainty and the associated risks underscores the importance of constant vigilance and responsiveness to rapidly changing market conditions.

1 Introduction

1.1 Study Motivation

Across the United States, the electricity sector is in a rapid state of transition, driven by multiple factors:

- An increasing preference for "clean" energy resources and interest in decarbonization of electricity supply at the state, utility, and customer levels;
- Significant realized cost reductions of renewable resources such as wind and solar, coupled with the emergence of new technologies such as battery storage; and
- Aging generation infrastructure leading to plant retirements and a corresponding need for investment in new generation resources.

These trends, and the elevated levels of investment in new renewable generation they have prompted throughout the country in the past decade, are likely to continue.

Since 2005, Xcel Energy's Upper Midwest system, which serves customers in Minnesota and four neighboring states, has made significant progress toward decarbonizing its energy supply. The Company's conversion of its High Bridge and Riverside coal plants, achievement of energy efficiency consistent with state standards, and investment in a total of over 3,000 MW of wind generation have led to a collective shift towards carbon-free generation resources, which are expected to represent approximately 60% of the Upper Midwest system's generation mix by 2020. The expected annual generation mix for the Upper Midwest system in 2020 is shown in Figure 1-1.

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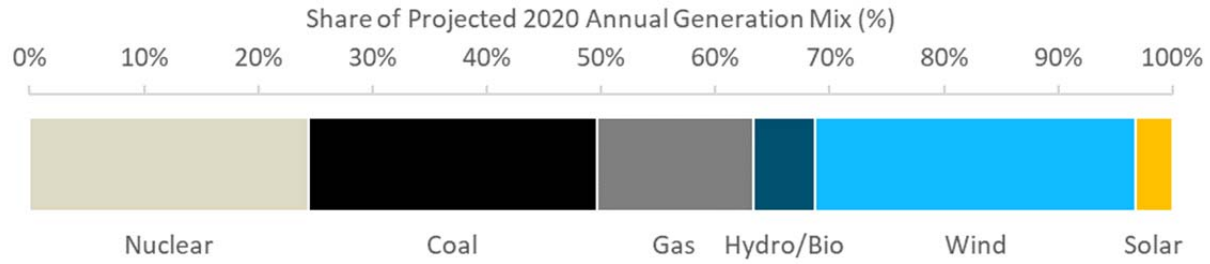
Figure 1-1. Projected annual generation mix in 2020

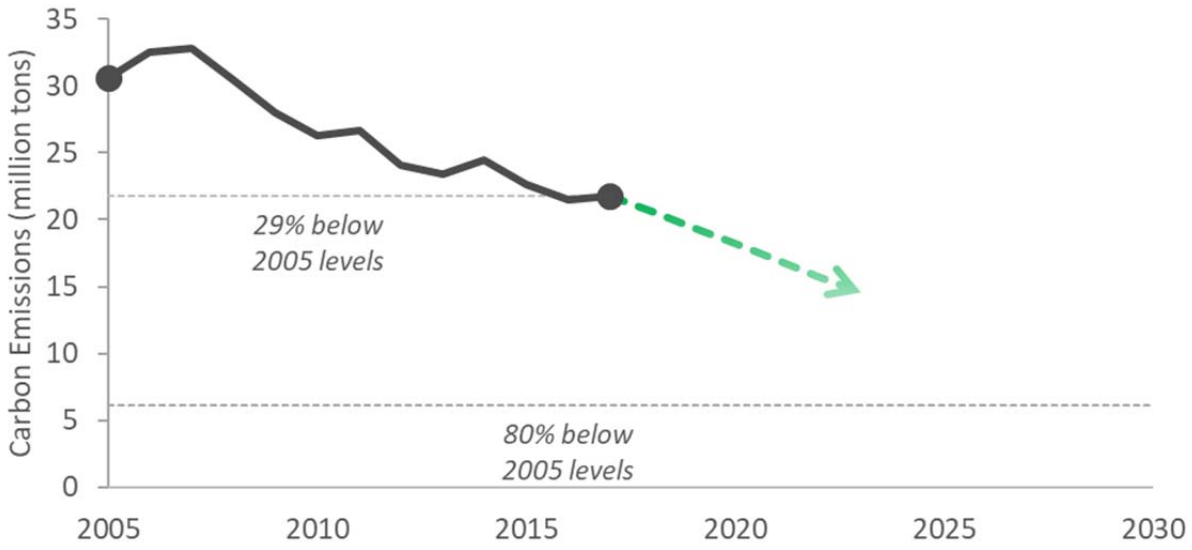


This shift has enabled significant carbon reductions in the Upper Midwest portfolio, whose 2017 emissions were roughly 30% below a 2005 benchmark level. Xcel also recently established notable forward-looking goals that imply significant continued effort in this area over the long term:

- Xcel's 2015 Upper Midwest Integrated Resource Plan established plans to retire two coal plants and meet 60% of customer loads with carbon-free resources by 2030; and
- In December 2018, Xcel announced a company-wide goal to reduce emissions by 80% by 2030 and to be 100% carbon-free by 2050, a first-of-its-kind target among U.S. utilities.

Thus, while the greenhouse gas emissions attributed to the Upper Midwest portfolio as of 2017 were roughly 30% below 2005 levels, significant additional reductions will be needed to meet the Company's long-term goals (see Figure 1-2).

Figure 1-2. Historical carbon emissions attributed to Xcel's Upper Midwest portfolio and a pathway towards long-term goals



Achieving these ambitious goals will require careful and strategic approaches to planning, procurement, and utility operations. While low-cost wind, solar and energy storage resources will make up the bulk of investments needed to meet Xcel's goals, additional capabilities will be needed to supplement these resources whose availability depends on uncontrollable meteorological phenomena. Balancing load and generation instantaneously and ensuring resource adequacy under all conditions (e.g., during periods of high load and low wind and solar output) requires an evolution in today's operational and planning practices. Designing a low-cost resource portfolio that simultaneously meets future reliability standards and clean energy objectives has become one of the principal long-term planning challenges for utilities today.

Within its current integrated resource planning cycle, whose analytical horizon stretches through 2034, Xcel's Upper Midwest system faces several significant questions that will establish a path to meeting long-term emissions goals. Among the key questions are: (1) how to manage retirement of aging coal

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generators; (2) whether to seek extensions for nuclear plants whose current licenses expire shortly after 2030; (3) what level of investment in renewables, storage, and efficiency will be needed to meet greenhouse gas reduction targets; and (4) the extent to which investment in new gas resources will be needed for reliability purposes.

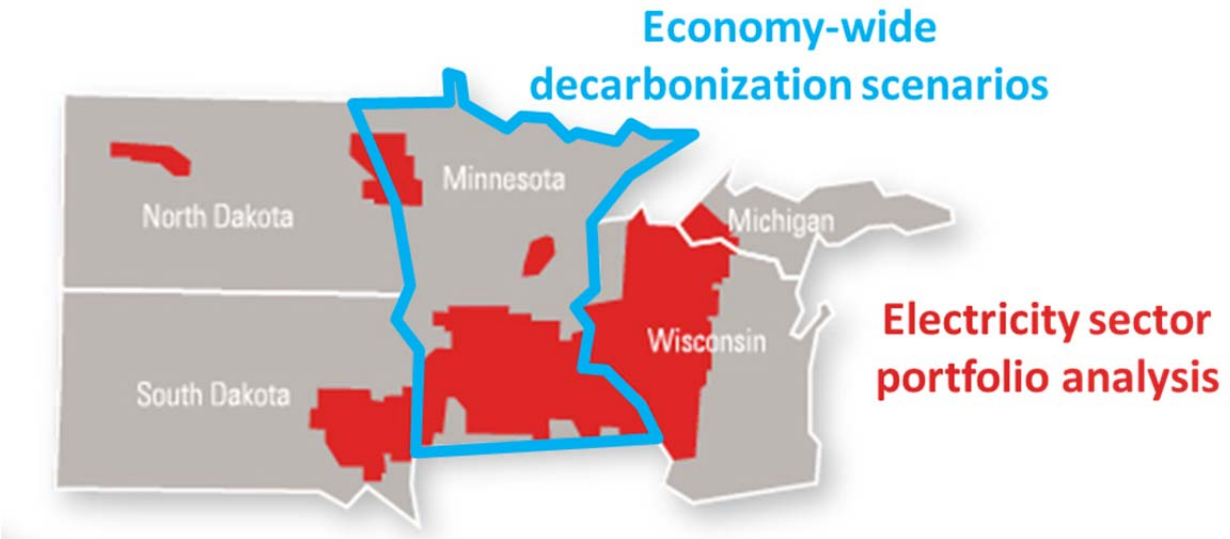
Both to inform its own strategic decision-making and to inform and engage stakeholders, Xcel commissioned two studies to provide an independent, unbiased, third-party perspective on these and related issues:

(1) An economy-wide analysis of deep decarbonization pathways for the State of Minnesota that establishes a vision for how the state could reduce carbon emissions 80% below 2005 levels by 2050; and

(2) An electricity portfolio optimization analysis that identifies a range of strategies Xcel could implement to meet near-term goals and align with long-term goals.

While the geographic scopes of these studies differ (see Figure 1-3.), they complement one another by creating general blueprints for decarbonizing electricity and the broader economy; in doing so, they highlight the central role of the electric utility in meeting long-term climate objectives. Together, these two studies supplement Xcel's own IRP analysis by providing an alternative and independent perspective that address the challenges facing Xcel's Upper Midwest system.

Figure 1-3. Overlapping geographic scopes of E3's two studies



1.2 Lessons from Pathways Analysis

E3's "Minnesota Decarbonization Analysis," an economy-wide study of decarbonization for the state, contributes to a growing body of literature that explores the landscape of what is needed to reach deep levels of decarbonization, typically 80% reductions below a baseline level by 2050. These studies, conducted by E3 and others, have generally converged on a consensus view that four foundational "pillars" are necessary to achieve such significant reductions across the economy:

- Deployment of ambitious levels of **energy efficiency & conservation** beyond levels of historical achievement;
- **Electrification of end uses** traditionally fueled by fossil fuels, including vehicles, space and water heating, and industrial processes;

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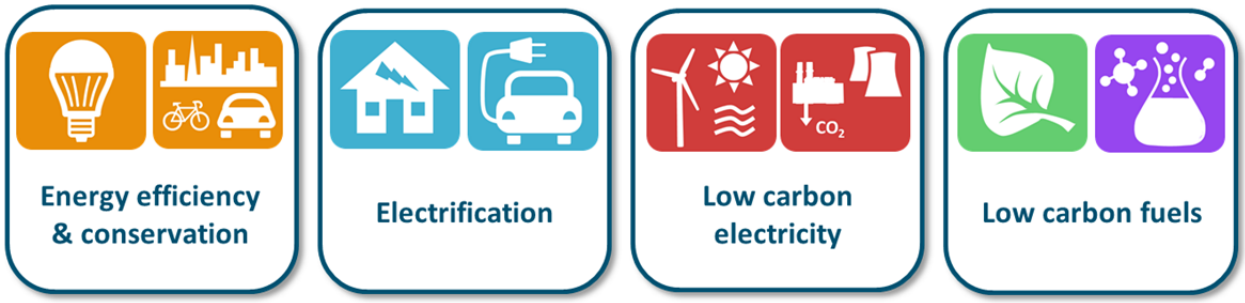
- Production of **low-carbon electricity** to supply clean energy to both existing and newly electrified loads; and
- Use of **low-carbon fuels**—for instance, biofuels, synthetic gas, and/or hydrogen—to supply energy to end uses that continue to rely on liquid and/or gaseous fuels.

Figure 1-4. Four pillars of deep decarbonization



These pillars highlight the central role of the electric sector in decarbonization: significantly reducing economy-wide greenhouse gas emissions requires the electric sector to decarbonize generation while supplying clean energy to new loads as more fossil-fueled end uses convert to electricity.

A number of the key findings from E3's decarbonization study for the state of Minnesota expand upon the necessity and role of these four pillars and further underscore the importance of decarbonizing electricity supply while minimizing costs to the extent possible:

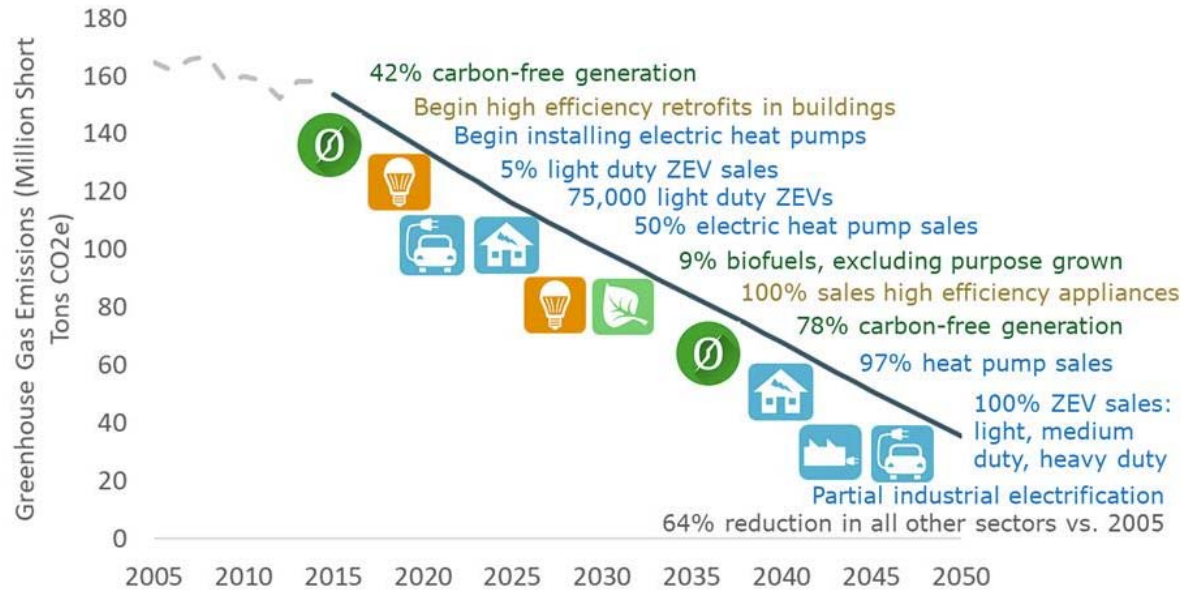
- **Electrification and zero-carbon electricity are necessary (but not sufficient) to reach statewide goals.** The analysis demonstrates how increased reliance on low-carbon electricity enables emission reductions by avoiding direct combustion of fossil fuels in households, businesses, and vehicles across a number of scenarios.
- **Buildings and transportation have significant potential to drive load growth, especially after 2025.** The analysis also highlights the significant potential for adoption of new electric appliances and vehicles, and the potential impact on total electricity requirements for Minnesota utilities. Transportation and building electrification drive electric load growth,

especially after 2030, particularly in a future with constraints on bioenergy. Electrification of space heating has a particularly large impact on both total load (MWh) and peak demand (MW).

+ **Reasonable electric rates and low costs for new electric devices are essential for electrification.** The levels of electrification modeled in buildings and transportation are dependent on consumer adoption, which will benefit from reductions in capital costs and reasonable electric rates, even as the electric grid continues to decarbonize.

The economy-wide emissions trajectory towards deep decarbonization, along with the key transformations that enable these reductions, are shown in Figure 1-5.

Figure 1-5. Emissions and infrastructure transformations in the "High Electrification" scenario from E3's economy-wide pathways analysis



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1.3 Study Overview

As a complement to the economy-wide pathways study, this study focuses on how to decarbonize electricity supply in the Upper Midwest. In doing so, it addresses several key questions implied by Xcel's aggressive targets:

- What is the composition of the Upper Midwest system portfolio—and what are its corresponding greenhouse gas emissions—under a "Reference Case" scenario reflecting a business-as-usual, least-cost approach to meeting future energy and capacity needs?
- What are Xcel's options—and what are the corresponding costs—for achieving steep emission reductions consistent with near- and long-term goals, and how do these compare to the Reference Case?
- What are the reliability implications of relying heavily on renewable and storage resources? Could an electric system achieve 100% emissions reductions using only today's commercially available technologies while maintaining reliability?

To answer these questions, this study uses scenario analysis to design and characterize a range of different portfolios that each achieve aggressive levels of decarbonization relative to a Reference Case. The portfolios are constructed from different assumptions about potential coal and nuclear plant retirements and future investments in natural gas resources, which in turn determine the quantity and timing of future renewables and storage additions and investments in demand-side resources needed to meet long-term carbon reduction goals. The analysis spans the years 2020 through 2045, extending beyond the traditional IRP planning horizon in an effort to provide additional information on the implications of Xcel's long-term goals; however, the analysis stops short of attempting to "solve" for how Xcel Energy might meet its 2050 goals in recognition of the likely but unpredictable role that future technological innovation will play in allowing Xcel to achieve the final increments of decarbonization. Figure 1-6 shows the building blocks this study used to construct alternative scenarios and develop portfolios.

Figure 1-6. Building blocks for scenario development.

Resource	Scenario Options			
Nuclear	Retire upon license expiry	Relicense Monticello only	Relicense both nuclear plants	Retire Prairie Island by 2030
Coal	Retire all plants at end of useful life	Retire AS King by 2030	Retire all coal by 2030	
Gas	Allow investment in new gas	Limit new gas additions to Sherco CC	Prohibit all new gas investment	
Wind	Add new wind to meet energy, capacity, and clean energy goals			
Solar	Add new solar to meet energy, capacity, and clean energy goals			
Storage	Add new storage to meet capacity & flexibility needs			
DR	Add new DR to meet capacity needs			
Efficiency	Deploy energy efficiency to meet energy, capacity & clean energy needs			

The study relies primarily on two complementary models developed by E3, both designed to investigate the implications of heavy reliance on renewables and storage:

+ **E3's Renewable Energy Capacity (RECAP) model**, a loss-of-load-probability model that provides a detailed and statistically robust perspective on the reliability of electric systems with conventional, renewable, storage, and demand-side resources; and
+ **E3's Renewable Energy Solutions (RESOLVE) model**, a capacity expansion model that uses optimization techniques to identify a least-cost portfolio of resource investments to meet future reliability and clean energy objectives.

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These tools complement one another and jointly provide a strong foundation for analyzing and understanding the implications of a long-term transition towards low-carbon and carbon-free resource portfolios. In this study, RECAP provides a rigorous, data-driven perspective on the future reliability needs of the Xcel portfolio and the ability of wind, solar, and storage to meet those needs; RESOLVE builds on this analysis to design least-cost portfolios that achieve reliability objectives while meeting clean energy goals, balancing large quantities of variable resources, and minimizing costs.

1.4 Relationship to Xcel's Analysis

By design, the scope of analysis conducted in this study overlaps considerably with the internal analysis conducted by Xcel Energy in the development of its preferred plan as filed in its Integrated Resource Plan. Wherever possible, this study relies on the same numerical inputs and assumptions as used by Xcel's IRP team, supplemented by publicly available data sources where necessary. This approach was chosen to ensure that the results of Xcel's internal analysis align with the rigorous, industry-standard approaches.

The methods employed in this study, which E3 has used across a wide range of North American jurisdictions, are generally consistent with those used in the Strategist model used by Xcel Energy's IRP team. However, E3's RESOLVE model and Strategist do deviate from one another in several key methodological areas; the key differences between the two are discussed further in Section 2.1.2.

The inputs and assumptions used in this study provided by Xcel Energy are consistent with public data sources that E3 has used in other studies. To that effect, the key findings of this study are E3's conclusions, and do not directly represent conclusions or future commitments of Xcel Energy. This study makes no recommendations for formal preferred plan for the company, but does offer a supplemental perspective for the Commission and stakeholders to consult in evaluating Xcel's proposed preferred plan.

1.5 Report Contents

The remainder of this report is organized as follows:

- **Section 2** describes the scenarios and modeling approach used in the study;
- **Section 3** describes the key modeling inputs and assumptions that shape the analysis;
- **Section 4** presents the results of the reliability analysis;
- **Section 5** presents the results of the portfolio analysis; and
- **Section 6** discusses the key conclusions reached from this study.

Additional details on the study's methods, data inputs, and results can be found in the technical appendices:

- **Appendix A** describes the methodology of RECAP;
- **Appendix B** describes the methodology of RESOLVE;
- **Appendix C** provides additional detail on the development of study inputs; and
- **Appendix D** provides additional detail model results across the scenarios and sensitivities.

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2 Modeling Methodology

2.1 Modeling Approach

This study relies upon two resource planning models developed by E3 and tailored towards analysis of electric systems at high penetrations of renewable generation to develop and analyze a range of scenarios to explore potential options for carbon reductions in the Upper Midwest system portfolio:

- **E3's Renewable Energy Capacity (RECAP) model**, a loss-of-load-probability model that provides a detailed and statistically robust perspective on electric systems that rely on a combination of conventional, renewable, storage, and demand-side resources; and
- **E3's Renewable Energy Solutions (RESOLVE) model**, a capacity expansion model that uses optimization techniques to identify a least-cost portfolio of resource investments to meet future reliability and clean energy objectives.

These two tools complement one another in their application, together providing a strong foundation with which to analyze and understand implications of long-term transitions towards low carbon and carbon-free portfolios. As illustrated in Figure 2-1, these models are used together: the study first uses RECAP to characterize potential contributions of different technologies towards system resource adequacy needs; this, in turn, serves as an input to RESOLVE, to ensure that the least-cost portfolio outcome meets reliability goals.

Figure 2-1. Two-phase approach used in this study

2.1.1 RELIABILITY ANALYSIS

2.1.1.1 Scope of Analysis

One of today's principal concerns among utilities and system operators alike is the preservation of resource adequacy in electric systems that are rapidly transitioning towards greater reliance on variable (e.g. wind and solar) and use-limited resources (e.g. storage, demand response) and away from traditional sources of firm, dispatchable capacity (e.g. nuclear, coal, and gas). Many jurisdictions—including the Midcontinent Independent System Operator (MISO), of which Xcel's Upper Midwest system is a member—have transitioned towards the use of "effective load carrying capability" (ELCC)—a rigorous measure of capacity value derived through loss-of-load-probability analysis—to measure the contributions of wind and solar towards resource adequacy needs, and there is growing consensus within the industry that such techniques will eventually be needed for storage at higher levels of deployment as well. This study's first phase begins with a detailed examination of the potential contributions of such resources towards Xcel Energy's future resource adequacy needs.

As a member of MISO, Xcel Energy is obligated to meet an annual planning reserve margin (PRM) requirement by either self-supplying capacity or purchasing it directly through the MISO market. The accounting conventions through which capacity from resources is accredited towards this requirement are administered by MISO; the contribution of each type of generation resource depends on its

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performance characteristics and availability to produce power during the most constrained periods of the year:

- Traditional dispatchable resources are accredited at their full firm capacity;[1]
- Wind and solar resources are assigned capacity value based on ELCC studies conducted by MISO (currently, 16% and 50%, respectively, but subject to periodic updates with changes to the system); and
- Energy storage with four hours of duration is assigned full capacity value.

Projecting how capacity accreditation for variable and use-limited resources will change in MISO over the twenty-five year horizon of this analysis—which would require forecasting changes in its load and resource mix and a corresponding loss-of-load-probability analysis across the full RTO footprint—is beyond the scope of this type of study.

Rather than undertaking such an exercise, this study relies on a simplifying convention for variable and use-limited resources that considers only the capacity value that those resources provide to Xcel's Upper Midwest system. This is accomplished by developing a model of the Upper Midwest loads and resource portfolio in RECAP and using the model to derive curves of the "effective load carrying capability" (ELCC) as a function of penetration for wind, solar, storage, and demand response. Through the development of these ELCC curves that reflect the capacity value of variable and use-limited resources, RECAP is used to derive inputs for a resource adequacy requirement to be used in the optimization process. The conventions used in this study are shown in Table 2-1, where they are contrasted against the actual obligations Xcel Energy faces as a MISO member.

[1] Traditional dispatchable resources are accredited based on their UCAP or unforced capacity value.

Table 2-1. Conventions used for resource adequacy accounting in this study compared to Xcel's obligation as a MISO member

Assumption	Xcel's MISO Obligation	RESOLVE Portfolio Analysis
Planning reserve margin requirement	3% above Xcel non-coincident peak demand	
Thermal/dispatchable plants	Plant-specific firm capacity rating	
Wind & solar ELCC	MISO accredited ELCC (currently 50% for solar and 16% for wind)	RECAP ELCC curves for Xcel Energy system
Energy storage ELCC	Full capacity accreditation for storage with >4 hour duration	RECAP ELCC curve for Xcel Energy system

Notably, this study preserves Xcel's PRM requirement of 3% above its noncoincident peak, which inherently captures a large portion of the reliability benefits that Xcel Energy realizes through its MISO membership: a lower planning reserve margin requirement due to the diversity benefit of participation in a capacity sharing pool. The important distinction between this study's approach and Xcel's obligation is the use of Xcel-specific ELCC curves for variable and use-limited resources, which ensures that each portfolio of resources is sufficient to meet Xcel's own resource adequacy needs while still relying on the diversity benefit afforded to it through MISO membership.

The reliability analysis conducted in the first phase serves a secondary purpose as well: it provides an opportunity to examine what infrastructure investments would be needed to achieve a reliable portfolio that relies solely on carbon-free, non-combustion resources (primarily nuclear, wind, solar, and storage). In addition to deriving ELCC curves for a variety of resources, this study uses RECAP to design two portfolios that rely exclusively on carbon-free resources to serve load by 2045: one that includes Xcel's existing nuclear plants and another that relies only on wind, solar, and storage to meet reliability needs. These two portfolios are compared against today's system to illustrate the magnitude of investment needed to reach a fully carbon-free portfolio without any fossil combustion.

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2.1.1.2 Methodology

The reliability analysis conducted in the first phase of this analysis is completed using RECAP, a loss-of-load-probability model developed by E3 and specifically tailored to answer questions on resource adequacy in systems heavily reliant on variable and use-limited resources. Its rigor lies in its simulation of the capability of a portfolio of generating resources to meet loads across a wide range of potential conditions, using a Monte Carlo approach to simulate thousands of potential years of plausible conditions on the system. RECAP incorporates features such as:

- Use of decades of historical weather data to develop synthetic hourly load shapes reflective of long-term patterns of load variability;
- Stochastic internal logic to produce chronological strips of load and corresponding renewable profiles that preserve correlations observed in a limited set of weather-matched chronological data;
- Stochastic simulation of forced outages based on expectations for mean time to failure and mean time to repair for dispatchable generators; and
- Time-sequential dispatch logic that allows the model to track state of charge and/or other constraints on use-limited resources (e.g. energy storage, demand response) that may limit their availability.

Through this robust simulation of load and generator availability, RECAP can be used to analyze whether an electric system's generation portfolio meets a specified reliability standard (most commonly, a standard of no more than "one day in ten years" of lost load). In evaluating resource adequacy, RECAP also produces a number of metrics directly useful to utilities in planning and procurement, including (1) a target planning reserve margin; (2) a variety of statistics for a given electricity system to characterize the size, frequency, and duration of reliability events; and (3) ELCC values for different types of resources on the system. Additional detail on the methodology of the RECAP model is presented in Appendix A.

This study relies on RECAP's simulation capabilities primarily to produce ELCC curves that serve as a key input into RESOLVE. The portfolio analysis relies on a PRM requirement to design a portfolio that meets reliability needs, and so RECAP is used to determine the extent to which variable and use-limited resources can contribute to meeting that requirement. RECAP is used to derive ELCC "curves" that capture how the capacity value of each resource changes as a function of penetration that in turn serve as inputs to a portfolio optimization process that uses this information to determine the appropriate level upon which to rely upon these resources to meet resource adequacy needs.

2.1.2 PORTFOLIO ANALYSIS

2.1.2.1 Scope of Analysis

The purpose of the second phase of this analysis is to design and evaluate a range of portfolios that simultaneously meet Xcel's reliability standards and ambitions for greenhouse gas reductions while also mitigating costs to its ratepayers. Designing portfolios to meet multiple objectives is a complex multidimensional problem that, in the context of increasing reliance on variable and use-limited resources, presents a new challenge to resource planners. In developing future resource plans, utilities must consider a broader range of available resource options (e.g. thermal generators, renewables, storage, demand-side resources), each with unique characteristics in their potential impacts on the system and interactive effects with other resources. Developing a least-cost plan to meet multiple objectives requires consideration of a range of different questions:

- What are the fixed costs associated with a specific portfolio of new resources due to investments and operations and maintenance?
- To what extent will a portfolio of resources meet resource adequacy needs, considering both the declining ELCC of different resource types and the interactive effects between technologies?
- How will a portfolio affect the operations of the electric system across the year, and thereby the cost and associated greenhouse gas intensity to meet utility load?

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- How could retirement of existing plants either facilitate or inhibit the achievement of utility goals?

This second phase uses optimization modeling techniques to answer these questions through the development of a range of portfolios to meet Xcel's reliability standards while achieving substantial levels of carbon reduction.

2.1.2.2 Methodology

In this phase, this study uses E3's RESOLVE model to optimize future generation portfolios. RESOLVE is a capacity expansion model that uses linear programming to identify optimal long-term generation and transmission investments in an electric system, subject to reliability, technical, and policy constraints. Designed specifically to address the capacity expansion questions for systems seeking to integrate large quantities of variable resources, RESOLVE layers capacity expansion logic on top of a reduced-form production cost model to determine the least-cost investment plan, accounting for both the up-front capital costs of new resources and the variable costs to operate the grid reliably over time. In an environment in which most new investments in the electric system have fixed costs significantly larger than their variable operating costs, this type of model provides a strong foundation to identify potential investment benefits associated with alternative scenarios.

RESOLVE's optimization capabilities allow it to select from among a wide range of potential new resources. The full range of resource options considered by RESOLVE in this study is shown in Table 2-2 below.

Figure 2-2. RESOLVE modeling methodology

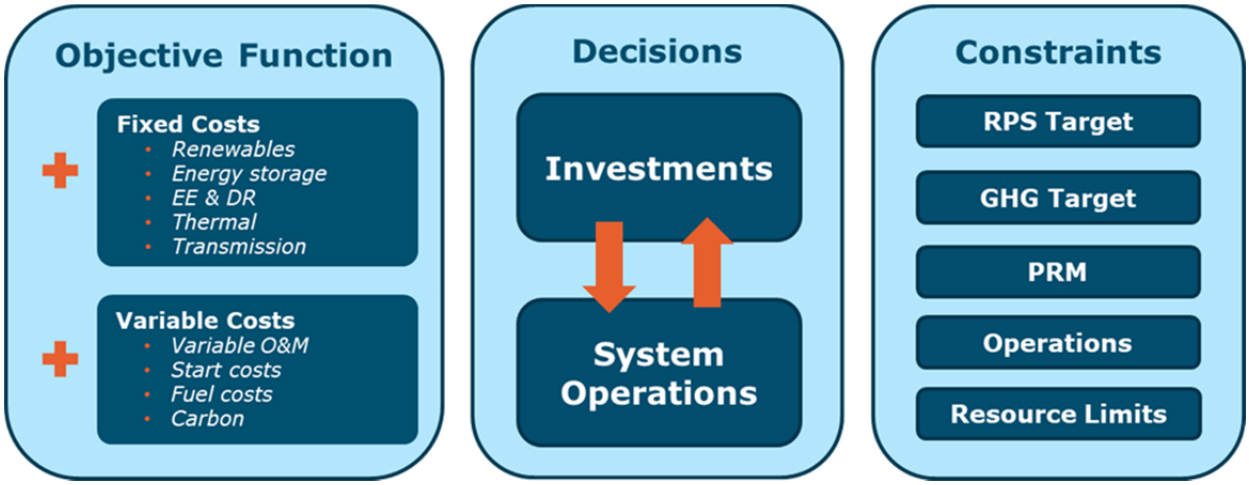

Table 2-2. Resource options considered in RESOLVE

Resource Option	Examples of Available Options	Capabilities
Natural Gas Generation	• Simple cycle gas turbines • Combined cycle gas turbines	• Dispatches economically based on heat rate, subject to operational constraints • Contributes to ramping & reserve needs • Provides large capacity value
Renewable Generation	• Solar PV • Wind	• Curtailable when needed to balance load • Provides limited capacity value based on ELCC
Energy Storage	• Batteries (4 hr)	• Balances hourly net load variability • Contributes to ramping & reserve needs • Provides limited capacity value based on ELCC
Energy Efficiency	• HVAC • Lighting	• Reduces demand throughout the year • Reduces resources need for reliability
Demand Response	• Interruptible tariff • Critical Peak Pricing	• Provides limited capacity value based on ELCC

To identify optimal investments in the electric sector, maintaining a robust representation of prospective resources' impact on system operations is fundamental to ensuring that the value each

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resource provides to the system is captured accurately. At the same time, the addition of investment decisions across multiple periods to a traditional unit commitment problem increases its computational complexity significantly. RESOLVE's simulation of operations has therefore been carefully designed to simplify a traditional unit commitment problem where possible while maintaining a level of detail sufficient to provide a reasonable valuation of potential new resources. The key attributes of RESOLVE's operational simulation are enumerated below:

- **Hourly chronological simulation of operations:** RESOLVE's representation of system operations uses an hourly resolution to capture the intraday variability of load and renewable generation. This level of resolution is necessary in a planning-level study to capture the intermittency of potential new wind and solar resources, which are not available at all times of day to meet demand and must be supplemented with other resources.
- **Planning reserve margin requirement:** When making investment decisions, RESOLVE requires the portfolio to include enough firm capacity to meet coincident system peak plus additional 3% of planning reserve margin (PRM) requirement. This value is Xcel's contribution as a utility to the overall MISO planning reserve margin of 8.4%. The contribution of each resource type towards this requirement depends on its attributes and varies by type: for instance, variable renewables are discounted compared to thermal generators because of limitations on their availability to produce energy during peak hours.
- **Greenhouse gas cap:** RESOLVE also allows users to specify and enforce a greenhouse gas constraint on the resource portfolio for a region. As the name suggests, the emission cap requires that annual emission generated in the entire system to be less than or equal to the designed maximum emission cap. As it designs future portfolios, RESOLVE chooses both (1) how to dispatch new and existing resources to meet the goal (e.g. displacing output from existing coal plants with increased natural gas generation) and (2) what additional investments are needed to further reduce carbon in the system.

Additional detail on the methodology of the RESOLVE model is included in Appendix B.

2.1.2.3 Comparison to Strategist

The Xcel Upper Midwest team uses the Strategist model for answering questions on capacity expansion and planning optimization. Although in the same family of model as E3's RESOLVE model, there are key differences in how investments are evaluated in both models. These differences are highlighted in Table 2-3. below.

Table 2-3. Key differences between RESOLVE & Strategist

Model Feature	Strategist	RESOLVE
System Operations	Load duration curve heuristic	Chronological hourly dispatch with simplified unit commitment
Day Sampling	Representative weeks for each month	Smart sample of ~40 representative days
Market Interactions	Purchases & sales determined based on exogenous wholesale price forecast	Market interactions simulated endogenously with representation of external loads & resources
Resource Adequacy	Planning reserve margin with deemed credits for each resource	Planning reserve margin with dynamically updating ELCC values for renewables

Some implications of these differences are highlighted below:

- Accurately capturing the impacts and operational value of resources like energy storage, for which simulation of chronological dispatch is important, is difficult in models that rely on load duration curve heuristics to approximate system operations—particularly as the penetrations of renewables and storage resources increase.
- The assumption that Xcel is a price taker in the MISO market, implicit in the use of static wholesale prices to represent the external market, may not fully capture the effects that large changes in Xcel's own portfolio could have on the market itself. As the portfolios of Xcel and other utilities within the MISO footprint shift away from fossil resources and towards higher levels of renewables, capturing the changing market dynamics and implications of Xcel's own decisions on the market itself will become an increasingly important link in resource planning.

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+ Similarly, the application of static capacity credits for resources like wind, solar, and storage will not capture the necessary evolution of capacity accreditation to ensure reliability at higher levels of penetration. Future resource planning efforts should consider how the capacity contributions of various future investments will change as penetrations increase rather than assuming capacity accreditation in the future remains consistent with today's rules.

Each of these implications suggests a need for resource planning practices in general to evolve towards a more dynamic, anticipatory paradigm to allow prudent planning in spite of a rapidly transforming system.

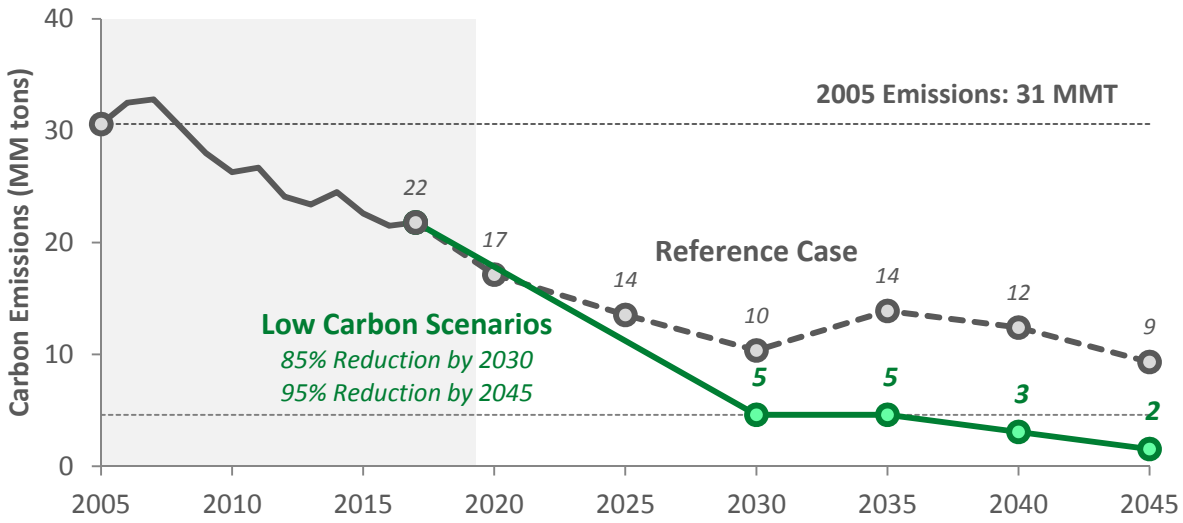
2.2 Scenarios & Sensitivities

2.2.1 OVERVIEW OF SCENARIOS

This study focuses on a suite of scenarios that examine the range of strategies Xcel could take to meet greenhouse gas reduction goals in the Upper Midwest system. Each of the scenarios and sensitivities, aside from the Reference Case, meet or surpass the carbon target shown in Figure 2-3; reaching an 85% reduction in carbon emissions by 2030 (beyond Xcel's actual 2030 target of an 80% reduction) and a 95% reduction in carbon emissions by 2045 (on track to meet Xcel's 2050 target of carbon neutrality).[2]

[2] The 2030 target modeled in this analysis is an assumption developed by E3 that reflects a plausible expectation that to achieve a company-wide goal of 80% carbon reductions by 2030 may require the Upper Midwest system to go beyond this target. This assumption (and the low carbon trajectory in its entirety) are not formally representative of carbon goals established by Xcel for its Upper Midwest system.

Figure 2-3. Future Upper Midwest carbon reduction pathway as modeled in this study compared to counterfactual Reference Case



The Reference Case modeled in this study is developed to provide a cost and emissions benchmark against which to compare each of the low carbon scenarios. It incorporates the following assumptions:

- **Achievement of existing RPS goals** associated with existing statutes—including a 30% RPS by 2020 for Xcel (as Minnesota's largest utility);
- **Planned new resources**, including over 2 GW of new renewable capacity by 2030, a new 835 MW combined cycle plant at the Sherco facility in 2027, and an additional 400 MW to Xcel's current DR program;
- **Announced retirement dates of existing coal plants**, including Sherco units 1, 2, and 3 (2026, 2023, and 2040), AS King (2037)
- **Retirement of nuclear plants at end of current licenses:** Monticello (2030), Prairie Island 1 and 2 (2033 and 2034)
- **Forecasted cost reductions** for new solar, wind, and storage technologies consistent with industry expectations.

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This study compares 21 "low carbon" scenarios against this Reference Case. The scenarios, listed in Table 2-4, were broadly designed in several categories to investigate key questions:

- A set of **Coal Retirement Cases**, which informs the value of retiring various levels of Xcel's coal fleet (AS King and Sherco 1, 2, and 3) to meet the carbon reduction goals;
- A set of **New Gas Prohibition Cases**, which prohibits the construction of new gas generation (including or not including the new Sherco CCGT), forcing all future energy and capacity needs to be met by carbon-free resources; and
- A set of **Nuclear Relicensing Cases**, which investigates the value of keeping the existing carbon-free, firm capacity (Monticello and Prairie Island 1 and 2) online through 2045.

Table 2-4. Matrix of scenarios evaluated

ID	AS King	Sherco 3	Prairie Island	Monticello	New Gas?
0	**Planned ret**	**Planned ret**	**Not relicensed**	**Not relicensed**	**Yes**
1	Planned ret	Planned ret	Not relicensed	Not relicensed	Yes
2	**Early retirement**	Planned ret	Not relicensed	Not relicensed	Yes
3	**Early retirement**	**Early retirement**	Not relicensed	Not relicensed	Yes
4	Planned ret	Planned ret	Not relicensed	Not relicensed	**Sherco CC only**
5	**Early retirement**	Planned ret	Not relicensed	Not relicensed	**Sherco CC only**
6	**Early retirement**	**Early retirement**	Not relicensed	Not relicensed	**Sherco CC only**
7	Planned ret	Planned ret	Not relicensed	Not relicensed	**None**
8	**Early retirement**	Planned ret	Not relicensed	Not relicensed	**None**
9	**Early retirement**	**Early retirement**	Not relicensed	Not relicensed	**None**
10	Planned ret	Planned ret	Not relicensed	**20-yr relicense**	Yes
11	**Early retirement**	Planned ret	Not relicensed	**20-yr relicense**	Yes
12	**Early retirement**	**Early retirement**	Not relicensed	**20-yr relicense**	Yes
13	Planned ret	Planned ret	**20-yr relicense**	**20-yr relicense**	Yes
14	**Early retirement**	Planned ret	**20-yr relicense**	**20-yr relicense**	Yes
15	**Early retirement**	**Early retirement**	**20-yr relicense**	**20-yr relicense**	Yes
16	Planned ret	Planned ret	**Early retirement**	Not relicensed	Yes
17	**Early retirement**	Planned ret	**Early retirement**	Not relicensed	Yes
18	**Early retirement**	**Early retirement**	**Early retirement**	Not relicensed	Yes
19	Planned ret	Planned ret	**20-yr relicense**	**20-yr relicense**	**Sherco CC only**
20	**Early retirement**	Planned ret	**20-yr relicense**	**20-yr relicense**	**Sherco CC only**
21	**Early retirement**	**Early retirement**	**20-yr relicense**	**20-yr relicense**	**Sherco CC only**

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2.2.2 SENSITIVITY ANALYSIS

The long-term scenario analysis conducted in this type of study relies on projections of future conditions that are inherently uncertain. Utilities have historically incorporated uncertainty in such factors as fuel price forecasts and load growth into their integrated resource planning analyses to account for this uncertainty. With the transition of the industry towards resources that consume less fuel but are more capital intensive, new sources of uncertainty become important considerations for resource planners—for instance, future anticipated cost reductions for resources like wind, solar, and battery storage. This study conducts sensitivity analyses on a number of such uncertainties to evaluate the robustness of the conclusions reached in this analysis. The list of sensitivities explored within this analysis is shown in Table 2-5. Inventory of sensitivities explored in analysis—while no means meant to represent a comprehensive analysis of all uncertainties faced by utilities, these represent a number of the key factors that should be considered in resource planning and decision-making. Sensitivities are not tested against all scenarios—instead, a subset of scenarios is selected for more detailed examination through sensitivities.

Table 2-5. Inventory of sensitivities explored in analysis

Sensitivity	Description
High/Low Gas Prices	Alternative projections of natural gas natural gas prices (+/- 50% adjustment to CAGR) that tests how future gas prices will impact cost of decarbonization.
High/Low Technology Costs	Alternative price projections for renewable & storage technologies that evaluates impact of future technology costs on cost of decarbonization.
Low Exports	Assumes Xcel cannot sell surplus generation into the MISO market beyond 2030, reflecting a bookend scenario for adverse market conditions in which demand for surplus power throughout MISO is limited
High Electrification Loads	Assumed loads increase by ~21 TWh by 2045 due to space & water heating electrification, as well as electric vehicle integration

3 Inputs & Assumptions

This study relies on a wide range of inputs and assumptions to populate the RESOLVE and RECAP models. Wherever possible, inputs and assumptions are aligned with those used directly by Xcel to prepare its own IRP filing for the Upper Midwest system; in some cases, data from publicly available information was used as a supplement to information provided by Xcel. The key categories of inputs and assumptions to E3's two portfolio analysis models are summarized in Table 3-1. Additional detail on each specific input is included in subsequent sections.

Table 3-1. Summary of some key inputs and assumptions for RESOLVE and RECAP

Input Category	Used in Model	Description
Demand forecast	RESOLVE, RECAP	Annual demand and peak forecast for the Upper Midwest system
Existing resources	RESOLVE, RECAP	Capacity, commission dates, retirement dates and operating characteristics for all existing and planned resources within the Xcel Upper Midwest system
New resources	RESOLVE, RECAP	Costs and performance for candidate resources considered in the portfolio optimization
Hourly profiles	RESOLVE, RECAP	Hourly profiles for all the components of demand; hourly generation profiles for solar and wind resources; hourly profiles for all other chronological hourly dispatch resources like EE
Fuel price forecasts	RESOLVE	Fuel price forecast data for all thermal resources
MISO market representation	RESOLVE	Load and resource assumptions for other external MISO zones connected to Xcel's Upper Midwest service territory

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3.1 Demand Forecast

3.1.1 BASE CASE

The demand forecast used in this study captures expected future changes in electricity demand within Xcel's Upper Midwest service territory. The demand forecast accounts for expected growth in loads due to future economic and demographic trends but does not account for the future impacts of Xcel's energy efficiency programs; these efficiency programs are represented instead in this analysis explicitly as a supply-side resource with a variable profile. The assumed demand forecast assumptions, shown in Table 3-2., align with Xcel's Upper Midwest IRP modeling assumptions.

Table 3-2. Xcel Base Case demand forecast

Category	Historical 2018	Forecast 2020	2025	2030	2035	2040	2045	CAGR '18-'45
Retail Sales (GWh)	44,348	45,129	46,589	49,704	51,577	53,007	53,921	0.7%
Peak Demand (MW)	9,241	9,399	9,927	10,628	11,426	11,956	12,420	1.1%

Retail sales represent the demand for electricity at the customer meter and are grossed up for transmission and distribution losses (7%) when simulating the operations of the bulk electric power system; peak demand is reported at the wholesale level and so already accounts for the impact of transmission & distribution losses.

3.1.2 HIGH ELECTRIFICATION SENSITIVITY

The results of the economy-wide deep decarbonization pathways analysis discussed in Section 1.1 suggests that achievement of deep decarbonization targets across the economy requires electrification of multiple end uses; particularly transportation, space heating, and water heating. To develop a High Electrification sensitivity for this study, E3 used projections of future electric sector load from the "High

Electrification" scenario in E3's pathways study, downscaled to represent the Upper Midwest service territory. This sensitivity explores the impact on the Xcel system of increased demand due to space and water heating electrification and increased electric vehicle integration. Table 3-3 shows the impacts of incremental electrification on Xcel's annual energy demand in this High Electrification sensitivity.

Table 3-3. Buildup of retail sales forecast used in High Electrification sensitivity

Category	Historical 2018	Forecast 2020	2025	2030	2035	2040	2045	CAGR '18-'45
Base Case	**44,348**	**45,129**	**46,589**	**49,704**	**51,577**	**53,007**	**53,921**	0.7%
Space Heating	-80	-87	-28	+315	+1,772	+4,030	+6,386	
Water Heating	+87	+145	+251	+160	+317	+713	+1,083	
Electric Vehicles	+38	+79	+338	+1,559	+4,733	+9,369	+13,639	
High Electrification	**44,393**	**45,266**	**47,149**	**51,738**	**58,400**	**67,118**	**75,030**	**2.0%**

Before 2030, the space heating component causes a decrease in total retail sales because the amount of electrified spacing heating is not yet enough to overcome the benefits from the increased efficiency. By 2045, all three components cause a 39% increase in annual retail sales relative to the Base Case. Through the modeling period, electric vehicle integration contributes the largest increase in retail sales on an annual basis.

The corresponding impact on peak demand from the high level of electrification is more significant (see Table 3-4), nearly doubling over the analysis horizon through 2045. The major driver of the significant increase in peak is the electrification of end use heating loads, which, beginning in the early 2030s, cause Xcel to shift from a summer to a winter peak. Thereafter, the magnitude of the winter peak rises dramatically with increased deployment of heat pumps and other newly electrified loads.

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Table 3-4. Buildup of peak demand forecast used in High Electrification Sensitivity

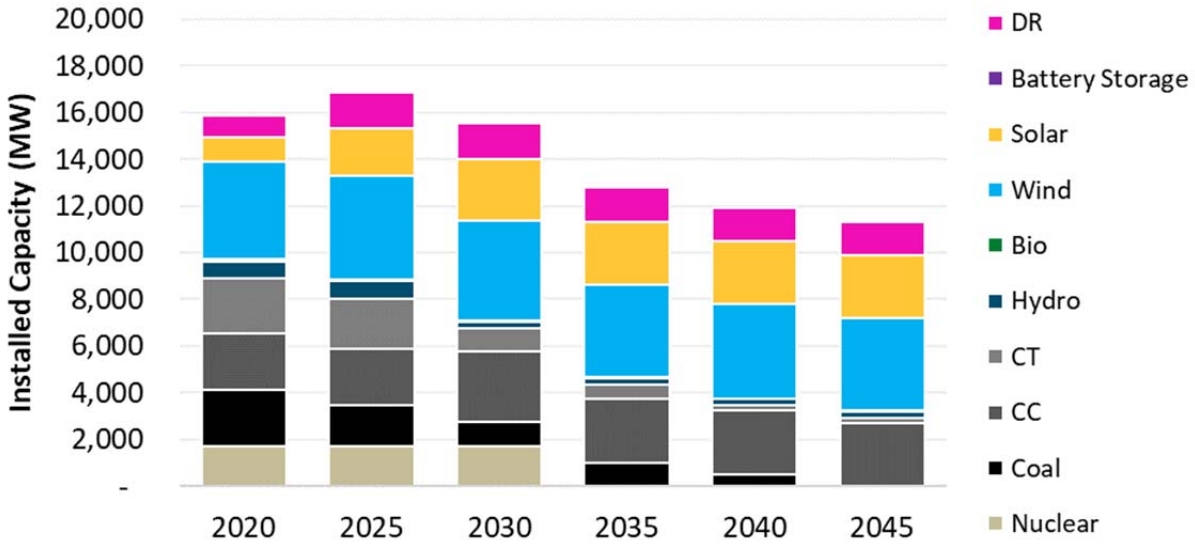
Category	Historical 2018	Forecast 2020	2025	2030	2035	2040	2045	CAGR '18-'45
Base Case	9,241	9,399	9,927	10,628	11,426	11,956	12,420	**1.1%**
Incremental Load From Electrification	8	+7	+77	+207	+855	+5,347	+10,369	
High Electrification	**9,249**	**9,406**	**10,004**	**10,835**	**12,281**	**17,302**	**22,789**	**3.4%**

3.2 Existing Resource Portfolio

The primary source for data on existing and planned generation is Xcel IRP modeling assumptions. The composition of Xcel's existing fleet is shown in Figure 3-1, reflecting Xcel's commitments and plans established by prior IRP. Key changes to the system captured in Figure 3-1 include:

- **Planned new resources**, including nearly 2 GW of new renewable capacity by 2030, a new 835 MW combined cycle plant at the Sherco facility in 2027, and an additional 400 MW to Xcel's current DR program from 2023;
- **Announced retirement dates of existing coal plants**, including Sherco units 1, 2, and 3 (2026, 2023, and 2040), AS King (2037); and
- **Retirement of nuclear plants at end of current licenses:** Monticello (2030), Prairie Island 1 and 2 (2033 and 2034).

Figure 3-1. Existing resource assumptions for Xcel portfolio over time



3.2.1 NUCLEAR

Xcel's current generation portfolio includes three nuclear units:

- Monticello (646 MW), whose license expires in 2031;
- Prairie Island 1 (546 MW), whose license expires in 2033; and
- Prairie Island 2 (546 MW), whose license expires in 2034.

Together, these baseload carbon-free resources are capable of producing roughly 14,000 GWh on an annual basis, enough to meet approximately 30% of Xcel's annual energy needs.

This study examines multiple options for retirement and relicensing of these existing nuclear units across different scenarios; these assumptions are summarized in Table 3-5. The Reference Case assumes that all units retire upon the expiry of their existing licenses, which results in a significant need for new investment to meet energy and capacity needs in the early 2030s; alternative scenarios examine the

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potential effects of extending the licenses at one or both facilities through the analysis horizon, testing the impact of retaining baseload carbon-free generation within the context of Xcel's future carbon reduction goals.

Table 3-5. Xcel nuclear plant assumptions

Reference Assumptions			
Plant	**Capacity (MW)**	**Retirement**	**Notes**
Monticello	646	2030	Plant life extended by 20 years in scenarios 10-15
Prairie Island 1	546	2033	Plant life extended by 20 years in scenarios 13-15
Prairie Island 2	546	2034	Plant life extended by 20 years in scenarios 13-15

Each nuclear plant is modeled as a baseload, must-run unit, available to produce energy at full capacity throughout the year but for several periods of assumed extended outage for maintenance and refueling.

3.2.2 COAL

Xcel currently owns four coal plants operating in the Upper Midwest service territory:

- Allan S King (511 MW), whose planned retirement date is in 2037;
- Sherco 1 (680 MW), whose planned retirement date is in 2026;
- Sherco 2 (682 MW), whose planned retirement date is in 2023; and
- Sherco 3 (517 MW), whose planned retirement date is in 2040.

This study examines multiple options for retirement of the two existing coal units with retirement dates beyond 2030; these assumptions are summarized in Table 3-6.

Table 3-6. Xcel coal plant assumptions

Reference Assumptions			
Plant	**Capacity (MW)**	**Retirement**	**Notes**
AS King	511	2037	Retired early in all scenarios **EXCEPT** 1,4,7,10,13,16
Sherco 1	680	2026	Planned retirement
Sherco 2	682	2023	Planned retirement
Sherco 3	517	2040	Retired early in scenarios 3,6,9,12,15 & 18

Operating assumptions for these existing coal plants are aligned with the assumptions used in Xcel's IRP modeling; key parameters that affect their dispatch include:

- Maximum power output (MW)
- Minimum stable level (MW)
- Heat rates at Pmin and Pmax (Btu/kWh)
- Minimum up & down time (hrs)
- Variable O&M cost ($/MWh)
- Forced outage rate (%)

This study assumes that the coal generators are dispatched according to signals from the broader MISO territory and not solely on the Upper Midwest system's dynamics. As such, each coal plant is modeled as a baseload, must-run unit, which can be dispatched down to the minimum power (Pmin) value if needed.

3.2.3 OTHER THERMAL RESOURCES

The remainder of Xcel's existing remaining thermal resources consist of owned and contracted natural gas, fuel oil, and biomass resources. The existing natural gas and fuel oil plants in Xcel's current

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portfolio, along with assumed retirement dates are summarized in Table 3-7 below. In addition to these existing resources, most scenarios examined in this study (with the exception of Scenarios 6-9) assume that a new combined cycle plant is installed at the Sherco site following the closure of Sherco Units 1 & 2.

Table 3-7. Xcel natural gas and fuel oil plant assumptions

Plant	Plant Type	Capacity (MW)	Retirement
Black Dog CC	Combined Cycle	298	2032
High Bridge	Combined Cycle	606	2048
Riverside	Combined Cycle	508	2049
LS Power Cottage Grove	Combined Cycle	245	2027
Mankato Energy Center	Combined Cycle	762	2046
Angus Anson (Units 2 & 3)	Combustion Turbine	218	2035
Angus Anson (Unit 4)	Combustion Turbine	168	2035
Blue Lake (Units 7 & 8)	Combustion Turbine	351	2034
Inverhills	Combustion Turbine	369	2026
Wheaton (Units 1 - 4)	Combustion Turbine	241	2025
InvEnergy	Combustion Turbine	358	2024
Bayfront (Unit 4)	Combustion Turbine	15	2034
Black Dog CT	Combustion Turbine	232	2058
Blue Lake (Units 1 - 4)	Fuel Oil	191	2023
French Island	Fuel Oil	160	2027
Wheaton (Unit 6)	Fuel Oil	70	2025
Total		**4,792**	

Operating characteristics for Xcel's thermal resources were provided to E3 by Xcel's resource planning team. The input assumptions used in this study are the same operating characteristics as those used in Xcel's modeling in Strategist. In general, the inputs and assumptions used to characterize the costs and

constraints on operating these units are the same parameters that are provided for coal plants (maximum and minimum power, heat rates and variable O&M cost, minimum up and down time, etc.). Together, these inputs affect the economics of how each plant can be dispatched to meet Xcel's load on an hourly basis, which in turn affects the economics and value of potential new resource additions.

Xcel's existing portfolio also includes a number of contracts with small biomass facilities; together, these contracts amount to 145 MW in 2020. This analysis assumes these contracts are not renewed upon expiration; the amount of contracted capacity contracts declines to 30 MW by 2030 and 4 MW by 2045.

3.2.4 HYDRO

The Xcel Upper Midwest portfolio also includes hydrogeneration facilities and contracts. The hydro resources modeled in the portfolio include:

- Local run-of-river facilities within the Xcel Upper Midwest service territory totaling 312 MW; and
- Contracts for hydro capacity with Manitoba Hydro that total approximately 850 MWs and expire in 2025.

3.2.5 RENEWABLES

Today, Xcel Upper Midwest's renewable portfolio includes 3,800 MW of wind resources, 323 MW of utility-scale solar PV, and 671 MW of customer solar PV associated with the Solar Rewards Community program. Based on recent solicitations as well as commitments made in the prior IRP cycle, this study assumes that the following resources are added to the Xcel portfolio across all scenarios:

- 520 MW of new wind PPA by 2030;
- 1,512 MW of utility-scale solar by 2030, and an additional 571 MW by 2045; and
- 122 MW of additional customer solar by 2030.

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3.3 New Resource Options

A broad range of new resources options are considered as candidates in the portfolio optimization process. These options generally align with those examined by Xcel in the development of its own IRP, including new gas, renewable, storage, and demand-side resources. The study also examines the impact of relicensing the nuclear plants in several scenarios. This section summarizes general assumptions on resource cost and performance used to characterize each of these options.

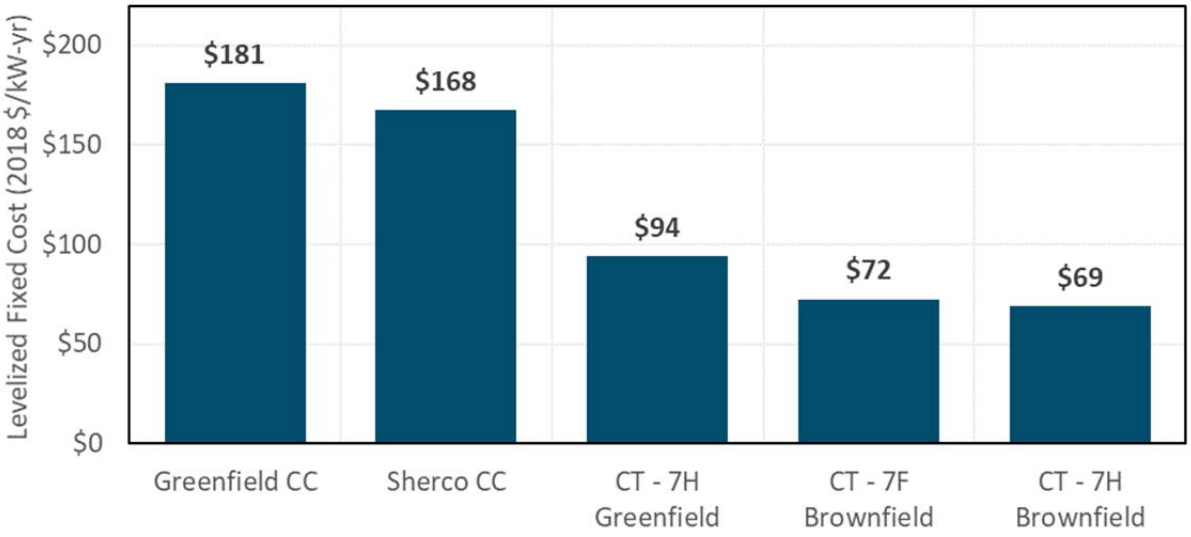
3.3.1 NATURAL GAS

Five generic gas generation resources are included as options for additional capacity:

- **Greenfield CCGT:** a generic new combined cycle plant that reflects both generation and transmission capital costs and the ongoing costs of operating the plant;
- **Sherco CC:** a new combined cycle plant located at the existing Sherco site that reflects generation costs but no interconnection or transmission costs (limited to 835 MW of potential);
- **Greenfield CT:** Greenfield 7H frame CTs are available as resource options, though an interconnection fee is required. As with the greenfield CCGT, the capacity potential is uncapped.
- **Brownfield CT:** Both 7H and 7F frames are available for selection, with the former more expensive. These resources are assumed to be built on existing sites and therefore do not require transmission costs. However, they are capacity limited to capture existing site availability constraints.

The levelized fixed costs associated with each generic gas resource in this analysis, as well as the estimated levelized cost of the Sherco combined cycle plant, were developed by Xcel Energy and provided to E3. As shown in Figure 3-2, the fixed cost per kW of CCGT is substantially higher than the cost of new combustion turbines. Gas-fired resources costs are expected to remain constant in real terms through 2050.

Figure 3-2. Levelized fixed costs of new gas generation resources.



3.3.2 RENEWABLES

Cost assumptions for new renewable resources in this study are based largely on NREL's Annual 2018 Technologies Baseline (ATB),[3] which provides an annual perspective on the current state of generation technology costs and a range of perspectives as to how those costs could change in the future. This study translates the 2018 ATB capital and fixed O&M cost assumptions for wind and solar PV (single-axis tracking) technologies into a levelized cost of energy (LCOE) metric for each type of resource that reflects an proxy for the price at which an independent developer might offer the resource to a credit-worthy utility through a long-term power purchase agreement (PPA). LCOEs for each resource vary through time due to assumed changes in technology cost, financing costs, and federal tax credits.

[3] The 2018 ATB was released in July 2018 and is available at: https://atb.nrel.gov/

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The LCOEs for new renewable resources also include a component to capture the transmission upgrades needed to ensure that resources can be delivered to loads. Transmission costs are additive to the capital cost of the resource itself and are based on assumptions developed by Xcel as inputs for its IRP.

3.3.2.1 Wind

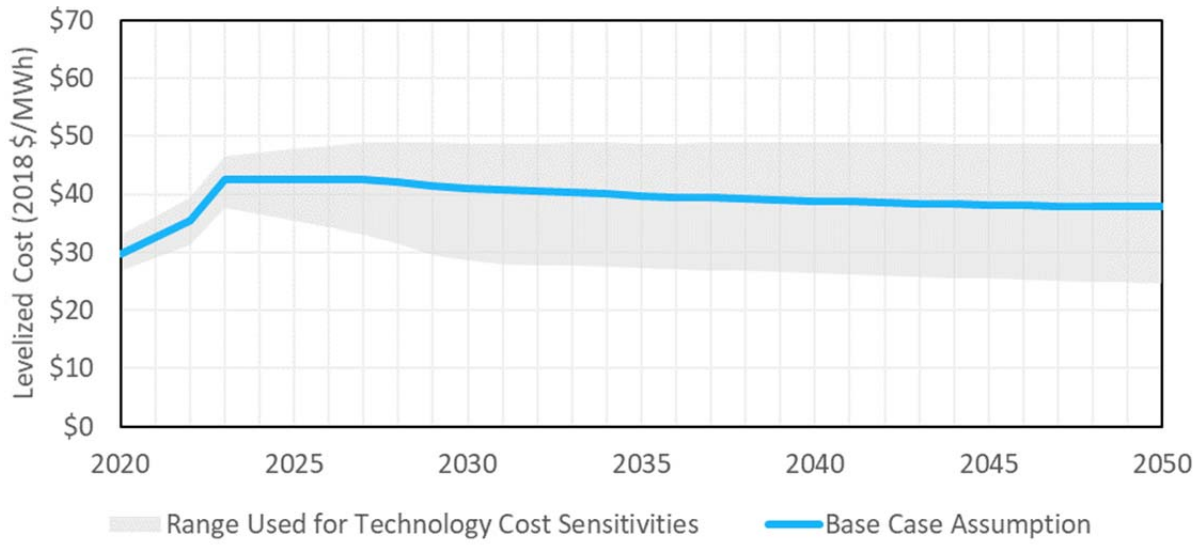
Table 3-8 shows the input assumptions and corresponding LCOEs for new wind resources in 2020 and 2030. Cost and performance assumptions for wind resources are translated into an LCOE that serves as an input to the portfolio optimization process. Near-term wind costs for high-quality resources are relatively low—in large part, due to the effect of the Federal Production Tax Credit (PTC); in the long run, the LCOE of wind is assumed to increase from today's level due to the expiration of the PTC, an effect that is partially offset by some improvements in capital costs.

LCOEs for new wind resources—both for the Base Case assumptions reported in Table 3-8 and the alternative high and low cost assumptions used in sensitivity analysis—are shown in Figure 3-3. The near-term trajectory of costs is heavily shaped by the expiration of the PTC, which results in a near-term cost increase; in the long run, the LCOE for new wind resources declines slightly in real terms as technology continues to improve at a modest pace.

Table 3-8. Key technology parameters for new wind resources

		Installation Year		
Assumption	**Units**	**2020**	**2030**	**Source**
Capital cost	$/kW	$1,531	$1,381	NREL Annual Technologies Baseline (TRG 2)
Transmission cost	$/kW	$400	$400	Xcel IRP assumption
Fixed O&M	$/kW-yr	$52	$48	NREL Annual Technologies Baseline (TRG 2)
Capacity factor	%	50%	50%	Xcel IRP assumption
Tax credit	$/MWh	$18	—	Federal Production Tax Credit
Financing costs				E3 standard pro-forma PPA assumptions
Hourly profile				Sites sampled from NREL WIND Toolkit
Levelized cost	**$/MWh**	**$30**	**$41**	**Calculated based on assumptions above**

Figure 3-3. LCOE projections for new wind resources: Base Case and High & Low Technology Cost sensitivities



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3.3.2.2 Solar

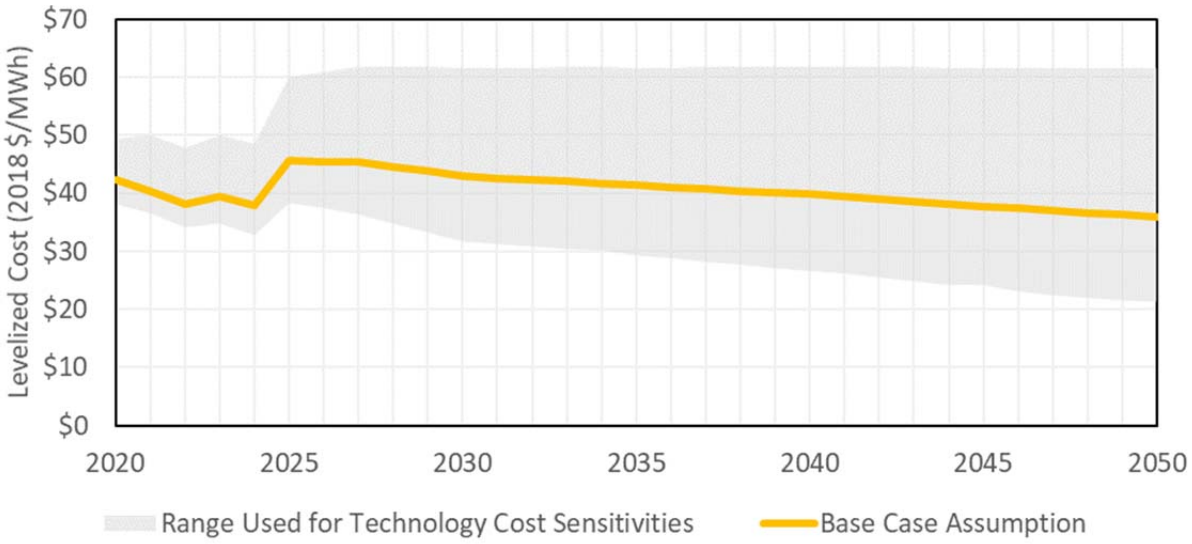
Table 3-9 shows the input assumptions and corresponding LCOEs for new solar resources in 2020 and 2030. Cost and performance assumptions for solar resources are translated into an LCOE that serves as an input to the portfolio optimization process. While the Federal Investment Tax Credit (ITC) available to solar resources today is scheduled to revert to a lower level of 10% in the next few years, continued anticipated cost reductions in capital costs over time helps to offset the effect of the sunsetting ITC on the resulting LCOEs for solar resources.

Figure 3-4 shows the trajectory of solar LCOEs through 2050 under the Base Case assumptions above, as well as the high and low ranges used in the technology cost sensitivities.

Table 3-9. Key technology inputs for new solar resources

		Installation Year		
Assumption	**Units**	**2020**	**2030**	**Source**
Capital cost	$/kW	$1,355	$1,154	NREL 2018 Annual Technologies Baseline
Transmission cost	$/kW	$140	$140	Xcel IRP assumptions
Fixed O&M	$/kW-yr	$11	$9	NREL 2018 Annual Technologies Baseline
Capacity factor	%	23%	23%	RESOLVE solar profiles
Tax credit	%	30%	10%	Federal Investment Tax Credit
Financing				E3 standard pro-forma PPA assumptions
Hourly profile				Sites sampled from NREL WIND Toolkit
Levelized cost	**$/MWh**	**$42**	**$43**	**Calculated based on assumptions above**

Figure 3-4. LCOE projections for new solar resources: Base Case and High & Low Technology Cost sensitivities



3.3.3 ENERGY STORAGE

The reliability and portfolio optimization analyses consider energy storage as a potential resource addition. Cost assumptions for new energy storage are based on Lazard's Levelized Cost of Storage 4.0,[4] which provides an assessment of the state of market for battery storage and a forward-looking projection of costs over a five-year period through 2022. Cost projections beyond this 2022 timeframe are derived by extrapolation of the cost declines anticipated in the next five years. While Lazard's study considers many technologies and applications in its assessment of the market, this study relies upon Lazard's characterization of a utility-scale battery system with four hours of duration. Table 3-10 presents the cost assumptions and corresponding levelized costs for a new four-hour battery.

Figure 3-5 shows the levelized fixed cost assumptions for battery storage across the analysis horizon.

[4] Report available at: https://www.lazard.com/media/450774/lazards-levelized-cost-of-storage-version-40-vfinal.pdf

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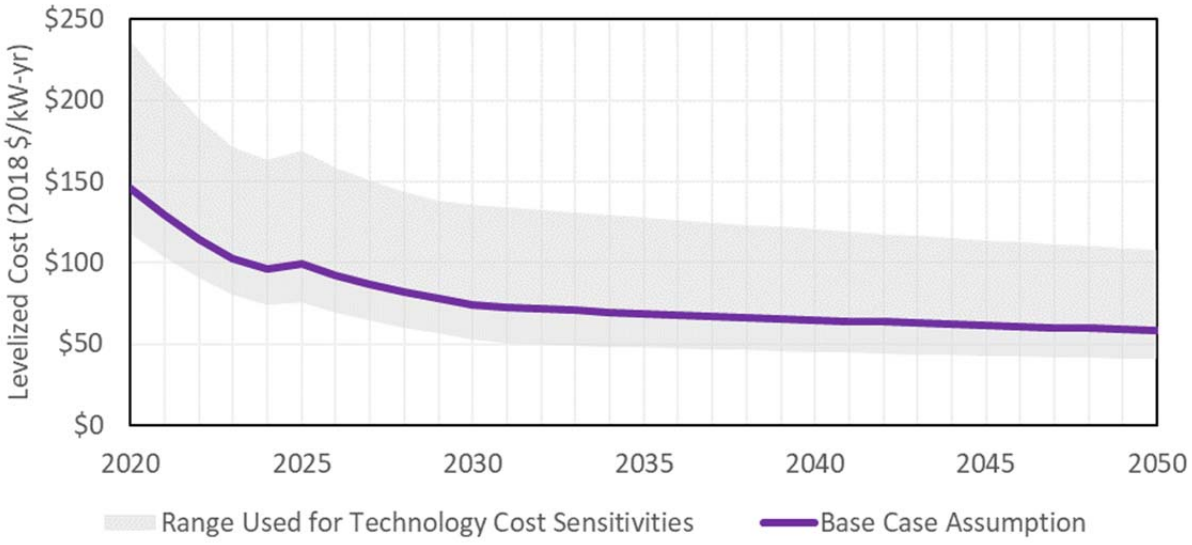
Table 3-10. Key technology inputs for new storage capacity (4-hr duration)

		Installation Year		
Assumption	**Units**	**2020**	**2030**	**Source**
Capital cost	$/kW	$1,311	$720	Lazard Levelized Cost of Storage 4.0
Transmission cost	$/kW	—	—	Xcel IRP assumptions
Fixed O&M	$/kW-yr	$17	$8	Lazard Levelized Cost of Storage 4.0
Periodic replacement	$/kW-yr	$41	$16	Lazard Levelized Cost of Storage 4.0
Financing costs				E3 standard pro-forma PPA assumptions
Levelized cost	**$/kW-yr**	**$146**	**$74**	**Calculated based on assumptions above**

Figure 3-5. Levelized cost projections for new storage resources: Base Case and High & Low Technology Cost sensitivities



3.3.4 NUCLEAR RELICENSING

Costs associated with maintaining and operating existing nuclear plants are broken into three categories:

- Ongoing fixed O&M: routine annual non-fuel costs associated with operating and maintaining the plant, incurred each year it is in operations;
- Fuel costs: costs associated with procurement of uranium to fuel reactors, incurred for each unit of energy generated; and
- Incremental relicensing cost: additional costs incurred on an annual basis associated with plant relicensing that are incurred beginning in the year after relicensing (applicable only in scenarios in which the plants are relicensed).

All cost assumptions for nuclear plants, including the increase in fixed costs associated with license extensions, were provided by Xcel.

3.3.5 DEMAND RESPONSE

New demand response resources are included as options to satisfy the need for new generation capacity. The cost and potential for new demand response is consistent with the Xcel IRP data assumptions. In the Xcel system there are three demand response programs capable of contributing to the need for peaking capability: (1) Saver's Switch, (2) Interruptible tariffs, and (3) Critical Peak Pricing (CPP). A supply curve of three bundles, each bundle comprising all three measures, is available for selection within the optimization; these bundles are summarized in Table 3-11 below.

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Table 3-11. Assumed cost and potential for new demand response resources

Program Type	Levelized Cost ($/kW-yr)	Maximum Technical Potential (MW)					
		2020	2025	2030	2035	2040	2045
Bundle 1	$54	270	380	456	567	717	717
Bundle 2	$71	107	145	189	257	352	352
Bundle 3	$130	89	110	110	116	135	135
Total		**467**	**635**	**755**	**940**	**1,204**	**1,204**

3.3.6 ENERGY EFFICIENCY

In this study, the model can optimize Xcel's new energy efficiency (EE) programs to meet a portion of future energy and capacity needs; this may also contribute to meeting carbon reduction goals. The data for capacity, potential, impacts shapes, and costs for energy efficiency is consistent with the Xcel IRP data. Measures were grouped into three categories according to cost and potential: (1) Program Achievable, (2) Optimal, (3) Maximum Achievable. The Program Achievable and Maximum Achievable bundles were developed based on the Minnesota Energy Efficiency Potential Study[5], while the Optimal bundle was developed by Xcel. This study optimizes the EE programs through 2034 and then holds the resulting level constant through the rest of the modeling period. The supply curve used in this study is shown in Figure 3-6. The levels of potential load reduction shown in Figure 3-6 represent the maximum impacts from the supply curve through 2034. The potential annual load and peak load impacts of the EE bundles are cumulative over time. The impacts on annual load and peak load assumptions are shown in Figure 3-7.

[5] Minnesota Energy Efficiency Potential Study: 2020-2029. December 2018, available at: https://www.mncee.org/MNCEE/media/PDFs/MN-Potential-Study_Final-Report_Publication-Date_2018-12-04.pdf

Figure 3-6. Supply curve of available energy efficiency measures (2034)

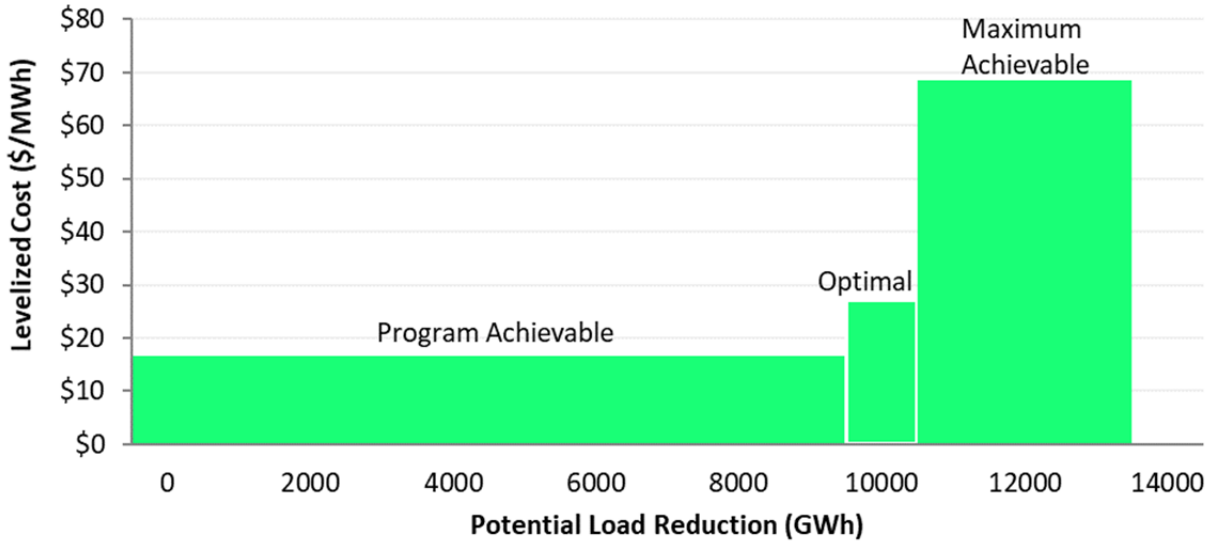
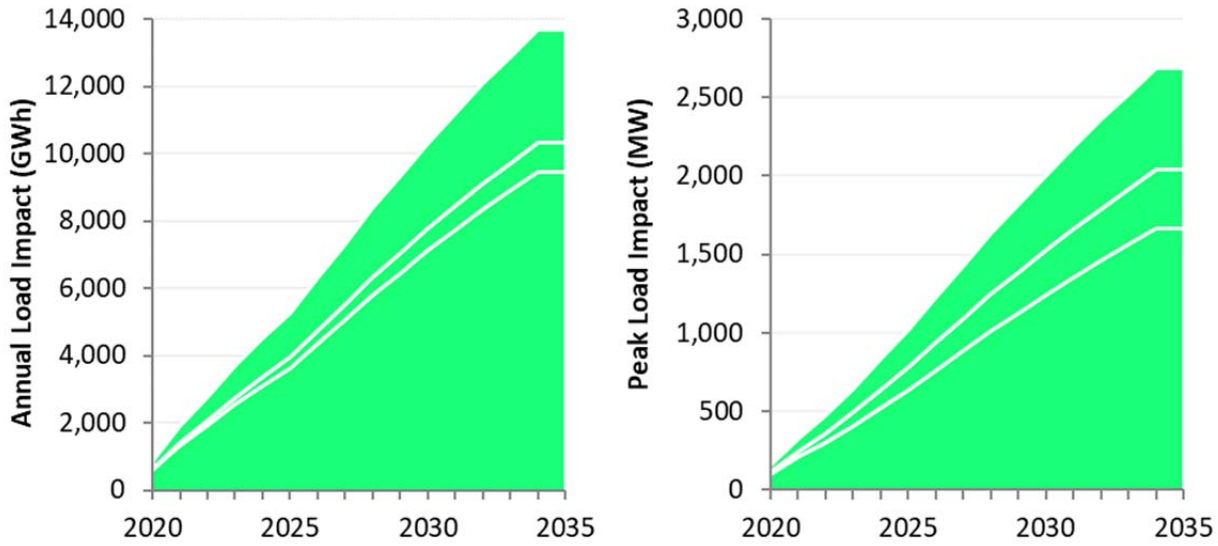


Figure 3-7. Xcel EE bundles annual load and peak load impacts assumptions



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3.4 Hourly Profiles

Hourly profiles for load and wind and solar resources are key inputs to this study. Load, wind, and solar each vary on an hourly, daily, and seasonal basis, and their variations are often correlated due to underlying meteorological phenomena that affect all three. Capturing these patterns in a statistically rigorous manner is crucial to enable planning of a system that can operate efficiently on a day-to-day basis and is resilient in spite of an increasingly intermittent and variable energy supply.

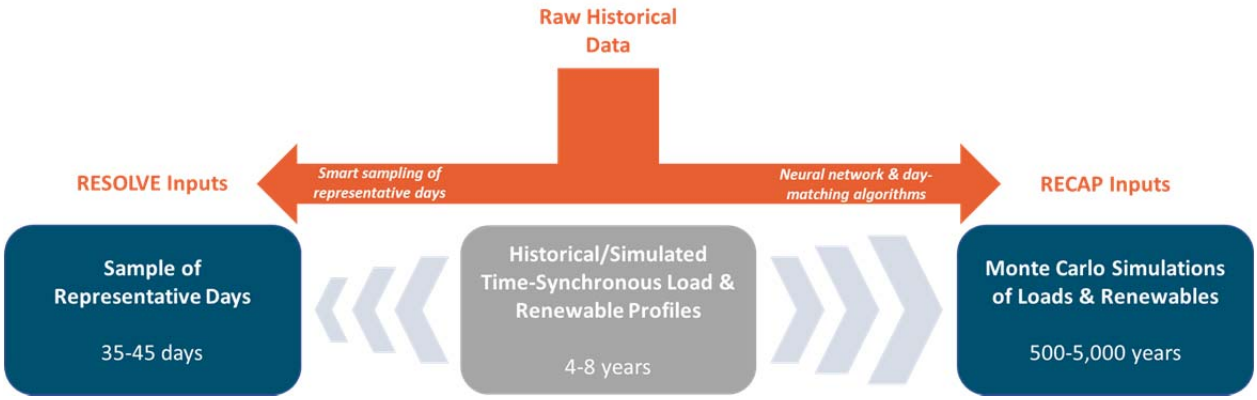
This study relies on a library of hourly load, wind, and solar profiles that reflect the meteorological conditions across the four-year time span from 2009 through 2012. Developing profiles that are weather-matched and time-synchronized in this manner ensures consistency across the data set, preserving the key underlying correlations among the variables. The hourly profiles for this study are based on the following sources:

- Load profiles for current end uses on the Xcel Upper Midwest system are based on actual metered historical loads for the 2009-2012 period;
- Load shapes for end uses that may be electrified in the future (e.g. space heating, water heating)—used only in the High Electrification sensitivity—are simulated based on hourly historical weather data using building simulation software;
- Wind profiles are developed for the same period using data from NREL's WIND Toolkit, which provides detailed geospatial simulations of wind speed and generation profiles for a large number of sites throughout the United States;
- Solar PV profiles are simulated using NREL's System Advisor Model (SAM) and solar irradiance data from the National Solar Radiation Database (NSRDB) for a variety of plausible locations throughout the Xcel Upper Midwest territory;

This library of profiles serves as a foundational dataset of inputs for both the reliability and the portfolio analysis. However, the series themselves are used in different ways, as depicted in Figure 3-8. In RECAP,

these series are extended through simulation of a much longer historical weather record; capturing such a broad set of plausible weather conditions is essential when examining whether a system is designed to meet a "one-day-in-ten-year" reliability standard. In contrast, in RESOLVE, a reduced representative subset of 37 days is used to enable portfolio optimization across multiple decades, sampled to reflect representative combinations of loads and associated renewable production profiles, from the time series described. For additional information on this process, see Appendix C.1.

Figure 3-8. Schematic of development of hourly profile inputs for RECAP & RESOLVE



3.5 Fuel Price Forecasts

Fuel prices were derived from Xcel's data of generators and their associated fuels and fuel costs. To arrive at a representative fuel price trajectory by resource, plants were binned into their respective fuel types and the average annual fuel price of each resource was then calculated. Fuel oil and biomass prices are both expected to decline in real terms through 2050 while coal and natural gas are expected increase in price. Fuel price projections used in this study are summarized in Table 3-12.

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Table 3-12. Fuel price forecasts ($/MMBtu)

Fuel Type	2020	2025	2030	2035	2040	2045	CAGR ('20-'45)
Coal	$2.03	$2.11	$2.18	$2.26	$2.34	$2.35	**0.6%**
Fuel Oil	$16.44	$15.52	$15.31	$15.11	$14.93	$14.77	**-0.4%**
Natural Gas	$2.59	$3.06	$3.44	$3.74	$4.01	$4.08	**1.8%**

Fuel prices are shaped on a monthly basis to capture the seasonal differences in costs; the degree of seasonal adjustment depends on the fuel. Natural gas, whose demand varies significantly on a seasonal basis due to heating loads in the winter, has the most significant differences in assumed pricing by month, whereas other fuels' prices remain relatively constant throughout the year. Seasonal shaping factors for each fuel are shown in Table 3-13.

Table 3-13. Seasonal shaping factors, expressed as a percentage of annual average price

Month	Coal	Fuel Oil	Natural Gas
January	100%	97%	111%
February	100%	101%	109%
March	100%	101%	103%
April	100%	101%	95%
May	100%	101%	93%
June	100%	101%	93%
July	100%	100%	95%
August	100%	100%	96%
September	100%	100%	96%
October	100%	100%	97%
November	100%	100%	104%
December	100%	99%	109%

In addition to the Base Case forecast for natural gas, this study also tests the impacts of high and low gas price sensitivities on key results and conclusions. These high and low sensitivities begin to diverge from the base forecast in 2022 and are based on adjustments of the base forecast 2018 – 2057 nominal CAGR, which is consistent with Xcel's modeling. In the Low Gas Price and High Gas Price sensitivities, prices grow at rates 50% lower and 50% higher than the Base Case (in nominal terms). The corresponding gas price forecasts associated with each sensitivity are shown in Table 3-14.

Table 3-14. Sensitivities on natural gas price forecasts in 2018 $

Fuel Type	2020	2025	2030	2035	2040	2045	CAGR ('20-'45)
Base Case	$2.59	$3.06	$3.44	$3.74	$4.01	$4.08	**1.8%**
Low Gas Price	$2.59	$2.88	$2.99	$3.00	$2.98	$2.80	**0.3%**
High Gas Price	$2.59	$3.26	$3.96	$4.64	$5.38	$5.92	**3.4%**

One area where this analysis does deviate notably from the analysis conducted by Xcel to support its integrated resource plan is in the treatment of carbon emissions costs. Under direction from the Public Utilities Commission, Xcel includes an explicit carbon cost in the evaluation and comparison of costs among portfolios in its IRP. Because the scenarios in this study are instead designed to meet a specific carbon goal, and to measure the cost associated with achieving that level of carbon reduction, an explicit carbon price adder is not included.

3.6 MISO Market Representation

Xcel's Upper Midwest system is a part of the Midwest Independent System Operator (MISO) pool. Membership in MISO provides Xcel with numerous benefits, including the ability to trade energy in a deep and liquid wholesale market on an hourly (and subhourly) basis, sharing of operating reserves

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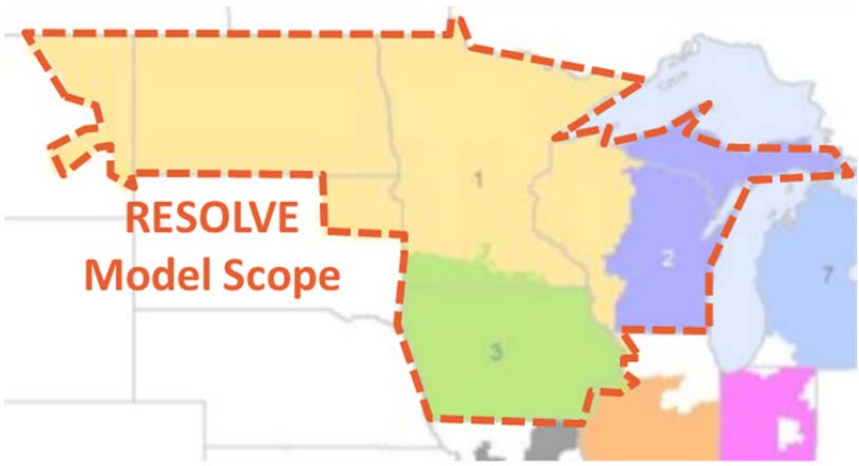
across a broad pool, and a lower planning reserve margin requirement that captures the benefit of load diversity across the MISO footprint.

Figure 3-9. Geographic scope of RESOLVE analysis



Each of these dynamics is accounted for in the optimization of Xcel's long-term resource portfolio to meet carbon reduction objectives.

- In addition to optimizing the investments and operations of the Xcel portfolio, RESOLVE simulates least-cost dispatch of the broader MISO pool (Load Resource Zones [LRZ] 1-3, as shown in Figure 3-9) on an hourly basis. This simulation thus allows for both purchases from and sales to the wholesale market, which are priced at the marginal cost of energy in the relevant zone. The assumed buildout and retirement of new resources to serve loads other than Xcel's own are based on MISO's "Continued Fleet Change" scenario as developed in its 2018 MISO Transmission Expansion Plan (MTEP) planning process. Market transactions between Xcel and the MISO are limited to 1,800 MW through 2023; thereafter, the limit is expanded to 2,300 MW through the rest of the modeling period.
- Operating reserve requirements are maintained at the current level that Xcel must provide today as a member of MISO:

1. Load following reserves requirements are set at 3% of load;
2. Frequency regulation reserve requirements are 27 MW; and
3. Spin reserve requirements are set at 1% of load.

+ The planning reserve margin requirement imposed upon Xcel's portfolio in this study—3% above Xcel's own system peak demand—reflects the benefit of diversity among Xcel's load profile and the other members of MISO.

Detailed load and resource assumptions for the external zones are presented in Appendix C.2.

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4 Reliability Analysis Results

4.1 Effective Load Carrying Capability Analysis

The capacity contribution towards resource adequacy of dispatch-limited resources – variable resources like wind and solar PV, and energy-limited resources, like storage and DR – is evaluated dynamically within RESOLVE based on the metric of ELCC. The concept of ELCC is most widely used to quantify the capacity contribution of a resource whose availability changes on an hourly basis; it represents the quantity of perfectly dispatchable generation that could be removed from the system by an incremental dispatch-limited generator. Essentially, the ELCC represents the capacity value each resource can contribute to the resource adequacy needs of the Xcel Upper Midwest system. This value depends on both the coincidence of each resource with peak loads and the characteristics of the other dispatch-limited resources on the system.

In this study, E3 used RECAP – a loss of load probability (LOLP) model – to evaluate the ELCC provided by a range of different portfolios of wind, solar, storage, and DR resources under specific conditions of load and generation resources in the Upper Midwest service territory; these ELCC values are not representative of ELCC values of resources in the broader MISO territory. The capacity value results from each RECAP run, associated with varying penetrations of wind, solar PV, storage, DR, are used to calculate marginal ELCC curves.

The marginal ELCC values for variable and use-limited resources used in this study are shown in Figure 4-1 and Figure 4-2. below.

Figure 4-1. Marginal ELCC of wind and solar resources for the Upper Midwest system in 2030

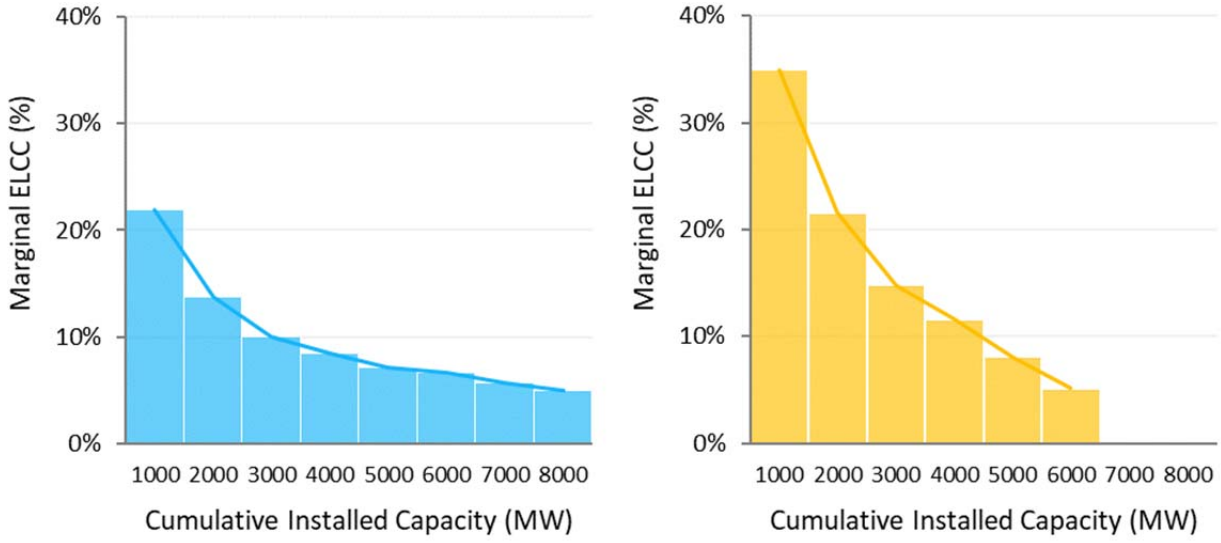
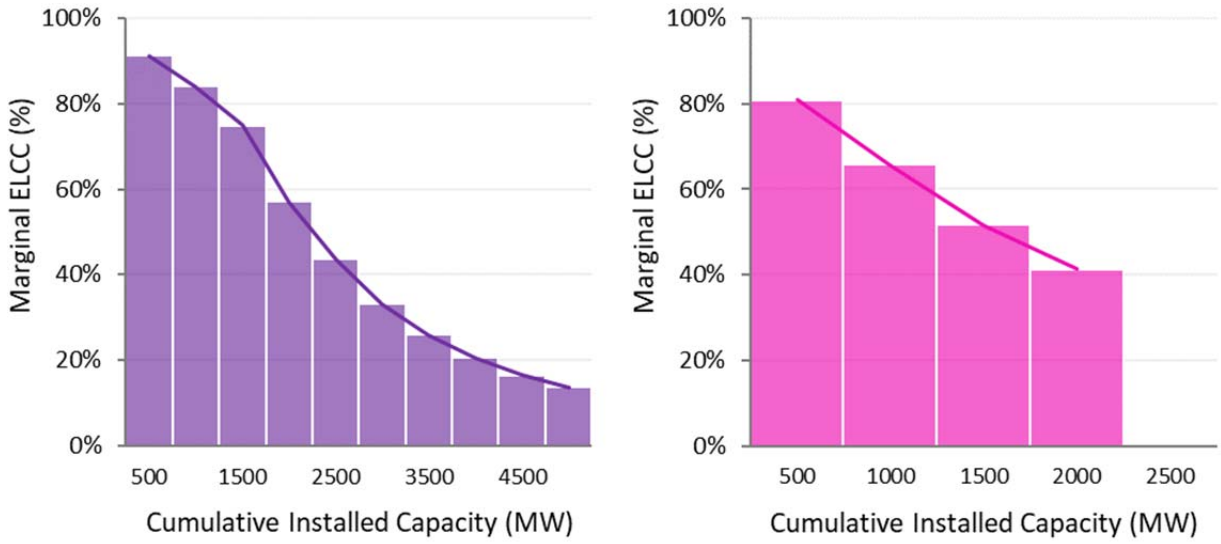


Figure 4-2. Marginal ELCC of 4-hr storage and DR resources for the Upper Midwest system in 2030



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Generally, as the penetration of any individual resource type grows, the its marginal capacity value decreases. This effect is well-established and understood for variable resources such as wind and solar; adding incremental quantities of these resources generally shifts periods of loss-of-load-probability towards periods when the resources produce less energy. For instance, as shown in Figure 4-1, the first 1,000 MW of wind resource has an ELCC of approximately 22%; the next 1,000 MW has an ELCC of about 15%; and the third 1,000 MW has an ELCC of 10%. Solar exhibits a similar decline in ELCC with increasing levels of deployment, an effect that results primarily from the shifting of the period of the net peak away into the evening hours when solar resources do not produce energy.

Despite significant differences in their characteristics compared to variable resources, use-limited resources like storage and DR also exhibit declining marginal ELCC; this effect is shown in Figure 4-2.. Initially, the marginal ELCC of a four-hour storage resource is relatively close to 100%: this reflects the fact that small amounts of storage can be dispatched when called upon to reduce load during periods of peak demand. However, as progressive amounts of storage are added to the system, their dispatch has the effect of flattening and broadening the peak period, eventually requiring resources that are capable of dispatching (or discharging) over longer extended periods. As a result, the relative effectiveness of a battery system with limited duration (when compared with a traditional firm resource) diminishes. This effect may be countered by extending the duration of the storage system (i.e. adding more cells to the battery system), though the cost of the additional cells may outweigh the incremental value it provides.

To ensure that the optimized generation fleet is sufficient to meet the Xcel Upper Midwest system's resource adequacy needs throughout the year, the ELCC curves shown above are incorporated into RESOLVE as input assumptions. These inputs enable RESOLVE to solve for a portfolio that meets a target planning reserve margin while accounting for the inherent cumulative limitations of variable and use-limited resources.

4.2 100% Carbon-Free Portfolio Analysis

A secondary question explored through the reliability analysis is the extent to which the future needs of Xcel's customers can be met exclusively through reliance on carbon-free resources. The declining ELCC curves shown above hint at the idea that the potential contributions of variable and use-limited resources towards reliability needs is pragmatically limited. This study uses RECAP to design two hypothetical portfolios that rely exlusively on a combination of carbon-free resources to meet Xcel's long-term reliability needs under a one-day-in-ten-year reliability standard: (1) a first porfolio that includes Xcel's existing nuclear plants and a combination of wind, solar, and storage resources; and (2) a second portfolio that relies exclusively on wind, solar, and storage. These portfolios are constructed to adhere to the following criteria:

- Each portfolio must comprise only carbon-free resources;
- Each portfolio must adhere to an LOLE standard of one day in ten years; and
- Each portfolio may not rely on the MISO market to supply wholesale power beyond the carbon-free resource that specifically make up the portfolio due to the fact that such generic wholesale purchases cannot be certified as carbon-free.

Each portfolio is created directly in RECAP through an iterative addition of wind, solar, and storage to Xcel's existing carbon-free resources until the appropriate reliability standard has been met;[6] this approach inherently achieves the goal of a carbon-free energy system. The resulting portfolios are shown in Figure 4-3.

[6] Resources are added in this iterative process according to an algorithm that adds small quantities of individual resources one at a time, in each step adding a discrete quantity of the resource that provides the highest marginal reliability benefit (i.e. reduction in LOLE) per unit of fixed cost.

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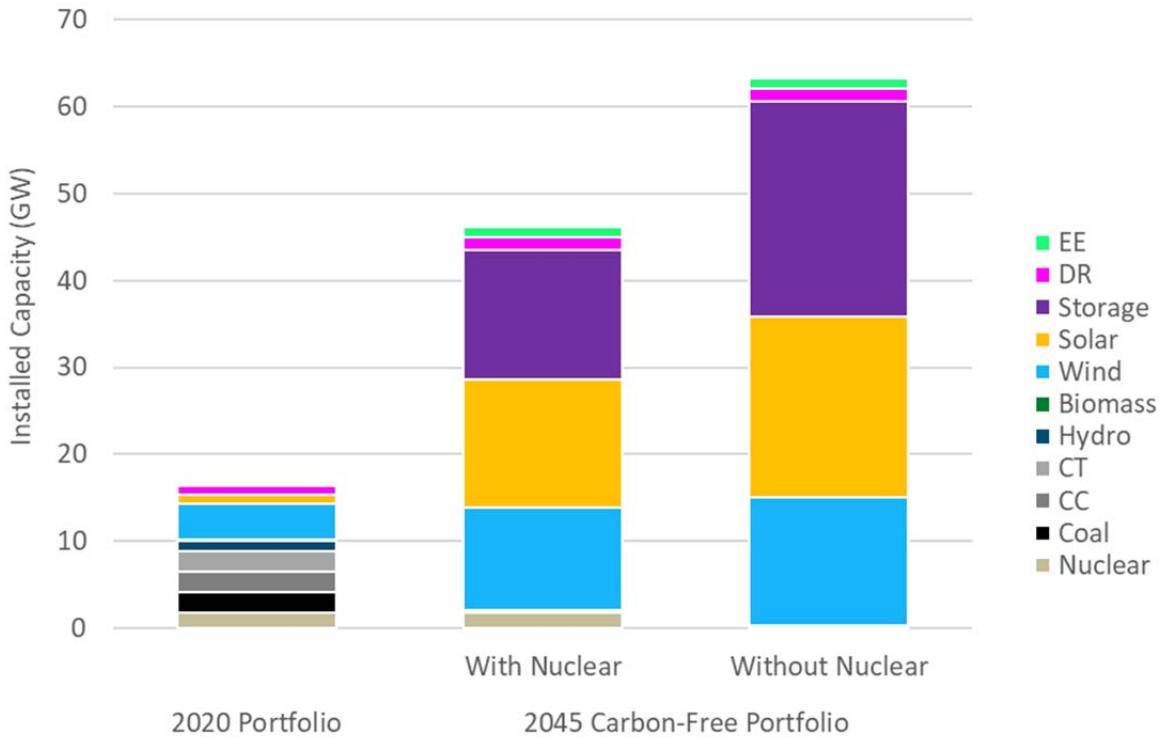
Figure 4-3. Total installed capacity to meet 2045 reliability needs with a fully decarbonized portfolio.



As shown above, the infrastructure requirements associated with meeting such objectives are incredibly large: while Xcel's projected system peak (not considering impacts of additional efficiency) is slightly larger than 12 GW in 2045, the total installed capacity needed to achieve reliability ranges from 45-60 GW, the vast majority of which comprises a mix of wind, solar, and storage. On an annual basis, these portfolios are capable of producing more than double the amount of energy needed to satisfy Xcel's Upper Midwest system demand; the overbuild is a consequence of the requirement that resources must be sufficient to meet demand not only under average conditions but under all but the most stringent conditions, including both periods of extreme high demand and sustained low renewable availability.

To illuminate the drivers of the large quantity of infrastructure needed to meet reliability needs with a combination of wind, solar, and storage, Figure 4-4 shows a nine-day snapshot of resource availability extracted from RECAP's loss-of-load-probability simulation in the portfolio that includes Xcel's existing nuclear plants. While traditionally loss-of-load-probability modeling has focused on ensuring resource sufficiency during periods of peak demand, these nine days highlight a new type of event that would ultimately lead to potential resource shortages on such a system: extended periods of low resource availability. Specifically, the loss-of-load event highlighted below—one of the rare events permitted under a "one-day-in-ten-year" standard—is a result of the following sequence of events:

- A unforced outage at one of Xcel's existing nuclear plants begins on the second day, reducing the amount of firm, baseload generation available to serve Xcel's load.
- This outage extends into the third day, coinciding with a period of low renewable availability, when the combined output of wind and solar resources is substantially lower than most typical days in that season (see, for example, Day 1 or Days 6-9) and is insufficient to meet load on its own in any hour.
- These two factors, in turn, require Xcel to discharge energy stored in its battery storage resources to meet load throughout the third day, depleting a large portion of their state of charge.
- While the level of renewable production increases on the fourth day, it remains below "typical" levels for this season and is merely sufficient to meet Xcel's load in most hours—but does not provide a surplus to restore state of charge to the energy storage systems.
- By the beginning of the fifth day, the state of charge of the energy storage systems has been fully depleted, and the lack of available renewable resources during non-daylight hours leaves the operator with no other option but to shed significant quantities of load—a major loss-of-load event that extends across most of the day and represents a substantial portion of Xcel's customers.

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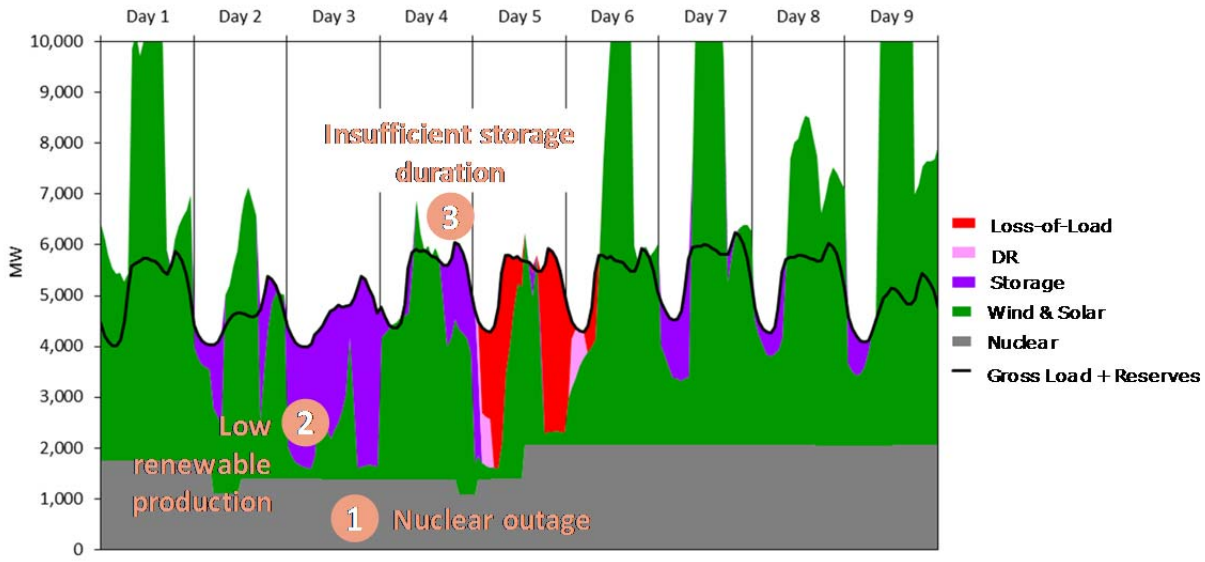
Figure 4-4. Illustrative sample of hourly dispatch patterns in a 100% Carbon Reduction Scenario



This illustrative sequence of events demonstrates that the challenge of relying exclusively on carbon-free resource options to serve load shifts from meeting peak hourly demands to meeting load across extended periods of low renewable availability; the types of weather events of concern on such a system shift from those that drive extreme levels of load (e.g. summer heat waves) to those that inhibit renewable production across extended periods (e.g. extended/extreme winter storms). This type of event hints at the types of resources that would provide the most value, from a reliability perspective, in a system that is heavily reliant on renewables: those that can be dispatched on demand at full capacity for periods of up to several days, but are rarely called upon to do so. Based on today's commercially available technologies and at current prices, natural gas combustion turbines arguably remain the most viable candidate resource to complement a portfolio of wind, solar, and storage resources due to their relatively low up-front cost and expectation of limited operations.

This analysis also underscores the value of Xcel's participation in the MISO wholesale market, if only indirectly. Today, Xcel and MISO's other member utilities benefit from the diversity of loads and resources through a collective reduction in the capacity needs to meet resource adequacy requirements; this is manifest as a lower planning reserve margin target for each member than would be required if they were to plan exclusively to meet their own reliability needs. Under a requirement that all load be served by carbon-free generation, this analysis assumes that Xcel would forego this benefit, magnifying the system's resource need while restricting the available options to meet it. This, in turn, suggests that careful consideration be given in clean energy target-setting and policy design to balance the aggressiveness of goals with their implications for the efficiency of markets, as imprudent choices could negate the widely-recognized benefits achieved through centralization of wholesale market operations.

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5 Portfolio Analysis Results

This section highlights the results of some of the main cases and sensitivities used to help answer the key questions surrounding Xcel's strategy to meet their climate goals. These results are presented in sections aligned with these questions: how much coal, if any, should Xcel retire; is new gas necessary or unnecessary to serve load reliably; and what value does Xcel's current nuclear fleet provide, given its carbon-free generation attribute? While all the cases were modeled from 2020 through 2045 in increments of five years, for many of these questions, focusing on one specific year helps provide the answer. This section focuses primarily on analytical results in 2030 or 2045, which generally coincide with Xcel's near-term and long-term climate goals.

5.1 Reference Case

The Reference Case represents a least-cost plan to meet future energy and capacity needs of Xcel's Upper Midwest system through 2045 given expected growth in demand and anticipated plant retirements across this period, absent any specific clean energy or carbon goals beyond current state policy. Accordingly, the Reference Case is not compliant with Xcel's current greenhouse gas goals. Instead, this case represents a "business-as-usual" scenario that serves as a useful point of comparison against which to measure cost and greenhouse gas impacts of more aggressive decarbonization scenarios.

Figure 5-1 below shows the resource additions and retirements across the analysis horizon, including both Xcel's prior commitment as well as new resources selected in RESOLVE's to meet future needs. By

2030, Sherco Units 1 and 2, representing 1.4 GW of firm capacity, as well as a total of 1.6 GW of existing gas plants are retired. This retiring capacity is replaced by a diverse portfolio of resources that includes battery storage, utility-scale solar, a new combined cycle plant at the Sherco site, an expansion of existing DR programs, and deployment of energy efficiency at levels above historical state standards. Similar general dynamics continue through the analysis horizon: by 2045, the remaining coal and nuclear capacity, as well as some aging gas units, are retired, replaced primarily by additional energy storage, solar, and new gas combustion turbines.

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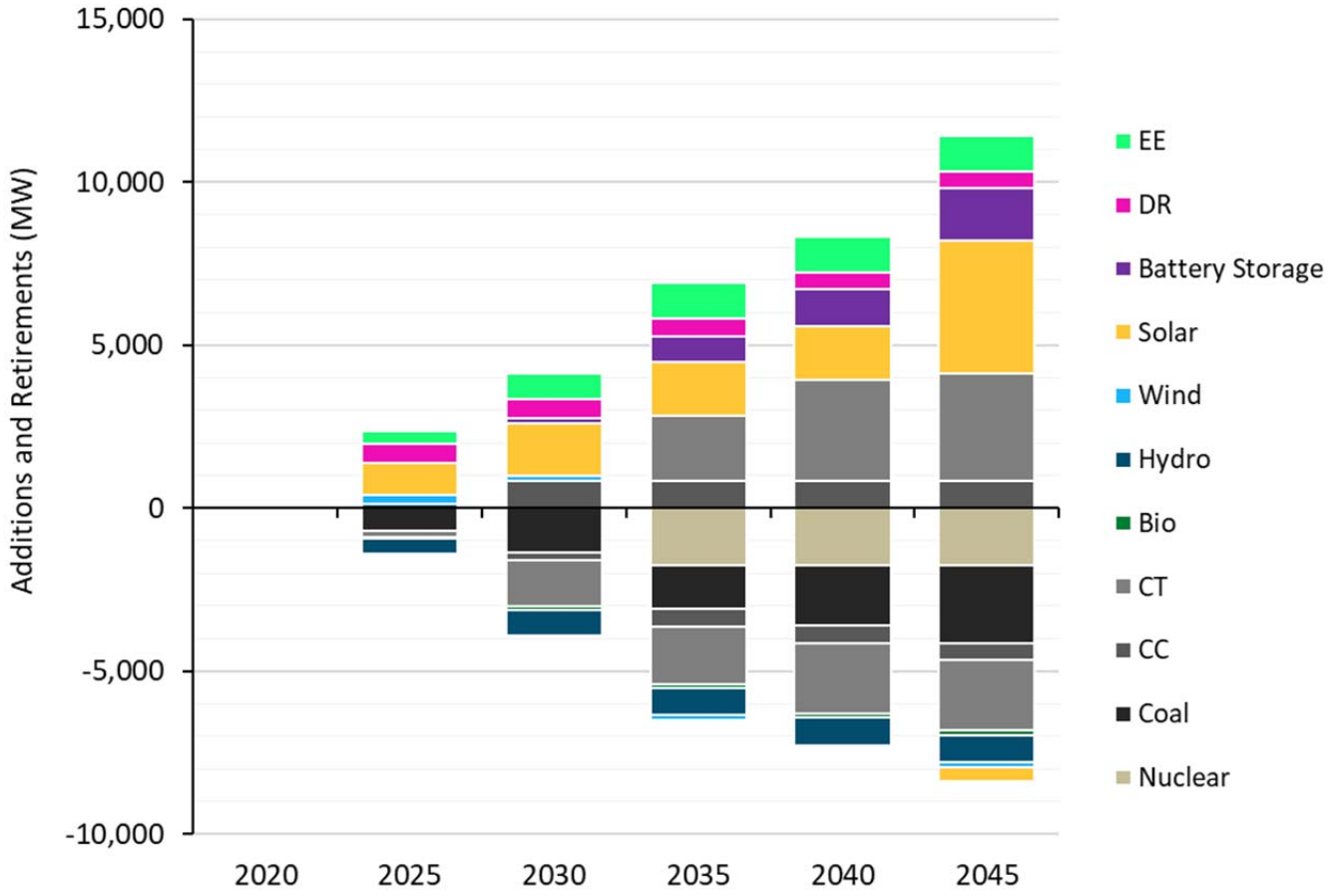
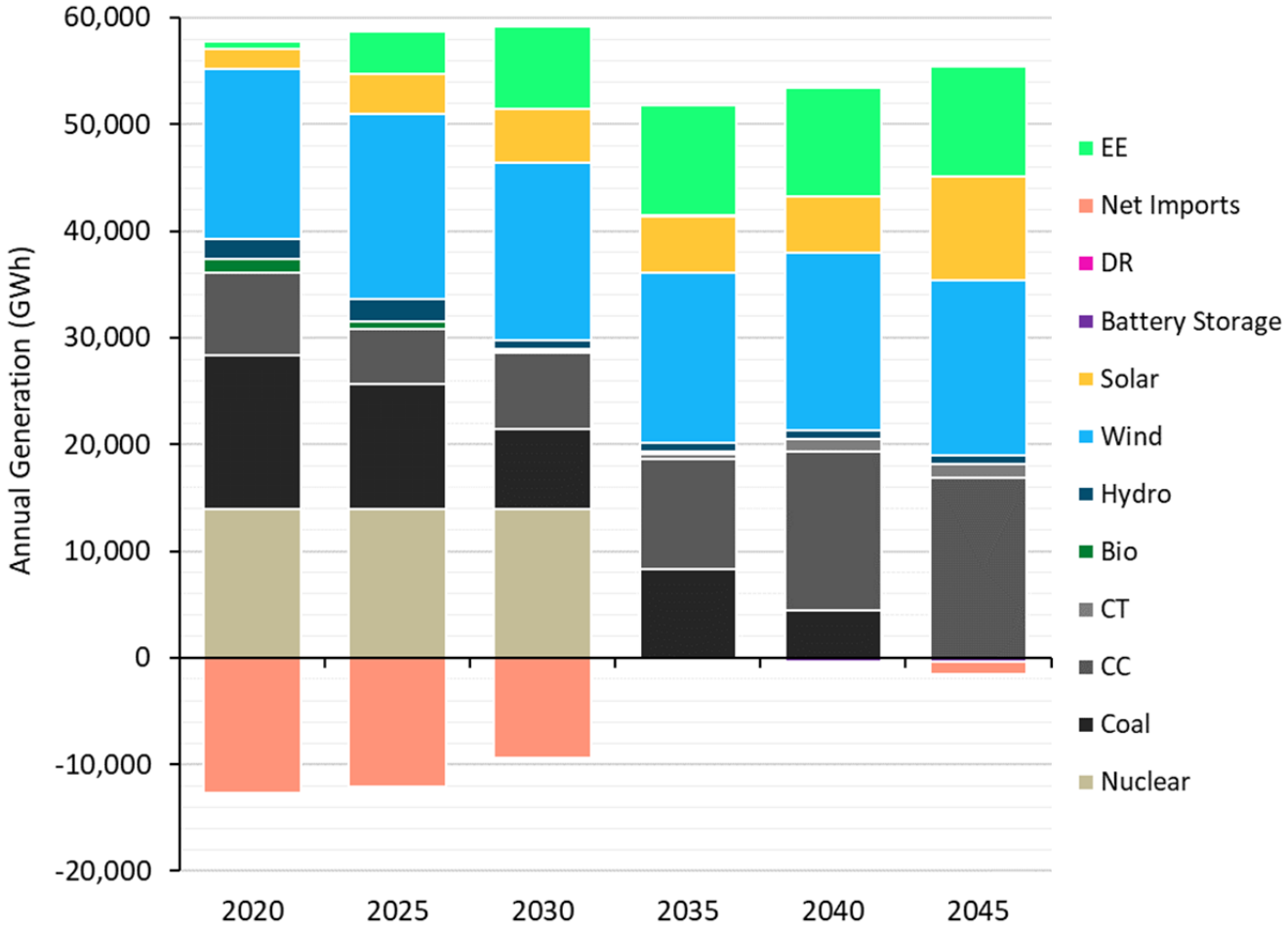
Figure 5-1. Reference Case capacity additions and retirements over study horizon



The annual generation mix in Figure 5-2 shows that despite the absence of a carbon target, the Reference Case generation mix across this period generally shifts away from the most carbon intensive resources (coal) and towards carbon-free alternatives (wind, solar, efficiency), the notable exception resulting from the retirement of existing nuclear plants shortly after 2030, prompting an increase in gas generation. These trends yield some carbon reductions in the near term—Xcel's 2030 emissions are roughly 60% below 2005—but are insufficient to achieve the level contemplated in this study.

Figure 5-2. Reference Case generation mix across analysis horizon



5.2 Summary of Carbon Reduction Scenarios

This study analyzes a wide range of scenarios to achieve its primary purpose—to examine the cost implications of viable strategies to meet its 2030 emissions goal and to achieve alignment with an emissions reduction pathway consistent with its ultimate 2050 goal of 100% carbon-free generation.

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Each scenario is therefore designed to meet milestones of 85% carbon reductions by 2030 and 95% carbon reductions by 2045.

Each scenario achieves these milestones through a unique combination of plant retirements of key existing generation assets (coal and nuclear) and investment in new resources (efficiency, renewables, storage, and natural gas). Additions and retirements across the full set of scenarios are shown in Figure 5-3 for 2030 and Figure 5-4 for 2045.

Figure 5-3. Additions and retirements for full sets of scenarios in 2030

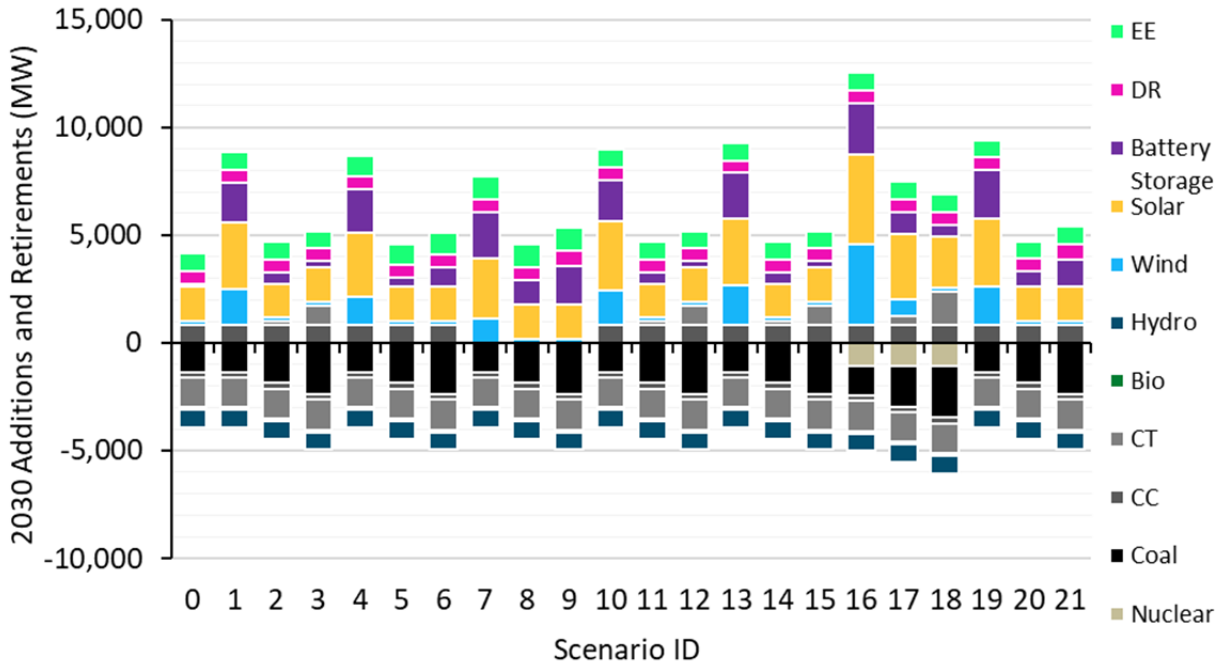
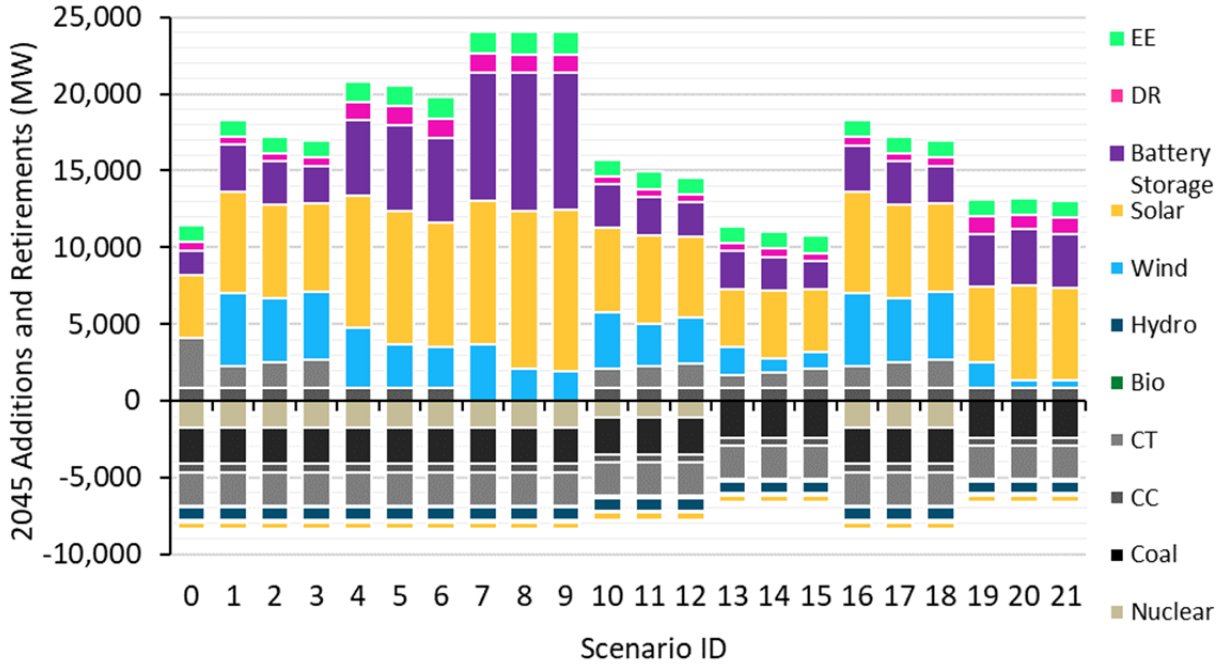


Figure 5-4. Additions and retirements for full set of scenarios in 2045



While the specific changes to Xcel's portfolio vary widely depending on the design of each scenario, several common themes are immediately apparent across all:

- Xcel's least-cost portfolios rely heavily on energy efficiency to mitigate future load growth; across all scenarios, the level of efficiency (at least 1.6%/yr through 2035) exceeds previous standards for program achievement (1.5%/yr).
- Significant investment in new wind and solar capacity (6-14 GW by 2045) as a source of carbon-free generation will be needed across all scenarios.
- Substantial investments in energy storage (2-9 GW by 2045) will help to facilitate integration of renewable resources while also helping to meet peak capacity needs;

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- By 2045, Xcel's generation portfolio will rely predominantly on carbon-free resources to meet annual energy needs, while gas generation will help to meet resource adequacy needs but will operate infrequently.

The various strategies to achieve greenhouse gas reductions reflected in the scenarios examined in this study produce a wide range of portfolios and resulting cost outcomes. Table 5-1 highlights several key results that help distinguish the various scenarios from one another, including:

- **Levelized cost of carbon abatement ($/ton),** the unit cost of carbon abatement across the analysis horizon (2020-2045) measured relative to the Reference Case;
- **2045 rate impact (cents/kWh),** the change in the average retail rate measured relative to the Reference Case;
- **2045 effective RPS (%),** the level of renewable penetration achieved in each scenario expressed as a percentage of annual retail sales;
- **2045 renewable curtailment (%),** the level of curtailment experienced in 2045 due to the imbalance between variable resource availability and hourly demand;
- **2045 new storage capacity,** the cumulative total capacity of new storage resources added from 2020-2045 to enable renewable integration and help meet resource adequacy needs; and
- **2045 new gas capacity,** the cumulative total capacity of new gas resources added from 2020-2045 to meet residual resource adequacy needs as part of a least-cost portfolio.

Table 5-1. Key metrics for all scenarios

Scenario	Levelized Cost of Abatement ($/ton)	2045 Portfolio Metrics				
		Average Rate Impact (cents/kWh)	Effective RPS (%)[7]	Renewable Curtailment (%)	New Storage Capacity (MW)	New Gas Capacity (MW)
Scenario 1	$62	+1.2	112%	7%	3,032	2,293
Scenario 2	$25	+0.7	107%	6%	2,786	2,541
Scenario 3	$21	+0.7	107%	6%	2,484	2,708
Scenario 4	$69	+1.5	118%	9%	4,968	835
Scenario 5	$37	+1.2	110%	7%	5,636	835
Scenario 6	$40	+1.2	108%	6%	5,589	835
Scenario 7	$72	+1.8	121%	10%	8,346	—
Scenario 8	$47	+1.6	113%	7%	8,984	—
Scenario 9	$54	+1.7	112%	7%	8,885	—
Scenario 10	$54	+0.9	99%	6%	2,819	2,060
Scenario 11	$20	+0.6	93%	5%	2,484	2,275
Scenario 12	$17	+0.5	93%	4%	2,273	2,453
Scenario 13	$41	+0.6	75%	4%	2,434	1,711
Scenario 14	$13	+0.3	70%	3%	2,187	1,872
Scenario 15	$13	+0.3	70%	3%	1,867	2,081
Scenario 16	$71	+1.2	112%	7%	3,032	2,296
Scenario 17	$28	+0.7	107%	6%	2,786	2,541
Scenario 18	$22	+0.7	107%	6%	2,484	2,708
Scenario 19	$43	+0.7	78%	5%	3,484	835
Scenario 20	$16	+0.5	73%	4%	3,726	835

[7] Effective RPS levels that exceed 100% result from two factors: (1) the effective RPS is calculated based on retail sales, which is lower than total generation needed to serve load due to transmission & distribution losses; and (2) the total annual generation in the portfolio exceeds the Upper Midwest load and a portion of the excess is sold into the MISO market.

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Scenario	Levelized Cost of Abatement ($/ton)	2045 Portfolio Metrics				
		Average Rate Impact (cents/kWh)	Effective RPS (%)[7]	Renewable Curtailment (%)	New Storage Capacity (MW)	New Gas Capacity (MW)
Scenario 21	$18	+0.5	73%	4%	3,499	835

The remainder of this section is dedicated to a detailed investigation into a specific subset of scenarios that illuminate tradeoffs among strategic choices of how to achieve long-term goals while containing costs to Xcel's customers and inform key questions on the nature of decarbonizing electricity, namely:

- What potential effect could an early exit from coal resources have upon the costs of meeting 2030 greenhouse gas goals?
- How would future restrictions upon Xcel's ability to invest in natural gas generation capacity to meet resource adequacy needs affect the cost of meeting greenhouse gas goals?
- What impact could extensions to the operating licenses of Xcel's existing nuclear plants have upon the costs of meeting long-term greenhouse gas goals?

Each question is investigated in depth in the subsequent three sections.

5.3 Scenario Analysis: Timing of Coal Exit

Xcel's coal resources are the most carbon-intensive source of generation in its portfolio. While Xcel has already committed to retire Sherco Units 1 & 2 (1.6 GW) in 2026 and 2023, respectively, retention of AS King and Sherco 3 through their current existing lifetimes (2037 and 2040, respectively) has direct implications upon the ability of the Upper Midwest system to achieve significant incremental carbon reductions by 2030. Thus, one of the key assumptions varied across scenarios in this study is the timing of their retirement, as acceleration of the closure of one or both plants prior to 2030 has a direct effect

upon the investments needed and consequent costs to achieve Xcel's interim milestones. This section compares the scenario results for three scenarios shown in Table 5-2.

Table 5-2. Scenarios examined to test impact of early coal retirements

ID	AS King	Sherco 3	Prairie Island	Monticello	New Gas?
0	**Planned ret**	**Planned ret**	**Not relicensed**	**Not relicensed**	**Yes**
1	Planned ret	Planned ret	Not relicensed	Not relicensed	Yes
2	**Early retirement**	Planned ret	Not relicensed	Not relicensed	Yes
3	**Early retirement**	**Early retirement**	Not relicensed	Not relicensed	Yes

5.3.1 PORTFOLIO RESULTS

Each of these scenarios achieves at least an 85% carbon reduction by 2030, but the range of approaches represented highlights the implications associated with retaining existing coal resources. Figure 5-5 and Figure 5-6 show the total installed capacity and annual generation mix associated with each of these three scenarios, along with the Reference Case.

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Figure 5-5. 2030 snapshot: installed capacity (MW) for Scenarios 1, 2 & 3

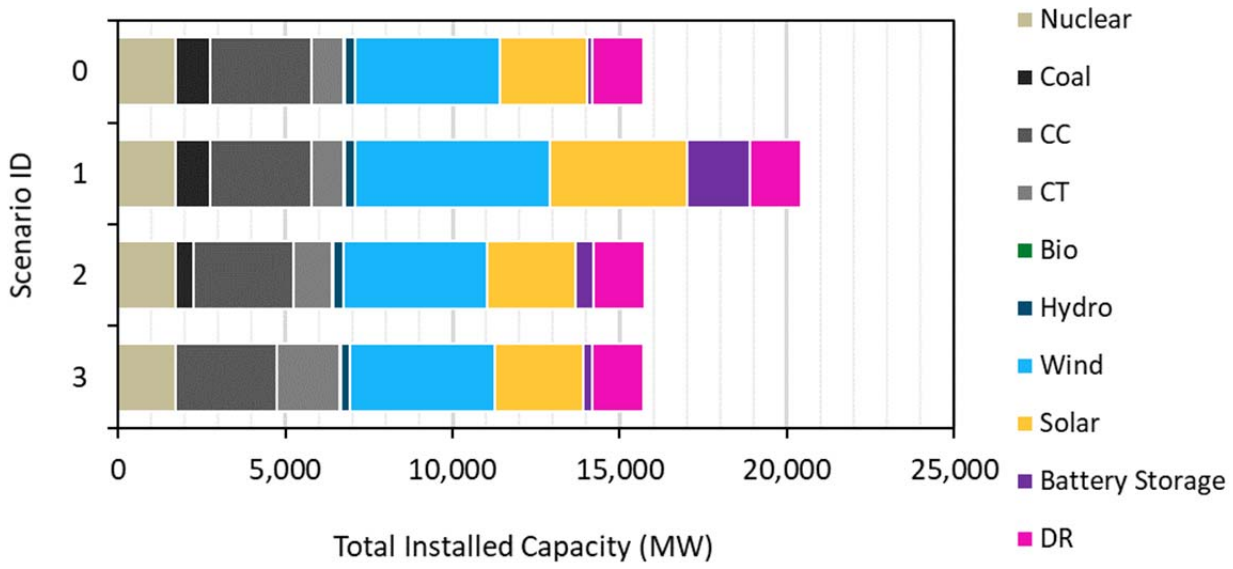
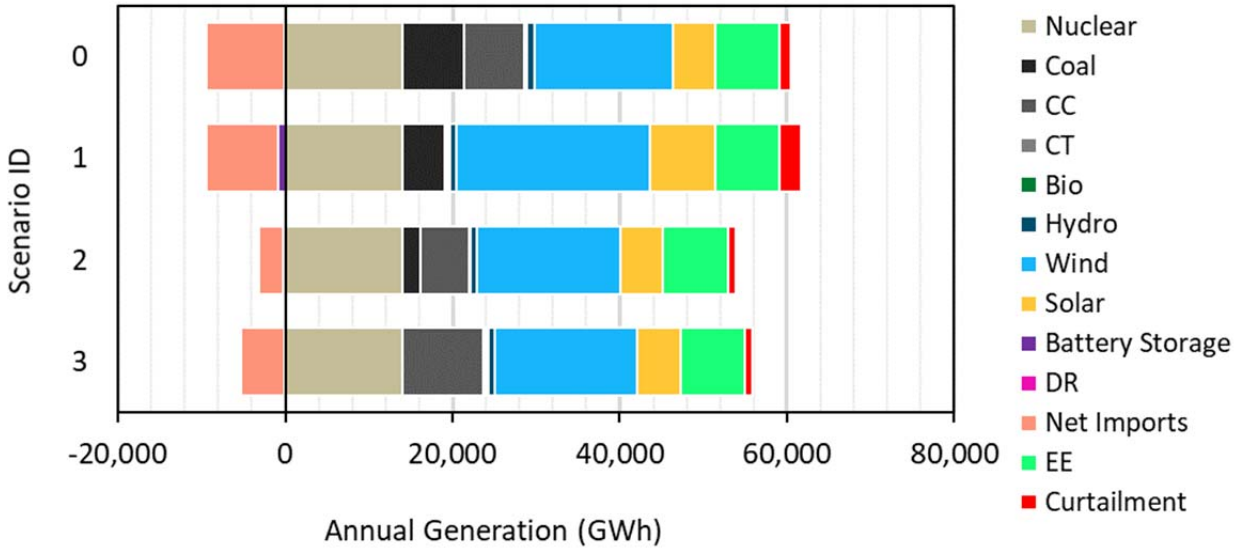


Figure 5-6. 2030 snapshot: annual generation (GWh) for Scenarios 1, 2 & 3



The contrast among portfolios informs several significant findings:

- Meeting Xcel's interim greenhouse gas goals while continuing to operate AS King and Sherco 3 will require very large investments in renewable generation and storage prior to 2030. Relative to the Reference Case, the corresponding carbon reduction scenario requires an additional 3 GW of wind and solar generation and an additional 1.9 GW of energy storage by 2030; these investments are needed to displace flexible gas generation from Xcel's portfolio. The level of renewables needed results in an "effective" renewable penetration of 74% by 2030—significant enough that storage investments are needed to help balance its variability.
- Scenarios that close one or both of Xcel's remaining coal plants by 2030 can achieve Xcel's 2030 carbon goals without significant need for carbon-free resources beyond those already specified in the Reference Case; however, additional investment in gas or other resources will be needed to meet resource adequacy needs absent the contributions of AS King and Sherco 3 to Xcel's resource adequacy needs.

The contrast among these portfolios is even more stark on an hourly basis. Figure 5-7 compares snapshots of hourly operations on two representative days: one in the spring, during which relatively low loads and high levels of renewable production tend to result in periodic surpluses of renewable generation; and one in the summer, when peaking loads require the full capability of Xcel's fleet to meet loads throughout the day.

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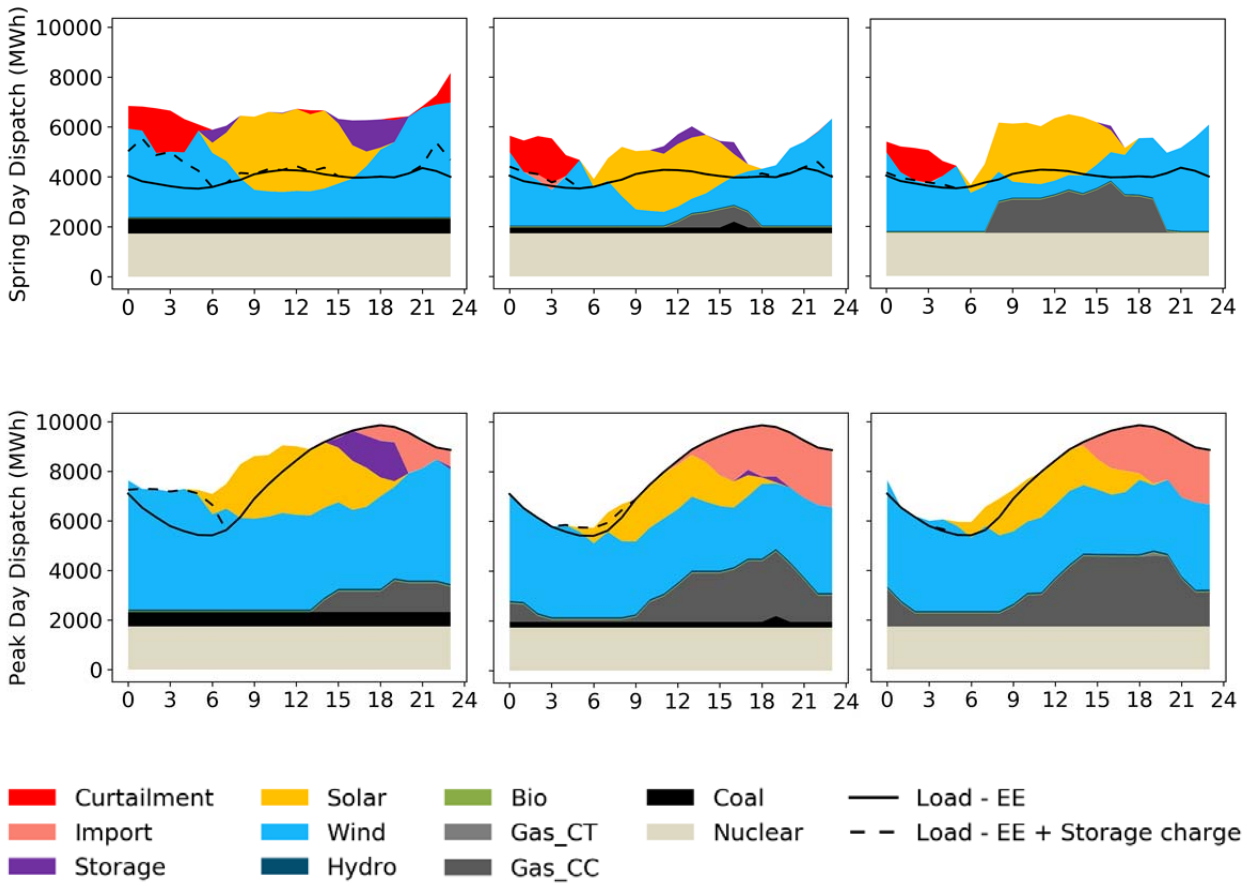
Figure 5-7. Dispatch patterns for Scenarios 1, 2, and 3 (left to right) on a representative spring day and peak summer day



The hourly operations in the representative spring day reveal how significant the renewable integration challenges associated with the scenarios that retain both coal plants through 2030 would be: the level of carbon-free resource production during the midday periods in 2030 exceeds the hourly demand of the Xcel system; the renewable integration challenge is compounded by the lack of flexibility of coal resources to accommodate their output; and despite the capability of energy storage to absorb some surplus and the ability to sell a relatively large quantity of surplus into the MISO market, 7% of available renewable generation is curtailed in 2030. This level of curtailment is substantially larger than the level

observed in scenarios that reduce reliance on coal (and, as a result, face a more manageable burden of renewable integration), which yield levels of curtailment in 2030 of approximately 4%.

5.3.2 COST IMPACTS

Two key cost metrics are used throughout this study to compare the impacts of various scenarios: (1) the **levelized cost of carbon abatement** and (2) the **annual rate impact** in five- year increments. The two metrics are intended to be complementary: the former serves as a useful means of summarizing the impacts associated with a scenario in a single metric, but obscures the some of the interesting dynamics related to the timing associated with those costs; the latter provides more resolution on how costs are incurred by Xcel's customers through time but makes one-to-one comparisons across scenarios more difficult.

Table 5-3 shows the levelized cost metric for these three scenarios. Scenario 1, which preserves both coal plants through their current existing lives, has a cost of carbon abatement significantly higher than either of the scenarios; this is driven by the large amount of infrastructure investment needed to meet near-term greenhouse gas goals while continuing to operate the coal plants through their current lifetimes. The levelized costs of abatement in Scenarios 2 and 3 are much closer—generally indicating that accelerating one retirement provides very large benefits to Xcel's customers in the context of meeting 2030 goals, while the accelerating the retirement of the second plant provides some additional benefit, though not as much as the first.

Table 5-3. Levelized costs of carbon abatement across scenarios.

Scenario	AS King Retirement	Sherco 3 Retirement	Levelized Cost of Abatement ($/ton)
Scenario 1	2037	2040	$62
Scenario 2	pre-2030	2040	$25

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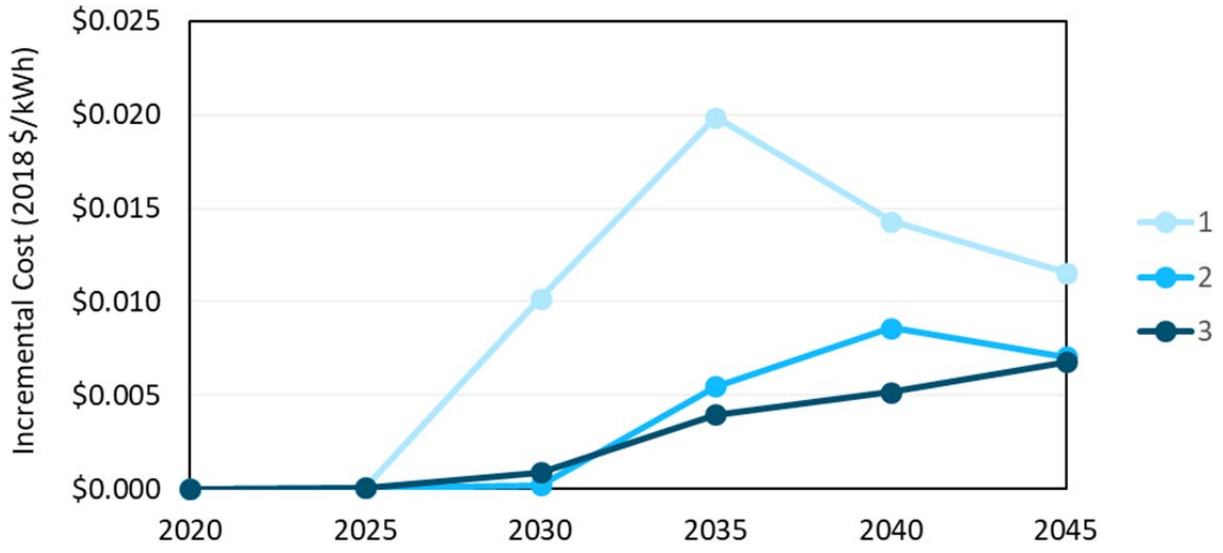
Scenario	AS King Retirement	Sherco 3 Retirement	Levelized Cost of Abatement ($/ton)
Scenario 3	pre-2030	pre-2030	$21

Figure 5-8 shows how the incremental costs (measured relative to the Reference Case) would be borne by ratepayers over time. In Scenario 1, the need for significant investments in renewables in the 2030 begins to drive substantial increases in rates; this effect is exacerbated by 2035 due to the assumed retirement of Xcel's nuclear plants with in this five-year window; only after 2035 does the incremental cost associated with Scenario 1 begin to drop as AS King and Sherco 3 reach the ends of their useful lives. In contrast, both Scenarios 2 and 3 meet the 2030 emissions reductions goals with minimal impact on rates, and lead to moderate impacts in the long run as additional renewable and storage resources are added to displace gas and help to replace retiring nuclear plants. Scenarios 2 and 3 do show some separation in rate impact in 2035 and 2040; Scenario 3, having retired both coal plants early, exhibits the lowest impact on rates associated with the more stringent greenhouse gas goals imposed in this decade.

Figure 5-8. Annual rate impact (relative to Reference Case) associated with Scenarios 1-3

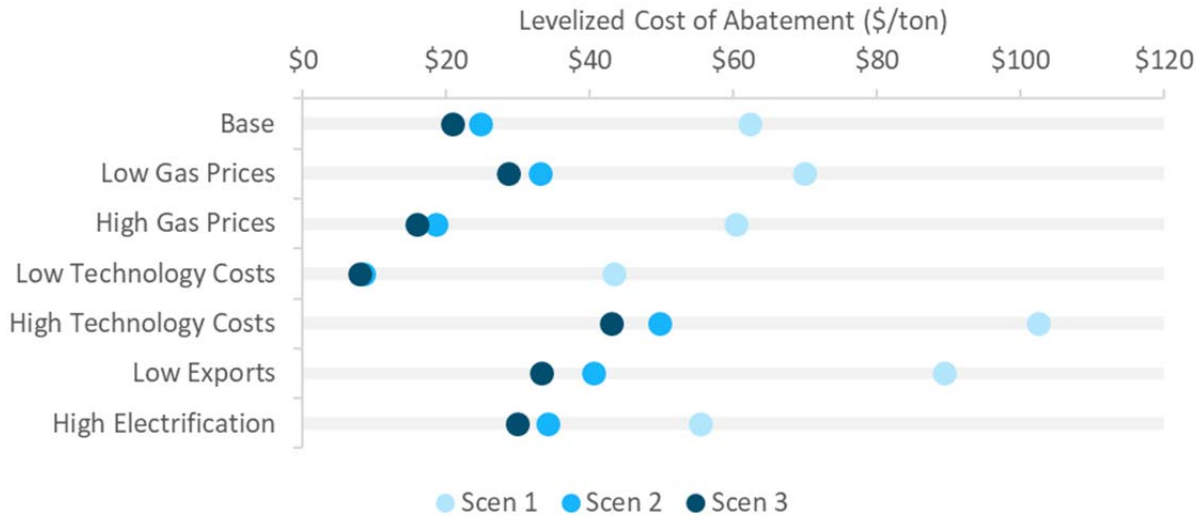


5.3.3 SENSITIVITY ANALYSIS

Sensitivity analysis on key uncertain inputs helps to highlight the level of confidence in the directional results that these results point towards. The four categories of sensitivity tested—gas prices, future technology costs, levels of electrification load, and the ability to export to the MISO market—lend further support to the conclusion that an accelerated shutdown of some combination of AS King and Sherco 3 will result in a more cost-effective pathway to achieving 2030 emissions goals.

Figure 5-9 summarizes the impact of the range of sensitivities on the levelized cost of abatement for the scenarios that vary the timing of Xcel's coal exit.

Figure 5-9. Sensitivity analysis on levelized cost of abatement across scenarios



Several findings are apparent from the range of sensitivities analyzed:

+ Most importantly, across all sources of uncertainty considered in this study, no alternative assumptions would alter the directional relationship among the scenarios examined: across all

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sensitivities, a long-term strategy that maintains coal assets through their current existing lifetimes results in the highest costs to meet interim and long-term reduction goals.

+ The cost of abatement is relatively insensitive to natural gas prices. Lower gas prices will tend to increase the costs of achieving carbon reductions across the analysis horizon. Because the Reference Case portfolio relies more heavily on gas across the horizon than any of the carbon reduction scenarios, lower gas prices result in a higher cost premium for the new sources of carbon-free generation. However, the overall exposure to gas price uncertainty is relatively low.

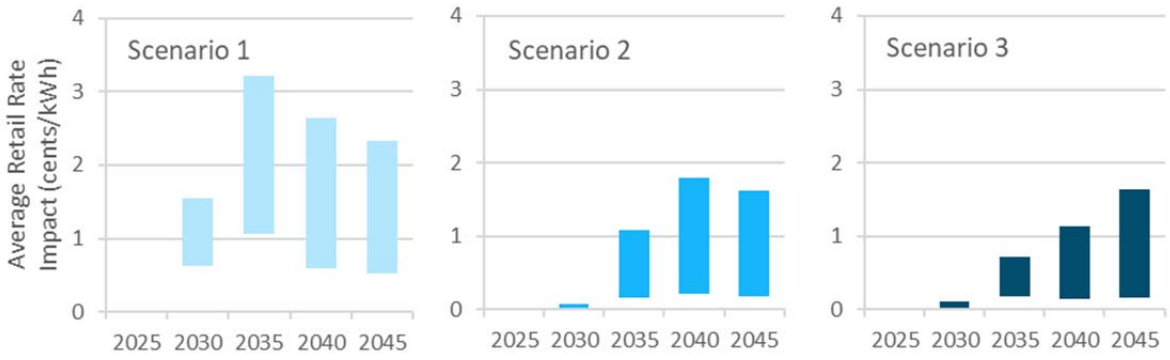
+ The scenarios do notably exhibit a wider range of sensitivity to future technology costs for renewables and storage than to gas prices: higher technology costs increase the cost of abatement by 50-60%; lower technology costs reduce the cost of abatement by 30-40%. The sensitivity to future costs highlights a changing paradigm for utilities whose long-term planning exercises focus not only on cost but on risk as well: as exposure to fossil fuel prices decreases, traditional sources of uncertainty (e.g. natural gas prices) will become less significant drivers of uncertainty than forecasts of technological evolution and innovation (e.g. assumptions on the future rate of decline of storage costs).

+ A common trend in the scenarios presented is reliance on market interactions to meet load in times of low renewable output, and to generate revenue by selling surplus renewable energy to offset a portion of its costs. However, if surrounding jurisdictions in MISO also move towards decarbonization, the ability to export in the times of overgeneration may be limited; assuming similar investment in low-carbon technologies to decarbonize. Compared to the Base Case assumptions, the level of curtailment is between 2.5 to 2.8 times greater for these sensitivities in 2045. The results suggest that in a world in which the region collectively pursues aggressive decarbonization, the cost of carbon abatement will increase.

+ Carbon abatement cost exhibits limited sensitivity to future load levels: while additional investment in carbon-free resources and complementary investments for reliability will be needed, the associated incremental costs are spread across a larger base of retail sales such that the overall cost of abatement does not increase substantially.

The sensitivities conducted also provide useful information on how the costs of achieving long-term goals might vary through time in any single scenario. Figure 5-10 shows the range of costs, expressed as the impact on average retail rates, through time in each scenario. This perspective highlights the fact that not only is a strategy that preserves both remaining coal plants through their remaining lives a higher cost pathway to low carbon goals, but it also has a higher level of risk: the range of potential cost outcomes for this portfolio is considerably larger than its counterparts due to the uncertain costs of the large amounts of renewable and storage investment needed to meet near-term carbon goals with both coal plants on line. Not only are costs lower in Scenarios 2 & 3, but they are generally more certain as well.

Figure 5-10. Year-by-year range of cost impacts for Scenarios 1, 2 & 3 across all sensitivities



5.3.4 IMPLICATIONS

The contrast among scenarios that retain AS King and Sherco 3 through their remaining useful lives and those that accelerate their shutdown to facilitate achievement of interim greenhouse gas goals provides insight into the impact of each potential decision. This analysis suggests that retiring the first coal plant reduces the necessary overbuild of renewables to meet Xcel's near-term climate goals. There is a significant decrease in levelized cost of carbon abatement by retiring AS King early. While the

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subsequent early retirement of Sherco 3 also reduces the levelized cost of abatement, the benefit is smaller than that of the first retirement.

5.4 Scenario Analysis: Limits on New Gas Infrastructure

Up to 7 GW of existing firm capacity in Xcel's Upper Midwest system may be retired by 2045. While significant investments in renewable energy and battery storage will be needed to meet Xcel's long-term carbon reduction target, the question of how much (if any) additional fossil-based firm capacity is necessary to ensure a reliable system cost-effectively remains. The reliability analysis described in Section 4 showed the sizeable investments in renewables and storage needed to serve load in the absence of any firm generation resources, indicating that retention of some level gas capacity in the Upper Midwest system that operates at low capacity factors would help meet Xcel's goals. This section investigates the cost implications of a range of limitations on new gas investments. One case (Scenario 6) restricts new investment to allow for only the development of a new combined cycle plant at the Sherco site; another (Scenario 9) prohibits any new gas capacity. The subset of scenarios examined in this section also assume that the retirements of the Sherco 3 and King plants are accelerated to pre-2030, as this was identified above as a key component of a least-cost strategy to meet near-term carbon reduction objectives. Table 5-4 shows the scenarios examined in this section.

Table 5-4. Scenarios examined to test impacts of new gas prohibition

ID	AS King	Sherco 3	Prairie Island	Monticello	New Gas?
0	**Planned ret**	**Planned ret**	**Not relicensed**	**Not relicensed**	**Yes**
3	**Early retirement**	**Early retirement**	Not relicensed	Not relicensed	Yes
6	**Early retirement**	**Early retirement**	Not relicensed	Not relicensed	**Sherco CC only**
9	**Early retirement**	**Early retirement**	Not relicensed	Not relicensed	**None**

5.4.1 PORTFOLIO RESULTS

These scenarios all achieve at least a 95% carbon reduction by 2045, but the range of new infrastructure investment shows the impact of potential restrictions on new gas investments. Figure 5-11 and Figure 5-12 show the total installed capacity and annual generation mix associated with each of these three scenarios, along with the Reference Case.

Figure 5-11. 2045 snapshot: installed capacity (MW) for Scenarios 3, 6 & 9

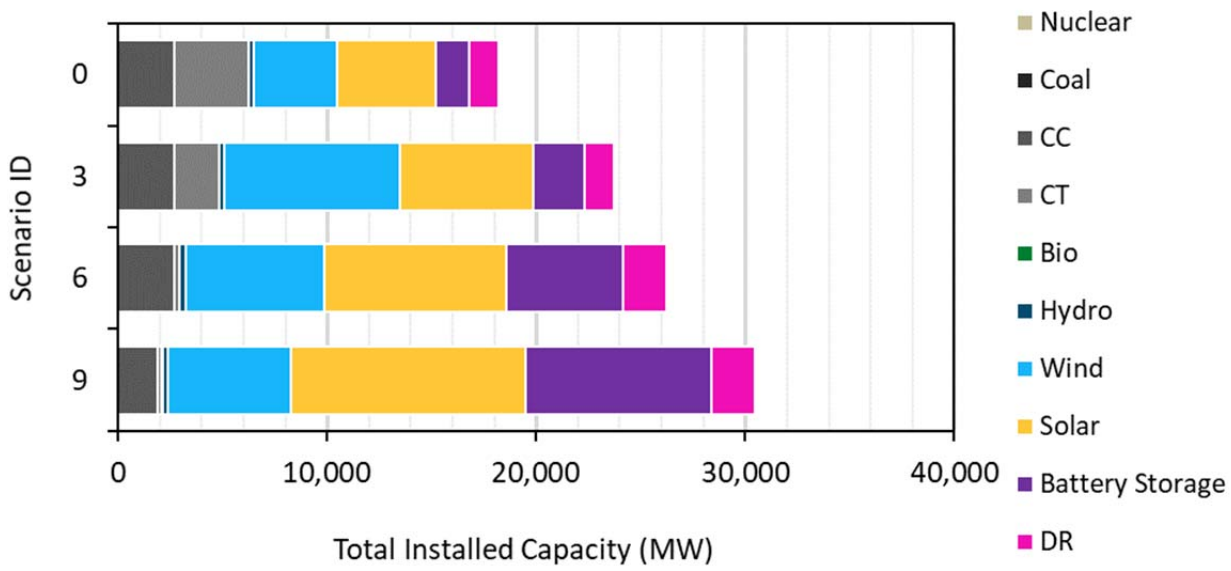

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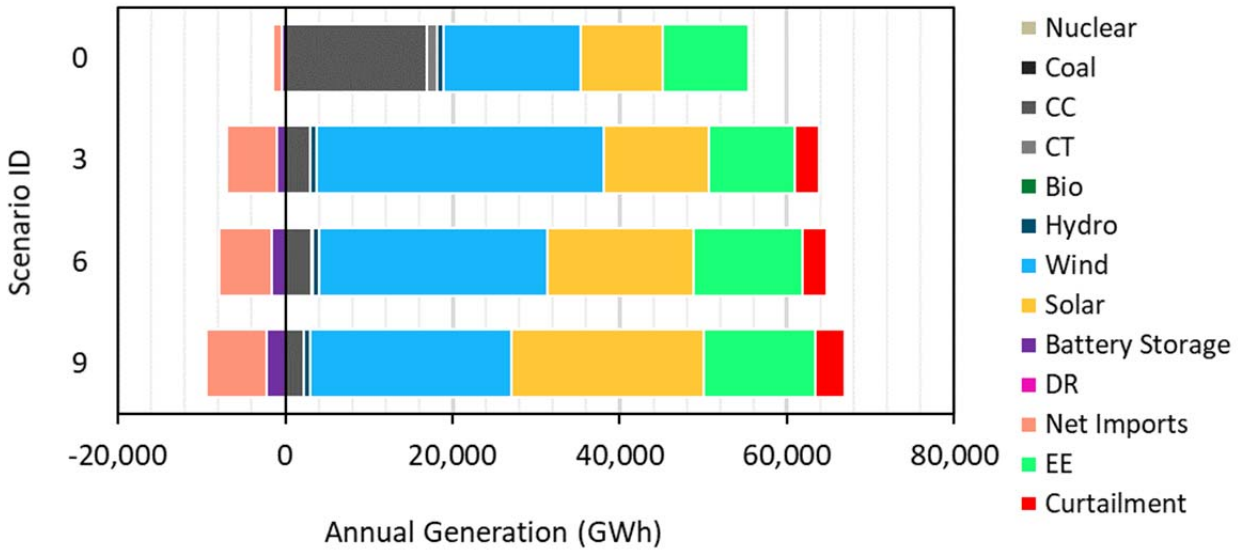
Figure 5-12. 2045 snapshot: annual generation (GWh) for Scenarios 3, 6 & 9

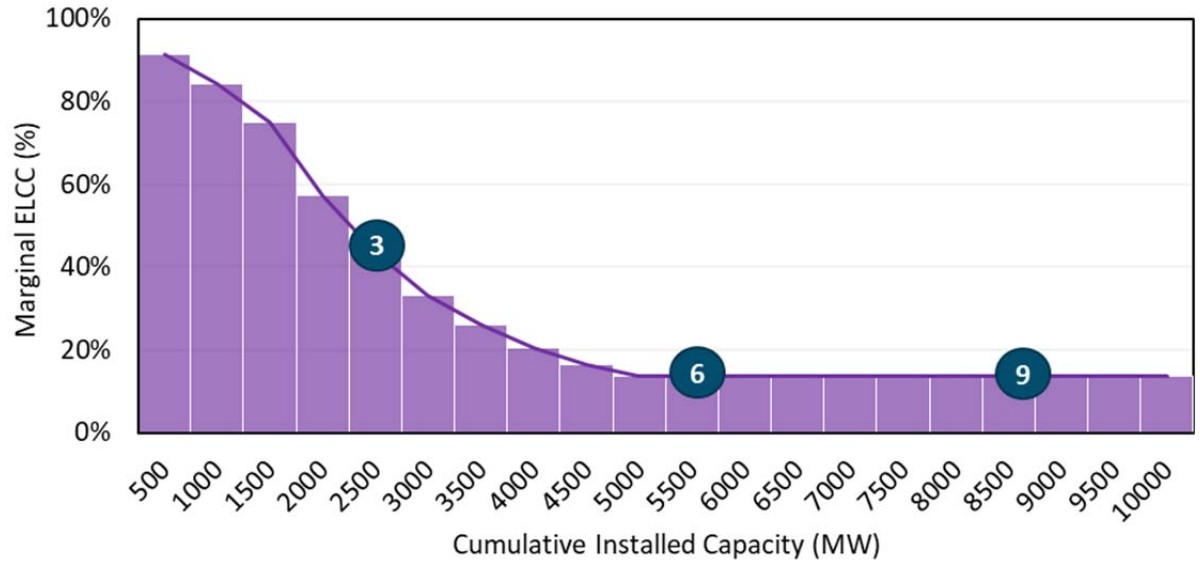


Comparing the portfolios informs several significant findings:

- The amount of capacity needed to meet reliability goals with limits on new gas resources is substantially higher than in scenarios that do not restrict new gas resources. Most of this additional capacity comes in the form of battery storage, but also includes some increases in high-cost tranches of efficiency and DR. The restrictions on gas resources in Scenarios 6 and 9 induce a limited increase in renewable capacity, as well as a shift from wind to solar, whose diurnal production pattern enables more frequent cycling of energy storage resources.
- Despite significant difference in capacity, the three scenarios result in very similar levels of annual gas generation (and corresponding greenhouse gas emissions). Despite the comparatively large buildout of CTs in Scenario 3, the total energy provided by those units in 2045 is insignificant, as they are built to meet resource adequacy needs but run infrequently. New gas units are valuable resources for preserving reliability and help reduce the costs of serving load in a largely decarbonized world. Scenarios 6 and 9 require a level of battery storage buildout that is much higher than any other scenario – 5.6 GW and 8.9 GW, respectively. As

detailed in Section 4, the ELCC of battery storage declines over time. Figure 5-13 shows where the scenarios studied in this section fall on the ELCC curve.

Figure 5-13. Marginal ELCC for storage resources in Scenarios 3, 6, and 9 in 2045



The level of battery capacity on the system in Scenarios 6 and 9 reach the minimum marginal ELCC contribution in the curve. To put this in perspective, the last 3.5 GW of batteries in scenario 9 receive about the same capacity credit as 500 MW of new combustion turbines. New CT capacity is typically used for reliability purposes and infrequently dispatched, as depicted for Scenario 3 in Figure 5-12, so giving preference to battery storage to provide these services seems an improper assignment of purpose when high levels of storage are already on the system.

5.4.2 COST IMPACTS

Table 5-5 shows the levelized cost of carbon abatement for these three scenarios. Scenario 3, seen previously, has the lowest cost of carbon abatement, while Scenarios 6 and 9 are almost two and three times more expensive, respectively. This premium represents the cost of meeting reliability needs with a

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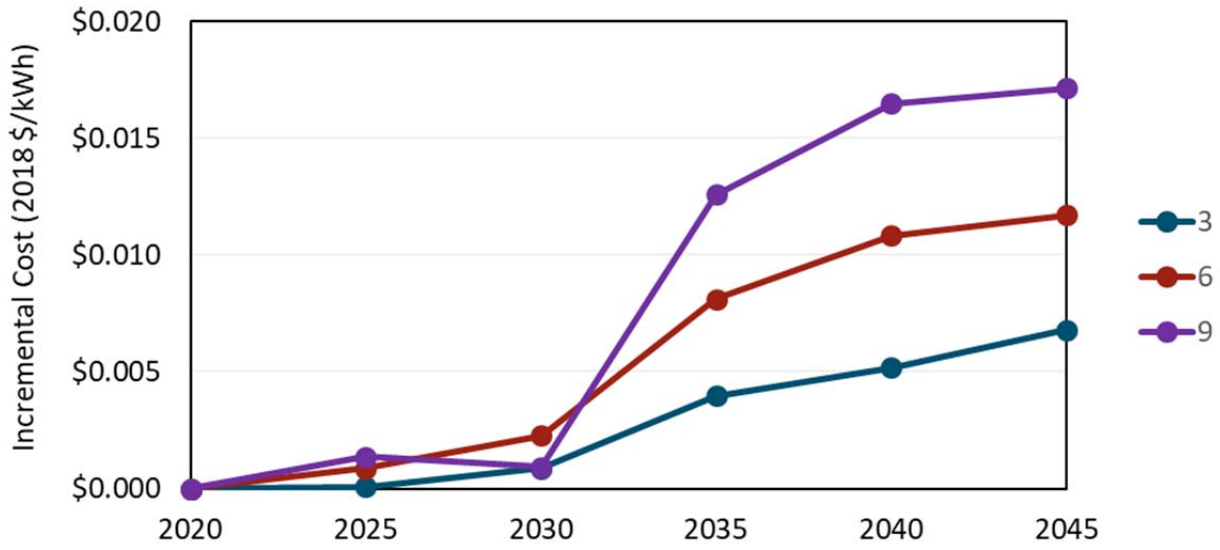
greater share of batteries, DR, EE, and renewables, given that each of these scenarios has the exact same carbon emissions in 2045.

Table 5-5. Levelized cost of carbon abatement across scenarios

Scenario	Gas Build Restriction	Levelized Cost of Abatement ($/ton)
Scenario 3	Unrestricted	$21
Scenario 6	Only Sherco CC	$40
Scenario 9	No New Gas	$54

Figure 5-14 highlights the annual rate impact over time, as shown in the previous results section. While the near-term impact is relatively small, the impacts grow substantially beyond 2030 due to continued load growth and the retirement of Xcel's existing nuclear plants, with the trend mirroring the trend in levelized cost of carbon abatement. The investment in capacity for reliability that would otherwise be cheap gas CTs increases 2045 rates by an additional $0.005/kWh and $0.010/kWh for Scenarios 6 and 9, respectively, compared to Scenario 3.

Figure 5-14. Annual rate impact (relative to Reference Case) associated with Scenarios 3, 6, and 9



5.4.3 SENSITIVITY ANALYSIS

The three sensitivity categories—gas prices, future technology costs, and levels of electrification load—again support the conclusion that prohibiting new gas units is not a cost-effective way to reach Xcel's 2045 emissions goal. Figure 5-15 shows how each sensitivity affects the levelized cost of abatement for these scenarios.

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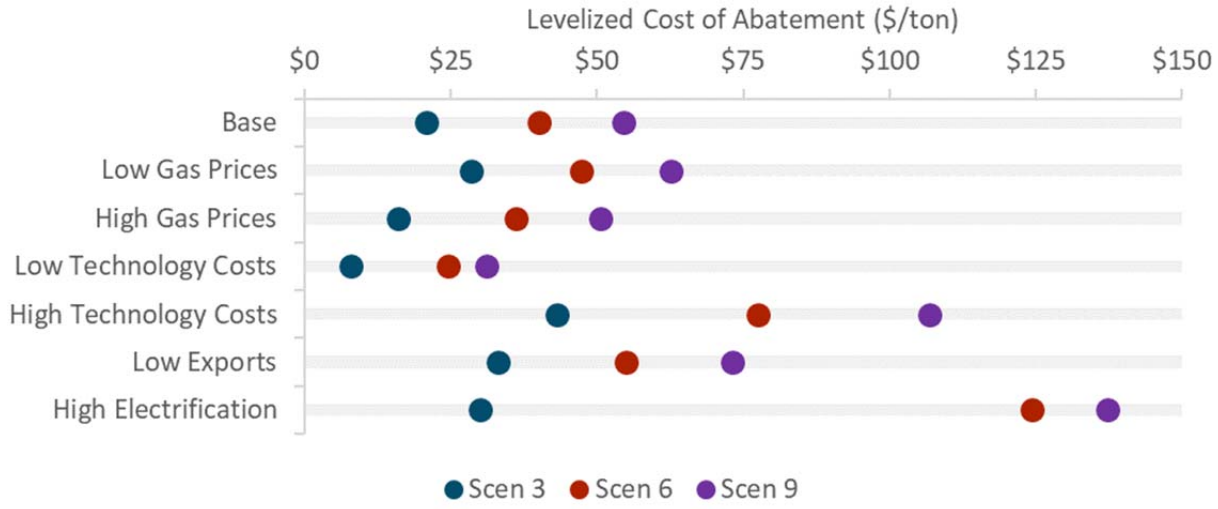
Figure 5-15. Sensitivity analysis on levelized cost of abatement across scenarios



The following are key takeaways from the sensitivities for these scenarios:

- As in the previous set of scenarios, none of the sensitivities alter the directional relationship among the scenarios examined: across all sensitivities, a long-term strategy that includes new gas investment ensures a cost-effective way to achieving Xcel's carbon reduction goals.
- The cost of abatement is, again, relatively insensitive to natural gas prices. Lower gas prices will tend to increase the costs of achieving carbon reductions across the analysis horizon due to the Reference Case portfolio relying more heavily on gas, while higher gas prices decrease the levelized cost of carbon abatement slightly.
- Because disallowing new gas build requires more investment in renewable energy and battery storage, the sensitivities around the costs of renewables and storage show a larger impact than gas prices. Lower technology costs reduce the levelized cost of abatement, but the difference between Scenario 3 and 6 still stays nearly the same. Higher technology costs almost double the abatement cost differences between the cases.

- Eliminating market revenues from exporting beyond 2030 shifts levelized costs of abatement upward, but the directional relationship between scenarios is preserved. Curtailment in these sensitivities is, again, over double the amount found using the Base Case assumptions in 2045.
- In a world with higher loads from electrification, prohibiting new gas buildout will have even greater implications. The overbuild seen in Scenarios 6 and 9 increases substantially in this sensitivity and is reflected by the extremely high cost of carbon abatement.

The range of impacts associated with individual scenarios provides another useful perspective on the potential consequences and implications of choosing a pathway towards decarbonization that prohibits new natural gas investments (see Figure 5-16). These scenarios (Scenarios 6 & 9) generally exhibit a wider range of cost outcomes than scenarios that allow new gas investments to contribute to reliability needs (here, Scenario 3). This range is driven by two factors. First, scenarios that prohibit new gas investment will require much larger investments in battery storage to meet reliability needs; future costs of battery storage are inherently highly uncertain. Second, the cost of meeting reliability needs in a high electrification future without new investments in natural gas proves to be considerably more challenging and costly than under the Base Case assumptions. The substantial increase in load also increases the level of resources needed to meet future resource adequacy needs; meeting all these future needs with energy storage and renewables will prove costly due to the inherent limits on their contributions to resource adequacy.

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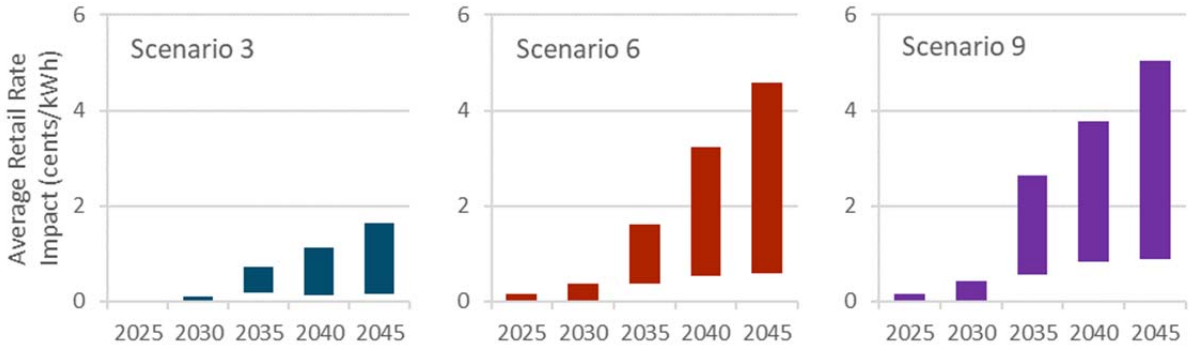
Figure 5-16. Year-by-year range of cost impacts for Scenarios 3, 6 & 9 across all sensitivities



5.4.4 IMPLICATIONS

This comparison of scenarios highlights the value of investments in new natural gas resources to enable achievement of deep carbon reductions while meeting reliability goals and minimizing costs. These gas investments—with the exception of the Sherco CC, all combustion turbines—provide a low-cost option to meet reliability standards but would operate rarely. While combinations of renewables, battery storage, DR, and EE, in conjunction with the remaining gas fleet in the Upper Midwest system, can serve load reliably, pursuing this pathway while excluding natural gas as an option is likely to contribute to significantly higher cost outcomes.

5.5 Scenario Analysis: Nuclear Relicensing

Xcel's two nuclear plants facilities, Monticello and Prairie Island, represent over 1.7 GW of firm capacity and have licenses that expire shortly after 2030. As depicted in the previous section, retaining some level of conventional firm capacity will help Xcel meet its long-term carbon reduction goal in a cost-effective way; the relicensing of Xcel's nuclear plants provides one possible option to meet a portion of that need. In this section, the value Xcel's nuclear fleet is examined by testing different combinations of

relicensing Xcel's nuclear fleet. Keeping some level of nuclear capacity online should reduce the need for investments to meet carbon goals (primarily renewables, efficiency) and to ensure a reliable system (primarily storage, gas, and DR). The scenarios analyzed in this section are shown in Table 5-6.

Table 5-6. Scenarios examined to test impact of nuclear relicensing

ID	AS King	Sherco 3	Prairie Island	Monticello	New Gas?
0	**Planned ret**	**Planned ret**	**Not relicensed**	**Not relicensed**	**Yes**
3	**Early retirement**	**Early retirement**	Not relicensed	Not relicensed	Yes
12	**Early retirement**	**Early retirement**	Not relicensed	**20-yr relicense**	Yes
15	**Early retirement**	**Early retirement**	**20-yr relicense**	**20-yr relicense**	Yes

5.5.1 PORTFOLIO RESULTS

The scenarios in this section again achieve a 95% reduction in carbon emissions in 2045. The installed capacity and annual generation, shown in Figure 5-17 and Figure 5-18, highlight the different strategies available to meet the long-term goal.

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Figure 5-17. 2045 snapshot: installed capacity (MW) for Scenarios 3, 12 & 15

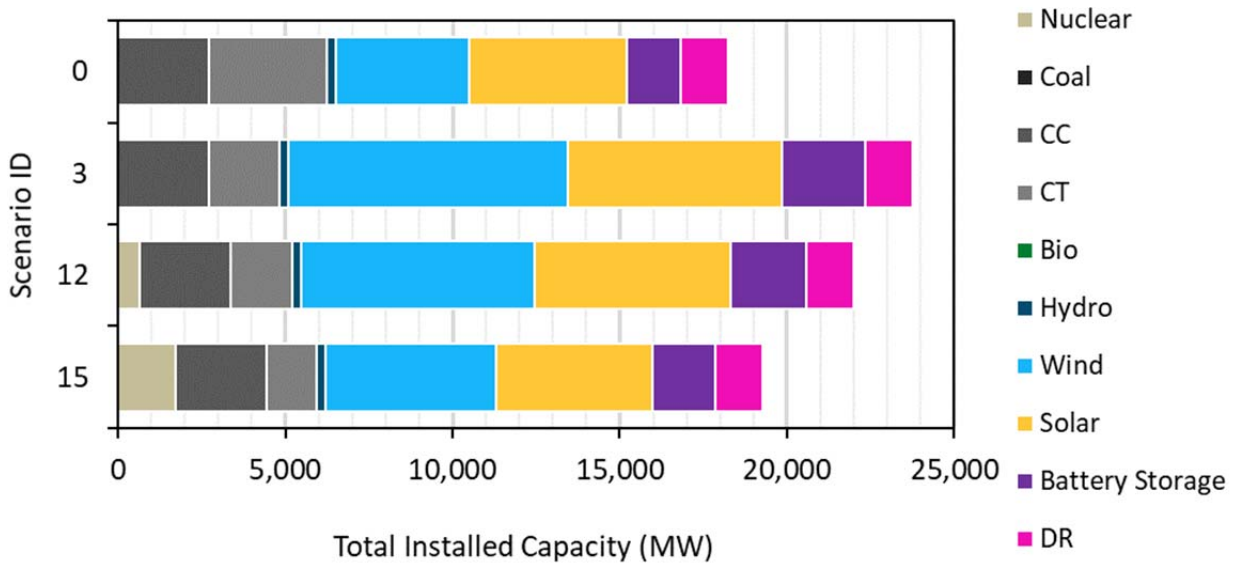
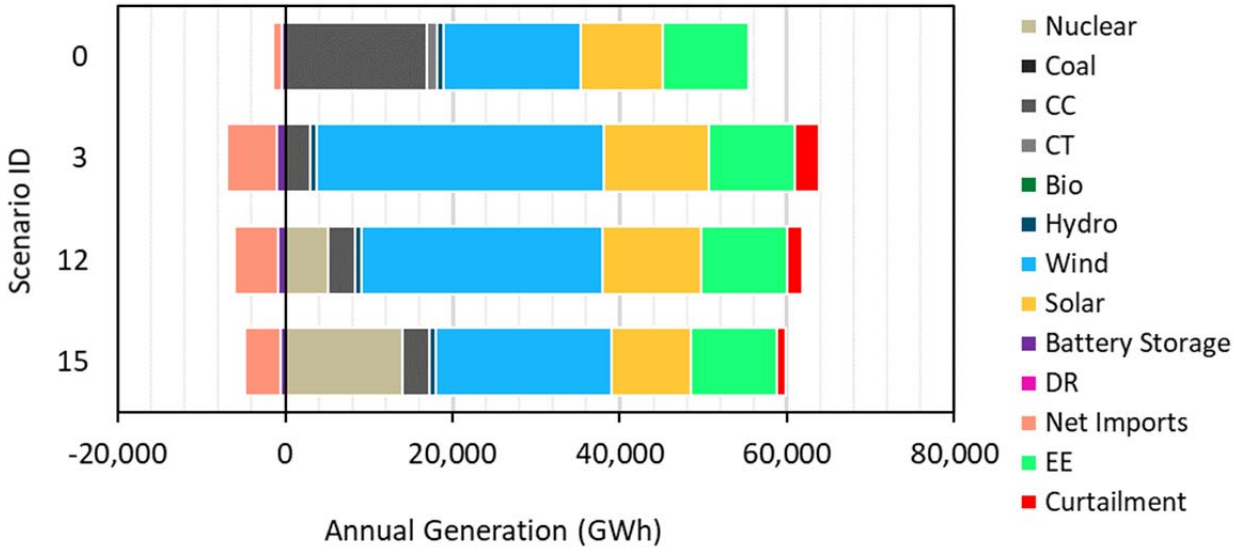


Figure 5-18. 2045 snapshot: annual generation (GWh) for Scenarios 3, 12 & 15



The key differences between these scenarios are as follows:

- Each incremental nuclear relicense significantly reduces investment in renewables, storage, and gas capacity. Relicensing a single plant (Monticello) reduces the amount of investment in new resources needed to meet the target by roughly 2,500 MW (2,000 MW of renewables, 200 MW gas, and 200 MW storage). Relicensing Prairie Island avoids an additional 5,000 MW of renewables and over 600 MW of both gas and storage. The baseload and carbon-free attributes of nuclear energy reduces the renewable overbuild needed in a low-carbon world.
- The relicensing of the nuclear plants reduces each portfolio's reliance on renewables as the primary source of carbon-free energy, and, in doing so, provides a valuable source of diversity that enables more efficient balancing of loads and resources. Each level of nuclear relicensing reduces the amount of renewable overgeneration that must be curtailed to manage periods of surplus renewable availability. In 2045, curtailment levels of 6% in Scenario 3 are reduced to 4% in Scenario 12 and then to 3% in Scenario 15. An Upper Midwest system with more nuclear relicensed thereby enables more efficient utilization of renewables.

The operations in each of the scenarios are shown for the typical spring and peak days in Figure 5-19.

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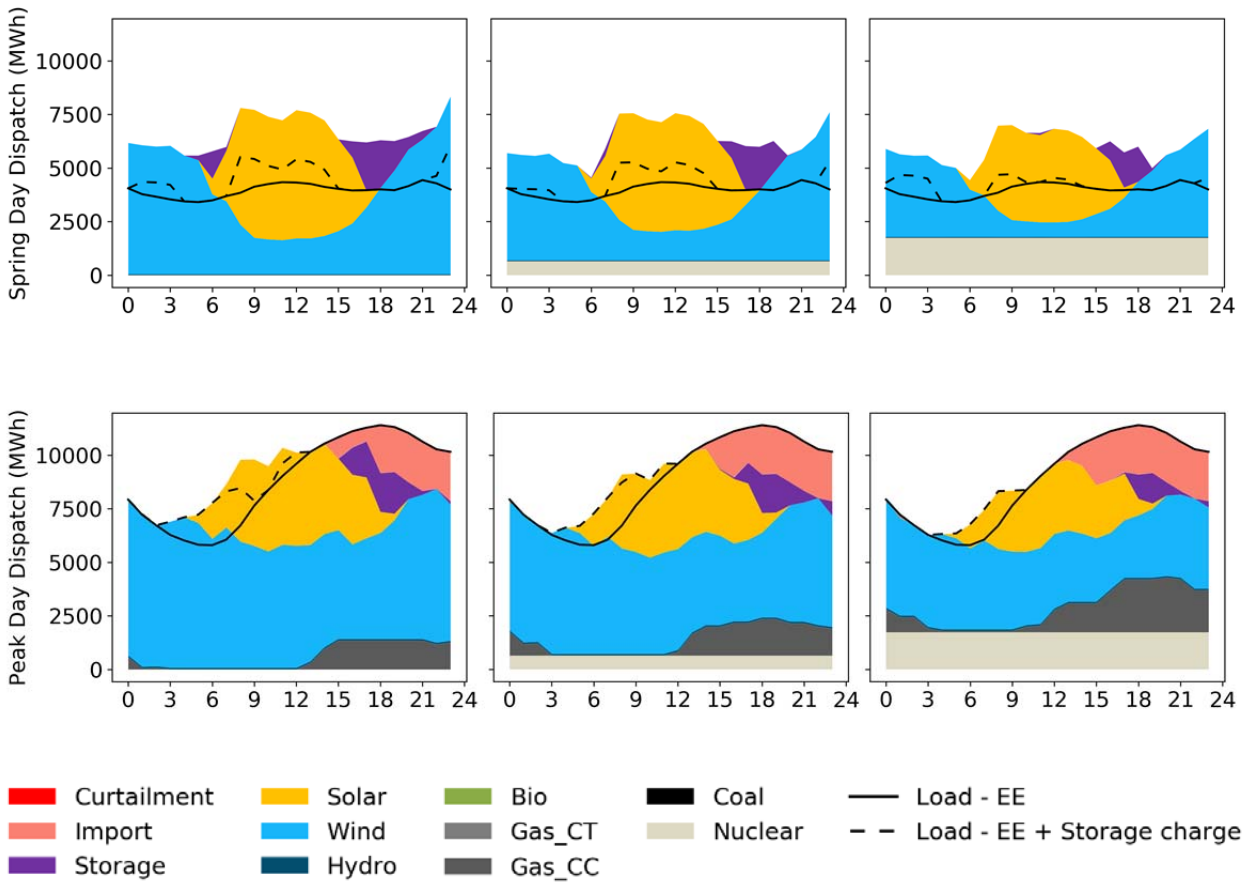
Figure 5-19. Dispatch patterns for Scenarios 3, 12, and 15 (left to right)



On the spring day, Scenarios 12 and 15 replace wind generation with nuclear energy almost one-to-one, and the renewable overgeneration, ultimately sold to the market, persists. The only behavior noticeably different is that of the battery capacity on the system, which cycles more frequently when less nuclear energy is available; often to sell to the market. That general trend also carries over to the peak day dispatch; but, instead of charging to sell to the market later in the day, the batteries charge up on renewable overgeneration to meet the evening peak. With less battery capacity and renewable

overgeneration in Scenarios 12 and 15, a larger portion of the peak load is met with imports and Upper Midwest gas.

5.5.2 COST IMPACTS

Each incremental relicensing of Xcel's nuclear plants reduces the levelized cost of carbon abatement by $4/ton compared to Scenario 3, as shown in Table 5-7. The trend is indicative of the avoided investments in renewables and batteries; the alternative to the firm, carbon-free capacity that nuclear energy provides.

Table 5-7. Levelized cost of carbon abatement across scenarios

Scenario	Monticello Relicensing	Prairie Island Relicensing	Levelized Cost of Abatement ($/ton)
Scenario 3	No	No	$21
Scenario 12	Yes	No	$17
Scenario 15	Yes	Yes	$13

Figure 5-20 shows the corresponding impact on average retail rates. The scenarios diverge beginning in 2035, when various levels of nuclear remain online for these scenarios. In that year, relicensing one nuclear plant reduces rates while relicensing both increases rates, compared to Scenario 3. Because the carbon goal in 2035 is not as stringent, relicensing the second unit exceeds the target and a premium is paid to do so. However, the following years show the value of relicensing both nuclear plants, as more renewable and battery investment is avoided. By 2045, rates are $0.004/kWh cheaper than Scenario 3, as opposed Scenario 12 which is only $0.001/kWh cheaper.

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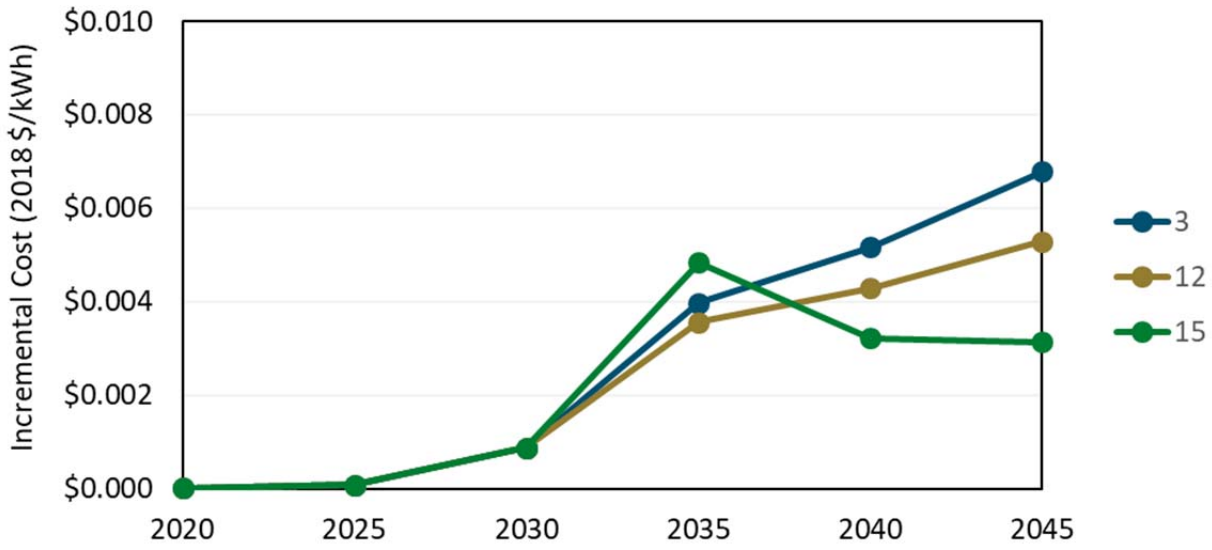
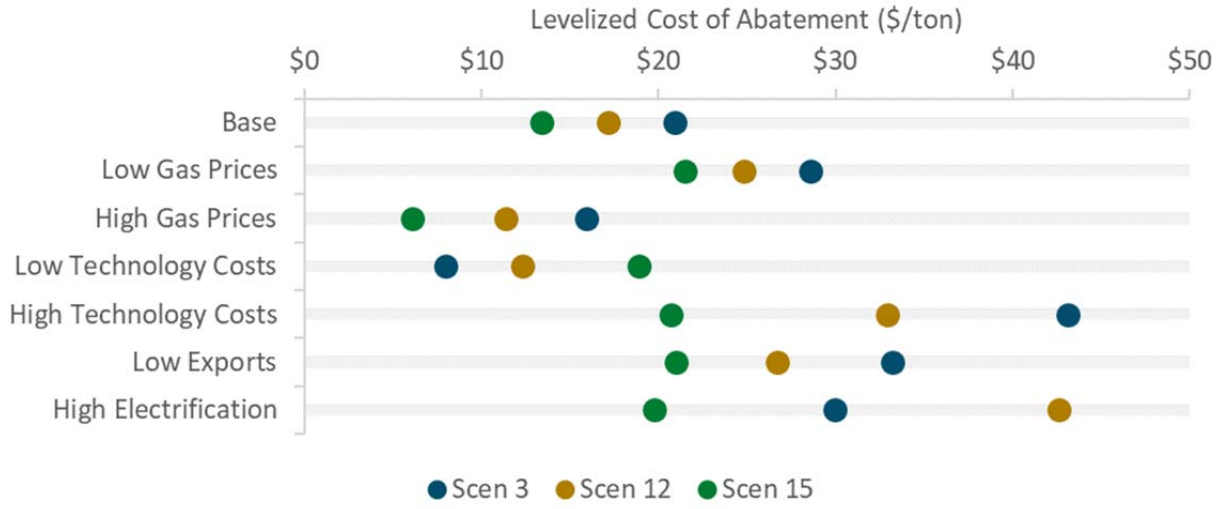
Figure 5-20. Annual rate impact (relative to Reference Case) associated with Scenarios 3, 12, and 15



5.5.3 SENSITIVITY ANALYSIS

For this set of cases, all but one sensitivity convey the same general takeaways as the Base Case assumptions. Figure 5-21 below shows the affects each sensitivity has on the levelized cost of carbon abatement.

Figure 5-21. Sensitivity analysis on levelized cost of abatement across scenarios



These are the takeaways from this sensitivity analysis:

- The High and Low Gas Price sensitivities again do not affect the general relationships among this set of scenarios. Lower gas prices increase the levelized cost of carbon abatement while higher gas prices decrease the levelized cost of abatement. Overall, the shift up or down for each scenario stays consistent with shifts for previously discussed scenarios.
- The Low Technology Cost sensitivity for this set of scenarios is the only sensitivity that changes the directional relationship among scenarios: under a low technology cost future, relicensing Xcel's nuclear plants may result in a higher cost to meet carbon reduction goals than replacement with a combination of wind, solar, storage, and gas. On the other hand, the High Technology Cost sensitivity has the opposite effect of the low technology sensitivity; making relicensing appear an even more cost-effective strategy to meeting long-term carbon goals.
- A long-term limit on exports beyond 2030 increases 2045 curtailment for Scenarios 12 and 15 by substantial amounts—from levels between 3 and 4% to 13%. the largest increases among this

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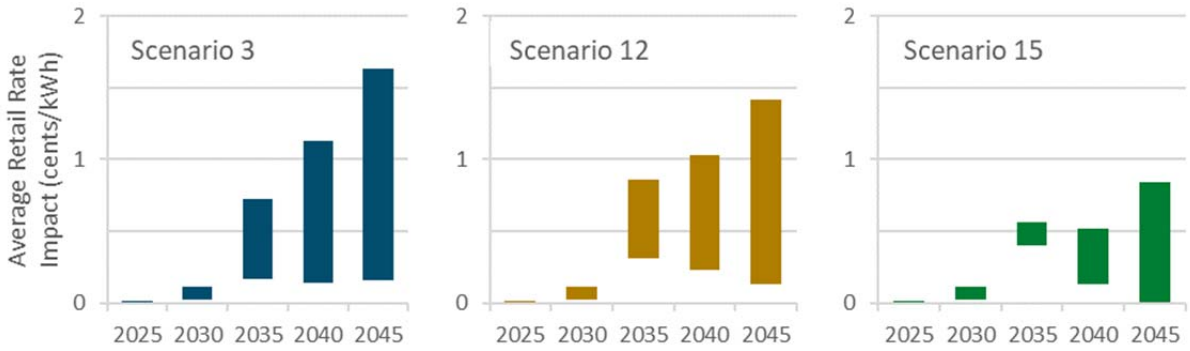
set of sensitivities. Despite the significant increase in curtailment, the levelized cost of carbon abatement increases similarly to the other low export scenarios.

+ For the High Electrification sensitivity, the costs only shift upwards, as seen previously. However, the magnitude of the shift is smallest for these scenarios compared to other High Electrification sensitivities.

Figure 5-22 shows the range of costs to Xcel's customers resulting from the range of sensitivities examined. In general, these results highlight a narrower band of uncertainty in future costs that results from scenarios that pursue nuclear relicensing. One characteristic of all three scenarios shown here, though (which are generally among the lowest cost options examined in this study) is a growing uncertainty with respect to cost over time. This crescendo of uncertainty reflects the reality that the cost of decarbonizing electricity in the long run remains inherently uncertain, and while this study highlights promising options and opportunities to mitigate this cost, precise measurement of how that will impact Xcel's customers is ultimately difficult to predict.

Figure 5-22. Year-by-year range of cost impacts for Scenarios 3, 12 & 15 across all sensitivities



5.5.4 IMPLICATIONS

The comparisons between scenarios illustrate the substantial value of Xcel's nuclear plants as a firm, carbon-free resources. The analysis shows benefits to Xcel resulting from a relicensing of both Monticello and Prairie Island as Xcel's carbon targets become increasingly stringent; the levelized cost of carbon abatement and 2045 rate impacts in the dual relicensing case are among the lowest of all the scenarios examined in this study.

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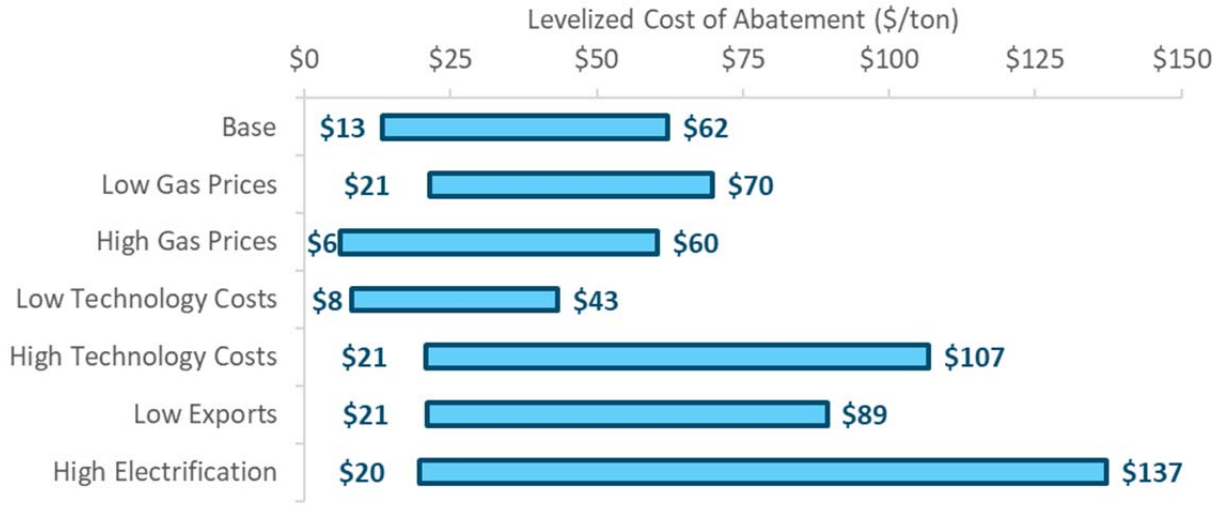
6 Conclusions

First—and perhaps most significantly—this study suggests that Xcel Energy can achieve substantial reductions in carbon emissions from its Upper Midwest portfolio at relatively low cost. Across the 21 scenarios examined in this study that achieve deep carbon reductions during the study horizon, the lowest-cost scenarios reduce carbon at a levelized cost of $15-20 per ton. The ability to achieve such large emissions reductions at such a relatively low cost results from several converging factors: (1) low natural gas prices, which enable low-cost fuel switching from coal to gas; (2) the relatively low (and falling) costs of new wind and solar resources due to technology improvements over the past decade; (3) a potential to increase deployment of energy efficiency and other demand-side programs to manage load growth; and (4) anticipated reductions in future battery storage costs, which enable integration of high penetrations of renewable generation.

Figure 6-1. Range of carbon abatement costs across all scenarios and sensitivities.



The lowest-cost near-term opportunity to reduce carbon in Xcel's Upper Midwest system is to replace coal generation with a combination of renewables, storage, efficiency, and natural gas generation. The four coal plants owned by Xcel produce approximately 85% of the Upper Midwest system's greenhouse gas emissions in the 2020 Reference Case; while Xcel has already established plans to retire two of these plants prior to 2030, this analysis suggests that accelerating the retirement of its remaining two plants and replacing them with a portfolio of efficiency, renewables, storage, and natural gas generation provides the least-cost pathway to reducing emissions consistent with Xcel's 2030 goals (see Figure 6-2).

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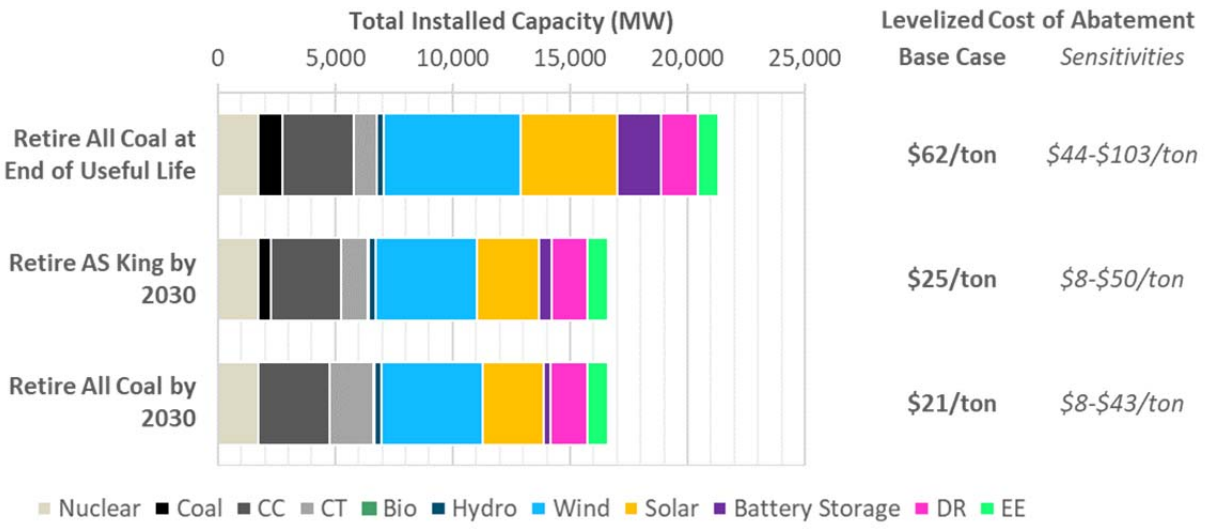
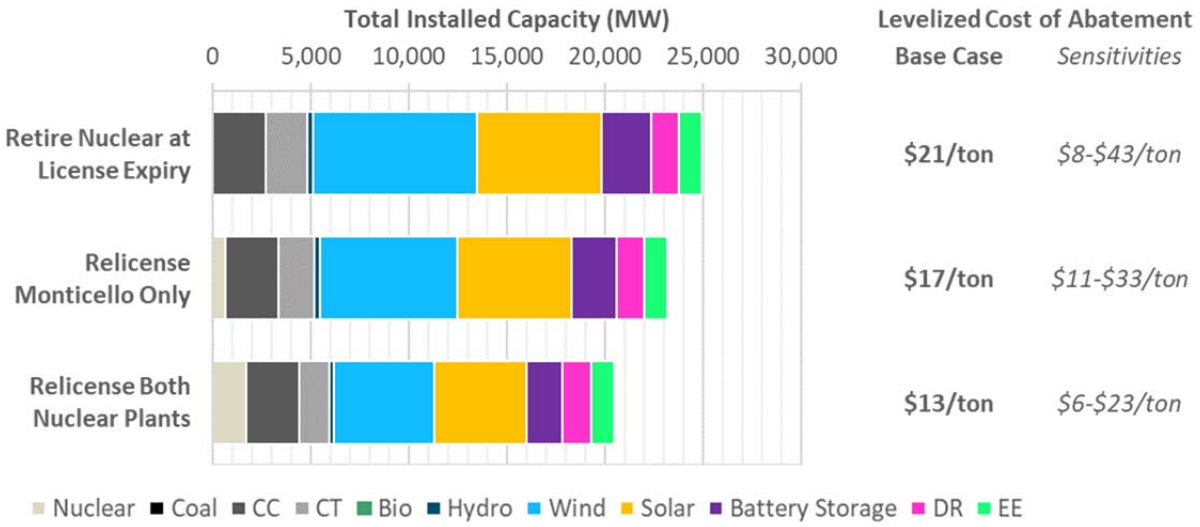
Figure 6-2. Snapshot of portfolios achieving 85% carbon reductions in 2030



A diverse portfolio of resources—including nuclear—offers the least-cost long-term pathway to deep carbon reductions. Beyond 2030, meeting Xcel's long-term carbon goals will require continued development of new carbon-free energy resources. At the same time, the expiration of existing licenses at both of Xcel's nuclear facilities in the early 2030s raises questions about the role of nuclear in Xcel's long-term generation portfolio. The scenario analysis conducted in this study suggests that under most circumstances, extending the licenses of both Monticello and Prairie Island to allow continued operation provides a least-cost option to meeting long-term carbon goals (Figure 6-3). This is due not only to the plants' ability to generate carbon-free electricity at relatively low cost but also, and perhaps more significantly, to the fact that nuclear generation (unlike wind, solar, or energy storage), as a "firm" resource, can generate at its full nameplate capacity for sustained periods when needed to meet Xcel's reliability needs. This unique combination of characteristics makes Xcel's existing nuclear plants inherently valuable to meeting Xcel's long-term carbon goals.

Figure 6-3. Xcel resource portfolios that achieve 95% carbon reductions in 2045



While new resources like wind, solar, and storage will play a central role in supplying carbon-free energy to Xcel's customers, these resources alone cannot meet Xcel's resource adequacy needs at reasonable costs. The reliability analysis conducted in this study highlights the limitations of renewable and storage resources to meet resource adequacy needs: due to variability and limits on duration, these resources offer less capacity value than firm resources that can produce at full capacity when needed. Further, because their marginal capacity value declines with increasing penetration, wind, solar, and storage offer a relatively poor substitute for traditional firm capacity resources in meeting reliability needs at scale (see Figure 6-4). Taken to an extreme, this study shows that a system designed to rely solely on renewables and storage to meet reliability needs would require prohibitively large investments. These findings underscore the need for an evolving approach to resource adequacy—by both Xcel and MISO—as renewables and storage reach greater levels of penetration. Such an approach is critical to ensure that sufficient resources are available even when variable renewables and storage alone cannot produce sufficient levels of generation to meet load.

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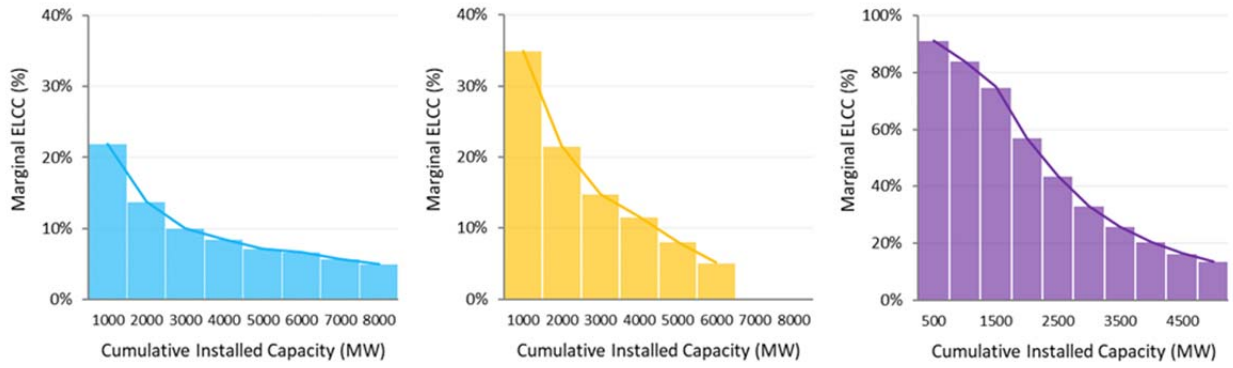
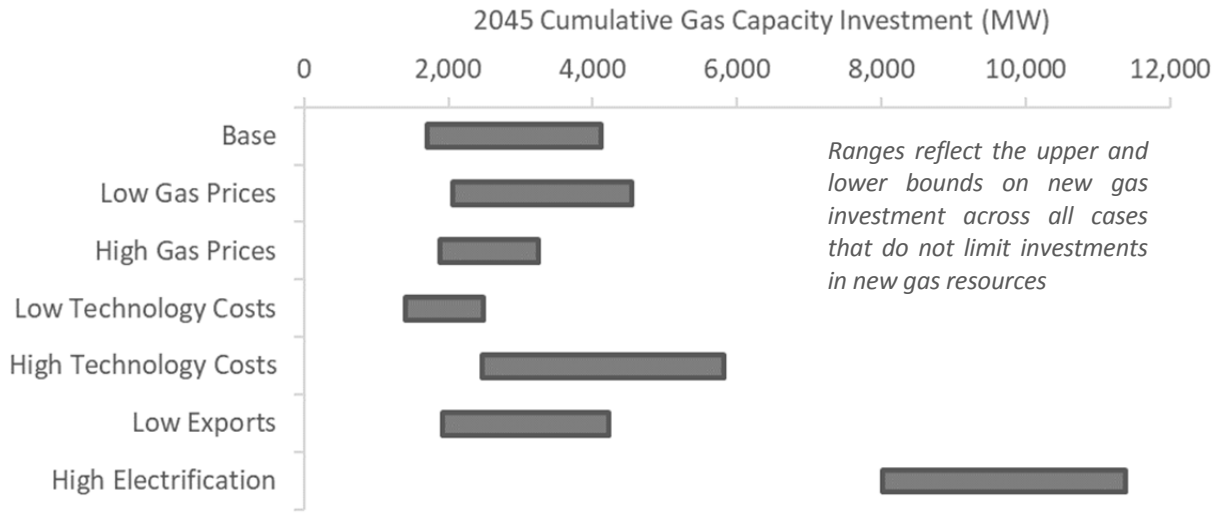
Figure 6-4. Marginal capacity values of wind, solar, and storage resources in Xcel's 2030 portfolio



Natural gas plants will be critically important to ensure a reliable system but will operate at low capacity factors. Because of the inherent limitations of renewables and storage resources to satisfy resource adequacy needs alone, some form of firm, dispatchable capacity will be needed to complement large anticipated investments in efficiency, renewables, and storage that needed to decarbonize Xcel's energy supply. While Xcel's existing nuclear plants are highly valuable because of their firm attributes, they alone are not sufficient to satisfy the need for firm capacity; natural gas resources will continue to play a crucial role in meeting system reliability. Figure 6-5 shows the range of new investments in natural gas resources across all the cases and sensitivities that allowed gas investment as part of the least-cost plan. Under Base Case assumptions, the level of new gas investments needed by 2045 spans a range from 2,000 to 4,000 MW (depending on whether existing nuclear plants are relicensed); among most other sensitivities, a similar range is observed. One sensitivity stands out for its outsized effect: in the High Electrification sensitivity, due to large new loads that increase winter peak significantly, the level of investment in new gas resources in least-cost portfolios is dramatically higher—8,000 to 11,000 MW. Collectively, these observations point to a more general finding: investment in new natural gas resources to meet capacity needs enables a low-cost pathway to decarbonize electricity and to facilitate levels of electrification needed to meet economy-wide carbon reduction goals.

Figure 6-5. Range of investments in new natural gas capacity resources by 2045 as part of a least-cost plan to achieve deep carbon reductions



Finally, while this study identifies a number of promising pathways towards Xcel's long-term carbon goals, the cost of achieving carbon reductions remains highly uncertain and subject to impacts of factors beyond the company's control. Even in the scenario that this study identifies as a least-cost plan—one that combined nuclear relicensing, accelerated coal retirements, and investments in renewables, storage, efficiency, and gas to meet long-term goals—the potential impacts upon retail rates calculated at the study's endpoint in 2045 spans a broad range from 150% above to 125% below the rate impact under Base Case assumptions. The largest potential sources of risk identified in this study result from uncertainty on the future cost of new renewable and storage resources and the uncertainty of how the changing generation mix in the broader MISO system will impact Xcel's opportunities to manage costs through market transactions. The exposure of Xcel's portfolio to such uncertainty and the associated risks underscores the importance of constant vigilance and responsiveness to rapidly changing market conditions as Xcel transitions towards a low carbon system.

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Appendix A. RECAP Methodology

A.1 Background

E3's **Renewable Energy Capacity Planning Model (RECAP)** is a loss-of-load-probability model designed to evaluate the resource adequacy of electric power systems, including systems with high penetrations of renewable energy and other dispatch-limited resources such as hydropower, energy storage, and demand response. RECAP was initially developed for the California Independent System Operator (CAISO) in 2011 to facilitate studies of renewable integration and has since been adapted for use in many jurisdictions across North America.

RECAP evaluates resource adequacy through time-sequential simulations of thousands of years of plausible system conditions to calculate a statistically significant measure of system reliability metrics as well as individual resource contributions to system reliability. The modeling framework is built around capturing correlations among weather, load, and renewable generation. RECAP also introduces stochastic forced outages of thermal plants and transmission assets and time-sequentially tracks hydro, demand response, and storage state of charge.

Figure A-1 provides a high-level overview of RECAP including key inputs, Monte Carlo simulation process, and key outputs.

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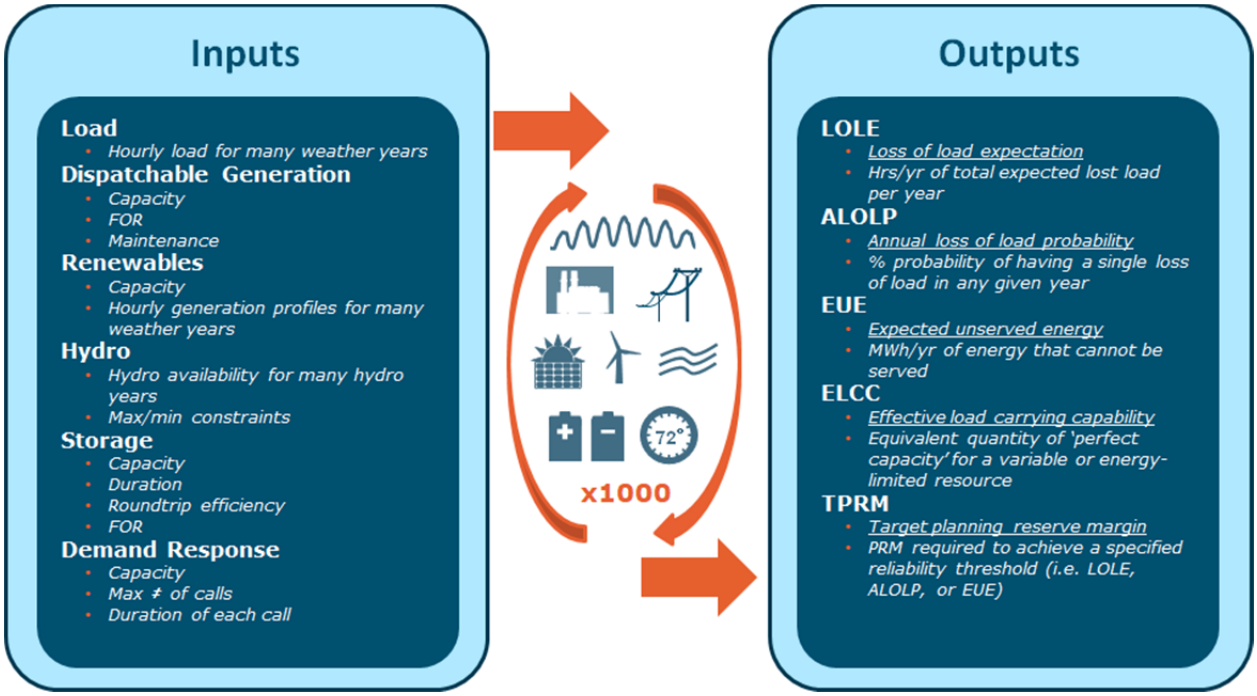
Figure A-1. RECAP model overview



A.2 Model Inputs

RECAP is designed to allow loss of load probability simulation on a wide range of electricity systems that may comprise a diverse mix of generating resources, each with different constraints and characteristics that affect their availability to serve load at different times. The input data for RECAP, summarized in Table A-1, enables a robust evaluation of loss-of-load-probability that can account for a broad variety of technologies and resource types, including:

- **Firm resources** capable of producing at their full rated capacity when called upon by operators (except during periods of maintenance and unforced outages);
- **Variable resources**, typically wind and solar, whose availability will vary on an hourly basis as a result of weather and solar irradiance patterns;

- **Hydroelectric resources** that can be dispatched relatively flexibly but have constraints related to streamflow and underlying hydrological conditions;
- **Storage resources** that can be dispatched flexibly but have limited durations across which they are available due to limits on state of charge; and
- **Demand response programs** that can be called upon as a last resort by operators to maintain reliability but typically have limits on the frequency and duration of calls that vary depending on the type of program.

Table A-1. Key inputs to RECAP model

Module	Inputs Needed
Load	• Annual energy demand • Annual 1-in-2 peak demand • Hourly profiles corresponding to a wide range of weather conditions (20+ years)
Firm Resources *(e.g. nuclear, coal, gas, biomass, geothermal)*	• Installed capacity by resource • Forced outage rate by resource • Maintenance profiles by resource
Variable Resources *(e.g. wind, solar, run-of-river hydro)*	• Installed capacity by resource • Hourly profiles for multiple years, ideally including multiple years of overlap with hourly load profile data
Imports/Market Purchases	• Assumed level of imports available from external markets available to contribute to portfolio reliability needs
Hydroelectric Resources	• Installed capacity by resource • Monthly/daily energy budgets across a range of plausible hydro conditions • Minimum output levels by month/day • Sustained peaking limitations by month/day
Storage Resources *(e.g. batteries, pumped storage)*	• Installed capacity by resource • Storage reservoir size by resource • Round-trip efficiency by resource
Demand Response Resources	• Program size by program • Limits on program calls (e.g. number of calls per year/month/day, length of calls)

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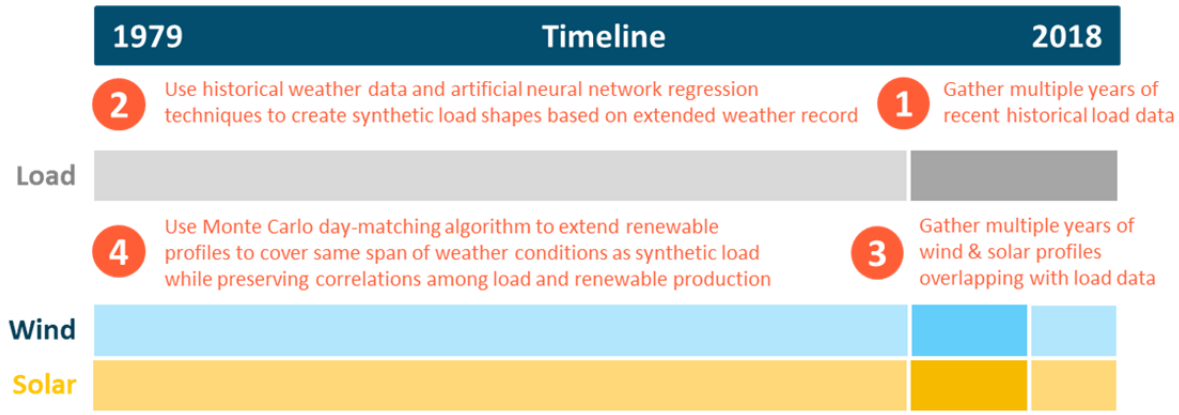
A.3 Model Methodology

A.3.1 LOAD & RENEWABLE SIMULATION

Generating an extensive record of load and renewable profiles that capture both the range of variability of each as well as the key correlations between them is a necessary but challenging step in reliability modeling. To generate such a record, RECAP relies upon historical time-synchronous load and renewable profiles but also uses statistical approaches to extend what is typically a limited historical record. The four-step process used in RECAP is shown in Figure A-2.

Figure A-2. Illustration of processes used to generate load & renewable profiles for RECAP



Step 1: Gather historical load data for multiple recent years

The hourly and seasonal patterns of load are typically captured in RECAP through the actual observed patterns of hourly load metered by utilities, RTOs, or others. In general, multiple years of recent historical load data (5-10 years) is collected to provide a reasonable breadth of potential underlying weather conditions.

Step 2: Use neural network regression to simulate hourly loads across long-run weather record

Typically, the availability of historical hourly load data that can be practically incorporated into RECAP is limited—both by data availability and by the fact that historic load shapes from previous years may not appropriately reflect the composition of end uses and customers that make up today's system (an issue that becomes increasingly pronounced farther back in time). At the same time, a rigorous approach to measuring reliability requires consideration of a breadth of potential weather conditions.

To allow consideration of a broad range of potential weather conditions observed across multiple decades in spite of the lack of useful historical load data during most of that period, RECAP uses a neural network regression algorithm to extend a relatively shorter sample of actual historical load data across a longer period based on key weather indicators and drivers across that longer period. The neural network algorithm is trained with a set of historical loads and associated underlying weather data and then used to simulate load levels that reflect the composition of end uses and the underlying economic conditions that reflect today's electricity demands while also capturing the underlying weather conditions across a much broader record. The key variables included in the neural network regression include:

- Daily minimum and maximum temperatures at multiple weather stations;
- An indicator for month (+/- 15 days);
- A flag for day-type (weekend vs. weekday);
- A day index to account for any growth observed during the training period.

Figure A-3 shows an example of the results of this process. The resulting shape can be scaled upward or downward to the appropriate level of annual and peak demand to match a future system's expected demand growth.

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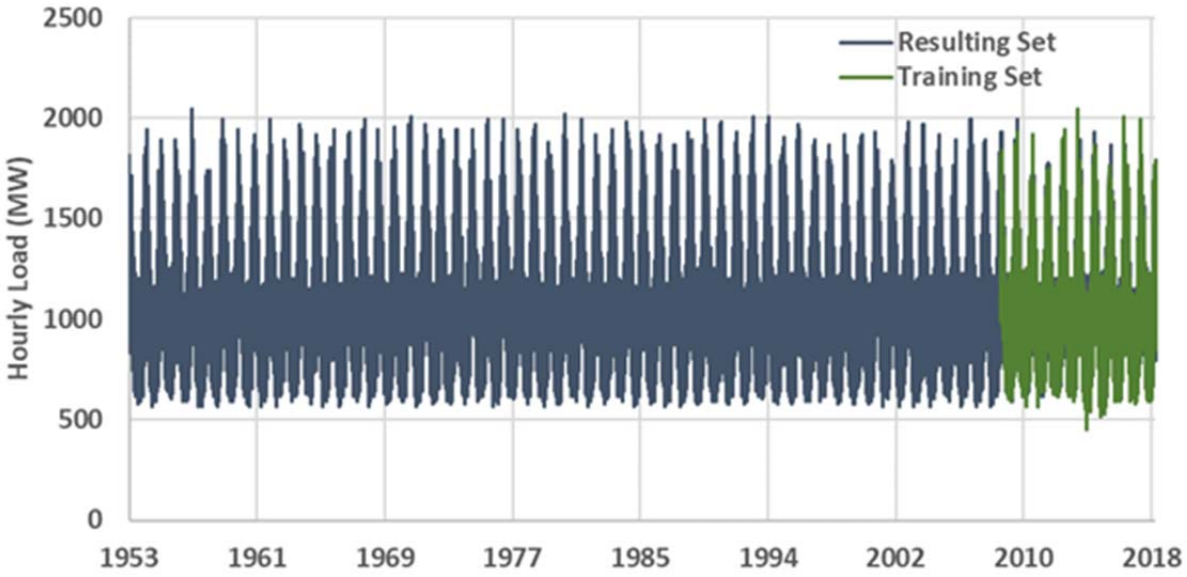
Figure A-3. Example of results of neural network regression to extend load across long weather record



Step 3: Gather historical (or simulated) renewable profiles for multiple recent years

Multiple years of actual and/or simulated hourly profiles for wind and solar resources are a key input to RECAP. Whenever possible, actual historical metered data is preferred, but in its absence (given the relatively small amount of renewable generation existing today), simulated hourly profiles from sources like NREL's WIND Toolkit and NREL's System Advisor Model provide coverage across multiple historical years (2007-'12 and 1998-'18, respectively). Several considerations are important in developing this data set:

- Hourly profiles should capture multiple years. The potential variability of renewable generation, particularly during periods of extreme load, is high enough that a single year may not appropriately capture its expected production during those periods. Therefore, multiple years (typically at least four) are needed.

- Hourly profiles should correspond to a period for which load data is also available. Developing a dataset of load and renewables that is weather-matched based on actual historical conditions allows the modeling to account for the actual observed correlations between load and renewables.
- Hourly profiles for wind and solar should (ideally) cover the same historical period. Like above, this allows the model to preserve actual observed correlations between wind and solar—not just between load and each renewable technology independently.

Step 4: Use a probabilistic day-matching algorithm to match renewable profiles to extended weather record

A stochastic rolling day-matching algorithm is used to match the limited sample of renewable profiles with the extended record of simulated load data using the observed relationship for years with overlapping data i.e., years with available renewable data. The day matching algorithm, illustrated in Figure A-4, selects a renewable profile for each day of the simulation based the corresponding level of load in that day and the level of renewable generation in the prior day(s).[8] The potential sample of renewable profiles from the historical record that are considered as potential matches for each day in the extended record is also restricted to days within +/- 15 calendar days of that day to ensure that seasonal factors (e.g. variations in patterns of insolation, which affects solar production on a seasonal basis) are also accounted for in the process. Ideally, this day matching algorithm can be run on both wind and solar profiles simultaneously—this is possible when the historical records for wind and solar profiles are contiguous—but the algorithm can also be run independently on wind and solar if overlapping records are not available.

[8] The number of prior days' renewable generation included in the matching algorithm can be varied as needed to ensure that extended weather events observed in the historical record (e.g. multi-day storm systems) occur within the stochastic simulation.

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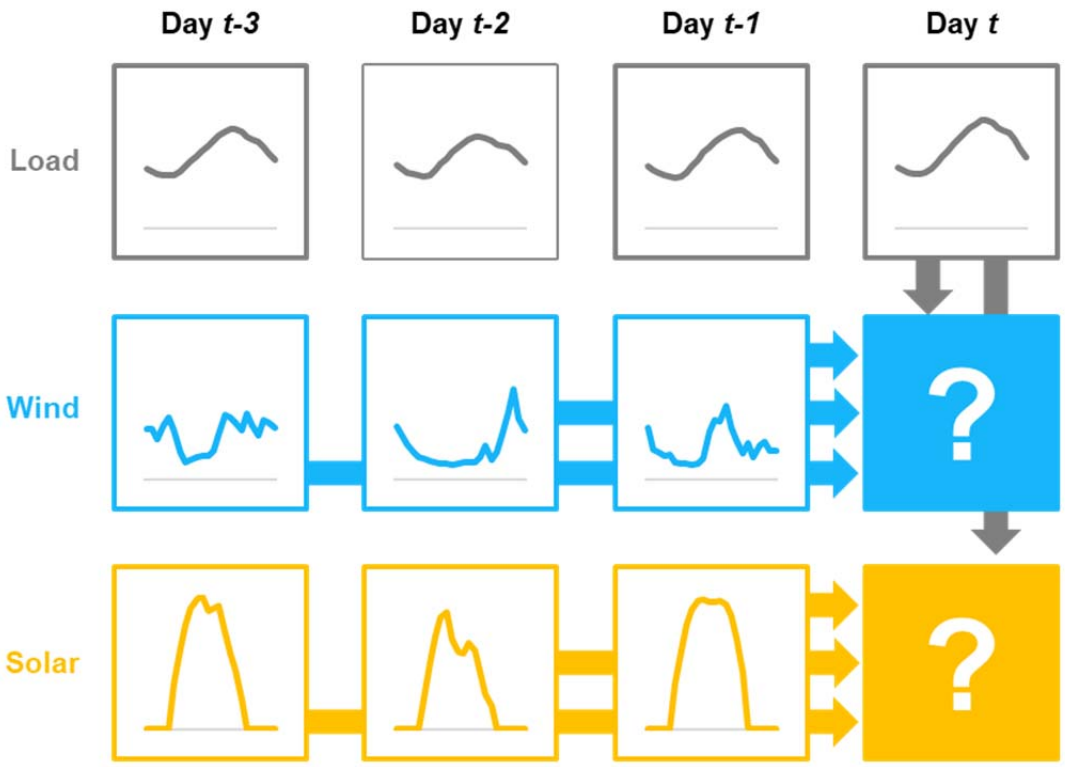
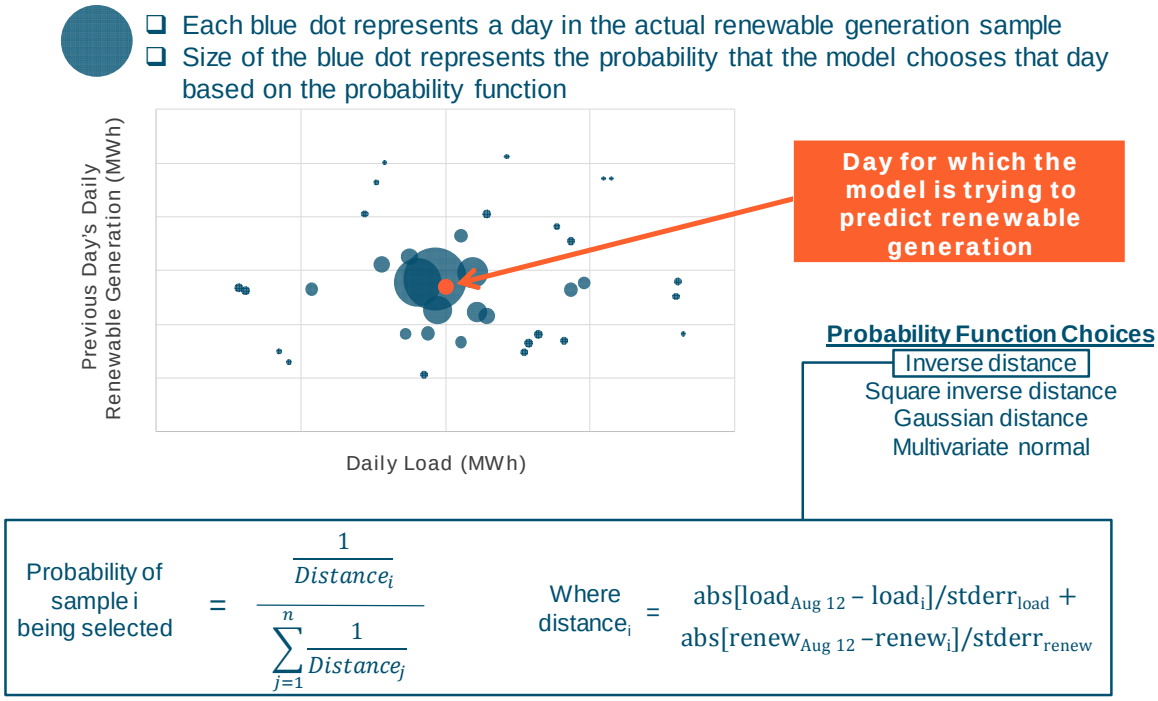
Figure A-4. Illustration of day-matching algorithm used to extend record of renewable profiles to match loads



The algorithm used to select renewable profiles is a probabilistic one that allows for stochastic pairings of load and renewable shapes—in other words, multiple plausible combinations of load and corresponding renewable profiles are generated for the extended weather record. The probability that any specific day from the historical weather record will be selected as a match is based on an inverse distance algorithm that measures the similarity between each possible day of renewable profiles in the historical record and the desired day in the longer record and assigns a probability to each one. Figure A-5 illustrates the assignment of probabilities for a specific individual day; the days in the historical

record that are "closest" to that day (in terms of that day's load and the previous day's renewable generation) are assigned the highest probability.

Figure A-5. Renewable profile selection process



A.3.2 LOSS OF LOAD PROBABILITY SIMULATION

Based on the inputs described above, RECAP simulates the loss of load probability for an electric system using a Monte Carlo approach to capture plausible combinations of load, variable renewables, and outages across hundreds of potential years. For each broad class of resource enumerated above, RECAP includes a module that evaluates the ability of each resource in that class to contribute to load in each hour of the simulation. The methodology used in each module is presented in

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Table A-2. Overview of methodology used to compare load and resource availability

Module	Methodology
Load	The hourly profile of electricity demand is determined based on an hourly load shape that covers a broad range of historical weather conditions (multiple decades) that is scaled to the desired level of annual and peak demand. The underlying load shape itself is a result of a pre-processing neural network regression that simulates hourly load shapes for the full available weather record based on recent historical loads and a longer record of weather data.
Firm Resources *(e.g. nuclear, coal, gas, biomass, geothermal)*	Available dispatchable generation is calculated stochastically in RECAP using forced outage rates (FOR) and mean time to repair (MTTR) for each individual generator. These outages are either partial or full plant outages based on a distribution of possible outage states. Over many simulated days, the model will generate outages such that the average generating availability of the plant will yield a value of (1-FOR).
Variable Resources *(e.g. wind, solar, run-of-river hydro)*	Availability of variable renewable resources is simulated stochastically based on the rolling probabilistic day-matching algorithm described above. This results in an hourly timeseries profile for all variable resources that aligns with the hourly load profile.
Imports/Market Purchases	Availability of generic resources from external areas (i.e. assumed wholesale market purchases) can be specified at an hourly, monthly, or annual level. This is an input to RECAP.
Hydroelectric Resources	To determine hydro availability, the model uses a monthly historical record of hydro production. For every simulated load year, a hydro year is chosen stochastically from the historical database. Associated hydro budgets are typically assigned on either a weekly or daily basis and then "dispatched" to minimize net load (load less variable resources and hydro) during that period while accounting for a number of constraints, including: • Minimum output levels that capture the lower limit on the level of generation that a system may produce when considering hydrological and other physical constraints on the system • Sustained peaking limits, which limit the output of the hydro system across a range of rolling time windows (e.g. 1-hour, 2-hour, 4-hour, and 10-hour) to capture how hydrological factors may limit the ability to discharge water through a dam for sustained periods of time.
Storage Resources *(e.g. batteries, pumped storage)*	The model dispatches storage if there is insufficient generating capacity to meet load net of renewables and hydro. Storage is reserved specifically for reliability events where load exceeds available generation. It is important to note that storage is not dispatched for economics in RECAP which in many cases is how storage would be dispatched in the real world. However, it is reasonable to assume that the types of reliability events that storage is being dispatched for (low wind and solar events), are reasonably foreseeable such that the system operator would ensure that storage is charged to the extent possible in advance of these events. (Further, presumably prices would be high during these types of reliability events so that the dispatch of storage for economics also would satisfy reliability objectives).

Module	Methodology
Demand Response Resources	The model dispatches demand response if there is still insufficient generating capacity to meet load even after storage. Demand response is the resource of last resort since demand response programs often have a limitation on the number of times they can be called upon over a set period of time. For this study, demand response was modeled using a maximum of 10 calls per year, with each call lasting for a maximum of 4 hours.

To the extent the portfolio of resources whose availability is determined through the steps above is insufficient to meet demand in any hour, a loss of load event is recorded. After simulating hundreds of years of possible Monte Carlo outcomes, RECAP calculates the system's LOLE and a variety of other reliability statistics.

A.3.3 EFFECTIVE LOAD CARRYING CAPABILITY CALCULATION

The simulation of LOLE for a given electric system enables the calculation of "effective load carrying capability" (ELCC) for individual resources, or, in more colloquial terms, their capacity value: a measure of the equivalent amount of "perfect capacity" that could be replaced with the addition of a specified resource while maintaining the same level of reliability. ELCC for individual resources (or combinations of resources) is calculated through iterative simulations of an electric system:

1. The LOLE for the electric system without the specified resource is simulated. If the resulting LOLE does not match the specified reliability target, the system "adjusted" to meet a target reliability standard (most commonly, one day in ten years). This adjustment occurs through the addition (or removal) of perfect capacity resources to achieve the desired reliability standard.
2. The specified resource is added to the system and LOLE is recalculated. This will result in a reduction in the system's LOLE, as the amount of available generation has increased.
3. Perfect capacity resources are removed from the system until the LOLE returns to the specified reliability target. The amount of perfect capacity removed from the system represents the ELCC of the specified resource (measured in MW); this metric can also be translated to percentage terms by dividing by the installed capacity of the specified resource.

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This approach can be used to determine the ELCC of any specific resource type evaluated within the model. In general, ELCC is not widely used to measure capacity value for firm resources (which are generally rated either at their full or unforced capacity) but provides a useful metric for characterizing the capacity value of renewable, storage, and demand response resources.

The ELCC of a resource depends not only on the characteristics of load in a specific area (i.e. how coincident its production is with load) but also upon the resource mix of the existing system (i.e. how it interacts with other resources). For instance, ELCCs for variable renewable resources are generally found to be higher on systems with large amounts of inherent storage capability (e.g. large hydro systems) than on systems that rely predominantly on thermal resources and have limited storage capability. ELCCs for a specific type of resource are also a function of the penetration of that resource type; in general, most resources exhibit declining capacity value with increasing scale. This is generally a result of the fact that continued addition of a single resource or technology will lead to saturation when that resource is available and will shift reliability events towards periods when that resource is not available. The diminishing impact of increasing solar generation as the net peak shifts to the evening illustrates this effect.

A.3.4 PLANNING RESERVE MARGIN CALCULATION

The results of RECAP can also be translated into a simpler and more widely used planning reserve margin requirement (PRM), a target for system reliability expressed as a percentage requirement above expected peak demand. PRM requirements are used by many utilities and RTOs in their administration of resource adequacy requirements. Thus, RECAP also expresses its outputs in terms of the PRM:

- The “actual” PRM of a system is calculated based on the summation of capacity provided by all resources; firm resources are rated at nameplate capacity, while hydro, variable, and use-limited resources are rated based on ELCC endogenously calculated as described above. This total amount of capacity is divided by the expected peak to provide a planning reserve margin.

- The "target" PRM of a system (i.e. the PRM needed to achieve a corresponding specified LOLE target) is calculated by adjusting the starting system as needed with perfect capacity resources to achieve the desired LOLE. The PRM for this adjusted system then represents the reserve margin needed to meet the comparable LOLE standard.

A.4 Key Model Outputs

A primary benefit of the RECAP model is the ability to produce an array of summary results that give insight into system reliability and the nature of frequency, magnitude, and duration of loss of load events on an electric system. The summary reliability statistics produced include:

- **Loss of load expectation (LOLE, measured in days per year),** the expected number of days in which loss-of-load events occur in each year;
- **Loss of load hours (LOLH, measured in hours per year),** the expected number of hours of lost load in each year;
- **Loss of load events (LOLEV, measured in events per year),** the expected number of reliability events that occur within each year;
- **Annual loss of load probability (ALOLP, measured in %),** the probability that at least one loss-of-load event will occur within a year; and
- **Expected unserved energy (EUE, measured in MWh per year),** the expected amount of unserved load within each year.

RECAP also produces a number of metrics that help translate these detailed reliability statistics into a more typical planning reserve margin framework. If the user specifies a specific reliability target (for example 0.1 days/yr LOLE, or "one day in ten years"), the model calculates the required quantity of capacity necessary to achieve that level of reliability through an internal search algorithm. Comparing the required quantity of capacity to the median (1-in-2) peak load yields the target planning reserve margin while comparing it to the quantity of existing firm capacity on the system yields a net capacity shortage. Included in this measure

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of firm capacity is the effective load carrying capability (ELCC) of all non-firm resources including wind, solar, hydro, demand response, and battery storage.

Appendix B. RESOLVE Methodology

B.1 Overview

RESOLVE is a resource investment model that uses linear programming to identify optimal long-term generation and transmission investments in an electric system, subject to reliability, technical, and policy constraints. Designed specifically to address the capacity expansion questions for systems seeking to integrate large quantities of variable resources, RESOLVE layers capacity expansion logic on top of a production cost model to determine the least-cost investment plan, accounting for both the up-front capital costs of new resources and the variable costs to operate the grid reliably over time. In an environment in which most new investments in the electric system have fixed costs significantly larger than their variable operating costs, this type of model provides a strong foundation to identify potential investment benefits associated with alternative scenarios.

RESOLVE's optimization capabilities allow it to select from among a wide range of potential new resources. In general, the options for new investments considered in this study are limited to those technologies that are commercially available today. This approach ensures that the greenhouse gas reduction portfolios developed in this study can be achieved without relying on assumed future technological breakthroughs. At the same time, it means that emerging technologies that could play a role in a low-carbon future for the Midwest—for instance, small modular nuclear reactors—are not evaluated within this study. This modeling choice is not meant to suggest that such emerging technologies should not have a role in meeting regional greenhouse gas reduction goals, but instead reflects a simplifying assumption made in this study. The full range of resource options considered by RESOLVE in this study is shown in Table B-1.

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Table B-1. Resource options considered in RESOLVE

Resource Option	Examples of Available Options	Functionality
Natural Gas Generation	• Simple cycle gas turbines • Reciprocating engines • Combined cycle gas turbines	• Dispatches economically based on heat rate, subject to ramping limitations • Contributes to meeting minimum generation and ramping constraints
Renewable Generation	• Solar PV • Wind • Biogas	• Dynamic downward dispatch (with cost penalty) of renewable resources to help balance load
Energy Storage	• Batteries (>1 hr)	• Stores excess energy for later dispatch • Contributes to meeting minimum generation and ramping constraints
Energy Efficiency	• HVAC • Lighting • Dryer, refrigeration, etc.	• Reduces load, retail sales, planning reserve margin need
Demand Response	• Saver's Switch • Interruptible tariff • Critical Peak Pricing	• Contributes to planning reserve margin needs

B.2 Operational Simulation

To identify optimal investments in the electric sector, maintaining a robust representation of prospective resources' impact on system operations is fundamental to ensuring that the value each resource provides to the system is captured accurately. At the same time, the addition of investment decisions across multiple periods to a traditional unit commitment problem increases its computational complexity significantly. RESOLVE's simulation of operations has therefore been carefully designed to simplify traditional unit commitment problem where possible while maintaining a level of detail

sufficient to provide a reasonable valuation of potential new resources. The key attributes of RESOLVE's operational simulation are enumerated below:

- **Hourly chronological simulation:** RESOLVE's representation of system operations uses an hourly resolution to capture the intraday variability of load and renewable generation. This level of resolution is necessary in a planning-level study to capture the intermittency of potential new wind and solar resources, which are not available at all times of day to meet demand and must be supplemented with other resources.
- **Aggregated generation classes:** rather than modeling each generator within the study footprint independently, generators in each region are grouped together into categories with other plants whose operational characteristics are similar (e.g. nuclear, coal, gas CCGT, gas CT). Grouping like plants together for the purpose of simulation reduces the computational complexity of the problem without significantly impacting the underlying economics of power system operations.
- **Linearized unit commitment:** RESOLVE includes a linear version of a traditional production simulation model. In RESOLVE's implementation, this means that the commitment variable for each class of generators is a continuous variable rather than an integer variable. Additional constraints on operations (e.g. Pmin, Pmax, ramp rate limits, minimum up and down time) further limit the flexibility of each class' operations.
- **Zonal transmission topology:** RESOLVE uses a zonal transmission topology to simulate flows among the regions represented in the analysis as model zones. In this study RESOLVE includes four zones: Xcel's Upper Midwest territory, NSP – the Primary Zone; MISO Load Resource Zone (LRZ) 1, MISO LRZ2, and MISO LRZ3. Given Xcel's territory exists primarily in MISO LRZ1, the NSP zone can only interact with LRZ1; while LRZ1 has ties to both LRZ2 and LRZ3.
- **Co-optimization of energy and ancillary services:** RESOLVE dispatches generation to meet load across the modeled regions, while simultaneous reserving flexible capacity within the Primary Zone to meet the contingency and flexibility reserve needs. As systems become increasingly constrained on flexibility, the inclusion of ancillary service needs in the dispatch problem is necessary to ensure a reasonable dispatch of resources that can serve load reliably.

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- **Smart sampling of days:** whereas production cost models are commonly used to simulate an entire calendar year (or multiple years) of operations, RESOLVE simulates the operations of the modeled system for a number of sampled independent days. Load, wind, and solar profiles for these selected days, sampled from the historical meteorological record over a specified period, are selected and assigned weights so that taken in aggregate, they produce a reasonable representation of complete distributions of potential conditions.[9] This allows RESOLVE to approximate annual operating costs and dynamics while simulating operations for only the selected days. In this study, a sample of 37 days is used, based on historical meteorological record from 2009 to 2012.
- **Hydro dispatch informed by historical operations:** RESOLVE captures the inherent limitations of the generation capability of the hydroelectric system by deriving constraints from actual operational data. Three types of constraints govern the operation of the hydro fleet as a whole: (1) daily energy budgets, which limit the amount of hydro generation in a day;[10] (2) maximum and minimum hydro generation levels, which constrain the hourly hydro generation; and (3) maximum multi-hour ramp rates, which limit the rate at which the output of the collective hydro system can change its output across periods from one to four hours. Collectively, these constraints limit the generation of the hydro fleet to reflect seasonal limits on water availability, downstream flow requirements, and non-power factors that impact the operations of the hydro system. The derivation of these constraints from actual hourly operations makes this representation of hydro operations conservative with respect to the amount of potential flexibility in the resource.

[9] An optimization algorithm is used to select the days and identify the weight for each day such that distributions of load, net load, wind, and solar generation match long-run distributions. For further detail on the smart sampling algorithm used in RESOLVE, see **Error! Reference source not found.**.

[10] Sometimes hydro operators can shift hydro energy from day to day: for example, if hydro operators know that tomorrow will be a peak day, they can save some hydro energy today and use them tomorrow to meet the system need. This flexibility can help integrating renewable into the system and it is going to be more and more valuable as the % of system renewable penetration increases. To capture this flexibility, model allows up to 5% of the hydro energy in each day to be shifted around within two months.

B.3 Additional Constraints

RESOLVE layers investment decisions on top of the operational model described above. Each new investment identified in RESOLVE has an impact on how the system operates; the portfolio of investments, as a whole, must satisfy a number of additional conditions.

- **Planning reserve margin:** When making investment decisions, RESOLVE requires the portfolio to include enough firm capacity to meet 1-in-2 system peak plus an additional specified amount of planning reserve margin (PRM) requirement. The contribution of each resource type towards this requirement depends on its attributes and varies by type: for instance, variable renewables are discounted more compared to thermal generations because the uncertainties of generation during peak hours. In this study, a PRM requirement of 3% is used for the Xcel Upper Midwest system.
- **Renewables Portfolio Standard (RPS) requirement:** RPS requirements have become the most common policy mechanism in the United States to encourage renewable development. RESOLVE enforces an RPS requirement as a percentage of retail sales to ensure that the total quantity of energy procured from renewable resources meets the RPS target in each year.
- **Greenhouse gas cap:** RESOLVE also allows users to specify and enforce a greenhouse gas constraint on the resource portfolio for a region. As the name suggests, the emission cap type policy requires that annual emission generated in the entire system to be less than or equal to the designed maximum emission cap. This type of policy is usually implemented by having limited amount of emission allowances within the system. As a result, thermal generators need to purchase allowances for the carbon they produced from the market or from carbon-free generators.
- **Resource potential limitations:** Many potential new resources are limited in their potential for new development. This is particularly true for renewable resources such as wind and solar. RESOLVE enforces limits on the maximum potential of each new resource that can be included in the portfolio, imposing practical limitations on the amount of any one type of resource that may be developed.

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RESOLVE considers each of these constraints simultaneously, selecting the combination of new generation resources that adheres to these constraints while minimizing the sum of investment and operational costs.

B.4 Key Model Outputs

RESOLVE produces a large amount of results from technology level unit commitment decisions to total carbon emission in the system. This extensive information gives users a complete view of the future system and makes RESOLVE versatile for different analysis. The following list of outputs is produced by RESOLVE and are the subject of discussion and interpretation in this study:

- **Total revenue requirement ($/yr):** The total revenue requirement reports the total costs incurred by utilities in the study footprint to provide service to its customers. This study focuses on the relative differences in revenue requirement among scenarios, generally measuring changes in the revenue requirement relative to the Reference Case. The cost impacts for each scenario comprise changes in fixed costs (capital & fixed O&M costs for new generation resources, incremental energy efficiency, new energy storage devices, and the required transmission resources with the new generation) and operating costs (variable O&M costs, fuel costs, costs of market purchases and revenues from surplus sales).
- **Greenhouse gas emissions (MMTCO2e):** This result summarizes the total annual carbon emission in the system with imports and exports adjustments. By comparing the carbon emissions and total resource costs between different scenarios, we can conclude the relative effectiveness of the strategic measure in enabling carbon reductions.
- **Resource additions for each period (MW):** The selected investment summarizes the cumulative new generation capacity investments by resources type. It provides an overview of what is built to meet both operational and emissions constraints over time.
- **Annual generation by resource type (GWh):** Energy balance shows the annual system load and energy produced by each resource type in each modeled year. It provides insights from a different angle than capacity investments. It can help answer questions like: Which types of

resources are dispatched more? How do the dispatch behaviors change over the years? And how do curtailment, imports, and exports vary year by year?

+ **Renewable curtailment (GWh):** RESOLVE estimates the amount of renewable curtailment that would be expected in each year of the analysis as a result of "oversupply"—when the total amount of must-run and renewable generation exceeds regional load plus export capability—based on its hourly simulation of operations. As the primary renewable integration challenge at high renewable penetrations, this measure is a useful proxy for renewable integration costs.
+ **Wholesale market prices ($/MWh):** outputs from RESOLVE can be used to estimate wholesale market prices on an hourly basis. As an optimization model, RESOLVE produces "shadow prices" in each hour that represent the marginal cost of generation given all the resources available at the time; these marginal costs serve as a proxy for wholesale market prices.
+ **Average greenhouse gas abatement cost ($/metric ton):** RESOLVE results can also be used to estimate average and marginal costs of greenhouse gas abatement by comparing the amount of greenhouse gas abatement achieved (relative to a Reference Case) and the incremental cost (relative to that same case).

For this study, most results focus on the snapshots of the system in 2030 and 2045, which correspond to key milestones for Xcel. However, in some cases, intermediate results are also presented when relevant to the study's objectives and key messages.

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Appendix C. Additional Inputs & Assumptions

C.1 Load & Renewable Profiles

C.1.1 PROFILE DEVELOPMENT

Xcel provided hourly load information from 2009 – 2012 for the Upper Midwest system. These loads were normalized to create a shape based on real data that could be applied to forecasted peak and demand for the study. While we acknowledge that these hourly profiles will change in the future, the statistical methods used in the RESOLVE day sampling methodology and RECAP neural network capture realistic relationships between load and renewable generation – all driven primarily by weather patterns – that should remain consistent in the future. For the portions of future load growth that represent inherently different characteristics than seen today – namely, electric space heating, electric water heating, and electric vehicles for the High Electrification sensitivity – the E3 PATHWAYS team worked with Xcel to generate separate load profiles that are layered on top of the base load discussed. PATHWAYS, which is a stock rollover model developed by E3 used to analyze economy-wide pathways to achieve deep decarbonization goals, was used to forecast the gross levels of electrification loads. These Minnesota-wide loads were scaled down proportionally for the Xcel Upper Midwest system, but the hourly profiles for each technology stayed consistent.

Hourly profiles for wind and solar generation are derived from the National Renewable Energy Laboratory's (NREL) WIND Toolkit and Solar Prospector, respectively (see Figure C-1), for the same set of load years. The WIND Toolkit provides simulated output for a large number of selected sites throughout the western United States derived using a mesoscale weather model. The Solar Prospector provides historical hourly irradiance data, which is used to simulate the output of hypothetical solar PV plants throughout the west. Various sites were chosen to create aggregate profiles that represent different

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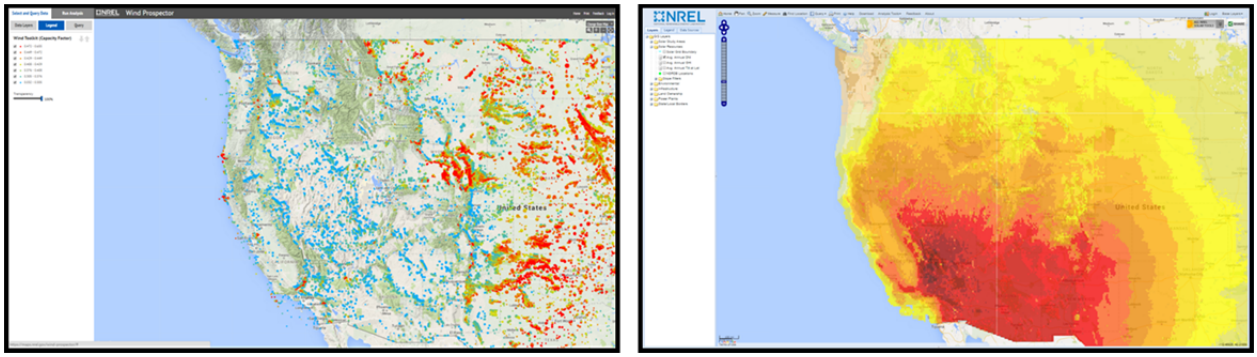
regions in the broad Xcel Upper Midwest service territory. These sites were screened and aggregated considering general location, MISO LRZ, and relatively close-by transmission interconnections. This resulted in four representative regions in Minnesota, two in Wisconsin, four in Iowa, and four in North Dakota. Each region was assigned a unique solar and wind profile. Both wind and solar profiles used in this study are scaled to match anticipated regional capacity factors.

Figure C-1. Screenshots from NREL's Wind Prospector (left) and Solar Prospector (right)



C.1.2 RECAP NEURAL NETWORK

As is often the case, the historical load record available to Xcel is far exceeded by historical weather data. RECAP relies on a neural network model to predict load given the relationship observed between real weathers and load data. Given a set of temporally matching historical temperature and load, the neural network develops a regression model by which it can then use to predict historical load given temperature data and other predictor data. In doing so, the available load data is effectively extended from a few years to fifty years or more.

E3 modeled hourly load in Xcel under consistent set of economic conditions using the weather years 1950-2012 using a neural network model. This process develops a relationship between recent daily load and the following independent variables:

- Max and min daily temperature (including one and two-day lag)
- Month (+/- 15 calendar days)
- Day-type (weekday/weekend/holiday)
- Day index for economic growth or other linear factor over the recent set of load data

The neural network model establishes a relationship between daily load and the independent variables by determining a set of coefficients to different nodes in hidden layers which represent intermediate steps in between the independent variables (temp, calendar, day index) and the dependent variable (load). The model trains itself through a set of iterations until the coefficients converge. Using the relationship established by the neural network, the model calculates daily load for all days in the weather record (1950-2012) under 2012 economic conditions. The final step converts these daily load totals into hourly loads. To do this, the model searches over the actual recent load data (4 years) to find the day that is closest in total daily load to the day that needs an hourly profile. The model is constrained to search within identical day-type (weekday/weekend/holiday) and +/- 15 calendar days when making the selection. The model then applies this hourly load profile to the daily load MWh.

This hourly load profile for the weather years 1950-2012 under 2012 economic conditions is then scaled to match the load forecast for future years in which RECAP is calculating reliability. This ”base” load profile only captures the loads that are present on the electricity system today and do not very well capture systematic changes to the load profile due to increased adoption of electric vehicles, building space and water heating, industrial electrification. Load modification through demand response is captured through explicit analysis of this resource.

Operating reserves of 200 MW are also added onto load in all hours with the assumption being that the system operator will shed load in order to maintain operating reserves of at least 200 MW in order to prevent the potentially more catastrophic consequences that might result due to an unexpected grid event coupled with insufficient operating reserves.

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C.1.3 RESOLVE DAY SAMPLING

Computation can be challenging for a model like RESOLVE that makes both investment and operational decisions across a long period of time. To alleviate this challenge, instead of simulating the system operation for an entire year, a subset of days is modeled to approximate the annual operating costs. In order to approximate the annual system operating costs while simulating only a subset of the number of days in a year, RESOLVE relies on a pre-processing sampling algorithm to select a combination of days whose characteristics are, together, representative of the conditions experienced by an electricity system over the course of multiple years. This pre-processing step uses optimization to sample a subset of conditions that, when taken in aggregate and weighted appropriately, provide a reasonable representation of the breadth of load, wind, and solar conditions observed in the historical record.

A multi-objective optimization model is used to pick a set of days (and associated weights) to match historical conditions for key indicators while also minimizing the number of days selected. The process for selecting the set of representative days follows several steps:

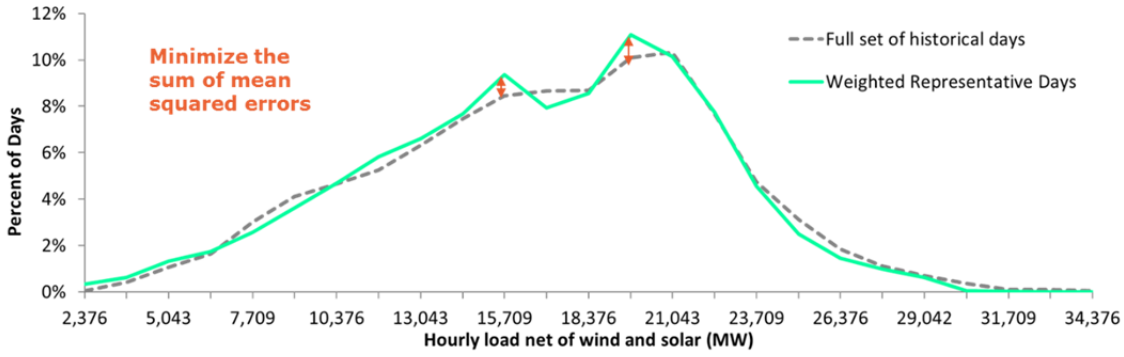
1. **Determine the number and type of days to select:** The user defines the number of days to be selected in the final subset, the minimum day weight to be assigned (so that each day selected has at least a certain importance associated), and optional day types for categorizing different selected days.
2. **The candidate pool of days is created:** Load, wind, and solar profiles are sampled from timeseries data as a representative sample of shapes. In the 2016 PSIP cases, we used simulated 2016 data for the representative sample; however, the algorithm can use multiple years of data to capture different weather years within its sample.
3. **Key variables are selected:** Key variables are selected as indicators for system conditions. In this study, the variables used to characterize the representation of a sample include: (1) distributions of hourly and daily load, net load, wind, and solar production; (2) distribution of hourly ramps of load net of wind and solar; (3) number of days per month; and (4) site-specific annual capacity factors for wind and solar profiles. These variables can also be weighted

differently, which allows the optimization model to prioritize the more important variables with higher weights when matching the distribution. This study prioritizes fit on the distributions for load, wind, and hydro conditions, as these three factors have a significant effect on the operations of the electric system.

4. **Optimization model selects an optimal set of days: From the candidate pool of days established in the first step, the optimization selects a set of days while minimizing the absolute errors for each of the criteria. If optional day types have been assigned by the user, t**he day selection algorithm will attempt to select at least one of each day type in the final sample. **The output from the optimization algorithm includes a set of days, as well as associated weights through which those days may be weighted to represent a** historic average year.

An optimization model is used in the day sampling process. As shown in Figure C-2 below, one component of the minimization is the alignment between historical and sampled hourly load distributions: the distribution of historical hourly net load is plotted as dotted gray line in the chart, and the model selects and weights a subset of days to match the historical distributions.

Figure C-2. Example of net load distribution



The mathematical formulation to minimize absolute error is show below:

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min: $$\sum_{b \in Bins} \left| OverallFreq_b - \sum_{d \in Days} \left(weight_d \times DailyFreq_{d,b} \right) \right|$$

subject to:

$$\sum_{d \in Days} weight_d = 1$$

$$weight_d \geq LowerBound \quad \forall\, d \in Days$$

$$SelectedDayIndicator_d \geq weight_d \quad \forall\, d \in Days$$

$$\sum_{d \in DayTypes(d)} SelectedDayIndicator_d \geq 1 \quad \forall\, DayTypes$$

where:

Bins = set of bins in histogram of criteria timeseries

Days = set of days in the historical timeseries

Overall Freq $_b$ = historical frequency of bin across timeseries

Daily Freq $_{d,b}$ = historical frequency in each day

TUNING = tuning parameter value

weight $_d$ = normalized weight for each day

The day sampling process yielded a set of days that show very small deviations from the historical distributions. The details for each of these days—the calendar days used for load, wind, and solar PV, and the associated weight attributed to the day—are shown in Table -1. Figure C-3 shows the comparison of distribution between the full set of candidate days and the representative days.

Table -1. Details for 37 days sampled for operational simulation in RESOLVE

Day Index	Weather Date	Day Weight	Day Index	Weather Date	Day Weight
1	12/22/2009	20.0	20	6/16/2012	10.4
2	8/26/2011	17.2	21	10/9/2010	9.4
3	10/26/2012	16.8	22	9/21/2012	8.4
4	5/10/2012	16.6	23	7/31/2009	7.3
5	4/17/2012	15.1	24	5/13/2010	7.0
6	4/2/2011	14.8	25	5/23/2010	7.0
7	2/27/2012	14.5	26	7/4/2011	6.0
8	3/9/2012	14.2	27	11/27/2010	5.8
9	6/12/2009	13.9	28	1/16/2011	5.7
10	1/17/2012	13.1	29	6/1/2011	5.6
11	7/13/2012	12.9	30	12/19/2010	5.5
12	11/18/2010	12.6	31	12/29/2011	5.5
13	1/2/2009	12.2	32	10/7/2010	4.8
14	3/22/2009	12.2	33	3/27/2010	4.7
15	11/14/2011	11.5	34	7/17/2010	4.1
16	2/10/2012	11.5	35	7/16/2012	3.1
17	8/5/2012	11.4	36	2/25/2012	2.3
18	9/11/2012	10.8	37	5/14/2009	0.4
19	9/9/2012	10.8	**Total**		**365.0**

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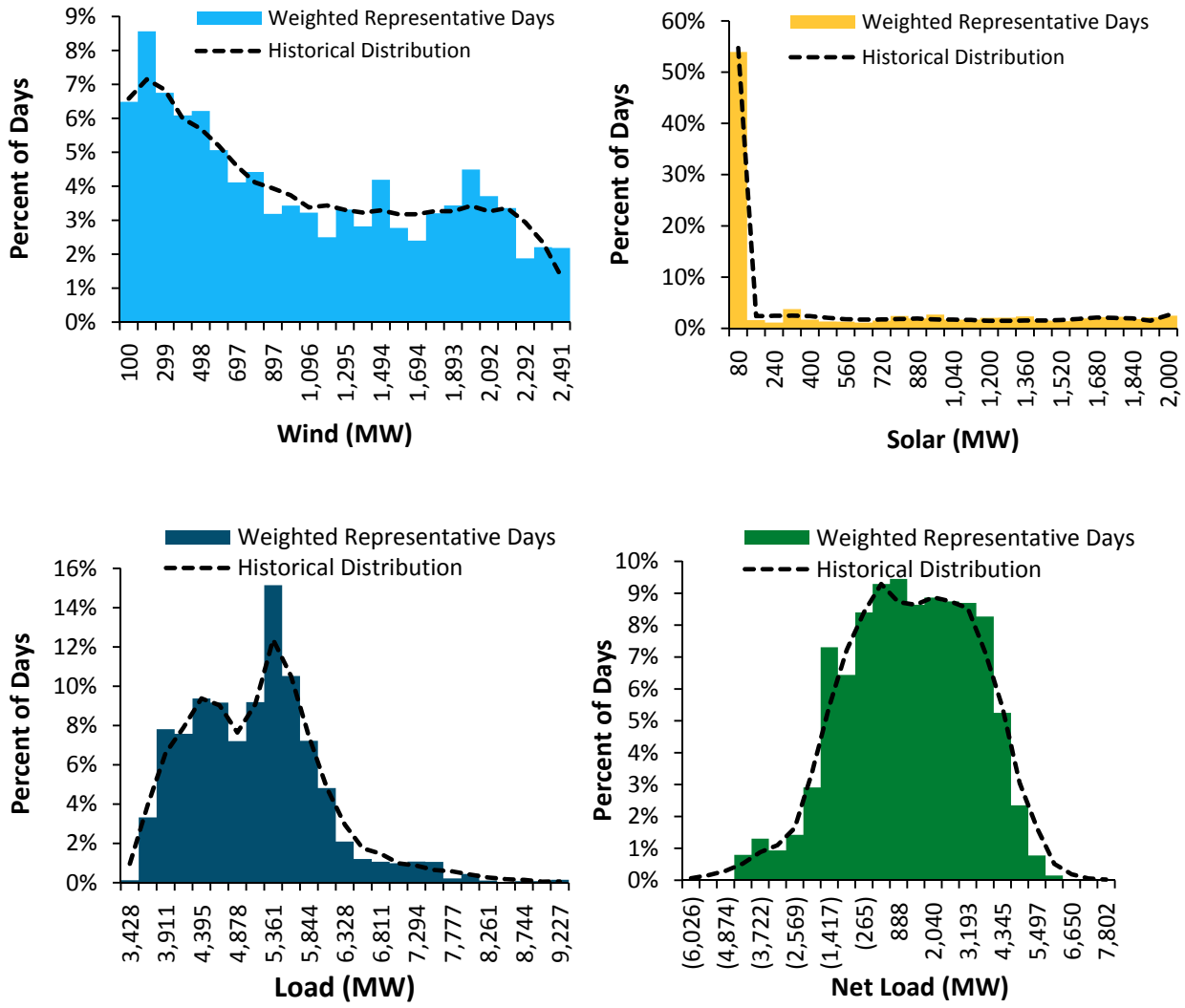
Figure C-3. The hourly distribution of wind, solar, load, and net load for historical and representative days



C.2 External Load & Resources

In this study, three MISO Load Resource Zones (LRZ) were modeled to represent Xcel Upper Midwest's interaction with the broader MISO market. The demand forecast for the external zones was based on data from the 2017 MISO Independent Load Forecast Update.[11] The assumed existing and planned resource portfolio was based on MISO's "Continued Fleet Change" in its 2018 MTEP report. The MTEP report only contains data till 2032, so beyond that this study assumes that coal plant retirements are replaced with natural gas combustion turbine generators.

Table C-2, Table C-3, and Table C-4 below show a summary of the load and resource assumptions for the three MISO zones modeled.

[11] MISO Independent Load Forecast Update, available at: https://www.purdue.edu/discoverypark/sufg/miso/reports-presentations.php

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Table C-2. Load and resource assumptions for MISO LRZ 1*

	2018	2020	2025	2030	2035	2040	2045
Annual Energy (GWh)	59,791	60,390	61,915	63,478	65,081	66,725	68,409
Annual Peak Demand (MW)	9,608	9,704	9,949	10,201	10,458	10,722	10,993
				Installed Capacity (MW)			
Technology	**2018**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**
Nuclear	-	-	-	-	-	-	-
Coal	4,506	4,010	3,624	3,160	3,160	1,735	138
Gas	2,874	2,874	3,654	4,613	4,604	6,277	8,150
Biomass	225	225	225	225	225	225	225
Hydro	252	252	252	252	252	252	252
Wind	3,201	3,201	3,451	4,415	4,975	4,975	4,975
Solar	146	146	206	329	583	583	583
Storage	-	-	-	-	-	-	-
DR	559	559	559	587	645	645	645
Total	**11,267**	**11,267**	**11,971**	**13,580**	**14,443**	**14,691**	**14,968**

***The load and resources report here do not include resources owned or contracted by Xcel to serve its Upper Midwest customers**

Table C-3. Load and resource assumptions for MISO LRZ 2

	2018	2020	2025	2030	2035	2040	2045
Annual Energy (GWh)	69,451	69,729	70,429	71,136	71,850	72,572	73,301
Annual Peak Demand (MW)	13,029	13,081	13,213	13,345	13,479	13,614	13,751
				Installed Capacity (MW)			
Technology	**2018**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**
Nuclear	1,203	1,203	1,203	1,203	1,203	1,203	1,203
Coal	6,923	5,735	5,026	4,167	4,093	2,659	2,289
Gas	7,882	8,584	8,520	8,977	9,130	10,702	10,435
Biomass	105	105	105	105	105	105	105
Hydro	381	381	381	381	381	381	374
Wind	1,074	1,074	1,190	1,409	1,630	1,630	1,630
Solar	2	2	82	243	614	614	614
Storage	-	-	-	-	-	-	-
DR	1.211	1,441	1,441	1,501	1,630	1,630	1,630
Total	**18,780**	**18,524**	**17,947**	**17,986**	**18,786**	**18,924**	**18,280**

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Table C-4. Load and resource assumptions for MISO LRZ 3

	2018	2020	2025	2030	2035	2040	2045
Annual Energy (GWh)	47,939	48,323	49,298	50,291	51,305	52,340	53,395
Annual Peak Demand (MW)	8,922	8,994	9,175	9,360	9,549	9,741	9,937
				Installed Capacity (MW)			
Technology	**2018**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**
Nuclear	640	640	640	640	640	640	640
Coal	5,140	5,140	4,927	4,654	4,619	2,473	839
Gas	3,603	3,603	3,849	4,499	4,714	6,989	8,508
Biomass	7	7	7	7	7	7	7
Hydro	7	7	7	7	7	7	7
Wind	7,106	7,306	7,610	8,929	10,100	10,100	10,100
Solar	8	8	140	404	860	860	860
Storage	-	-	-	-	-	-	-
DR	684	684	684	720	798	798	798
Total	**17,194**	**17,394**	**17,864**	**19,860**	**21,745**	**21,875**	**21,759**

Appendix D. Detailed Scenario Results

This section shows detailed results for each scenario and sensitivity analyzed.

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D.1 Base Case Portfolios

Table D-1. Total installed capacity in 2030 by scenario (MW)

Scenario ID	Nuclear	Coal	Gas CCGT	Gas CT	Biomass	Hydro	Solar	Wind	Storage	DR	Energy Efficiency
Reference	1,738	1,028	3,009	984	30	291	2,627	4,320	150	1,532	887
Scenario 1	1,738	1,028	3,009	984	30	291	4,097	5,830	1,876	1,532	887
Scenario 2	1,738	517	3,009	1,141	30	291	2,627	4,320	531	1,532	887
Scenario 3	1,738	—	3,009	1,882	30	291	2,627	4,320	286	1,532	887
Scenario 4	1,738	1,028	3,009	984	30	291	3,977	5,467	2,035	1,532	1,027
Scenario 5	1,738	517	3,009	984	30	291	2,627	4,320	438	1,532	1,027
Scenario 6	1,738	—	3,009	984	30	291	2,627	4,320	892	1,532	1,101
Scenario 7	1,738	1,028	2,174	984	30	291	3,821	5,283	2,159	1,532	1,148
Scenario 8	1,738	517	2,174	984	30	291	2,627	4,320	1,154	1,532	1,148
Scenario 9	1,738	—	2,174	984	30	291	2,627	4,320	1,801	1,666	1,148
Scenario 10	1,738	1,028	3,009	984	30	291	4,254	5,723	1,924	1,532	887
Scenario 11	1,738	517	3,009	1,141	30	291	2,627	4,320	531	1,532	887
Scenario 12	1,738	—	3,009	1,882	30	291	2,627	4,320	286	1,532	887
Scenario 13	1,738	1,028	3,009	984	30	291	4,113	5,988	2,126	1,532	887
Scenario 14	1,738	517	3,009	1,141	30	291	2,627	4,320	531	1,532	887
Scenario 15	1,738	—	3,009	1,882	30	291	2,627	4,320	286	1,532	887
Scenario 16	646	1,028	3,009	984	30	291	5,181	7,907	2,387	1,532	887
Scenario 17	646	517	3,009	1,375	30	291	4,055	4,930	1,063	1,532	887
Scenario 18	646	—	3,009	2,520	30	291	3,435	4,320	531	1,532	887
Scenario 19	1,738	1,028	3,009	984	30	291	4,194	5,906	2,252	1,532	887
Scenario 20	1,738	517	3,009	984	30	291	2,627	4,320	718	1,532	887
Scenario 21	1,738	—	3,009	984	30	291	2,627	4,320	1,273	1,666	887

Table D-2. Total installed capacity in 2045 by scenario (MW)

Scenario ID	Nuclear	Coal	Gas CCGT	Gas CT	Biomass	Hydro	Solar	Wind	Storage	DR	Energy Efficiency
Reference	—	—	2,711	3,518	4	278	4,703	3,995	1,599	1,419	1,178
Scenario 1	—	—	2,711	1,690	4	278	7,252	8,706	3,032	1,419	1,178
Scenario 2	—	—	2,711	1,938	4	278	6,727	8,147	2,786	1,419	1,178
Scenario 3	—	—	2,711	2,105	4	278	6,386	8,357	2,484	1,419	1,178
Scenario 4	—	—	2,711	232	4	278	9,182	7,953	4,968	2,020	1,416
Scenario 5	—	—	2,711	232	4	278	9,260	6,872	5,636	2,096	1,416
Scenario 6	—	—	2,711	232	4	278	8,696	6,653	5,589	2,096	1,490
Scenario 7	—	—	1,876	232	4	278	10,002	7,654	8,346	2,096	1,537
Scenario 8	—	—	1,876	232	4	278	10,952	6,054	8,984	2,096	1,537
Scenario 9	—	—	1,876	232	4	278	11,213	5,881	8,885	2,096	1,537
Scenario 10	646	—	2,711	1,457	4	278	6,150	7,668	2,819	1,419	1,178
Scenario 11	646	—	2,711	1,672	4	278	6,366	6,772	2,484	1,419	1,178
Scenario 12	646	—	2,711	1,850	4	278	5,840	6,975	2,273	1,419	1,178
Scenario 13	1,738	—	2,711	1,108	4	278	4,399	5,807	2,434	1,419	1,178
Scenario 14	1,738	—	2,711	1,269	4	278	5,023	4,907	2,187	1,419	1,178
Scenario 15	1,738	—	2,711	1,478	4	278	4,688	5,085	1,867	1,419	1,178
Scenario 16	—	—	2,711	1,693	4	278	7,220	8,716	3,032	1,419	1,178
Scenario 17	—	—	2,711	1,938	4	278	6,727	8,147	2,786	1,419	1,178
Scenario 18	—	—	2,711	2,105	4	278	6,386	8,357	2,484	1,419	1,178
Scenario 19	1,738	—	2,711	232	4	278	5,544	5,636	3,484	2,020	1,178
Scenario 20	1,738	—	2,711	232	4	278	6,783	4,484	3,726	1,789	1,178
Scenario 21	1,738	—	2,711	232	4	278	6,634	4,471	3,499	2,020	1,178

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D.2 Sensitivity Analysis Portfolios

Table D-3. Total installed capacity in 2045 by scenario (Low Gas sensitivity) (MW)

Scenario ID	Nuclear	Coal	Gas CCGT	Gas CT	Biomass	Hydro	Solar	Wind	Storage	DR	Energy Efficiency
Reference	—	—	2,711	3,948	4	278	2,688	3,995	1,558	1,419	1,178
Scenario 1	—	—	2,711	1,722	4	278	6,930	8,672	3,104	1,419	1,178
Scenario 2	—	—	2,711	1,947	4	278	6,185	8,207	2,967	1,419	1,178
Scenario 3	—	—	2,711	2,174	4	278	5,726	8,437	2,568	1,419	1,178
Scenario 4											
Scenario 5											
Scenario 6	—	—	2,711	232	4	278	8,682	6,114	5,589	2,096	1,537
Scenario 7											
Scenario 8											
Scenario 9	—	—	1,876	232	4	278	11,323	5,282	9,446	2,096	1,537
Scenario 10											
Scenario 11											
Scenario 12	646	—	2,711	1,830	4	278	5,138	7,108	2,484	1,419	1,178
Scenario 13											
Scenario 14											
Scenario 15	1,738	—	2,711	1,464	4	278	4,274	5,084	2,007	1,419	1,178
Scenario 16											
Scenario 17											
Scenario 18											
Scenario 19											
Scenario 20											
Scenario 21											

Table D-4. Total installed capacity in 2045 by scenario (High Gas sensitivity) (MW)

Scenario ID	Nuclear	Coal	Gas CCGT	Gas CT	Biomass	Hydro	Solar	Wind	Storage	DR	Energy Efficiency
Reference	—	—	2,711	2,650	4	278	6,650	6,543	1,863	1,419	1,178
Scenario 1	—	—	2,711	1,633	4	278	7,496	8,827	3,023	1,419	1,178
Scenario 2	—	—	2,711	1,791	4	278	7,469	8,307	2,790	1,419	1,178
Scenario 3	—	—	2,711	1,978	4	278	7,112	8,369	2,484	1,419	1,178
Scenario 4											
Scenario 5											
Scenario 6	—	—	2,711	232	4	278	8,672	8,180	5,042	2,096	1,416
Scenario 7											
Scenario 8											
Scenario 9	—	—	1,876	232	4	278	11,179	7,219	7,454	2,096	1,537
Scenario 10											
Scenario 11											
Scenario 12	646	—	2,711	1,648	4	278	6,600	7,297	2,338	1,419	1,178
Scenario 13											
Scenario 14											
Scenario 15	1,738	—	2,711	1,289	4	278	5,510	5,545	1,863	1,419	1,178
Scenario 16											
Scenario 17											
Scenario 18											
Scenario 19											
Scenario 20											
Scenario 21											

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Table D-5. Total installed capacity in 2045 by scenario (Low Technology Cost sensitivity) (MW)

Scenario ID	Nuclear	Coal	Gas CCGT	Gas CT	Biomass	Hydro	Solar	Wind	Storage	DR	Energy Efficiency
Reference	—	—	2,711	1,883	4	278	7,688	7,208	2,842	1,419	1,178
Scenario 1	—	—	2,711	1,346	4	278	7,705	8,971	3,676	1,419	1,178
Scenario 2	—	—	2,711	1,561	4	278	7,688	8,453	3,221	1,419	1,178
Scenario 3	—	—	2,711	1,619	4	278	7,688	8,380	3,081	1,419	1,178
Scenario 4											
Scenario 5											
Scenario 6	—	—	2,711	232	4	278	9,368	8,431	5,866	2,020	1,276
Scenario 7											
Scenario 8											
Scenario 9	—	—	1,876	232	4	278	11,119	7,995	8,202	2,096	1,416
Scenario 10											
Scenario 11											
Scenario 12	646	—	2,711	1,264	4	278	7,350	7,156	2,940	1,419	1,178
Scenario 13											
Scenario 14											
Scenario 15	1,738	—	2,711	806	4	278	6,510	5,374	2,484	1,419	1,178
Scenario 16											
Scenario 17											
Scenario 18											
Scenario 19											
Scenario 20											
Scenario 21											

Table D-6. Total installed capacity in 2045 by scenario (High Technology Cost sensitivity) (MW)

Scenario ID	Nuclear	Coal	Gas CCGT	Gas CT	Biomass	Hydro	Solar	Wind	Storage	DR	Energy Efficiency
Reference	—	—	2,711	5,212	4	278	2,688	3,995	67	1,419	1,178
Scenario 1	—	—	2,711	1,861	4	278	5,971	8,763	2,312	1,419	1,416
Scenario 2	—	—	2,711	2,607	4	278	4,536	8,674	1,847	1,419	1,276
Scenario 3	—	—	2,711	2,960	4	278	4,395	9,035	1,358	1,419	1,276
Scenario 4											
Scenario 5											
Scenario 6	—	—	2,711	232	4	278	8,173	6,791	5,202	2,096	1,563
Scenario 7											
Scenario 8											
Scenario 9	—	—	1,876	232	4	278	11,464	6,301	7,788	2,096	1,563
Scenario 10											
Scenario 11											
Scenario 12	646	—	2,711	2,737	4	278	3,808	7,685	1,152	1,419	1,276
Scenario 13											
Scenario 14											
Scenario 15	1,738	—	2,711	2,514	4	278	3,106	5,840	826	1,419	1,178
Scenario 16											
Scenario 17											
Scenario 18											
Scenario 19											
Scenario 20											
Scenario 21											

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Table D-7. Total installed capacity in 2045 by scenario (High Electrification sensitivity) (MW)

Scenario ID	Nuclear	Coal	Gas CCGT	Gas CT	Biomass	Hydro	Solar	Wind	Storage	DR	Energy Efficiency
Reference	—	—	2,711	10,779	4	278	7,688	4,891	3,418	1,419	1,178
Scenario 1	—	—	2,711	7,935	4	278	7,830	14,893	5,697	1,419	1,178
Scenario 2	—	—	2,711	7,973	4	278	7,688	14,862	5,697	1,419	1,178
Scenario 3	—	—	2,711	7,904	4	278	7,688	14,893	5,894	1,419	1,178
Scenario 4											
Scenario 5											
Scenario 6	—	—	2,711	232	4	278	24,349	9,156	33,603	2,096	1,537
Scenario 7											
Scenario 8											
Scenario 9	—	—	1,876	232	4	278	24,523	9,521	38,809	2,096	1,537
Scenario 10											
Scenario 11											
Scenario 12	646	—	2,711	7,539	4	278	7,688	13,401	5,697	1,419	1,178
Scenario 13											
Scenario 14											
Scenario 15	1,738	—	2,711	7,416	4	278	6,864	11,294	4,709	1,419	1,178
Scenario 16											
Scenario 17											
Scenario 18											
Scenario 19											
Scenario 20											
Scenario 21											

Table D-8. Total installed capacity in 2045 by scenario (Low Export sensitivity) (MW)

Scenario ID	Nuclear	Coal	Gas CCGT	Gas CT	Biomass	Hydro	Solar	Wind	Storage	DR	Energy Efficiency
Reference	—	—	2,711	3,617	4	278	3,740	3,995	1,667	1,419	1,178
Scenario 1	—	—	2,711	1,608	4	278	6,800	8,257	3,679	1,419	1,178
Scenario 2	—	—	2,711	1,992	4	278	5,478	8,238	3,159	1,419	1,178
Scenario 3	—	—	2,711	2,089	4	278	5,110	8,433	3,026	1,419	1,178
Scenario 4											
Scenario 5											
Scenario 6	—	—	2,711	232	4	278	8,074	6,222	6,181	2,096	1,537
Scenario 7											
Scenario 8											
Scenario 9	—	—	1,876	232	4	278	8,901	5,880	11,538	2,096	1,537
Scenario 10											
Scenario 11											
Scenario 12	646	—	2,711	1,746	4	278	4,640	7,063	2,892	1,419	1,178
Scenario 13											
Scenario 14											
Scenario 15	1,738	—	2,711	1,319	4	278	3,771	5,067	2,427	1,419	1,178
Scenario 16											
Scenario 17											
Scenario 18											
Scenario 19											
Scenario 20											
Scenario 21											

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Minnesota Decarbonization Scenarios

The Role of the Electric Sector

June 20, 2019

Prepared for Xcel Energy

By Energy and Environmental Economics, Inc.

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1 Background

The Next Generation Energy Act (NGEA), signed in 2007, sets greenhouse gas (GHG) emission targets for Minnesota of 80% reductions by 2050 relative to 2005 levels with interim targets of 15% reductions by 2015 and 30% reductions by 2025.

Xcel Energy Northern States Power (NSP) hired E3 to develop a set of long-term economy-wide, deep decarbonization scenarios for the state of Minnesota. These scenarios provide an exploration of the cross-sectoral implications of meeting economy-wide carbon reduction goals, and highlight the role of Xcel Energy, and the electric sector as a whole, in meeting the state's economy-wide carbon goal.

This report describes background, modeling approach, and results of the Minnesota economy-wide decarbonization scenario analysis. An additional E3 analysis focusing on Xcel Energy NSP system portfolio and reliability, is discussed in a separate report. The geography of each analysis is shown in Figure 1.

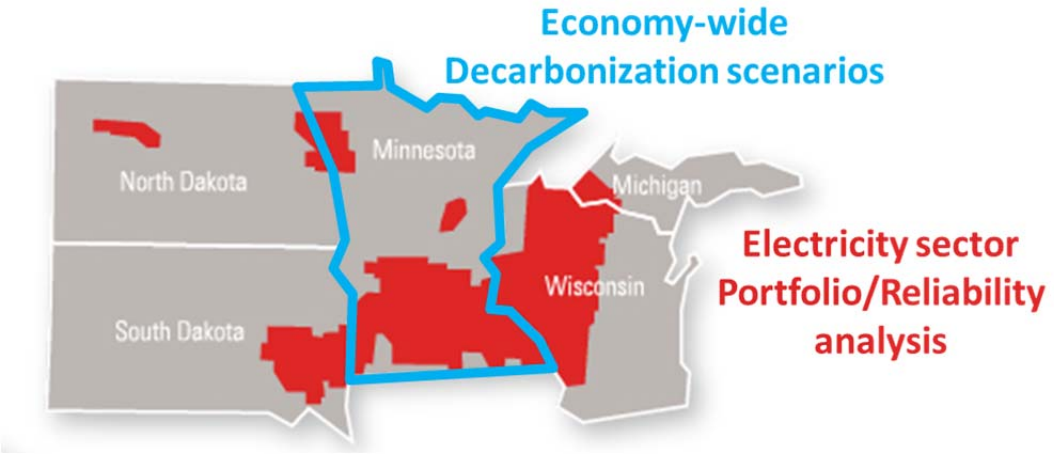


Figure 1. E3 Analysis Geographies for (1) Minnesota economy-wide decarbonization scenarios, and (2) Xcel Energy NSP portfolio and reliability analysis

Figure 2 shows all GHG emissions in the state of Minnesota by sector and subsector.[1] The largest sources of emissions in the state are electricity generation and transportation.[2] This analysis focused on the sectors that are most relevant to an electric utility: electricity generation, transportation, and buildings. Emissions from other sectors (agriculture, industry, and waste) were represented at a high level.

[1] Data pulled from MPCA 2014 GHG Inventory
[2] This work was based on the Minnesota Pollution Control Agency (MPCA) 2014 greenhouse gas inventory. At the time of this report, the MPCA has released updated inventory data through 2016 and transportation is now the largest emitter of GHGs in the state.

Figure 2. Minnesota GHG emissions by category in 2014

2 Approach

2.1 PATHWAYS Model Philosophy

This study used a PATHWAYS model to develop the reference case emission projection. The PATHWAYS model is an economy-wide representation of infrastructure, energy use, and emissions within a specific jurisdiction. The PATHWAYS model represents bottom-up and user-defined emissions accounting scenarios to test "what if" questions around future energy and climate policies. PATHWAYS modeling typically includes the following features:

- Detailed stock rollover in residential, commercial and transportation subsectors
- Interactive effects with electricity demand and electricity supply sectors
- Sustainable biomass feedstock supply curves
- Non-combustion and non-energy emissions

The inclusion of both supply and demand sectors captures interactions between sectors such as increased penetration of electric vehicles and a changing mix of technologies supplying electricity. The focus of the Pathways model is to compare user-defined policy and market adoption scenarios and to track physical accounting of energy flows within all sectors of the economy.

2.2 PATHWAYS in LEAP

E3 built a bottom-up PATHWAYS model of the Minnesota economy using the LEAP tool (Long-range Energy Alternatives Planning system)[3]. This model quantifies the energy and emissions associated with the projected trends in energy use and complementary policies targeting future mitigated emissions. We modeled the period of 2015-2050.

LEAP is an integrated, scenario-based modeling tool that can be used to track energy consumption, production and resource extraction in all sectors of an economy. It can be used to account for both energy sector and non-energy sector greenhouse gas (GHG) emission sources and sinks. LEAP is not a model of a specific energy system, but rather a modeling framework that can be adapted for different jurisdictions.

[3] LEAP is developed by the Stockholm Environment Institute. More information on the LEAP software can be found at www.energycommunity.org

E3 built a model of Minnesota's energy and non-energy emission sources, projecting them through 2050 using different scenarios to understand current trajectories and different pathways that can be reached through complementary policies within the state.

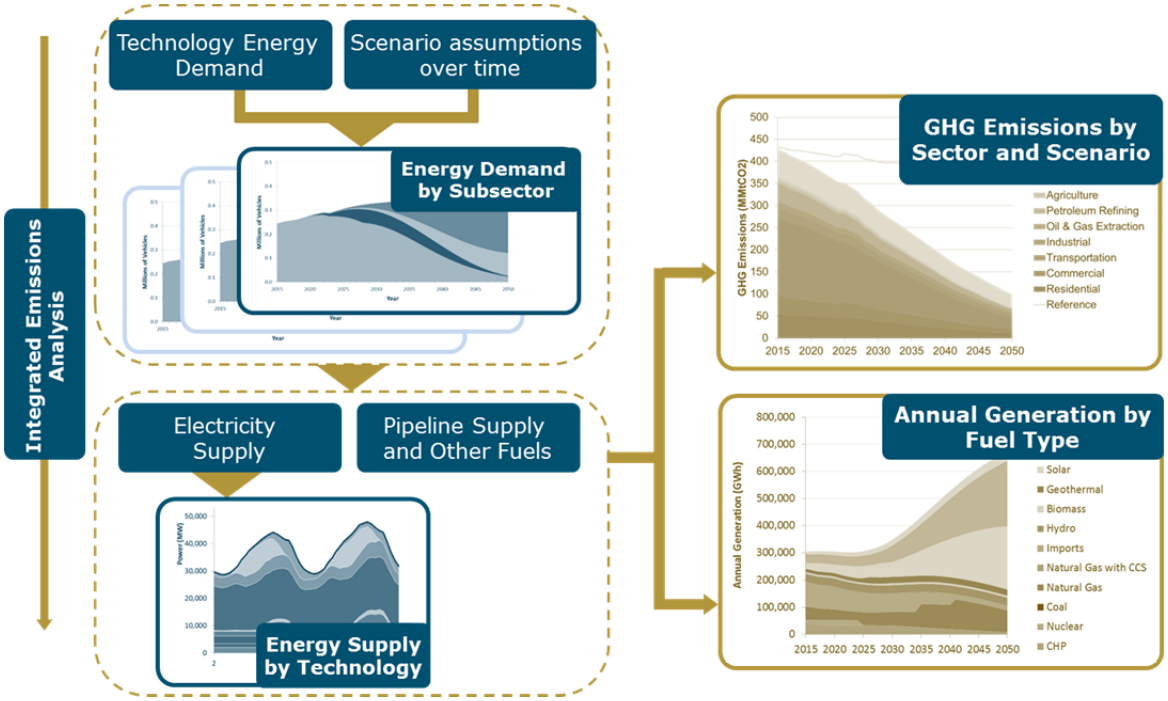


Figure 3. PATHWAYS Energy Modeling Framework

2.3 Scenarios

E3 modeled three scenarios to evaluate a range of emissions reductions from complementary policies.

- **Reference Scenario**: a current policy scenario, including utility-driven energy efficiency, expected adoption of zero emission vehicles, federal fuel economy standards for light-duty vehicles (LDVs)
- **High Electrification Scenario:** a mitigation scenario that includes increased adoption of electric and hydrogen vehicles in medium-duty vehicles (MDVs) and heavy-duty vehicles (HDVs) as well as electric space heating and water heating appliances in buildings.
- **High Biofuels Scenario:** a mitigation scenario that includes lower levels of electrification in favor of higher shares of low-carbon biofuels.

Table 1. Key Assumptions in all scenarios[4]

	Reference Scenario	**High Electrification Scenario**	**High Biofuels Scenario**
Carbon-free electricity generation	48% by 2025, held constant through 2050	48% by 2025, 90% by 2050	
Nuclear power	Retires at end of license	Relicensed or replaced with other carbon-free generation	
Building energy efficiency	50% of appliance sales are high-efficiency by 2030	100% of appliance sales are high-efficiency by 2030 100% adoption of efficient building shell/weatherization measures by 2030 15% reduction in non-stock energy below Reference Scenario by 2030, 30% by 2050 5% reduction in key demands due to smart appliances and conservation by 2030	
Sales of electric heat pump equipment	None	50% by 2030, 100% by 2050, replacing electric, natural gas and LPG	20-30% sales by 2030, replacing only electric and LPG equipment
Zero-emission vehicles	10% of sales by 2030 (Xcel "likely" sales forecast) for LDVs	LDVs: 50% by 2030, 100% by 2050 MDVs: 50% by 2030, 100% by 2050 HDVs: 40% by 2030, 100% by 2050	LDVs: 50% by 2030, 100% by 2050 MDVs: 50% by 2030, 80% by 2050 HDVs: 20% by 2030, 50% by 2050
Vehicle fuel economy	Federal CAFE standards for LDVs by 2026		
Conventional biofuels	20% biodiesel blend in diesel by 2018 (MN239.77); 30% ethanol blend in gasoline by 2025 (MN239.7911)	Transition to advanced biofuels by 2050	
Advanced Biofuels	None	Advanced biofuels without purpose-grown biomass feedstocks	Advanced biofuels with purpose-grown biomass feedstocks
Other sectors (agriculture, waste, industry)	Energy consumption grows at AEO 2017 reference scenario rates by fuel; non-energy GHG emissions held constant at MPCA 2014 Inventory levels	Reduction of 64% below 2005 GHG Emissions by 2050	Reduction of 69% below 2005 GHG Emissions by 2050

[4] More detailed assumptions are included in the sections that follow

In addition to mitigation scenarios, we developed three sensitivities to test the impact on emissions of federal action and consumer adoption. The three sensitivities were defined as follows and are documented further in Section 3.2.4:

1. **Efficiency, Electrification, and Clean Electricity Only**: Evaluates the impact of only pursuing building efficiency, high adoption of electric vehicles and household devices, and clean electricity towards meeting GHG targets
2. **No CAFE Extension**: Evaluates the impact of EPA's proposal to freeze federal Corporate Average Fuel Economy (CAFE) standards at 2020 levels.
3. **Lower Electric Adoption**: Evaluates the combined impact of lower consumer adoption of electric vehicles and electric household devices.

2.4 Inputs

To populate the Minnesota PATHWAYS model, we focused on in-state data sources where possible, supplementing with national data sets to fill remaining data gaps. Specific inputs are listed below.

2.4.1 FIRST YEAR EMISSIONS BENCHMARKING

In 2014, Minnesota had a population of 5.45 Million people residing in 2.1 Million households.[5] In each sector of the economy, we create a representation of a base year (2014) of infrastructure and energy, and then identify key variables that drive activity change over the duration of each scenario (2015-2050). Table 2 shows emissions benchmarking from the MN PATHWAYS model created for this analysis and the Pollution Control Agency (PCA) 2014 GHG Inventory.

[5] Source: Minnesota State Demographic Center

Table 2. Emissions Benchmarking in Minnesota PATHWAYS model to Minnesota PCA GHG inventory in 2014. MST = million short tons.

Sector	MPCA 2014 [MST CO2e]	PATHWAYS 2014 [MST CO2e]	Difference [MST CO2e]	Difference [%]
Buildings	19.0	19.0	0.0	0%
Transportation	39.1	39.2	0.1	0%
Electricity Generation	46.7	46.6	0.0	0%
Other	53.4	53.4	0.0	0%
Total	**158.2**	**158.2**	**0.0**	**0%**

2.4.2 KEY DRIVERS AND DEMOGRAPHICS

Each sector includes assumptions about key drivers of activity within that sector. Table 3 identifies the key drivers behind each sector's energy consumption in the reference scenario. Additional detail is available in the sections that follow.

Table 3. Key Drivers by PATHWAYS Sector in the Reference Scenario

Sector	**Key Driver**	**Compound annual growth rate [%]**	**Data Source**
Buildings	Population	0.44%	MN State Demography Center
Industry	Energy growth	Varies by fuel	EIA AEO 2018 growth rates (2018-2050)
On Road Transportation	Vehicle-miles traveled (VMT)	0.5% LDV 1.3% MDV 1.2% HDV	EIA AEO 2018
Off Road Transportation	Energy growth	Varies by fuel	EIA AEO 2018 growth rates (2018-2050)
Electricity Generation	Electric load growth	-0.1% average 2015-2030 (0.2% 2015-2050)	Built up from Pathways demands in Buildings, Industry, Transportation

The sections that follow will detail scenario assumptions for each key sector in the Minnesota PATHWAYS model.

2.4.3 BUILDINGS SECTOR

2.4.3.1 Base Year

The Minnesota LEAP model includes a stock-rollover representation of 17 residential and 10 commercial building subsectors, including space heating, water heating, and lighting. Sectoral energy demand is benchmarked to energy consumption by fuel from the Minnesota GHG inventory for 2014 and is disaggregated by subsector based on the EIA National Energy Modeling System (NEMS) technology characterization. All residential and commercial subsectors are listed in Table 4.

Table 4. Representation of 2014 Building Energy Consumption by Subsector in Minnesota

Sector	Subsector	Modeling Approach	Energy Use in 2014 [Tbtu]	Percent of 2014 Energy Use [%]
Residential	Central Air Conditioning	Stock Rollover	3.2	1%
	Room Air Conditioning	Stock Rollover	0.2	0%
	Building Shell	Stock Rollover	-	0%
	Clothes drying	Stock Rollover	4.7	1%
	Clothes washing	Stock Rollover	0.7	0%
	Cooking	Stock Rollover	5.7	1%
	Dishwashing	Stock Rollover	1.9	0%
	Freezing	Stock Rollover	1.7	0%
	Reflector Lighting	Stock Rollover	0.8	0%
	General Service Lighting	Stock Rollover	3.7	1%
	Exterior Lighting	Stock Rollover	0.6	0%
	Linear fluorescent lighting	Stock Rollover	0.6	0%
	Single Family Space Heating	Stock Rollover	103.6	23%
	Multi Family Space Heating	Stock Rollover	16.3	4%
	Refrigeration	Stock Rollover	7.7	2%
	Water heating	Stock Rollover	43.2	10%
	Residential Other*	Total Energy by Fuel	59.2	13%
Commercial	Air conditioning	Stock Rollover	1.9	0%
	Cooking	Stock Rollover	15.9	4%
	General service lighting	Stock Rollover	7.0	2%
	High intensity discharge lighting	Stock Rollover	7.5	2%
	Linear fluorescent lighting	Stock Rollover	7.6	2%
	Refrigeration	Stock Rollover	3.5	1%
	Space heating	Stock Rollover	66.5	15%
	Ventilation	Stock Rollover	9.5	2%
	Water Heating	Stock Rollover	7.5	2%
	Commercial Other*	Total Energy by Fuel	64.2	14%
All Building Sectors			**444.7**	**100%**

*Residential Other includes furnace fans, plug loads (e.g. computers, phones, speakers, printers), secondary heating, fireplaces, and outdoor grills. Commercial Other includes plug loads, office equipment, fireplaces, and outdoor grills.

2.4.3.2 Reference Scenario

The primary reference measure represented in buildings is the achievement of electric energy efficiency. Energy efficiency in buildings is implemented in the PATHWAYS model in one of three ways:

1. As new appliance or lighting end use technology used in the residential and commercial sectors (e.g., a greater share of high efficiency appliances is assumed to be purchased). New equipment is typically assumed to replace existing equipment "on burn-out", e.g., at the end of the useful lifetime of existing equipment.

2. As a reduction in energy services demand, due to smart devices (e.g. programmable thermostats), conservation, or behavior change.

3. For the sectors that are not modeled using specific technology stocks (Residential Other and Commercial Other), energy efficiency is modeled as a reduction in total energy demand.

Table 5. Reference Scenario Assumptions for Building Energy Efficiency

Category of Building Measures	Reference Scenario Assumption
Building retrofits for high efficiency building shells	None
New appliance sales	50% of new sales of all appliances are assumed to be efficient (e.g. EnergyStar) by 2030. See Figure 4.
Building electrification	None
Behavioral conservation and smart devices	None
Other non-stock sectors	None

Since the model is based on a bottom-up forecast of technology stock changes in the residential and commercial sectors, the model does not use a single load forecast or energy efficiency savings forecast as a model input. It is important to note that the modeling assumptions used in this analysis may not reflect specific future energy efficiency programs or activities.

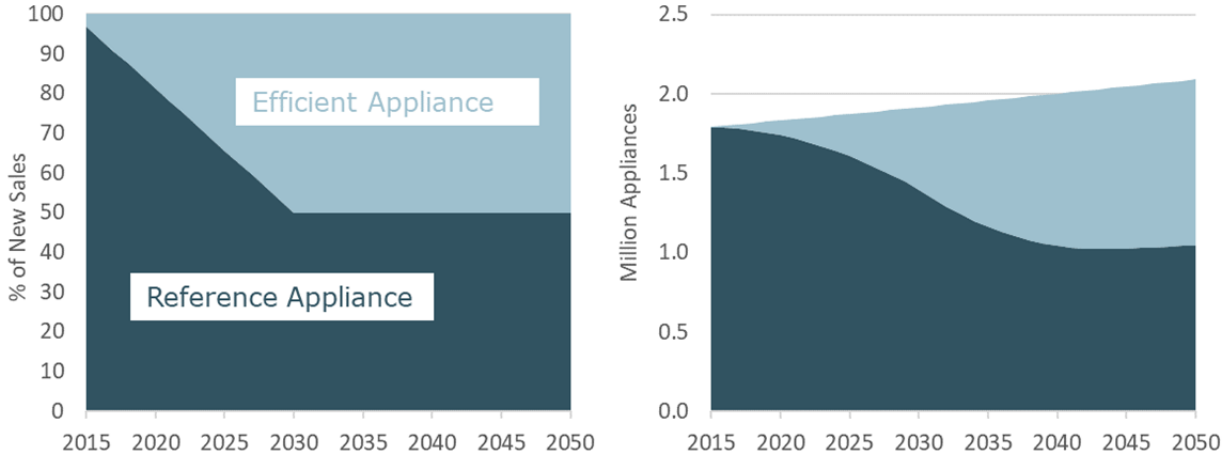


Figure 4. Assumed New Sales for Building Appliances (left) and Resulting Appliance Stocks (right), Reference Scenario

2.4.3.3 Mitigation Scenarios

Each Mitigation Scenario includes more aggressive energy efficiency and electrification in buildings. The High Electrification Scenario assumes more ambitious adoption of electric heat pumps for space heating and water heating, while the High Biofuels Scenario assumes electric heat pumps displace only existing electric and LPG equipment. See Table 6 for a full list of assumptions.

Table 6. Mitigation Scenario Assumptions for Building Energy Efficiency

Category of Building Measures	**High Electrification Scenario**	**High Biofuels Scenario**
Building retrofits for high efficiency building shells	100% adoption of efficient building shell and weatherization measures by 2030	
New appliance sales	100% of new sales of all appliances are assumed to be efficient (e.g. EnergyStar) by 2030.	
Building electrification	50% sales of electric heat pumps by 2030, 95% by 2050, replacing electric, natural gas and LPG systems	20-30% sales of electric heat pumps by 2030, replacing only electric and LPG equipment
Behavioral conservation and smart devices	10% reduction in energy services demand below Reference Scenario in residential lighting, space heating, and water heating	
Other non-stock sectors	30% reduction in energy consumption below Reference Scenario by 2050	

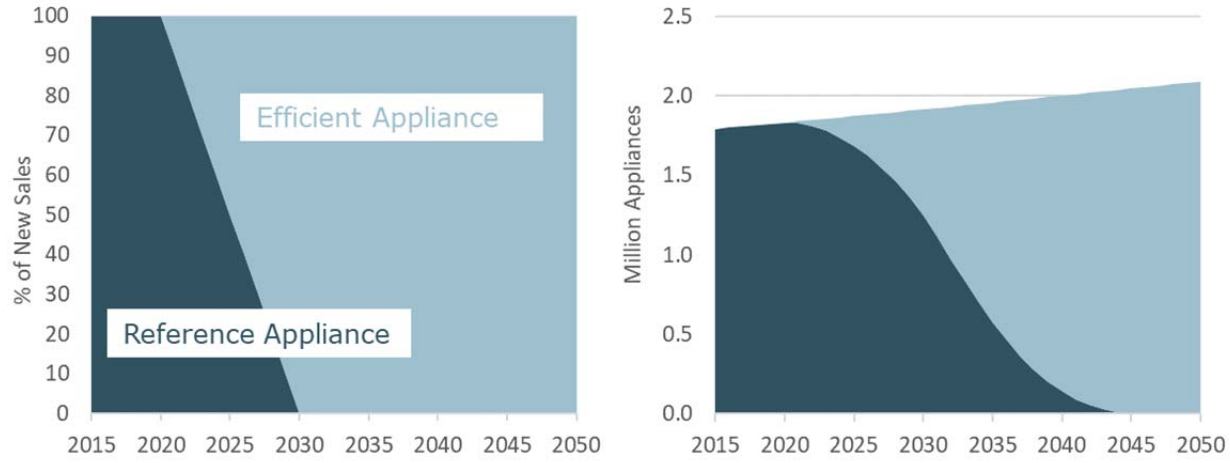


Figure 5. Assumed New Sales for Building Appliances (left) and Resulting Appliance Stocks (right), High Electrification Scenario

A key assumption across our scenarios is the adoption of high efficiency electric heat pumps for space heating and water heating. Currently in Minnesota electric heat pumps make up less than one percent of space heaters and water heaters.

In the High Biofuels Scenario we assume a shift to heat pump space heaters (20-30% of new sales by 2030), displacing sales of existing electric and LPG equipment. In the High Electrification Scenario, we assume significant adoption of heat pumps for both space heating and water heating, reducing sales of natural gas, existing electric, and LPG systems. The total number of electric heat pump space heaters in Minnesota residences is reported in Figure 6.

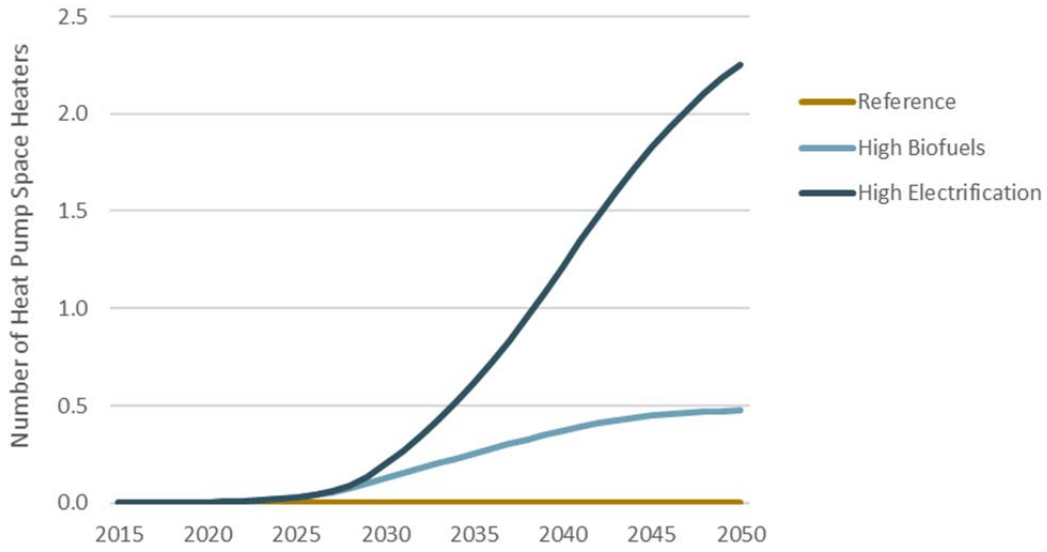


Figure 6. Total number of residential electric heat pump space heaters in all scenarios.

2.4.4 TRANSPORTATION SECTOR

2.4.4.1 Base Year

The Minnesota LEAP model includes a stock-rollover representation of four transportation sectors and an energy representation of six subsectors. Sectoral energy demand is benchmarked to energy consumption by fuel from the Minnesota GHG inventory for 2014 and is disaggregated by subsector based on the EIA National Energy Modeling System (NEMS) technology characterization and additional data from PCA. All subsectors represented in the transportation sector are listed in Table 7.

Table 7. Transportation 2014 Subsector Energy Consumption in Minnesota

Sector	Subsector	Modeling Approach	Estimated Energy Use in 2014 [TBtu]	Estimated % of 2014 Energy Use [%]
Light Duty Vehicles	Light Duty Autos	Stock Rollover	128	26%
	Light Duty Trucks	Stock Rollover	148	30%
Medium Duty Vehicles	Medium Duty Trucks	Stock Rollover	71	14%
Heavy Duty Vehicles	Heavy Duty Trucks	Stock Rollover	74	15%
Transportation Other	Aviation	Total Energy by Fuel	46	9%
	Rail	Total Energy by Fuel	15	3%
	Motorcycles	Total Energy by Fuel	3	1%
	Bus	Total Energy by Fuel	4	1%
	Military and Off-Highway	Total Energy by Fuel	7	1%
	Marine	Total Energy by Fuel	4	1%
All Transportation Sectors			**501**	**100%**

2.4.4.2 Reference Scenario

Two key measures were represented in the Minnesota PATHWAYS Reference Scenario: (1) Federal Light Duty Vehicle (LDV) Corporate Average Fuel Economy (CAFE) Standards, and (2) expected sales of zero-emission vehicles (ZEVs) in Minnesota. LDV CAFE Standards are represented in the marginal fuel economy of new gasoline vehicles sold in addition to an increased share of ZEVs sold. Increasing marginal fuel economy assumed is shown in Figure 7 for light-duty automobiles (LDA) and light-duty trucks (LDT).

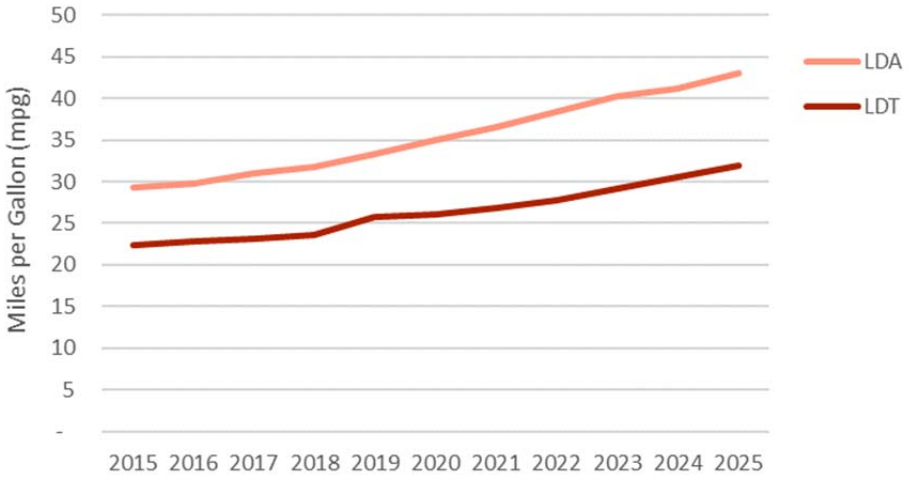


Figure 7. Marginal Fuel Economy for Gasoline LDVs in Minnesota

The second key measure, expected ZEVs in Minnesota, is represented through increasing sales of plug-in hybrid vehicles (PHEVs) and battery electric vehicles (BEVs) over time. We used Xcel Energy's "likely" sales of BEVs for their service territory and assumed that for the state of Minnesota. We assume that new sales increase linearly to be 20% ZEV sales by 2020. In our stock rollover methodology, this means that of all the cars that are purchased in 2020 (either due to retirement or new growth), 15% will be battery electric vehicles and 5% will be plug-in hybrid electric vehicles. This assumption is shown for light duty autos (LDAs) and light duty trucks (LDTs) in Figure 8. No changes were assumed in the heavy-duty fleet.

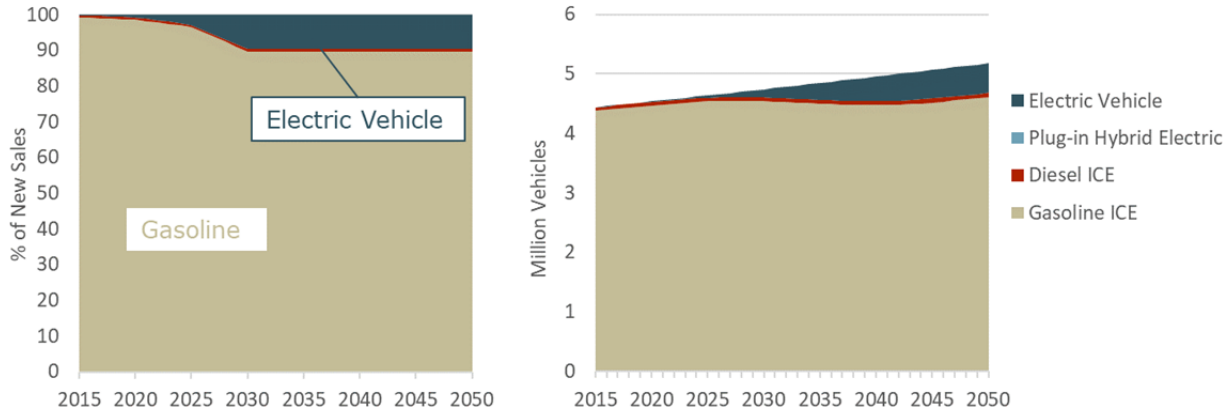


Figure 8. Assumed new light duty vehicle sales (left) and resulting stocks (right), Reference Scenario

In other subsectors of transportation, total energy consumption in Table 7 was assumed to grow at EIA AEO 2018 growth rates by fuel.

2.4.4.3 Mitigation Scenarios

Both Mitigation Scenarios assume significant reductions in light-duty vehicle-miles traveled (VMT), which could be achieved through urban design, transportation demand management, or mode shifting. Both scenarios assume aggressive electrification in light duty vehicles, up to 100% of new sales in 2050, representing no internal combustion vehicles being sold after that year. The High Electrification Scenario includes more aggressive zero-emission vehicle sales in medium- and heavy-duty vehicles, reaching 100% of new sales by 2050. The High Biofuels Scenario includes lower adoption of ZEVs in medium- and heavy-duty vehicles, where biofuels are assumed to be blended into transportation fuels.

Table 8. Mitigation Scenario Assumptions for Transportation

Category of Transportation Measures	High Electrification Scenario	High Biofuels Scenario
Vehicle Miles Traveled (VMT) reductions in light duty vehicles	Annual VMT is reduced by 15% below Reference by 2050	
Zero-emission Light Duty Vehicle (LDV) sales	50% sales by 2030, 100% by 2050	
Zero-emission Medium Duty Vehicle (MDV) sales	50% by 2030, 100% by 2050	50% by 2030, 80% by 2050
Zero-emission Heavy Duty Vehicle (HDV) sales	50% by 2030, 100% by 2050	20% by 2030, 50% by 2050
Aviation efficiency	Reduction in energy use of 40% below Reference Scenario by 2050	
Transportation Other	AEO 2018 reference scenario growth rates by fuel	

Assumptions for total new sales of light-duty vehicles and resulting total stocks is shown in Figure 9.

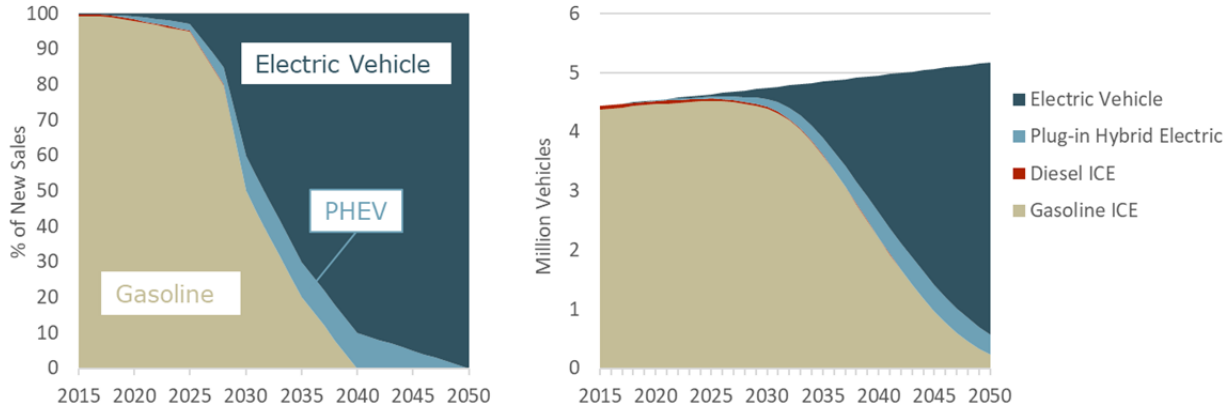


Figure 9. Assumed new light duty vehicle sales (left) and resulting stocks (right), High Electrification and High Biofuels Scenario

2.4.5 ELECTRICITY SECTOR

The Minnesota PATHWAYS model contains a dedicated branch for modeling electricity generation. Operations in the electricity sector are modeled on an annual basis, based on projected changes in electric capacity, generation, and changes in load. More detailed analysis of capacity expansion and operations for Xcel Energy Northern States Power were modeled in a parallel project with E3's RESOLVE and RECAP models.

2.4.5.1 Base Year

In-state generation capacity for Minnesota resources is based on EIA. Assumed generation by resource is shown in Table 9.

Table 9. Minnesota Electricity Generation in 2014[6]

Resource	Generation [TWh]	Share of 2014 Generation [%]
Nuclear	12.7	17%
Coal	28.0	38%
Natural Gas	3.9	5%
Oil	0.1	0%
Hydro	0.5	1%
Biomass	2.2	3%
Onshore Wind	9.7	13%
Utility Solar	0.0	0%
Net Imports	15.7	22%
Total	**72.7**	**100%**

2.4.5.2 Reference Scenario

In the Minnesota PATHWAYS model, total electricity demand is calculated from independent assumptions in each demand sector (buildings, transportation, industry, and agriculture). This approach ensures that we take into account linkages between sectors so that our generation and emissions from the electric sector are aligned with electrification loads in our mitigation scenarios. The Minnesota PATHWAYS model simulates dispatch of in-state generators and imported power from the Midcontinent Independent System Operator (MISO) to meet electricity demands in each year based on assumed percent shares of generation coming from generator types. All scenarios include an assumption of 6% transmission and distribution losses.

In the Reference Scenario, we assume that in-state nuclear facilities retire at the end of their license and are replaced with imported power. We assume moderate reductions in coal generation to reflect planned utility retirements. Table 10 shows the assumed share of electricity generation by resource.

Table 10. Assumed share of electricity generation by resource type, Reference Scenario

	2020	2030	2040	2050
Carbon-Free Generation*	43.6%	49.8%	33.7%	33.7%
Natural Gas	7.1%	10.0%	10.0%	10.0%
Oil	0.1%	0.1%	0.1%	0.1%
Coal	33.9%	30.0%	30.0%	30.0%

[6] US Energy Information Administration, Minnesota Electricity Profile, Table 5, full data available online: https://www.eia.gov/electricity/state/minnesota/index.php

Net Imports	15.3%	10.1%	26.2%	26.2%
Total	100.0%	100.0%	100.0%	100.0%

*Carbon-Free Generation includes utility-scale solar, onshore wind, biomass, hydro-electric, and nuclear generators

2.4.5.3 Mitigation Scenarios

Each Mitigation Scenario assumes significant ramp up of carbon-free generation over the next 30 years. Both Mitigation Scenarios are designed to meet the same share of carbon-free electricity by 2050, as shown in Table 11.

Table 11. Assumed share of electricity generation by resource type, Mitigation Scenarios

	2020	2030	2040	2050
Carbon-Free Generation*	42.5%	56.2%	73.6%	90.0%
Natural Gas	5.3%	5.3%	5.3%	5.3%
Oil	0.1%	0.0%	0.0%	0.0%
Coal	31.5%	20.0%	10.0%	0.0%
Net Imports	20.6%	18.4%	11.1%	4.7%
Total	100.0%	100.0%	100.0%	100.0%

*Carbon-Free Generation includes utility-scale solar, onshore wind, biomass, hydro-electric, and nuclear generators

Even though both scenarios have the same share of generation being met by carbon-free electricity, total generation is very different due to assumptions about electrification, as shown in Figure 10.

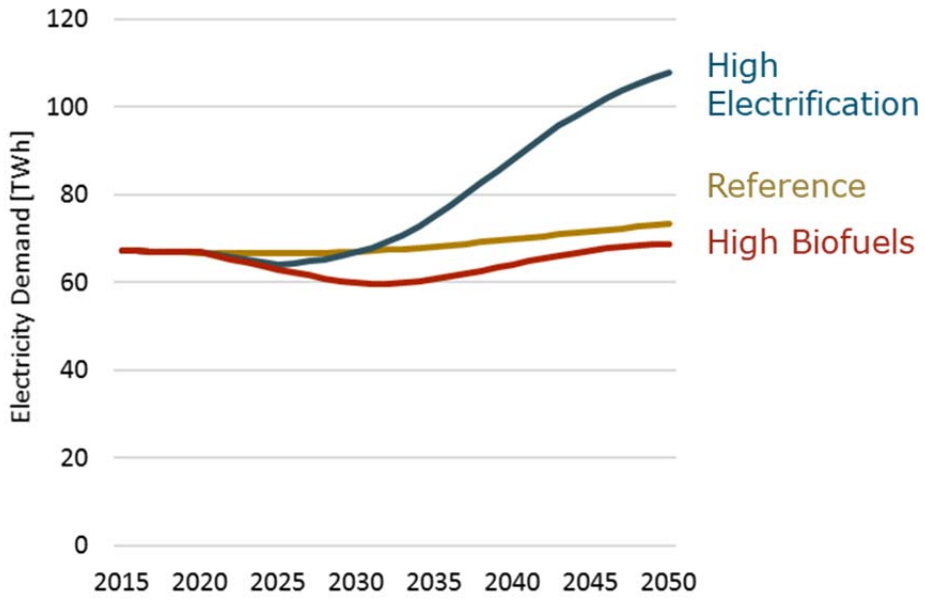


Figure 10. Electricity demand by scenario

2.4.6 BIOFUEL SUPPLY

The decarbonization transition will require strategic use of limited biomass and careful screening of sustainable feedstocks to ensure that bioenergy produces zero carbon emissions and is sustainably grown without producing adverse land-use impacts. Examples of biomass products that are used to produce biofuels include corn, soybeans, sugar cane, forest products, manure, switch grass and other agricultural waste products, such as corn stover.

Minnesota has a robust conventional biofuels industry that produces ethanol (from corn) and biodiesel (from soy and other waste oils). Our Reference Scenario assumes continued growth of the conventional biofuels industry, while our Mitigation Scenarios assume a transition after 2030 to an advanced biofuels industry. Note that both conventional biofuels and advanced biofuels are treated as having zero carbon emissions at the point of combustion from the Minnesota PCA Inventory accounting.

New sustainable biomass feedstock assessments are taken from the 2016 DOE Billion Ton Study (BTS) Update[7], which estimates sustainable yield of a variety of raw biomass sources, including agricultural (including dedicated energy crops), forestry (including new forests and residues), and waste streams (including municipal waste and forest residues).

2.4.6.1 Reference Scenario

The Reference Scenario assumes compliance with current targets for conventional ethanol and biodiesel. For ethanol, we assume a 30% blend of ethanol in motor gasoline by 2025.[8] For biodiesel we include the seasonal Minnesota B20 mandate, modeled as a 10% blend of biodiesel for the whole year.[9]

2.4.6.2 Mitigation Scenarios

In our Mitigation Scenarios, we assume a transition from conventional biofuel blends in the next 10 years to advanced biofuel production by 2050.

To determine available sustainable biomass supply through our study period, we assumed that Minnesota would have access to its population-weighted share of the total national feedstock supply, which is about 2% of the total supply. This approach assumes that all US states begin to transition to developing advanced biofuels with these resources. Minnesota has more biomass feedstocks within the state than its population-weighted share, which indicates that Minnesota would be able to sell excess biofuel products into a national market.

Figure 11 shows the national estimated biomass feedstock supply. The High Biofuel Scenario assumes that both residues and energy crops are available, while the High Electrification Scenario assumes only residue categories are available. The “Residues” category includes agricultural residues, food waste, forest residues, municipal solid waste, and manure. Residue feedstocks have fewer concerns about land-use constraints and competition with food crops.

[7] DOE, 2016 Billion-Ton Report. Available online: https://www.energy.gov/eere/bioenergy/2016-billion-ton-report
[8] 239.7911 Petroleum Replacement Promotion: https://www.revisor.mn.gov/statutes/cite/239.7911
[9] 239.77 Biodiesel Content Mandate: https://www.revisor.mn.gov/statutes/cite/239.77

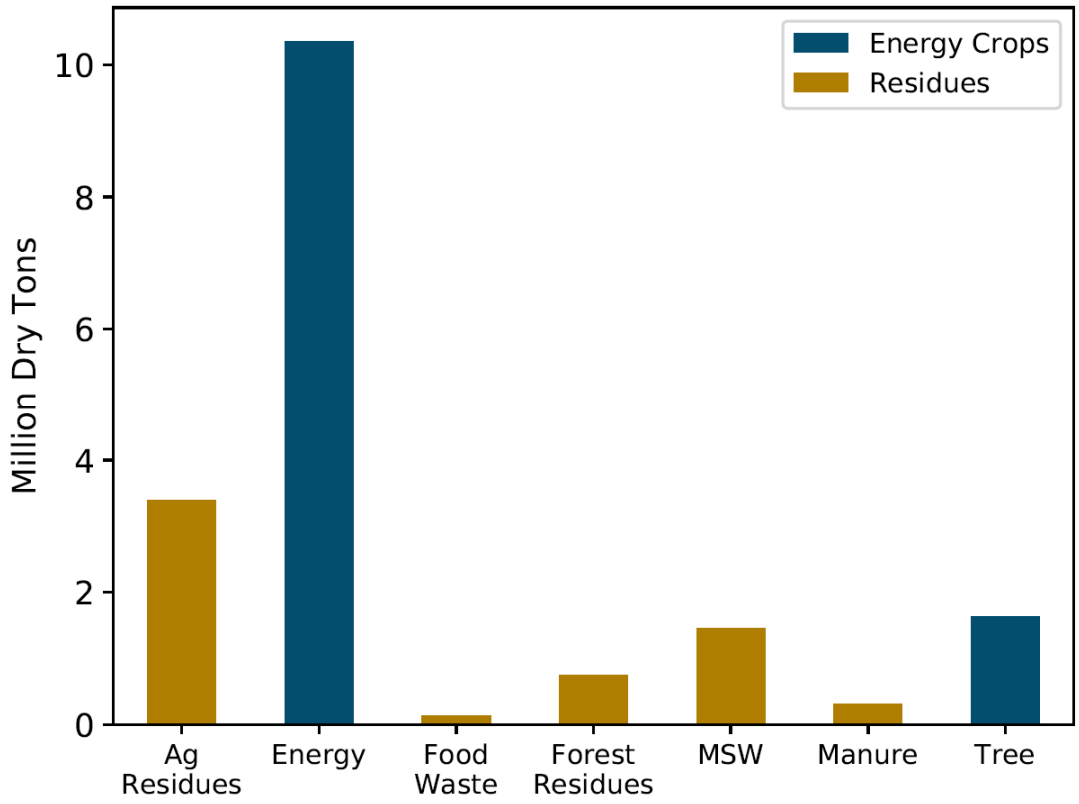


Figure 11. Minnesota Biomass Feedstock Supply by 2040 by Resource Category

To calculate the optimal portfolio of biofuels, E3 has developed a model which generates biofuel supply curves that determine the availability and cost of renewable liquid and gaseous fuels. The model optimizes the selection of combinations of feedstocks and conversion pathways. The model adds preparation, process, transportation, and delivery costs to BTS feedstock cost curves to achieve supply curves by feedstock and conversion pathway. To obtain biofuel demand, we apply the percentage biofuel penetration targets to aggregate calculated final energy demand.

Figure 12 shows the total resulting advanced biofuel consumption by fuel for each scenario. Because the High Biofuels Scenario includes feedstocks from energy crops and dedicated forests, that scenario is able to use more than two times the total quantity of biofuels than the High Electrification Scenario, which is limited to wastes and residues.

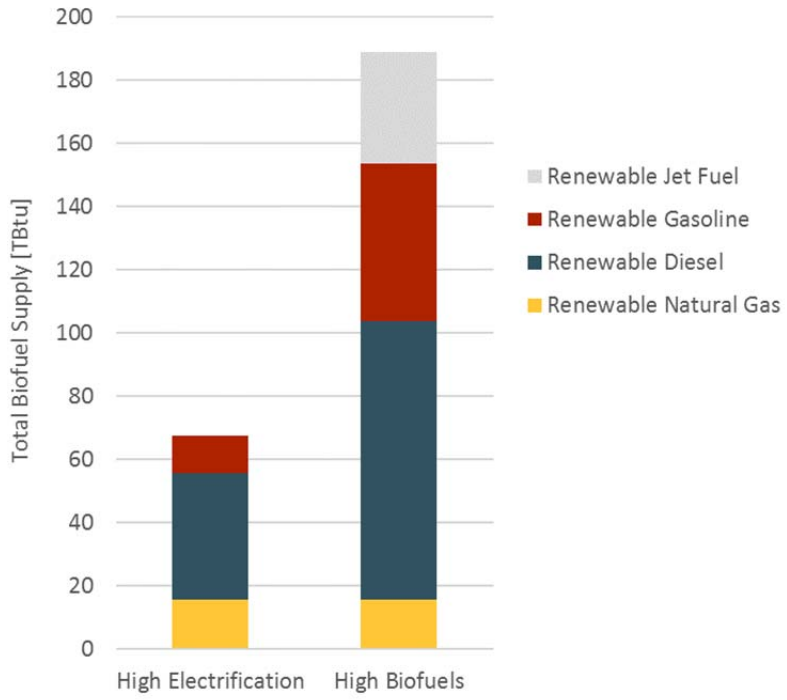


Figure 12. Total Advanced Biofuel Production by Biofuel in 2050, Mitigation Scenarios

Figure 12 highlights a different view of the same result, showing total consumption of gasoline, diesel, and natural gas by the share that is blended biofuel (and therefore zero-carbon) and the remaining share that is fossil.

2.4.7 OTHER SECTORS

This analysis focused in detail on the electricity generation, transportation, and buildings sectors. Additional sectors not modeled in significant detail are the agriculture, industry, and waste sectors.

2.4.7.1 Base Year

All energy consumption in industry, agriculture, and waste is represented as total annual energy consumption by fuel, as shown in Table 12.

Table 12. Energy Consumption in Industry, Agriculture, and Waste sectors by fuel in Minnesota, 2014

Sector	Fuel	Modeling Approach	Estimated Energy Use in 2014 [Tbtu]	Estimated % of 2014 Energy Use [%]
Industry (All Subsectors)	Electricity	Total Energy by Fuel	78.7	21%
	Gasoline	Total Energy by Fuel	2.7	1%
	Residual Fuel Oil	Total Energy by Fuel	0.1	0%
	Coal	Total Energy by Fuel	19.0	5%
	Petroleum Coke	Total Energy by Fuel	1.6	0%
	Refinery Feedstocks	Total Energy by Fuel	18.7	5%
	Wood	Total Energy by Fuel	27.2	7%
	Natural Gas	Total Energy by Fuel	154.1	41%
	LPG	Total Energy by Fuel	0.0	0%
	Diesel	Total Energy by Fuel	39.0	10%
	Renewable Diesel	Total Energy by Fuel	1.7	0%
	Coal Coke	Total Energy by Fuel	0.6	0%
Agriculture (All Subsectors)	Electricity	Total Energy by Fuel	-	0%
	Gasoline	Total Energy by Fuel	3.3	1%
	Natural Gas	Total Energy by Fuel	-	0%
	LPG	Total Energy by Fuel	10.5	3%
	Diesel	Total Energy by Fuel	16.4	4%
	Renewable Diesel	Total Energy by Fuel	0.7	0%
Waste (All Subsectors)	Natural Gas	Total Energy by Fuel	0.3	0%
	Diesel	Total Energy by Fuel	0.4	0%
	Renewable Diesel	Total Energy by Fuel	0.0	0%
All Sectors			**374.8**	**100%**

Additional non-energy emissions in industry, agriculture, and waste sectors were represented as total annual emissions, as shown in Table 13.

Table 13. Non-Energy Emissions in Industry, Agriculture, and Waste sectors in Minnesota, 2014

Sector	Fuel	Modeling Approach	Estimated Emissions 2014 [MST CO2e]	Estimated % of 2014 Non-Energy Emissions [%]
Agriculture	Animals	Total emissions	10.1	30%
	Crops	Total emissions	16.4	49%
	Other	Total emissions	0.0	0%
Industrial	Coal Storage	Total emissions	0.0	0%
	Industrial Process	Total emissions	0.6	2%
	Industrial Other	Total emissions	0.0	0%
	Oil Refining	Total emissions	0.0	0%
	Refinery Processes	Total emissions	1.7	5%
	Semiconductor Manufacture	Total emissions	0.3	1%
	Taconite Induration	Total emissions	2.1	6%
Waste	Industrial Landfills	Total emissions	0.1	0%
	Landfill gas combustion and flaring	Total emissions	0.0	0%
	MMSW Landfills	Total emissions	2.1	6%
	Medical	Total emissions	0.0	0%
	Rural Open Burning	Total emissions	0.0	0%
	Sludge	Total emissions	0.0	0%
	Waste Processing	Total emissions	0.2	1%
	Waste Solvent	Total emissions	0.0	0%
	Wastewater Treatment	Total emissions	0.4	1%
	Yard Waste Composting	Total emissions	0.0	0%
	Sequestration in landfills	Total emissions	-0.6	-2%
Total			33.7	100%

2.4.7.2 Reference Scenario

In the Reference Scenario, all energy consumption is assumed to grow at EIA AEO 2018 growth rates by fuel. All non-combustion emissions are held constant at 2014 levels.

2.4.7.3 Mitigation Scenarios

The overall approach for Mitigation Scenarios is to first calculate emission reductions from other sectors, and then to calculate the required reduction from remaining sectors in order to hit economy-wide NGEA goals by 2050. In both scenarios, we find that industry, agriculture, and waste sectors require a reduction that is lower than that in buildings, transportation, and electricity generation. This might be a fair assumption if it would be more expensive to decarbonize these sectors or if new technologies and measure would take longer to ramp up. The one specified assumption is that in the High Electrification Scenario, we assumed half of agricultural equipment could be electrified by 2050. Mitigation Scenario assumptions for other sectors are documented in Table 15.

Table 14. Mitigation Scenario Assumptions for Industry, Agriculture, Waste, and Non-Combustion Emissions

Category of Other Measures	**High Electrification Scenario**	**High Biofuels Scenario**
Electrification	50% of agricultural equipment energy use was assumed to be electrified by 2050.	None
Emissions Reductions for All Sectors below 2005 Levels	64%	69%

3 Results

3.1 GHG Emissions

Based on the assumptions outlined in Section 2 above, GHG emissions are calculated for Minnesota as shown in Figure 13. In the Reference Scenario, emission reductions are achieved in the initial years due to energy efficiency in buildings and transportation, as well as cleaner electricity generation. Emissions begin to rise after current policies no longer have an incremental effect and increased population and economic activity continue to increase energy use. Mitigation Scenarios fall short of the 2025 goal but meet the 2050 NGEA target.

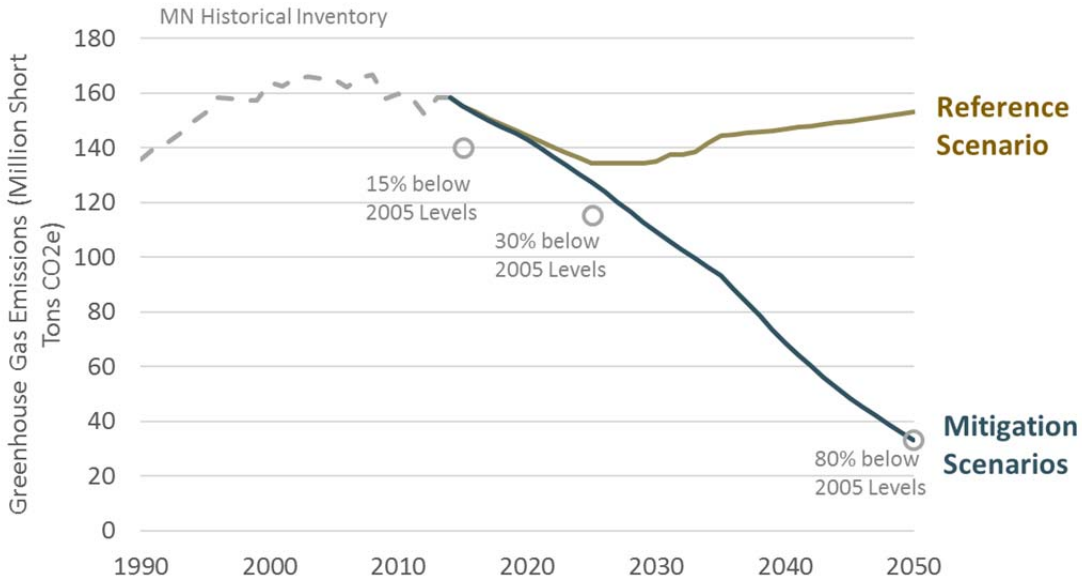


Figure 13. Minnesota GHG Emissions Results for Reference Scenario, 2015-2050

Emissions by Scenario are shown in Table 15 below.

Table 15. Total GHG Emissions by Scenario [Million Short Tons CO2e]

	2015	2020	2025	2030	2035	2040	2045	2050
Reference Scenario	155	144	134	135	144	147	150	153
High Electrification Scenario	155	143	127	109	93	69	48	33
High Biofuels Scenario	155	143	127	108	93	71	50	33
NGEA GHG Goals	140		115					33

Emissions for each modeled sector are shown over time in Figure 14 in the Reference Scenario. The largest direct reductions are in electricity generation, due to the retirement of in-state coal units and reduced demand due to efficiency, and transportation, due to federal CAFE standards and increased sales of ZEVs.

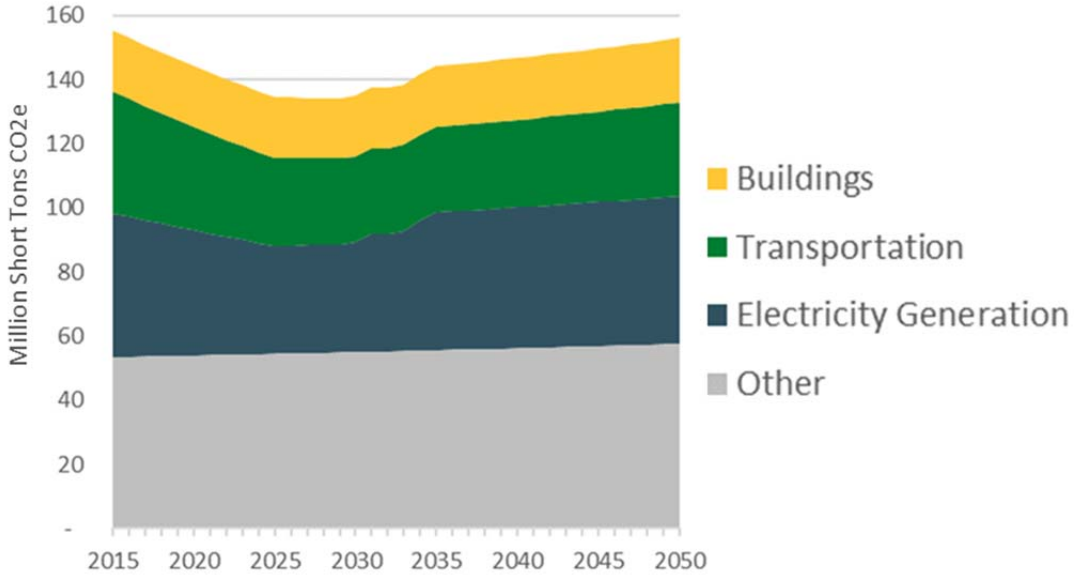


Figure 14. Minnesota GHG Emissions by Sector in the Reference Scenario, 2015-2050[10]

Emissions reductions by sector for each mitigation scenario is shown in Figure 15 and Increased electrification in the High Electrification scenario requires fewer reductions in "Other" sectors, but increases electricity generation demands, allowing for greater reductions in the High Biofuels Scenario.

Table 16. The High Electrification Scenario shows significant reductions in buildings and transportation due to adoption of electric appliances. The High Biofuels Scenario achieves fewer reductions in buildings and greater reductions in transportation due to allocating increased biofuels largely to on road vehicles.

[10] Other includes Agriculture, Industry, and Waste emissions

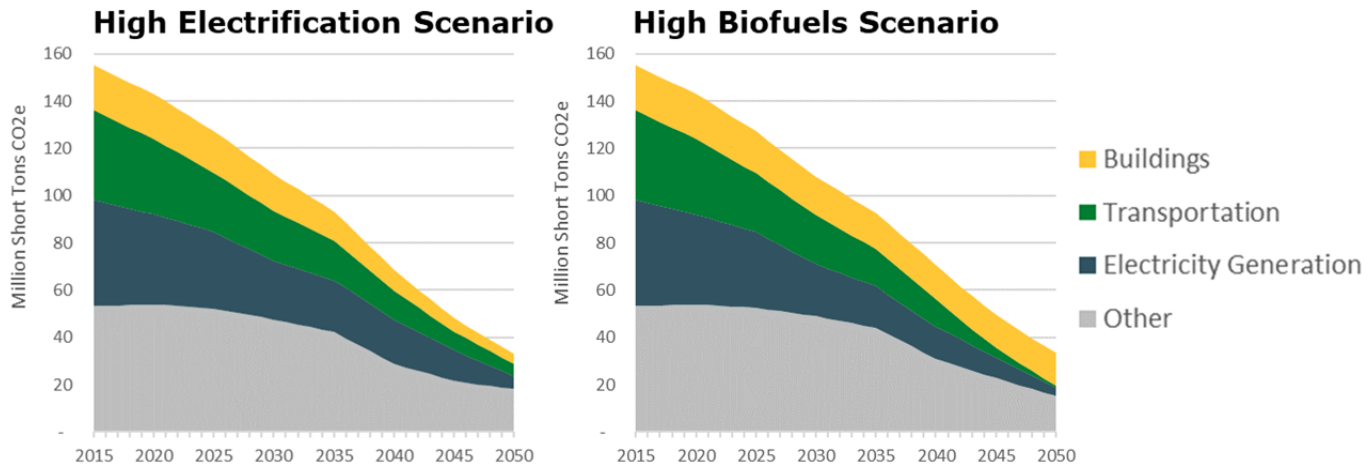


Figure 15. Minnesota GHG Emissions by Sector in Mitigation Scenarios, 2015-2050

Increased electrification in the High Electrification scenario requires fewer reductions in "Other" sectors, but increases electricity generation demands, allowing for greater reductions in the High Biofuels Scenario.

Table 16. GHG Reductions in Mitigation Scenarios in 2050 relative to 2005 emissions by sector

	High Electrification Scenario	High Biofuels Scenario
Buildings	-74%	-14%
Transportation	-87%	-98%
Electricity Generation	-91%	-94%
Other	-64%	-69%
Total	**-80%**	**-80%**

3.2 Sectoral Findings

3.2.1 BUILDINGS

The focus of measures in buildings is on energy efficiency and electrification. Increased sales of more efficient appliances and devices result in increased stock of those devices over time as old devices retire. Increased sales of efficient devices along with behavioral conservation and reductions in non-stock energy consumption results in significant reductions in total energy consumption as shown in Figure 16. Both scenarios achieve significant energy efficiency relative to the Reference Scenario, but the High Electrification Scenario achieves greater reductions in final energy consumption due to switching from natural gas appliances to more efficient electric heat pumps. Figure 16 also breaks out the impact of conventional efficiency and efficiency through electrification. The section between the black and grey

lines highlights the reduction in building energy consumption from measures like improved device efficiency, improved building shell (e.g. insultation), and smart devices. The section below the grey line highlights the additional reduction in energy consumption from switching to high-efficiency electric heat pump technologies in space heating and water heating.[11]

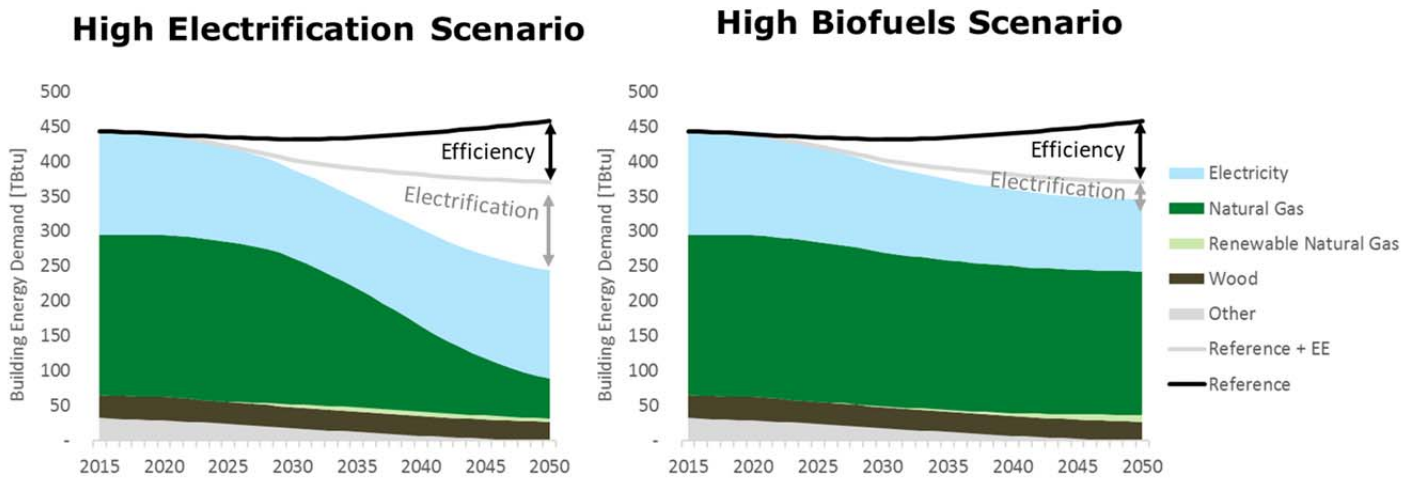


Figure 16. Total energy consumption by fuel and scenario in buildings

3.2.2 TRANSPORTATION

Reductions in emissions in the transportation sector are achieved through efficiency, electrification, and biofuels. Energy efficiency is included in two forms: (1) federal CAFE standards for new vehicle sales, and (2) VMT reductions due to transit and smart growth measures. New sales of vehicles with more efficient electric drive trains achieve significant efficiency and the potential to reduce emissions further by consuming cleaner electricity. Benefits of displacing fossil fuels with renewable diesel, renewable gasoline, and renewable jet fuel further reduces emissions within the transportation sector.

Figure 17 highlights the impacts of energy efficiency on total final energy demand in transportation. Both Mitigation Scenarios show significant reductions in total energy consumption relative to the Reference Scenario due to reductions in vehicle miles traveled and more efficient electric drive trains. In the High Electrification Scenario, hydrogen fuel cell heavy-duty trucks and electric medium-duty trucks are used. In the High Biofuels Scenario, advanced biofuels displace all remaining petroleum fuels by 2050.

[11] Note that these scenarios do not include a detailed analysis of electric heat pump performance in Minnesota.

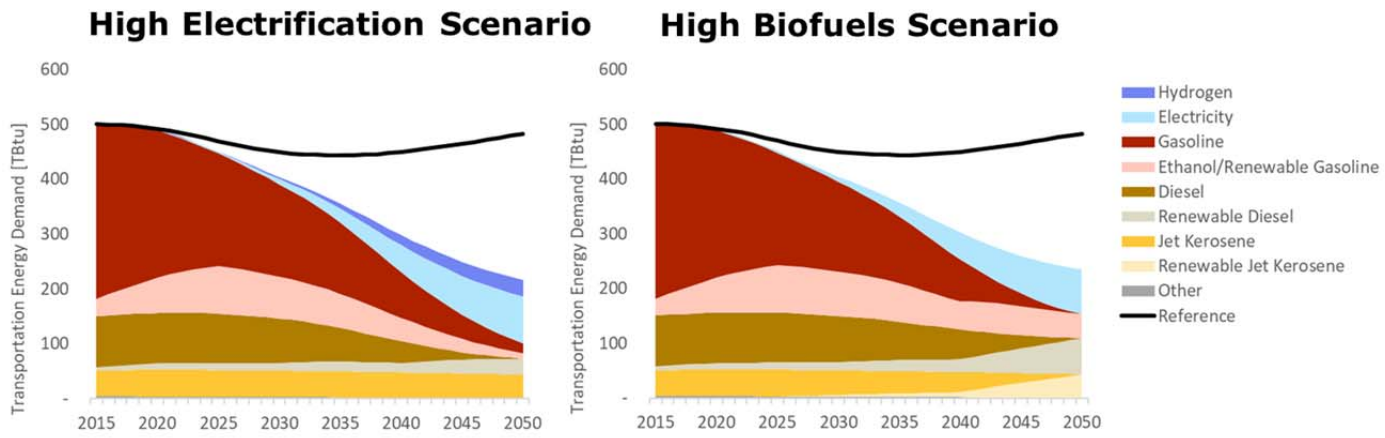


Figure 17. Total energy consumption by fuel and scenario in transportation

3.2.3 ELECTRICITY GENERATION

Each mitigation scenario has very different assumptions about adoption of electric technologies and therefore different projections of electricity demand, as shown in Figure 18. The High Electrification Scenario includes high adoption of electric household appliances, electric vehicles, and electrolysis to produce hydrogen for heavy-duty vehicles. The High Biofuels Scenario includes adoption of electric vehicles in light and medium duty vehicles, but lower electrification in other sectors. This leads to a load increase of 60% relative to 2015 in the High Electrification Scenario, and a much smaller load increase in the High Biofuels Scenario.

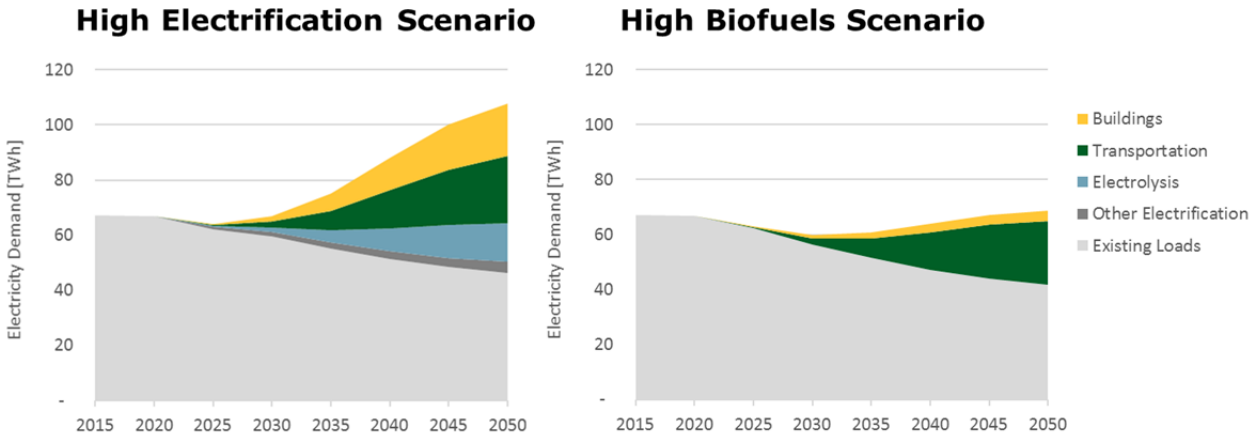


Figure 18. Electricity demand by sector and mitigation scenario

Demands for electricity determine required electricity generation. Each mitigation scenario achieves a 90% share of carbon-free electricity by 2050, but serves very different electricity demand, as shown in Figure 19.

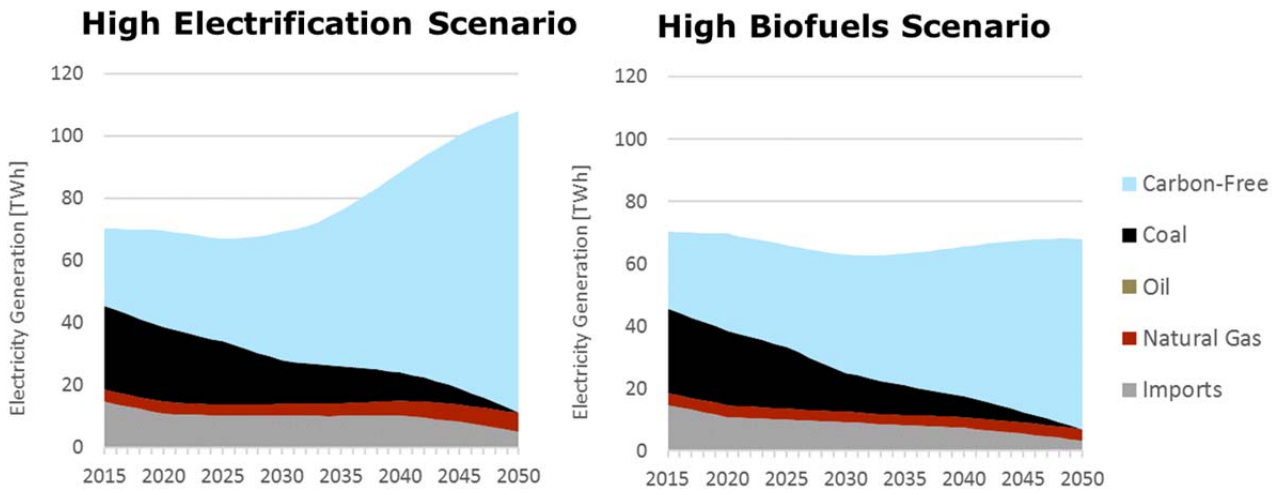


Figure 19. Total electricity generation by sources and mitigation scenario

Our accounting of GHG emissions aligns with the approach taken in the PCA's GHG Inventory, which accounts for all emissions from production of electricity in the electricity generation sector. In our scenarios, this shows a significant reduction in direct GHG reductions due to transitioning to carbon-free resources in our mitigation scenarios (see solid blue bars in Figure 20). In addition to those emission reductions, additional emissions are avoided in buildings and transportation, where electrification avoids emissions from direct combustion of natural gas, gasoline, and diesel fuels. Both Mitigation Scenarios reach 90% carbon-free electricity in 2050, but since the High Electrification scenario serves about 60% higher loads, total emissions in that scenario are 2 Million Short Tons higher, as shown in Table 17Table 18. Also shown are enabled emissions reductions in buildings and transportation in negative hatched bars, representing the petroleum and natural gas emissions avoided by switching to electric vehicles and appliances. Both Mitigation Scenarios see additional emission reductions due to electrification in buildings and transportation. The High Electrification scenario has increased direct electricity emissions of serving higher loads, but avoids an additional 20 MST CO2e elsewhere in the economy through electrification compared to the High Biofuels scenario

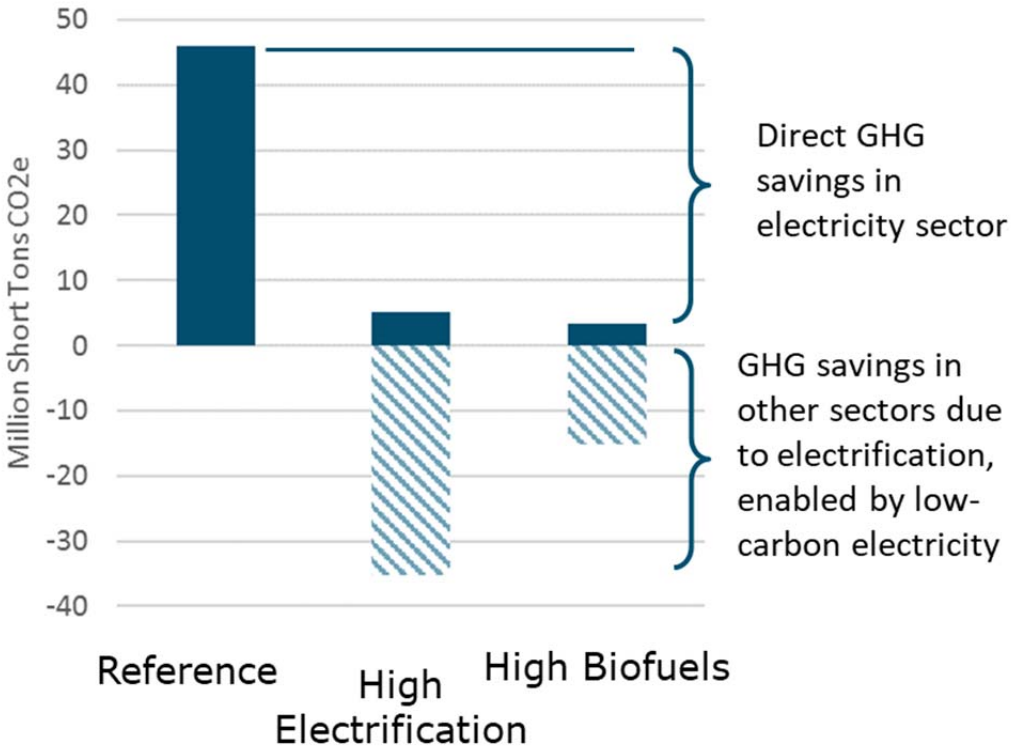


Figure 20. Electric sector GHG emissions by scenario in 2050

Table 17. Electric sector direct GHG emissions and indirect GHG reductions in 2050 [MST CO2e]

	Reference Scenario	High Electrification Scenario	High Biofuels Scenario
Total Direct Emissions from Electricity Generation	46	5	3
Total Emission Reductions from Other Sectors by Switching to Electric Devices		-35	-15

3.2.4 SENSITIVITY ANALYSIS

In addition to mitigation scenarios, we developed three sensitivities to test the impact on emissions of federal action and consumer adoption. The three sensitivities were defined as follows:

1. **Sensitivity #1: Efficiency, Electrification, and Clean Electricity Only**: Evaluates the impact of only pursuing building efficiency, high adoption of electric vehicles and household devices, and clean electricity towards meeting GHG targets
2. **Sensitivity #2: No CAFE Extension**: Evaluates the impact of freezing federal Corporate Average Fuel Economy (CAFE) standards from at 2020 levels.

3. **Sensitivity #3: Lower Electric Adoption**: Evaluates the combined impact of lower consumer adoption of electric vehicles and electric household devices.

3.2.4.1 Sensitivity #1: Efficiency, Electrification, and Clean Electricity

The first sensitivity we tested was a mitigation scenario that focused first on the emissions benefits of pursuing aggressive efficiency and electrification with higher shares of carbon-free electricity. This sensitivity is different from the High Electrification Scenario, which includes measures in other sectors such as industry, agriculture, and waste that allow the scenario to meet economy-wide goals

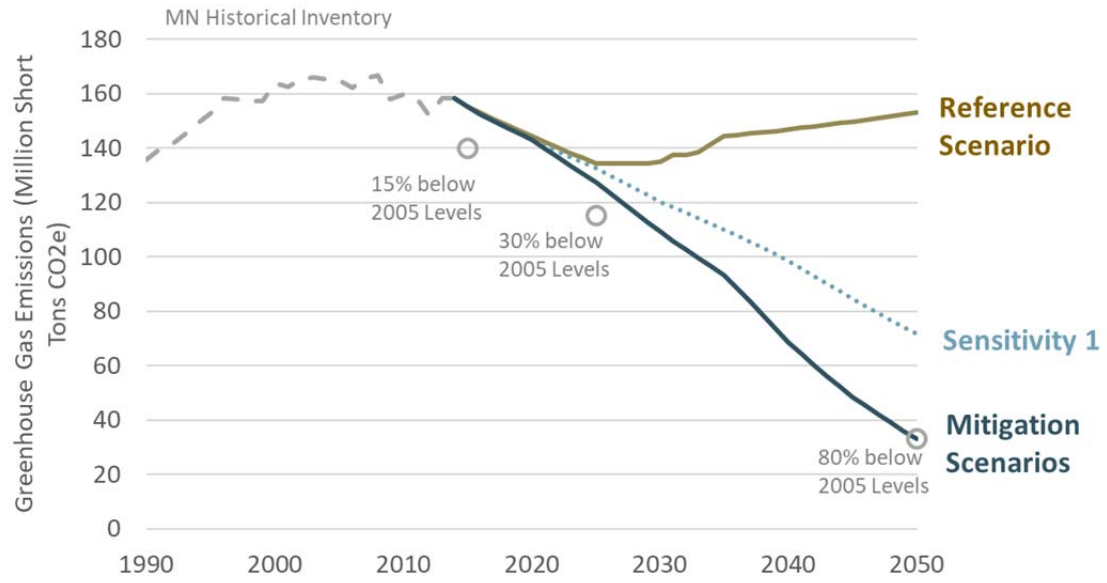


Figure 21. GHG Emissions from Sensitivity 1 relative to Reference and Mitigation Scenarios

This scenario highlights the need for additional measures and actions to meet the economy-wide GHG goal.

3.2.4.2 Sensitivity #2: No CAFE Extension

Federal Corporate Average Fuel Economy (CAFE) Standards impact the on-road efficiency of new light-duty vehicles sold in the US. The current federal administration has proposed freezing the standards at 2020 levels, removing the extension of the program from 2021 to 2026. We ran a sensitivity on our Reference Scenario and High Electrification Scenarios to quantify the impact of removing this federal program.

All scenarios benefit from CAFE improvements through 2020, but the sensitivity assumes no incremental improvement in new vehicles sold starting in 2021.

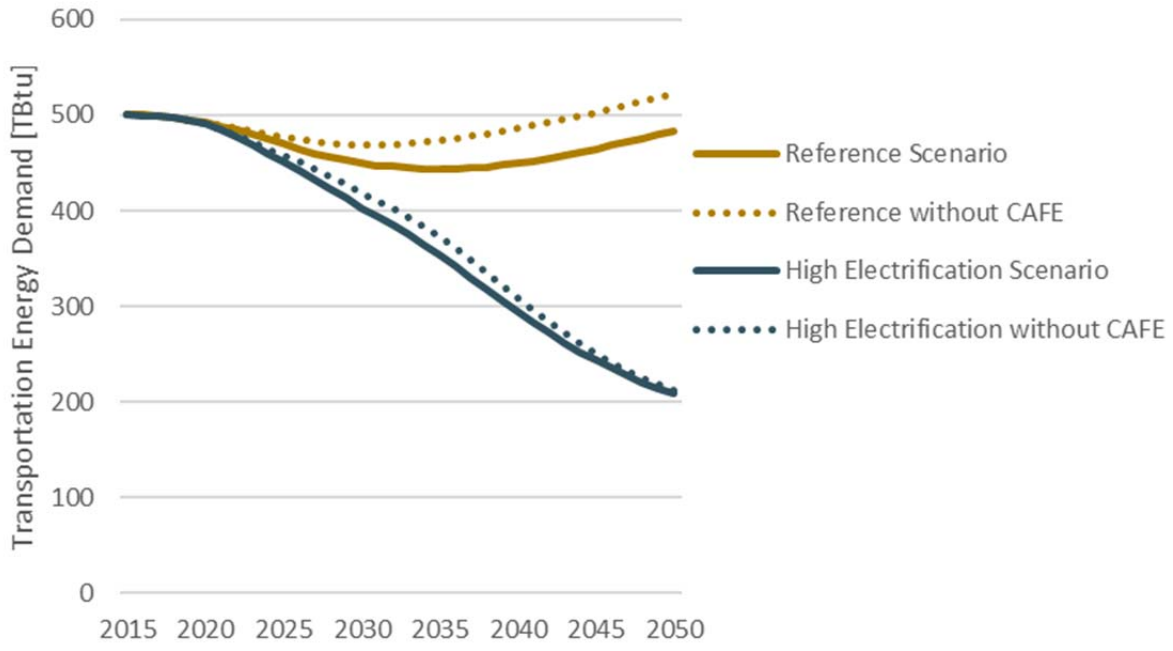


Figure 22. Total energy consumption in transportation by scenario and sensitivity

As shown in Figure 22, federal fuel economy standards have a larger impact on the Reference Scenario, which assumes more internal combustion engine vehicles are sold. Impacts are smaller in the High Electrification Scenario, especially by 2050, due to increasing share of electric vehicles on the road.

Emissions impacts are small relative to economy-wide emissions (see Figure 23). Incremental emissions are 1.5 MST CO2e in 2050 in the Reference Scenario and 0.1 MST CO2e in the High Electrification Scenario.

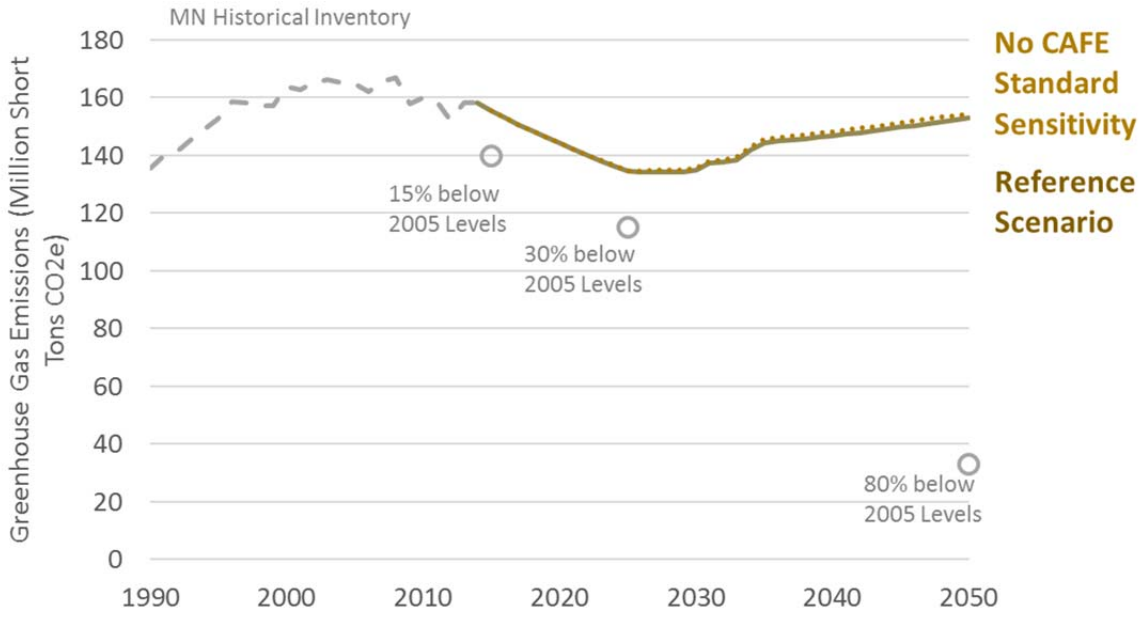


Figure 23. Total Minnesota GHG Emissions in the Reference Scenario and No CAFE Standard Extension Sensitivity

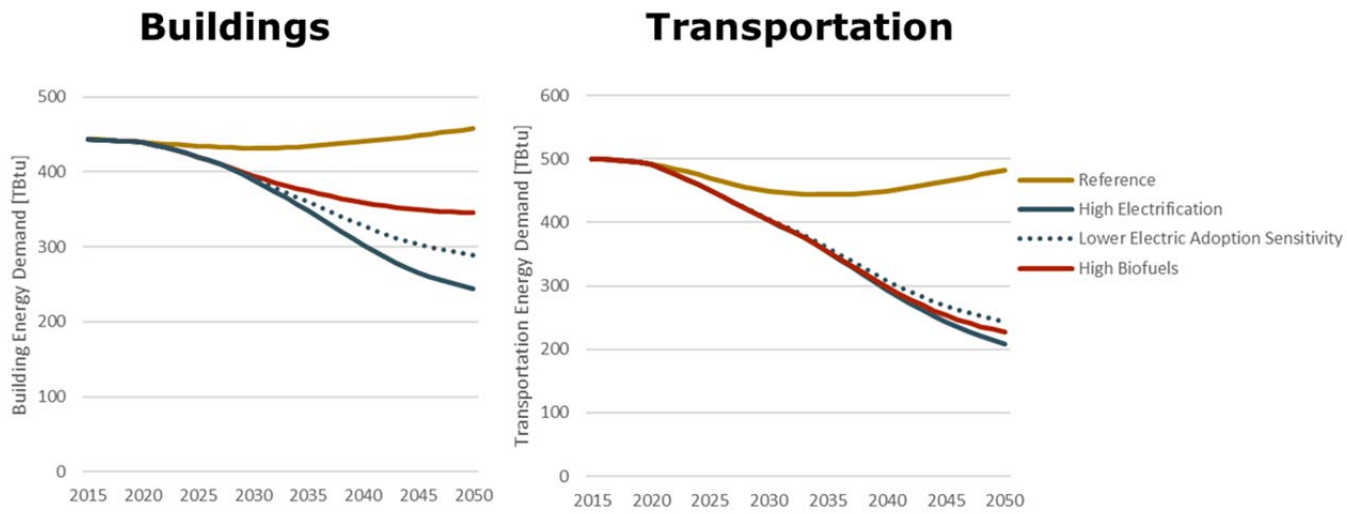
3.2.4.3 Sensitivity #3: Lower Electric Adoption

Rates of consumer adoption for new electric vehicles and electric appliances are uncertain. Our High Electrification Scenario assumes that no internal combustion engine vehicles or natural gas furnaces are sold by 2050. This sensitivity tests a lower level of adoption of key electric technologies, aligning with assumptions from NREL's Electrification Futures Study.[12] Full assumptions are shown in Table 18.

Table 18. New sales assumptions for key electric technologies in Mitigation Scenarios and Sensitivity #3 [% of new sales]

	High Electrification Scenario	High Biofuels Scenario	Lower Electric Adoption Sensitivity
Medium Duty ZEVs	100%	80%	60%
Heavy Duty ZEVs	100%	50%	40%
Heat Pumps in Residential Space Heating	100%	22%	80%
Heat Pumps in Residential Water Heating	100%	33%	30%
Heat Pumps in Commercial Space Heating	98%	2%	60%
Heat Pumps in Commercial Water Heating	100%	8%	30%

Impacts on energy consumption of the Lower Electric Adoption Sensitivity are shown by sector in Figure 24. The largest impacts are seen in buildings, representing the NREL assumption of lower adoption of heat pump water heaters and commercial space heaters than assumed in the High Electrification Scenario.



[12] Report available online: https://www.nrel.gov/docs/fy18osti/71500.pdf

Figure 24. Total energy consumption in buildings and transportation by scenario and sensitivity

Figure 25 shows the emissions gap of 7.9 MST CO2e in 2050 created by lower levels of adoption relative to the High Electrification Scenario. If adoption is lower than expected in the High Electrification Scenario, emissions in Minnesota will fall short of the 2050 NGEA goal and additional measures would need to compensate.

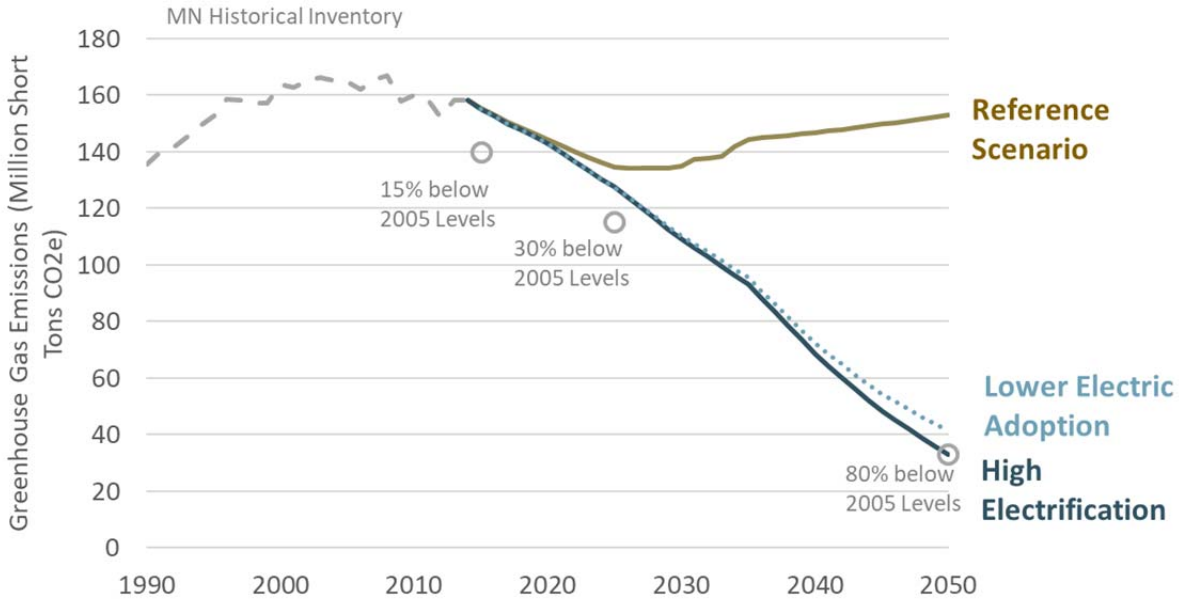


Figure 25. Total Minnesota GHG emissions in Lower Electric Adoption Sensitivity

3.3 Key Findings

The goal of this analysis was to develop a set of long-term economy-wide scenarios that reach the Next Generation Energy Act GHG emission targets for Minnesota of 80% reductions by 2050 relative to 2005 levels. These scenarios provide an exploration of the cross-sectoral implications of meeting economy-wide carbon reduction goals and highlight the role of the electric sector in meeting the state's economy-wide carbon goal. Based on the detailed analysis of Minnesota's statewide energy and emissions, we find the following:

Significant action is needed in every sector to decarbonize the state of Minnesota. This analysis highlights the need for aggressive action across all sectors of Minnesota's economy to meet a statewide goal of 80% reduction below 2005 levels. Reaching the NGEA goal of 80% GHG reductions by 2050 is challenging and will require significant effort beyond current policies within the state.

Buildings and transportation have significant potential to drive load growth, especially after 2025. The High Electrification Scenario highlights the significant potential for adoption of new electric appliances and vehicles, and the potential impact on total electricity requirements for Minnesota utilities. Transportation and building electrification drive electric load growth, especially after 2030, particularly in a future with less biofuels. Electrification of space heating has a particularly large impact on both total load (MWh) and peak demand (MW).

Reasonable electric rates and low costs for new electric devices are essential for electrification. The levels of electrification modeled in buildings and transportation are dependent on consumer adoption, which will benefit from reductions in capital costs and reasonable electric rates, even as the electric grid continues to decarbonize.

Electrification and zero-carbon electricity are necessary but not enough to reach statewide goals. Each Mitigation Scenario shows that increased reliance on low-carbon electricity enables emission reductions by avoiding direct combustion of fossil fuels in households, businesses, and vehicles. We also show that electrification and carbon-free electricity are necessary building blocks of a Mitigation Scenario but are not sufficient without additional measures and actions within the state.

This work highlights areas of future research. The scenarios modeled in this analysis represent an initial modeling assessment of required emission reductions in the state. This analysis has focused on emissions in electricity generation, buildings, and transportation, but further research is needed to explore building electrification impacts in Minnesota's climate and next steps for policy implementation within the state. In other sectors, further research is needed around opportunities in biofuels, agriculture, waste, and industrial sectors.

XCEL - NSP

NSP WIND AND SOLAR INTEGRATION STUDY

FINAL REPORT

October 22, 2018

EnerNex
A CESI Company

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leidos

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SECTION 1 INTRODUCTION

As part of the 2015 NSP Integrated Resource Plan, the Company was ordered to obtain a wind integration study. The objective of this study was to estimate the costs of integrating wind generation onto the Company system. These costs are associated with the uncertain and variable nature of wind generation and represent additional costs required to maintain overall system operations and reliability. Results from the study were used in the resource planning and selection process to ensure that wind generation resources continue to be compared on a level playing field with other technologies.

For the upcoming 2019 IRP filing, the Company employed EnerNex to perform another study to examine the impact of wind and solar integration on the NSP system as well. This study analyzed the integration costs under different levels of renewable penetration in three different time periods to assess the impact of major coal retirements and other key changes. EnerNex contracted with Leidos Engineering to perform the PROMOD analysis.

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SECTION 2 STUDY ASSUMPTOINS

The following list of study assumptions were made in the study.

Data used in the study is based upon the Continued Fleet Change scenario from MISO MTEP18 database. It was agreed that the use of this database would best represent the NSP system for this study.

The NSP resources are located within the LRZ1 zone of MISO and were identified by Xcel – NSP. LRZ1 has other resources and load serving resources that do not belong to Xcel – NSP however have transmission ties to NSP.

Reserves modeled for all MISO in MTEP18 are 1957 MW. NSP reserves are Operating: 27 MW, Spin: 65 MW, and Supplemental: 71 MW.

Incremental wind and solar included in MTEP 18 forecast will not count as part of NSP incremental wind and solar. The assumption being that the MISO increments consider other 3rd party additions to LRZ1. The incremental wind in this study is specific to the NSP system.

The 62MW Marshal Solar Project is added to MTEP18 database.

The 25 MW MN Solar 1 project is removed from the MTEP18 database.

The Fibrowatt Benson: 1 biomass resource is removed from the MTEP18 database. The facility is shutting down.

The Virginia: ST biomass resource is removed from the MTEP18 database. The facility is shutting down.

The Hibbing: ST biomass resource is removed from the MTEP18 database. The facility is shutting down.

Scenario 1: Year 2022 add incremental NSP wind of 1500 MW, 1000 MW solar, 400 MW DR, add BD6

Scenario 2: Year 2027 builds on Scenario 1 adding incremental NSP wind of 1000 MW, 1000 MW solar, and Sherco CC; retire Sherco 1 & 2

Scenario 3: Year 2032 builds on Scenario 2 adding incremental NSP wind of 500 MW, 1000 MW solar, retire King

Scenario 4: Year 2032 also builds on Scenario 2 adding incremental NSP wind of 1500 MW (500 MW from Scenario 3 plus additional 1000 MW), 3000 MW solar (1000 MW from Scenario 3 plus additional 2000 MW), and Retire all Nuclear. The cases studied are shown in Table 1.

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Table 1: Scenarios Studied

Scenario	Year	Wind	Solar	Other Changes
Base	2022	-	-	-
1	2022	+1,500 MW	+1,000 MW	Add 400 MW DR, Add Black Dog 6
2	2027	Scenario 1 +1,000 MW	Scenario 1 +1,000 MW	Retire Sherco 1&2, Add Sherco CC
3	2032	Scenario 2 +500 MW	Scenario 2 +1,000 MW	Retire King
4	2032	Scenario 2 +1,500 MW	Scenario 2 +3,000 MW	Retire All Nuclear

The additional incremental wind and solar resources will be modeled by selecting profiles from the MTEP18 database that are NSP resources in LRZ1. To help minimize congestion each incremental resource will be assigned to an NSP bus capable of handling the increased generation. There are 38 wind profiles and 17 solar profiles in the MTEP18 database from which to select incremental wind and solar profiles. These profiles will be scaled to meet the required capacity for the incremental wind and solar in each scenario.

The MTEP18 database uses wind profiles obtained from the NREL Wind database year 2012. MISO provided the site ID's associated with most of the existing NSP wind plants. Site ID's not identified by MISO were assigned NREL Site ID's by selecting a site close to the PSS/E bus location, shaded ID's in Table 2.

Table 2: NREL Wind Site ID's

NREL Site ID	Wind Plant Name in PROMOD
104639	Adams Community Wind Farm:WT1 12
115771	Agassiz Beach LLC:AB30
88774	Big Blue Wind Farm:WT1 18
98957	Buffalo Ridge I:WT1 26
100238	Buffalo Ridge II:WT1 105
96106	Buffalo Ridge Windplant WPP 19:WT1 73
93199	Chanarambie Station:WT1 57
96604	Community Wind North Farm:WT1
105797	Danielson Wind Farms:WT
92352	East Ridge Wind Project (MN):WT1
91950	Fenton Wind Power Plant:WT1 137
93469	G McNeilus Windfarm:WT1 10_NSP
110282	Grant County Wind Farm (MN):WT1 10
93711	Jeffers Wind Energy Center:WT
95031	Lake Benton I:WT1 143
89269	Lake Benton II:EXIS

98718	Lakota Ridge:NMO1
97410	MinnDakota Wind Project:WT1 100
93963	Moraine Wind:WT1 34
90285	Pleasant Valley WF
90461	Prairie Rose Wind:WT1 119
93697	Ridgewind Wind Project:WT1 11
98959	Shaokatan Hills:6150
92745	Uilk Wind Farm:WT1
91947	Valley View Transmission:WT1 5
120485	Velva Wind Farm:WT1 18
92755	Viking Wind Power Project:1
92752	Woodstock Windfarm:WIND
92751	Chanarambie Wind Farm
88743	Christoffer Wind Energy Project:1
116116	Courtenay Wind Farm:WT1 100
92751	CP Node_NSP_CHARA_TR4
104629	CP Node_NSP_WESTSID1
90700	Ewington Energy Wind Project:WT1 10
92179	Freeborn Wind Resource Project
89068	Grand Meadow Wind Farm:WT1 67
89317	Mower County Wind Farm (FPL):WT1 43
89487	Nobles Wind Project:WT1 134

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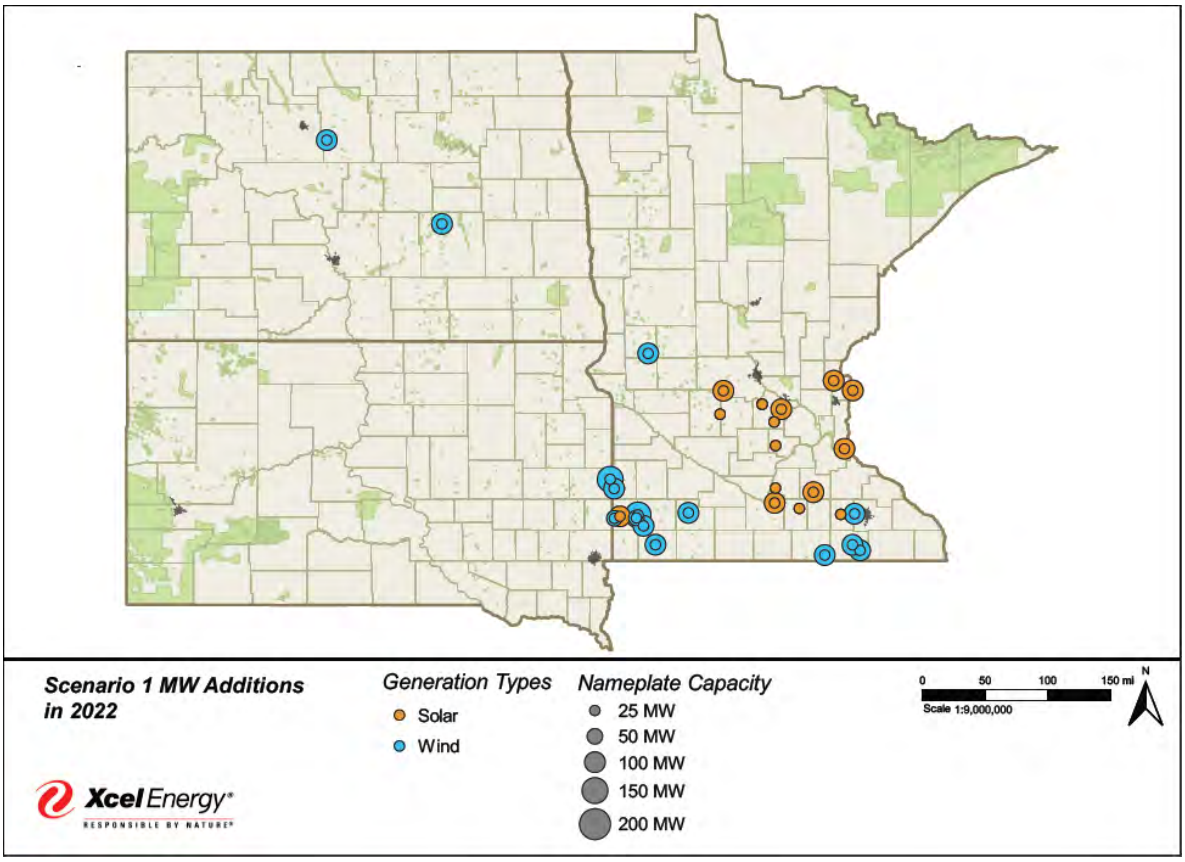

Figure 1: Scenario 1 Wind and Solar PV Site Map

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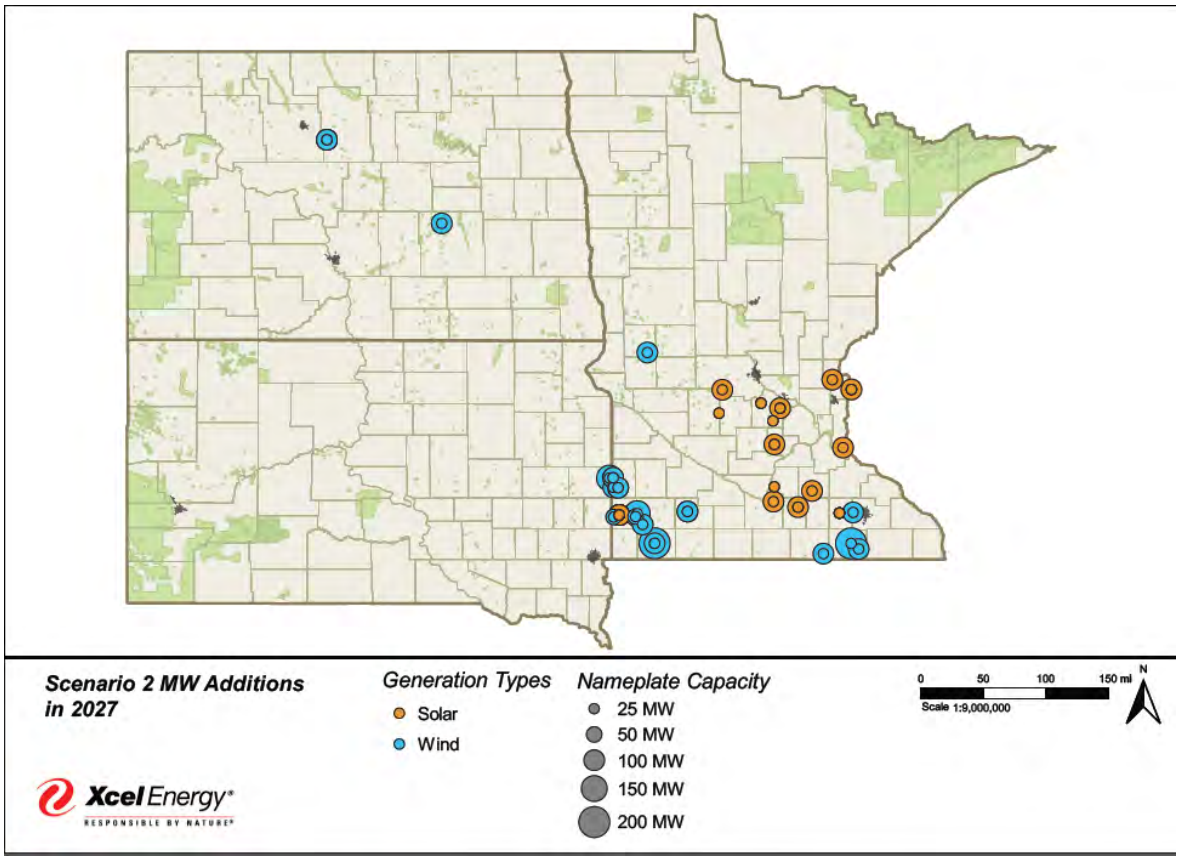

Figure 2: Scenario 2 Wind and Solar PV Site Map

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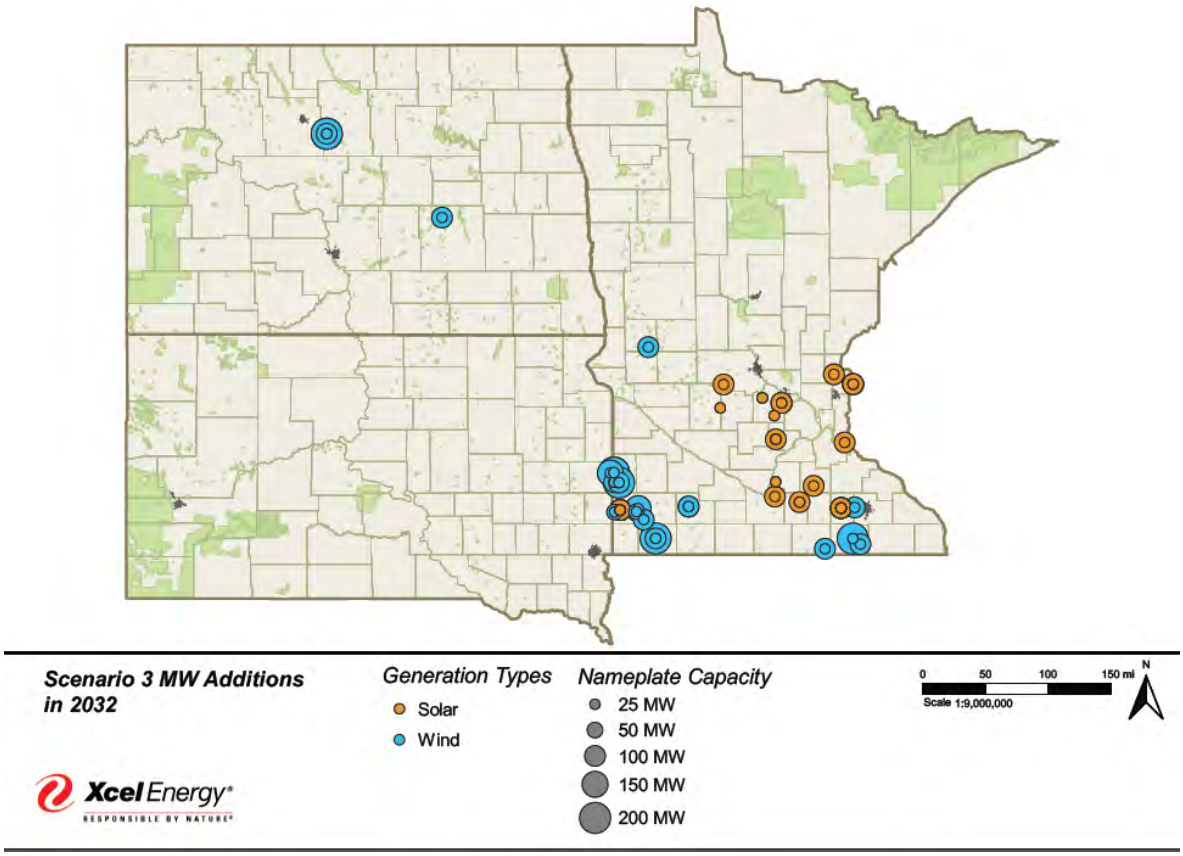

Figure 3: scenario 3 Wind and Solar PV Site Map

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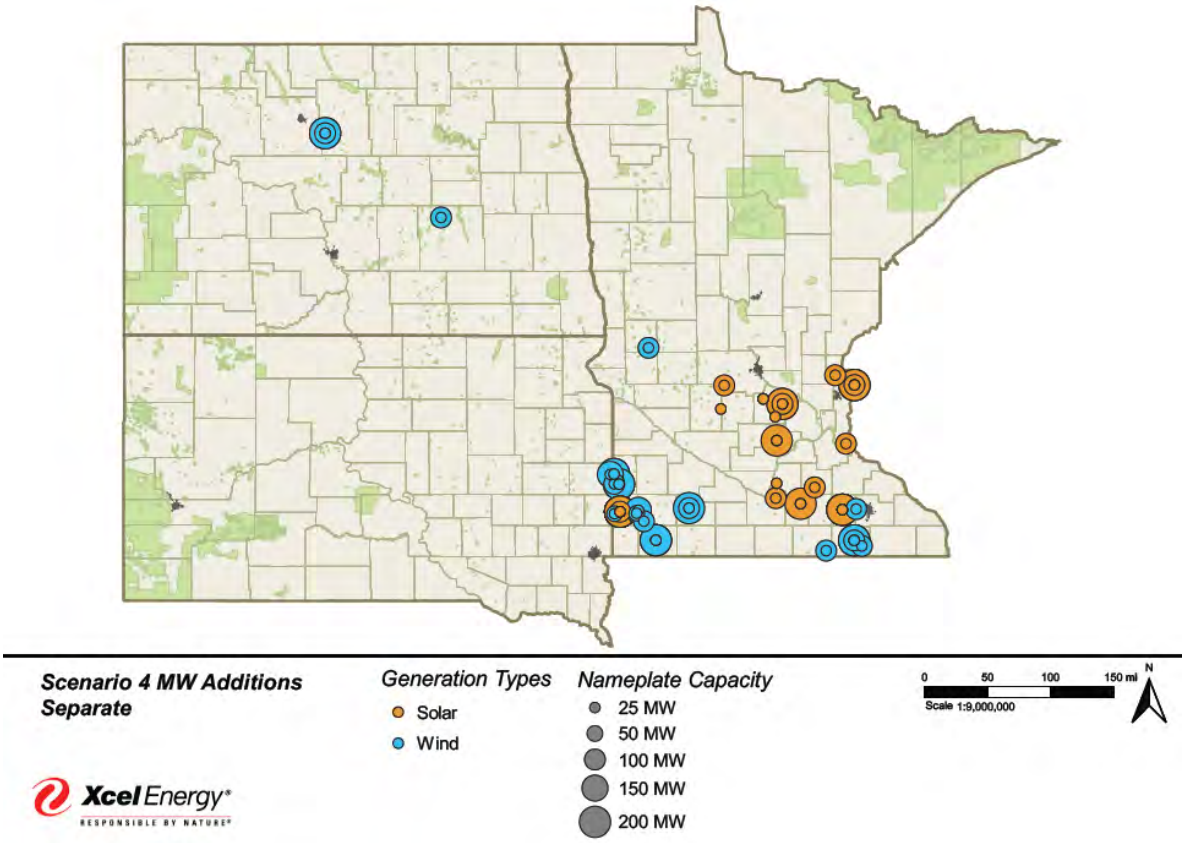

Figure 4: Scenario 4 Wind and Solar PV Site Map

Day ahead forecasts for incremental wind were obtained directly from the NREL Wind database.

Day ahead forecasts for solar and Load were calculated by NSP using a statistical approach using as a basis the actual and forecast data for solar and Load. For solar Northstar and Marshal Plant data from the most recent 12 months were used assuming this would mimic the current level of forecast accuracy. Whenever actual generation profile = 0 MW the forecast for that hour would also be 0 MW. Solar production included generation plus curtailed energy was separated into deciles of 0% -10%, 10% - 20%, etc. A Forecast % adder calculated by taking the difference between Forecast and Gen and dividing by the capacity of solar plant. The associated forecast % is calculated by summing Generation % by capacity of solar facility. The Northstar decile patterns were used to develop forecasts for 100MW facilities. The Marshal Plant decile patterns were used to develop forecasts for 25 MW facilities. Forecast profiles were not allowed to be less than zero or larger than 100% capacity. This method produced Forecast profiles with slightly higher capacity factor than generation profile (over forecast). In the most recent 12 month period both Northstar and Marshal Forecasts had higher capacity factor than Actual generation. The MAPE for the aggregate solar Forecast is better than that for all individual solar plants. This is expected due to geographic diversity of the various solar plants.

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SECTION 3 METHODOLOGY

The NSP system is a dispatched by the MISO. Therefore the evaluation of the impact of wind and solar PV on the NSP system requires modeling the MISO and extracting the dispatch costs for the NSP resources. The MISO employs the PROMOD tool in evaluation of its system and developed the MTEP18 database as a model representing the operating companies under its jurisdiction. This study used the MTEP18 database and PROMOD tool in modeling the increase in wind and solar PV penetration on the NSP system. Leidos Engineering performed the PROMOD analysis.

Four scenarios were modeled as described in the assumptions section above. Each scenario applied additional wind and solar PV to the NSP system in addition to the base wind and solar modeled in the MTEP18 database.

Two PROMOD runs were performed for each scenario. The first is a "No error" run (NE) that models a perfect knowledge of actual production for NSP wind and solar resources, with no forecast error assumed. The final production energy profiles for NSP wind and solar generation were used in both the unit commitment decision (similar to Day-ahead market decision) and dispatch optimization (similar to Real-time market). This run also assumes perfect knowledge of the actual NSP load in both commitment and dispatch steps. This run provides the optimal operating dispatch for the NSP resources.

The second PROMOD run is a "Forecast Error" run (FE) that takes into account the day-ahead forecast for wind, solar PV and NSP load. This run performs the unit commitment of the NSP resources based upon the wind, solar PV and NSP load day-ahead forecasts and then performs the dispatch optimization of all resources based upon the actual wind, solar PV and NSP load. The result of this run is different from the first run in that it incorporates the cost of uncertainty due to the wind, solar PV and load forecast errors. For example an over forecast of wind and Solar PV can result in an under commitment of other resources, assuming the load forecast is the same as the actual. An hourly chronological program like PROMOD allows for various combinations of over and under forecasts of wind, solar PV and load throughout the studied year.

The results from the No Error (NE) and Forecast Error runs (FE) are compared for different analysis that will be described later in the report. These include spinning reserve, resource cycling, fuel burn and integration cost due to forecast error.

The data required for modeling wind and solar PV resources in the NSP system was collected with the support of NSP. Wind production and day ahead forecasts were extracted from the NREL wind database using base year 2012. This is consistent with the wind data modeled in the MTEP18 database. Solar production data and the NSP load data were extracted by PROMOD from the MTEP18 database for study year 2022. The Solar and NSP load day ahead forecast were derived statistically from existing solar and NSP load day ahead forecast and actual data. The wind, solar PV and load data were analyzed with results shown in separate presentation.

In order to insure the additional wind and solar PV energy can be integrated into the NSP system a preliminary analysis using proxy wind and solar profiles were used and modeled in PROMOD. Each scenario was set up with the specified generator retirements and incremental renewable generation at transmission buses as designated by NSP. Congestion was measured by flow-gate shadow price ($/MWh), the marginal cost of system dispatch to mitigate congestion. Over 600 flow gates in MTEP 18

were assessed to identify flow gates that become very congested to incremental NSP Renewables. Severe congestion on the Adams 161/69 transformer Adams – Beaver Crk 161 flow-gate was identified in the preliminary analysis of PROMOD runs.. It was then noted that the MTEP18 database being used was lacking an update from the MISO for this transmission line. The upgrade was provided by MISO and implemented in the database for the study.

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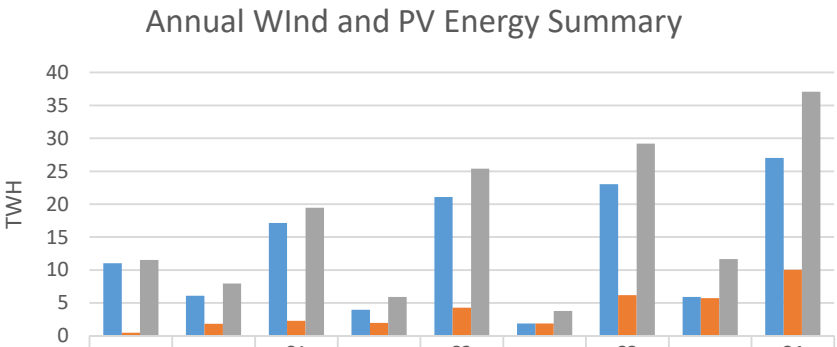
SECTION 4 RENEWABLE CHARACTERIZATION

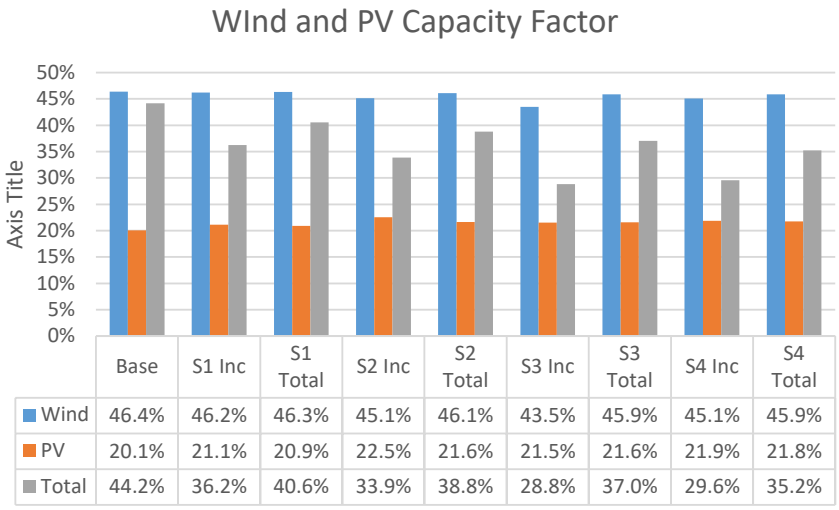
This section provides an analysis of the wind and solar PV modeled in this study. The annual wind and solar PV annual production for each scenario is shown in Figure 5. The total base renewable energy in 2022 is 11.5 TWH of which 11.1 TWH is wind. Scenario 2 models year 2027 builds off of Scenario 1 with total annual renewable energy of 19.5 TWH with wind contributing 17.1 TWH. Scenario 3 and Scenario 4 models year 2032 and are build off of Scenario 2. Scenario 3 has total annual renewable energy of 29.2 TWH of which wind contributes 23 TWH and Scenario 4 has total annual renewable energy of 37.1 TWH of which 27 TWH consists of wind.



	Base	S1 Inc	S1 Total	S2 Inc	S2 Total	S3 Inc	S3 Total	S4 Inc	S4 Total
Wind	11.1	6.1	17.1	4.0	21.1	1.9	23.0	5.9	27.0
PV	0.5	1.9	2.3	2.0	4.3	1.9	6.2	5.7	10.0
Total	11.5	7.9	19.5	5.9	25.4	3.8	29.2	11.7	37.1

Figure 5: Scenario Renewable Annual Energy Summary

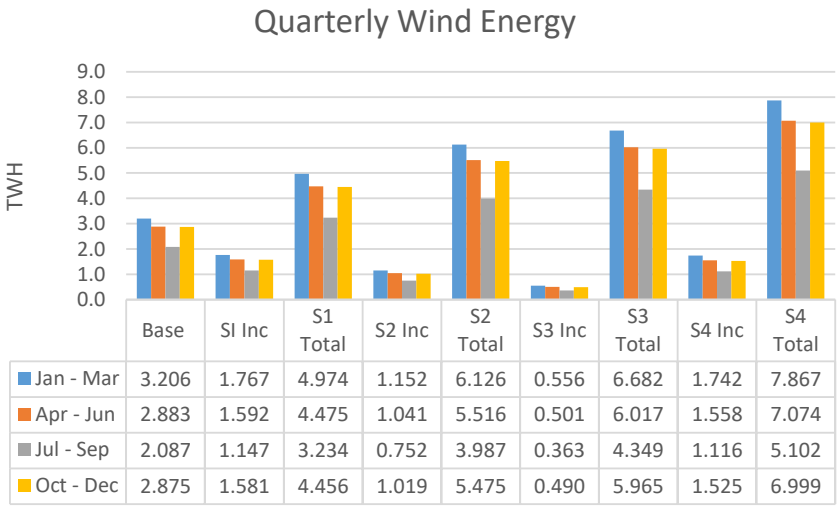
The capacity factors for the aggregated wind and solar PV resources in the study are shown in Figure 6. The Capacity factors for wind in each scenario are in the 46% range with the Base, Scenrio1, Scenario 2, Scenario 3 and Scenario 4 having capacity factors of 46.4%, 46.3%, 46.1%, 45.9% and 45.1% respectively. Solar PV aggregated annual capacity factors for the Base, Scenario1, Scenario 2, Scenario 3 and Scenario 4 are 20.1%, 20.9%, 21.6%, 21.6% and 21.9%.



	Base	S1 Inc	S1 Total	S2 Inc	S2 Total	S3 Inc	S3 Total	S4 Inc	S4 Total
Wind	46.4%	46.2%	46.3%	45.1%	46.1%	43.5%	45.9%	45.1%	45.9%
PV	20.1%	21.1%	20.9%	22.5%	21.6%	21.5%	21.6%	21.9%	21.8%
Total	44.2%	36.2%	40.6%	33.9%	38.8%	28.8%	37.0%	29.6%	35.2%

Figure 6: Scenario Renewable Annual Capacity Factor

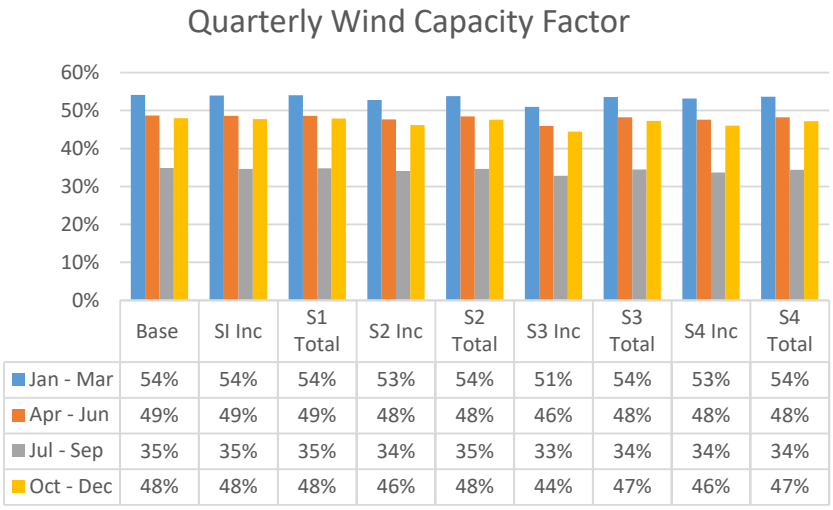
Examining the quarterly renewable energy production, wind energy production is greatest in the January through March months with July through September being the lowest production time in the year. The Wind energy production in the April through June and October through December months are approximately the same Figure 7.



	Base	SI Inc	S1 Total	S2 Inc	S2 Total	S3 Inc	S3 Total	S4 Inc	S4 Total
Jan - Mar	3.206	1.767	4.974	1.152	6.126	0.556	6.682	1.742	7.867
Apr - Jun	2.883	1.592	4.475	1.041	5.516	0.501	6.017	1.558	7.074
Jul - Sep	2.087	1.147	3.234	0.752	3.987	0.363	4.349	1.116	5.102
Oct - Dec	2.875	1.581	4.456	1.019	5.475	0.490	5.965	1.525	6.999

Figure 7: Scenario Quarterly Aggregated Wind Production

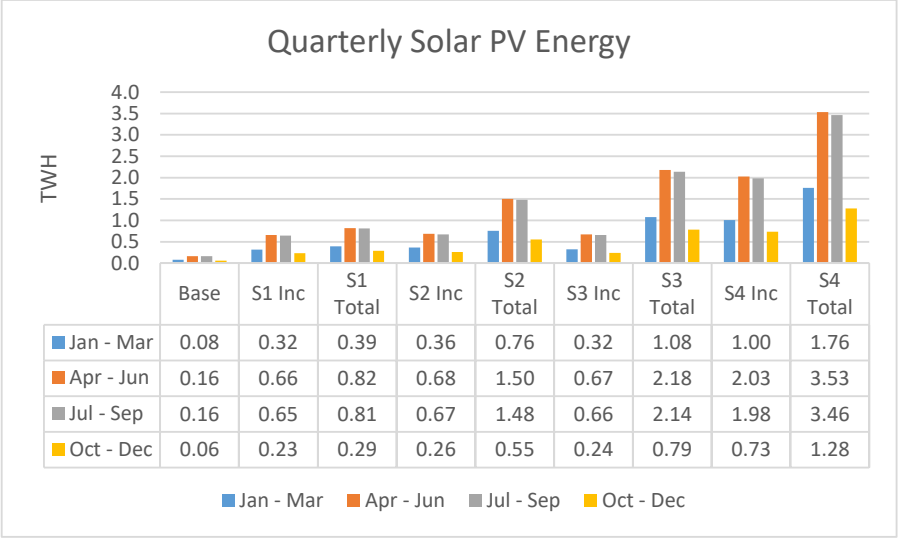
The quarterly wind capacity factors are consistent across all scenarios with capacity factor being the greatest in the January to March months and lowest in the July through September months Figure 8



	Base	SI Inc	S1 Total	S2 Inc	S2 Total	S3 Inc	S3 Total	S4 Inc	S4 Total
Jan - Mar	54%	54%	54%	53%	54%	51%	54%	53%	54%
Apr - Jun	49%	49%	49%	48%	48%	46%	48%	48%	48%
Jul - Sep	35%	35%	35%	34%	35%	33%	34%	34%	34%
Oct - Dec	48%	48%	48%	46%	48%	44%	47%	46%	47%

Figure 8: Scenario Quarterly Aggregated Wind Capacity Factor

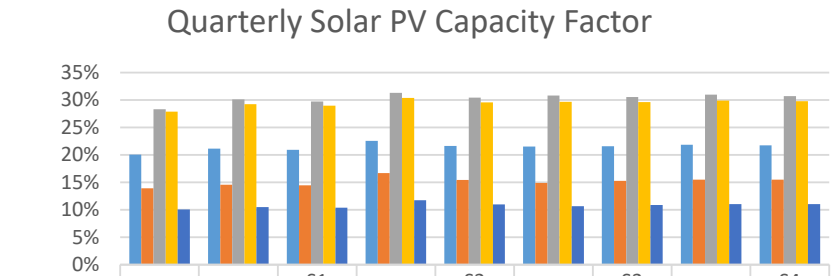
The quarterly solar PV production is about the same for the quarters April through June and July through September. The minimum solar PV production occurs in the October through December time period as shown in Figure 9.



	Base	S1 Inc	S1 Total	S2 Inc	S2 Total	S3 Inc	S3 Total	S4 Inc	S4 Total
Jan - Mar	0.08	0.32	0.39	0.36	0.76	0.32	1.08	1.00	1.76
Apr - Jun	0.16	0.66	0.82	0.68	1.50	0.67	2.18	2.03	3.53
Jul - Sep	0.16	0.65	0.81	0.67	1.48	0.66	2.14	1.98	3.46
Oct - Dec	0.06	0.23	0.29	0.26	0.55	0.24	0.79	0.73	1.28

Figure 9: Scenario Quarterly Aggregated Solar PV Production

The quarterly solar PV capacity factor is about the same for the quarters April through June and July through September with a range from 28% to 31%. The minimum solar PV production occurs in the October through December time period with range of 10% to 12% as shown in Figure 10



	Base	S1 Inc	S1 Total	S2 Inc	S2 Total	S3 Inc	S3 Total	S4 Inc	S4 Total
Annual	20%	21%	21%	23%	22%	22%	22%	22%	22%
Jan - Mar	14%	15%	14%	17%	15%	15%	15%	16%	15%
Apr - Jun	28%	30%	30%	31%	30%	31%	31%	31%	31%
Jul - Sep	28%	29%	29%	30%	30%	30%	30%	30%	30%
Oct - Dec	10%	11%	10%	12%	11%	11%	11%	11%	11%

Figure 10: Quarterly Scenario Aggregated Solar PV Capacity Factor

Wind variability was quantified in this study by examining the change in aggregated wind production from one hour to the next. An up – ramp is defined when the present hour is greater than the previous hour and a down – ramp is defined when the present hour is less than the previous hour. This analysis evaluated the hour to hour aggregated changes in wind production over the study year for each scenario. As expected the maximum up and down ramps increase as the penetration of wind increases. The maximum up – ramp range is 879 MW for the Base to 2087 MW hour to hour change in Scenario 4. Similarly calculated the maximum down – ramp range is 1132 MW for the Base to 2770 MW in Scenario 4. Figure 11 shows the plot of the hour to hour changes over the year sorted from high to low. A Histogram shows the up – ramps and down – ramps in Figure 12. Table 3 shows the top 5 up and down ramps for each scenario. Table 4 shows the percent of hours when up – ramps and down – ramps exceed 5% and 10% of the wind rated capacity.

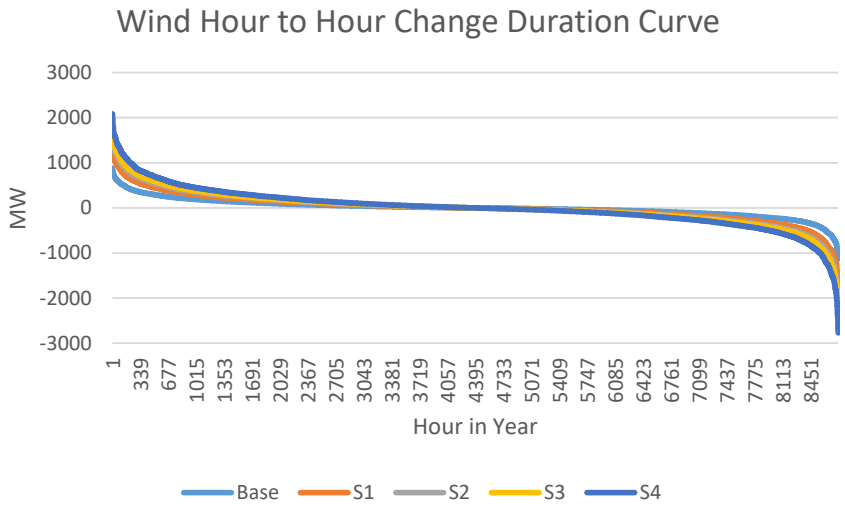


Figure 11: Wind One Hour Ramp Duration Curve

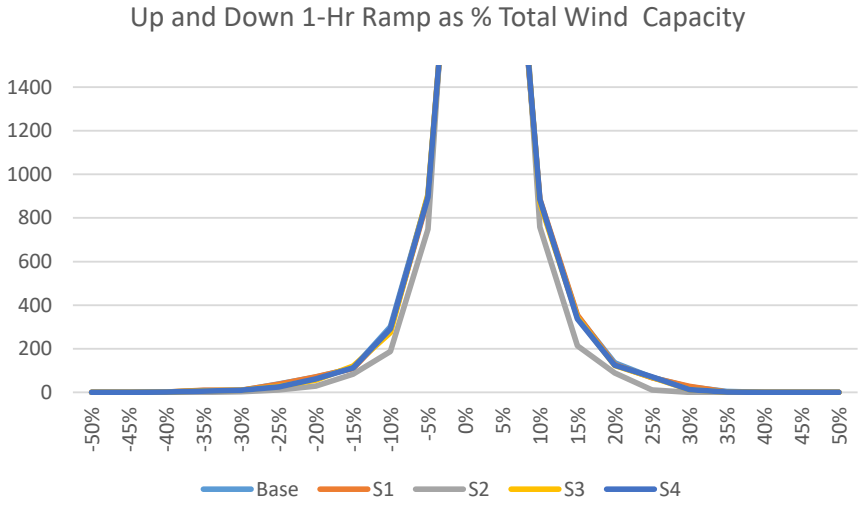


Figure 12: Wind One Hour Ramp Histogram

Table 3: Aggregated Wind One Hour Up and Down Ramp Ranking

Largest MW Up and down ramps										
	Wind Capacity MW	2712		4212		5212		5712		6712
Up	Date	Base	Date	S1	Date	S2	Date	S3	Date	S4
1	06/28/2012 01:00	879	08/30/2012 00:00	1293	08/30/2012 00:00	1648	08/30/2012 00:00	1830	08/30/2012 00:00	2087
2	02/06/2012 23:00	849	11/28/2012 22:00	1276	11/28/2012 22:00	1570	11/28/2012 22:00	1698	11/28/2012 22:00	2024
3	05/03/2012 07:00	838	11/30/2012 23:00	1260	02/06/2012 23:00	1557	02/06/2012 23:00	1662	05/03/2012 07:00	1964
4	08/30/2012 00:00	824	05/03/2012 07:00	1256	11/30/2012 23:00	1487	10/21/2012 00:00	1627	02/06/2012 23:00	1951
5	11/30/2012 23:00	811	02/06/2012 23:00	1239	10/21/2012 00:00	1486	11/30/2012 23:00	1571	10/21/2012 00:00	1866
Down	Date	Base	Date	S1	Date	S2	Date	S3	Date	S4
5	07/23/2012 11:00	1028	07/20/2012 12:00	1570	11/08/2012 15:00	1880	09/16/2012 14:00	2094	11/08/2012 15:00	2444
4	06/28/2012 13:00	1038	06/28/2012 13:00	1580	09/16/2012 14:00	1974	11/08/2012 15:00	2095	09/16/2012 14:00	2519
3	09/16/2012 14:00	1047	09/16/2012 14:00	1632	07/20/2012 12:00	2064	06/06/2012 12:00	2227	06/06/2012 12:00	2639
2	06/06/2012 12:00	1101	06/06/2012 12:00	1733	06/06/2012 12:00	2080	07/20/2012 12:00	2330	07/20/2012 12:00	2686
1	10/21/2012 15:00	1132	10/21/2012 15:00	1742	10/21/2012 15:00	2141	10/21/2012 15:00	2334	10/21/2012 15:00	2770

Table 4: Up – Ramp and Down – Ramp as Percent of Wind Capacity

Number and Percent of ramps in year within +/- % of Rated Capacity					
	Base	**S1**	**S2**	**S3**	**S4**
Hrs -5%	2956	3005	3327	2975	3004
Hrs +5%	2927	2902	3324	2988	2946
% Hrs in Year	**67%**	**67%**	**76%**	**68%**	**68%**
Hrs -10%	3858	3893	4076	3884	3900
Hrs +10%	3804	3788	4082	3858	3831
% Hrs in Year	**87%**	**88%**	**93%**	**88%**	**88%**

Solar PV variability was quantified in this study in a similar way as wind by examining the change in aggregated Solar PV production from one hour to the next. This study evaluated the hour to hour aggregated changes in solar PV production over the study year for each scenario. As expected the maximum up and down ramps increase as the penetration of solar PV increases. The maximum up – ramp range is 94 MW for the Base to 2252 MW hour to hour change in Scenario 4. Similarly calculated the maximum down – ramp range is 93 MW for the Base to 2351 MW in Scenario 4. Figure 13 shows the plot of the hour to hour changes over the year sorted from high to low. Table 3 shows the top 5 up and down ramps for each scenario. A Histogram shows the up – ramps and down – ramps in Figure 14. Table 5 shows the top 5 up and down ramps for each scenario. Table 6 shows the percent of hours when up – ramps and down – ramps exceed 5% and 10% of the solar PV rated capacity.

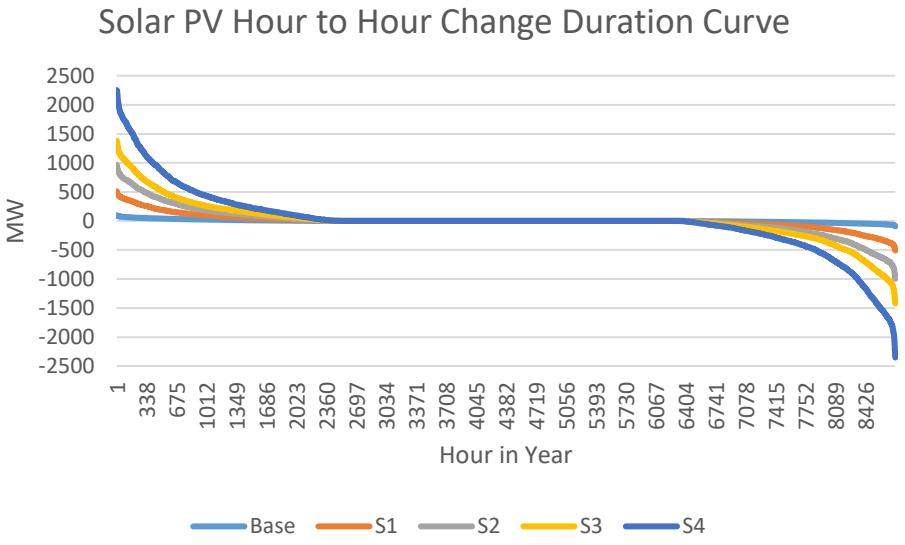


Figure 13: Solar PV One Hour Ramp Duration Curve

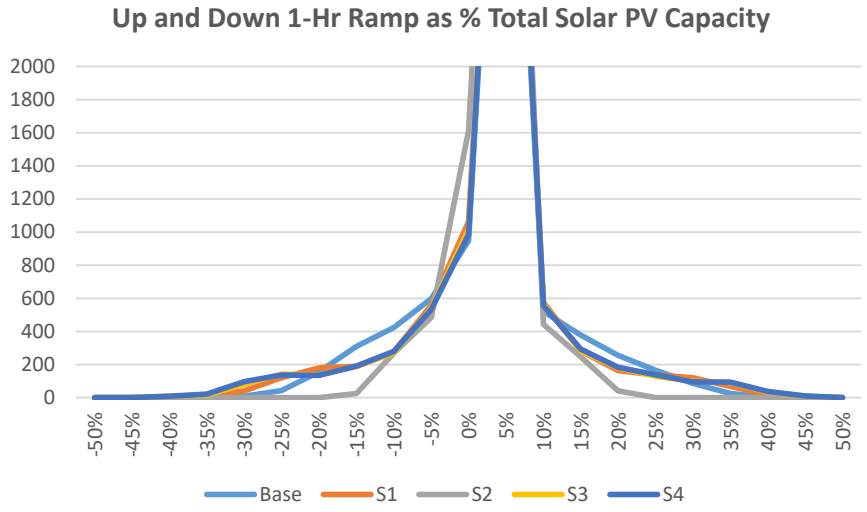


Figure 14: Solar PV One Hour Ramp Histogram

Table 5: Aggregated Solar PV One Hour Up and Down Ramp Ranking

Largest MW up and down ramps										
Solar PV Capacity MW		264		1264		2264		3264		5264
Up	Date	Base	Date	S1	Date	S2	Date	S3	Date	S4
1	04/12/2022 09:00	94	04/12/2022 09:00	510	05/03/2022 12:00	966	04/12/2022 09:00	1381	04/12/2022 09:00	2252
2	02/27/2022 10:00	93	04/09/2022 09:00	484	04/08/2022 10:00	952	04/14/2022 09:00	1364	01/21/2022 11:00	2249
3	05/12/2022 09:00	93	04/14/2022 09:00	483	04/12/2022 09:00	934	01/21/2022 11:00	1352	04/14/2022 09:00	2244
4	04/07/2022 10:00	93	04/29/2022 09:00	481	04/14/2022 09:00	925	04/13/2022 09:00	1336	03/12/2022 10:00	2199
5	04/08/2022 10:00	92	04/08/2022 10:00	480	06/13/2022 09:00	922	04/07/2022 10:00	1334	04/13/2022 09:00	2197
Down	Date	Base	Date	S1	Date	S2	Date	S3	Date	S4
5	04/11/2022 20:00	83	02/12/2022 19:00	488	02/14/2022 19:00	938	02/14/2022 19:00	1357	02/14/2022 19:00	2234
4	04/12/2022 20:00	83	04/11/2022 20:00	488	04/12/2022 20:00	940	04/12/2022 20:00	1364	03/17/2022 19:00	2264
3	04/25/2022 15:00	84	04/12/2022 20:00	496	02/13/2022 19:00	984	04/13/2022 20:00	1404	02/13/2022 19:00	2315
2	02/10/2022 19:00	86	02/13/2022 19:00	501	02/12/2022 19:00	989	02/13/2022 19:00	1408	04/13/2022 20:00	2321
1	02/21/2022 19:00	93	02/21/2022 19:00	507	03/17/2022 19:00	995	02/12/2022 19:00	1420	02/12/2022 19:00	2351

Table 6: Up – Ramp and Down – Ramp as Percent of Solar PV Capacity

Number and Percent of 1-Hr Solar PV ramps in year within +/- 5% of Rated Capacity					
	Base	S1	S2	S3	S4
Hrs -5%	947	1062	1612	1016	986
Hrs +5%	4840	4957	5639	4976	4970
% Hrs in Year	66%	69%	83%	68%	68%
Hrs -10%	1544	1620	2097	1556	1518
Hrs +10%	5361	5534	6082	5541	5526
% Hrs in Year	79%	82%	93%	81%	80%

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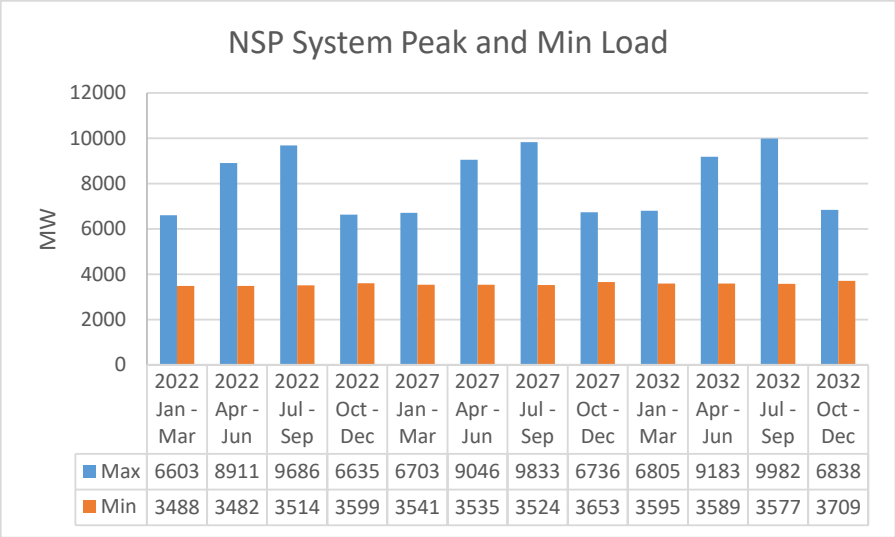
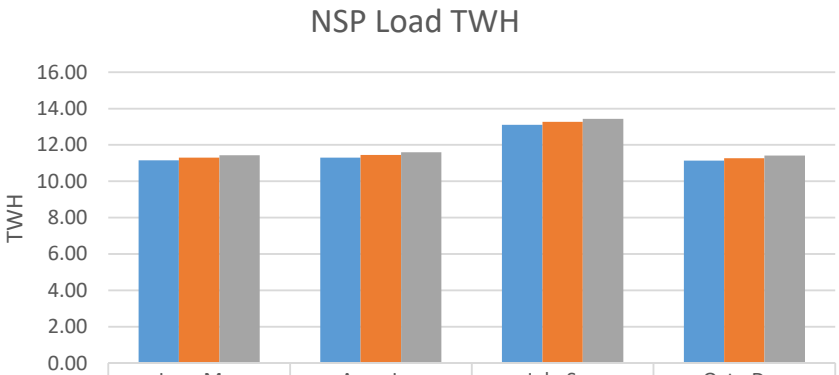
SECTION 5 NSP SYSTEM LOAD

NSP system load for the study years was extracted from the MTEP18 database. Peak load in 2022 is 9686 MW and escalated to 9833 MW in 2027 and again to 9982 MW in 2032. Minimum load in each study year of 2022, 2027 and 2032 is 3482 MW, 3524 MW and 3577 MW respectively. The quarterly NSP system peak and minimum load for each scenario is shown in Figure 15. The annual NSP load demand in TWH in 2022 is 46, 69 TWH, in 2027 load demand is 47.28 TWH and in 2032 load demand is 47.89 TWH as shown in Figure 16. The NSP load factor is shown in Figure 17.



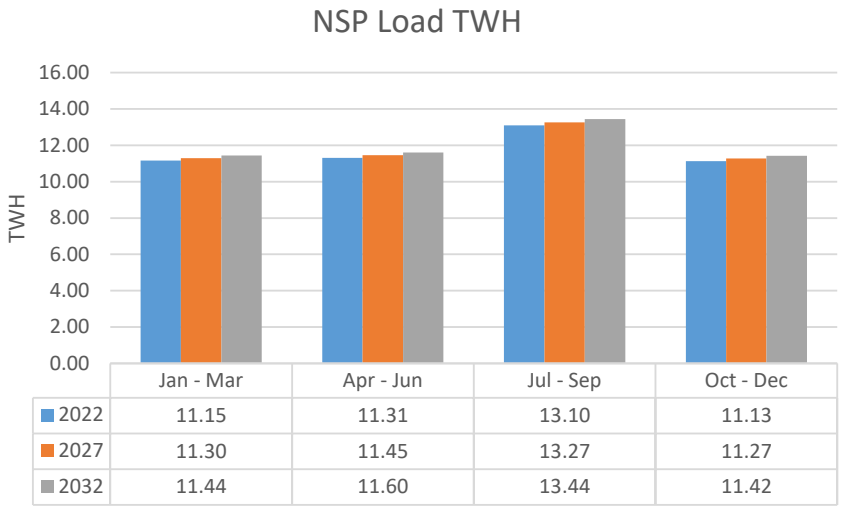
	2022 Jan - Mar	2022 Apr - Jun	2022 Jul - Sep	2022 Oct - Dec	2027 Jan - Mar	2027 Apr - Jun	2027 Jul - Sep	2027 Oct - Dec	2032 Jan - Mar	2032 Apr - Jun	2032 Jul - Sep	2032 Oct - Dec
Max	6603	8911	9686	6635	6703	9046	9833	6736	6805	9183	9982	6838
Min	3488	3482	3514	3599	3541	3535	3524	3653	3595	3589	3577	3709

Figure 15: NSP System Load for Each Scenario



	Jan - Mar	Apr - Jun	Jul - Sep	Oct - Dec
2022	11.15	11.31	13.10	11.13
2027	11.30	11.45	13.27	11.27
2032	11.44	11.60	13.44	11.42

Figure 16: NSP Load Demand by Quarter



	Jan - Mar	Apr - Jun	Jul - Sep	Oct - Dec
2022	11.15	11.31	13.10	11.13
2027	11.30	11.45	13.27	11.27
2032	11.44	11.60	13.44	11.42

Figure 17: NSP Load Factor by Quarter

The NSP load variability, change from hour to hour, was examined in a similar way as the variable wind and solar PV resources. The changes in NSP system load from hour to hour was evaluated and ranked from largest hourly change to smallest Figure 18. In addition the hourly changes were evaluated in a histogram placing the hourly changes into bins representing 25 MW bins, Figure 19. Table 7 shows the five largest and smallest changes in hourly load.

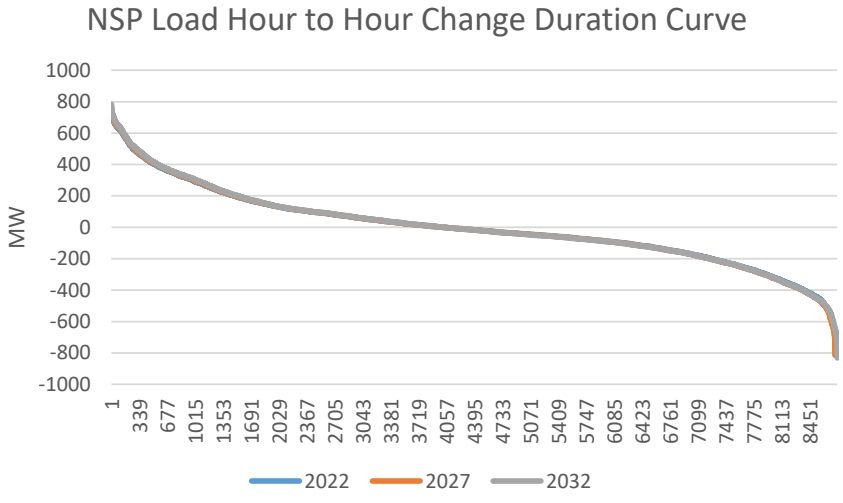


Figure 18: Study Year Load Variability Duration Curve

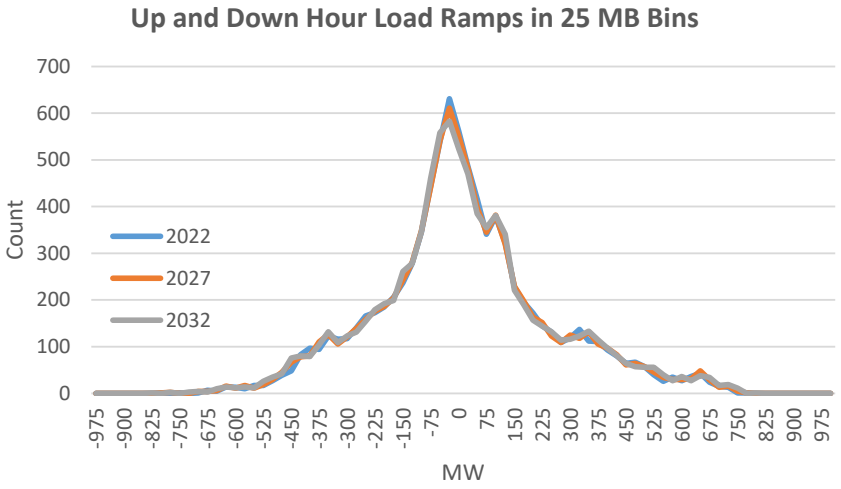


Figure 19: Load Ramp Histogram for each Scenario

Table 7: Five Larges Up and Down Hour Load Change

5 largest up and down ramps						
	Date	Ramp	Date	Ramp	Date	Ramp
Up 1	11/08/2022 08:00	761	11/09/2027 08:00	772	11/09/2032 08:00	783
2	10/03/2022 07:00	729	10/04/2027 07:00	737	10/04/2032 07:00	746
3	11/28/2022 08:00	723	11/29/2027 08:00	734	11/29/2032 08:00	746
4	10/12/2022 07:00	722	10/13/2027 07:00	733	10/13/2032 07:00	743
5	10/24/2022 07:00	720	10/25/2027 07:00	729	12/08/2032 08:00	742
Down 5	07/20/2022 00:00	-692	08/05/2027 00:00	-714	08/05/2032 00:00	-726
4	07/19/2022 00:00	-698	07/20/2027 00:00	-719	07/20/2032 00:00	-733
3	08/04/2022 00:00	-707	08/07/2027 00:00	-777	08/07/2032 00:00	-790
2	08/06/2022 00:00	-766	07/01/2027 01:00	-778	07/01/2032 01:00	-794
1	08/03/2022 23:00	-814	08/04/2027 23:00	-814	08/04/2032 23:00	-832

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SECTION 6 NET LOAD

Net load in this section is defined to be the result of subtracting in each hour of the study the amount of wind and solar PV from the NSP system load. This analysis provides further insight into the effects of wind and solar PV on the NSP system making the assumption that the energy produced by wind and solar PV are must take resource and applied to serving system load or off system sale. Table 8 shows for the Base and each Scenario the annual load MWH, Net Load MWH, Renewable MWH, Wind MWH, Solar PV MWH, % of renewable penetration, % of wind penetration, % of solar PV penetration, number of days in the year when renewable energy is greater than load demand, and the number of weeks in the year when renewable energy is greater than load demand. The annual MWH for net load from Scenario 1 to Scenario 4 is reduced by 61%. In Scenario 2 through Scenario 4 there are days when the renewable production exceeds load demand. Additionally in Scenario 4 there are six weeks in the year when renewable production exceeds the weekly NSP demand. Remedial action of curtailment or selling the additional energy can provide mitigation of this excess production.

Table 8: Net Load Characterization for each Scenario

Annual	Base	S1	S2	S3	S4
Load MWH	46,689,259	46,689,259	47,284,693	47,887,784	47,887,784
Net Load MWH	35,879,431	27,300,971	22,008,297	18,637,437	10,736,553
Ren MWH	10,809,828	19,388,288	25,276,396	29,250,347	37,151,231
Wind MWH	10,345,983	17,073,715	20,987,190	23,070,216	27,107,553
PV MWH	463,845	2,314,573	4,289,206	6,180,131	10,043,679
Renewable Penetration % of MWH	23%	42%	53%	61%	78%
Wind Penetration % of MWH	22%	37%	44%	48%	57%
Solar PV Penetration % of MWH	1%	5%	9%	13%	21%
# days Renewable MWH > Load MWH	0	0	19	37	99
# Weeks Renewable MWH > Load MWH	0	0	0	0	6

Net load analysis provided the ability to compare the previously described load analysis to net load. Figure 21 shows the peak and min load and net load by quarter and year. Here it can be seen that renewable configurations in this analysis have a greater effect on minimum load than on the peak load. Another way of observing net load is by examining a histogram counting the number of hour in the year when load or net load falls with a given MW range. The histogram shown in Figure 20 uses the peak load in 2032 and the minimum load in Scenario 4 as boundaries and places in bins sized to 1% of this range. It can be seen in this figure how the NSP net load is modified by the increase in renewable wind and Solar PV.

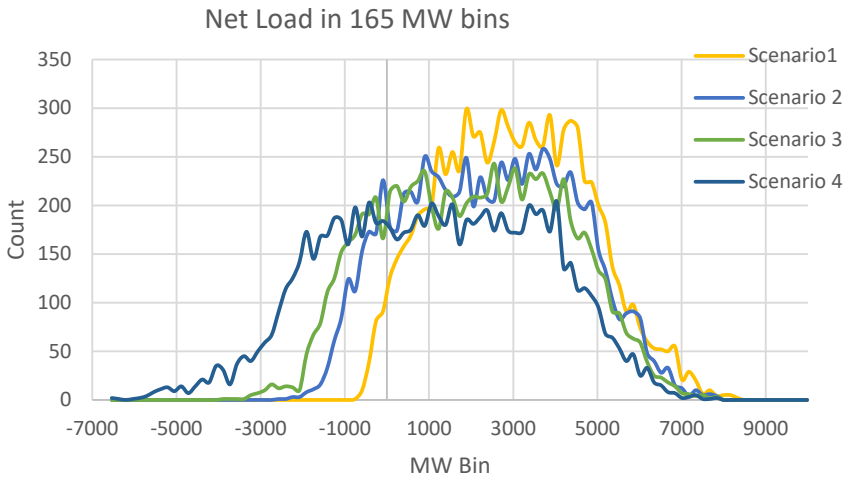

Figure 20: Histogram of Net Load for each study year and Scenario

The analysis of hour to hour net load changes was performed in the same way as load in that the hourly changes were ordered from high to low and plotted in Figure 22, Figure 23, Figure 24 and Figure 25. The hourly load change is plotted to show the differences between the hourly changes in load verses net load. These plots show the number of hour in the year when net load is less than 0 MW, from 179 hours in Scenario 1 to 2988 hours in Scenario 4.

The magnitude and number of hour to hour changes in net load increase in each scenario as penetration increases. This is shown in Figure 26, Figure 27 and Figure 28. The histogram for net load is shown in

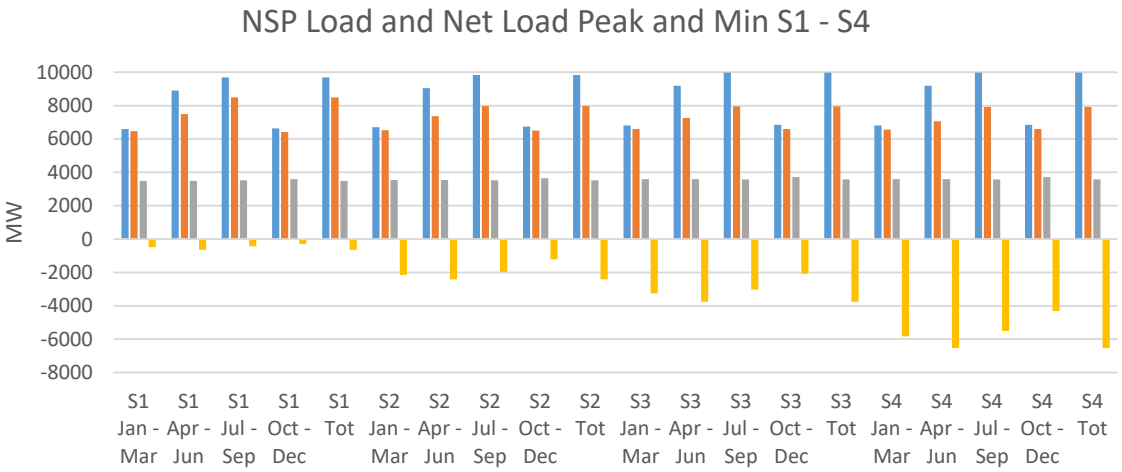

Figure 21: Load and Net Load Peak and Min

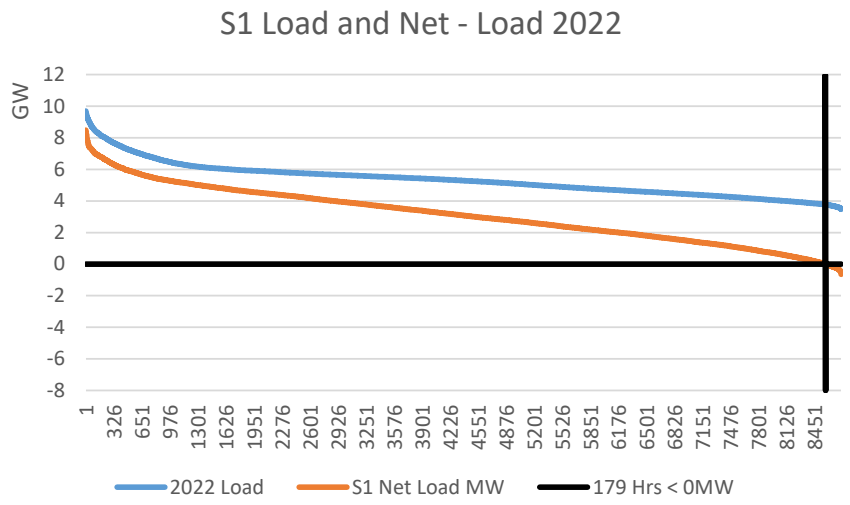

Figure 22: Scenario 1 Load and Net Load Duration Curves

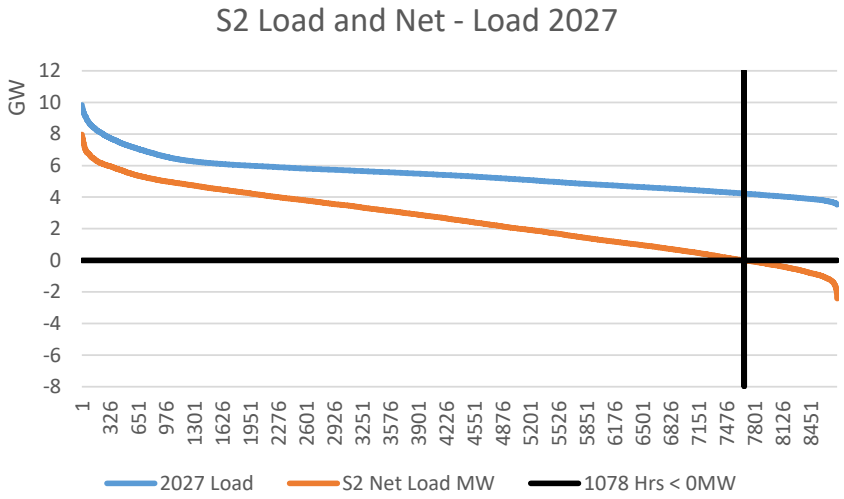

Figure 23: Scenario 2 Load and Net Load Duration Curves

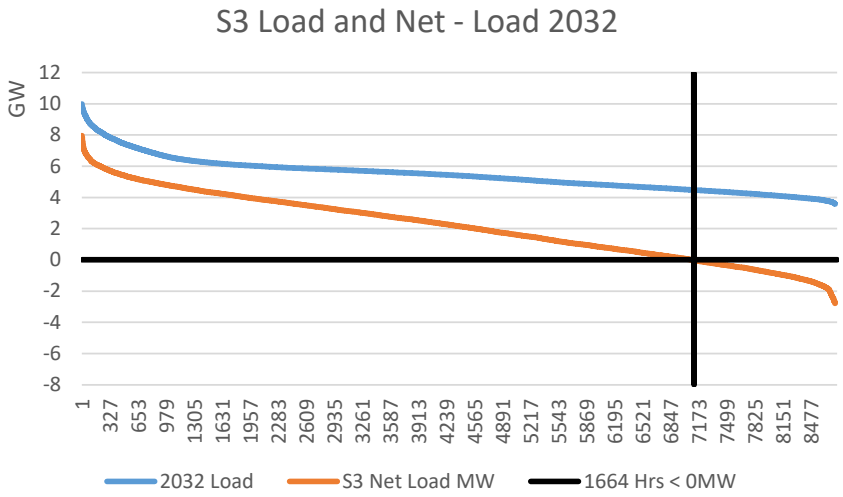

Figure 24: Scenario 3 Load and Net Load Duration Curves

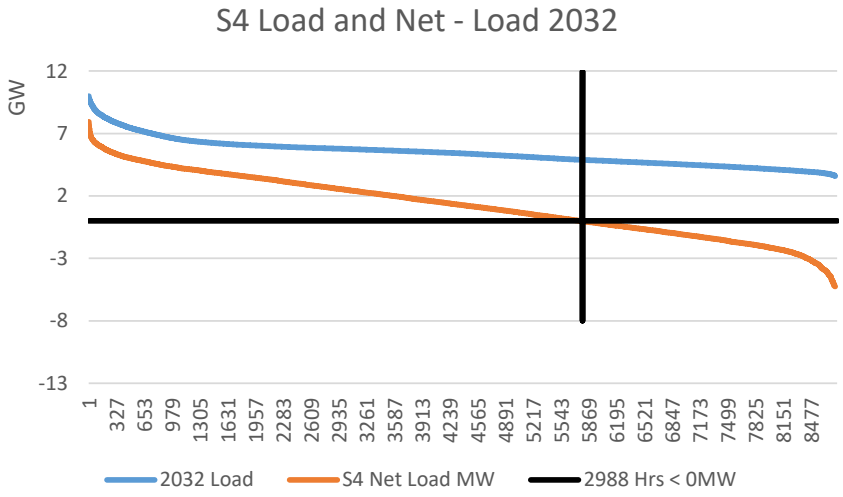

Figure 25: Scenario 4 Load and Net Load Duration Curves

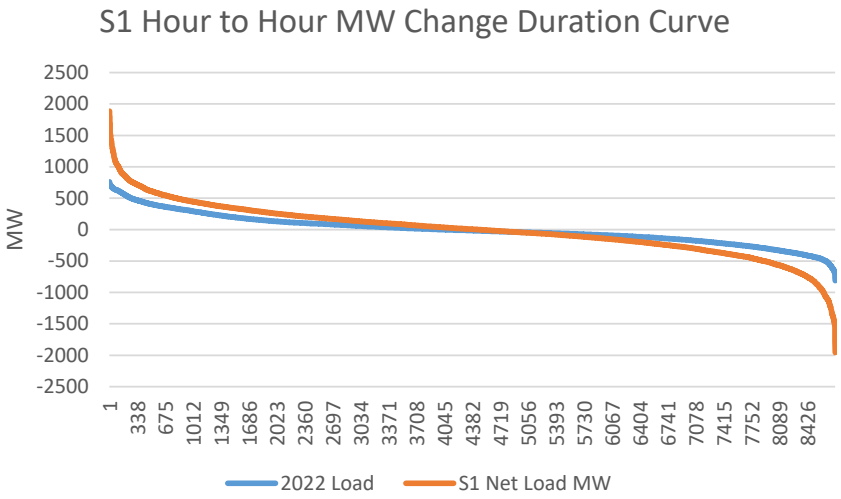

Figure 26: Scenario 1 Hour to Hour Change Duration Curves

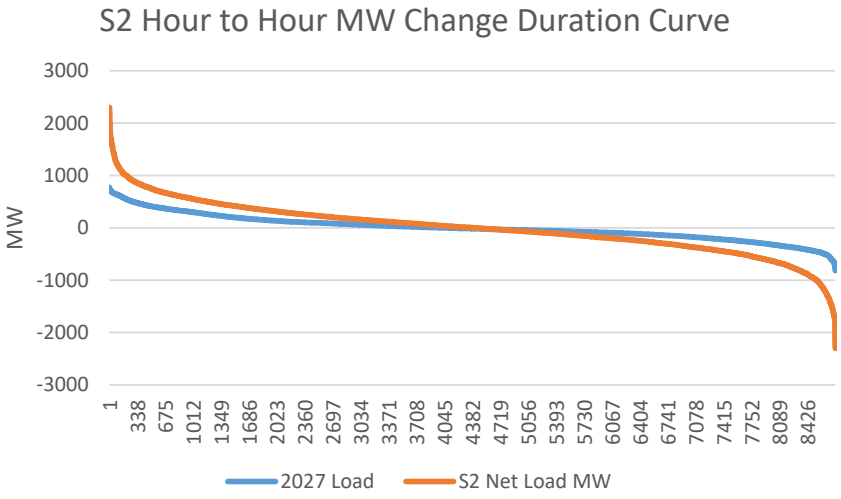

Figure 27: Scenario 2 Hour to Hour Change Duration Curve

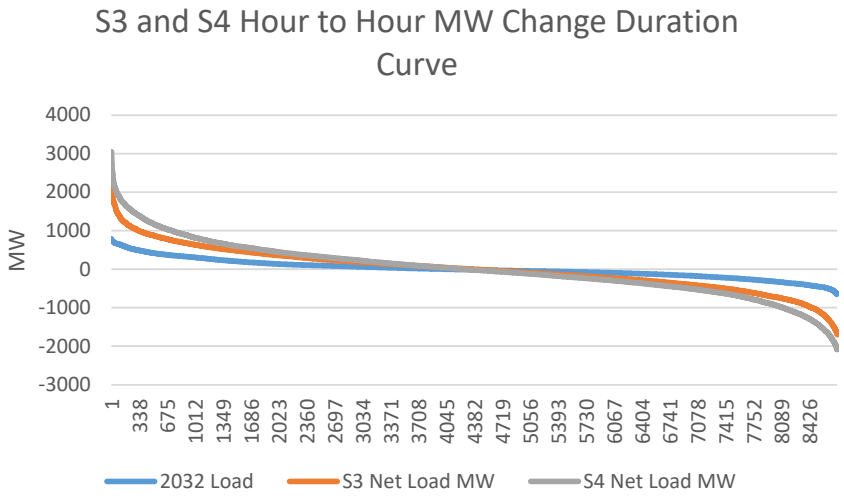

Figure 28: Scenarios 3 and 4 Hour to Hour Change Duration Curve

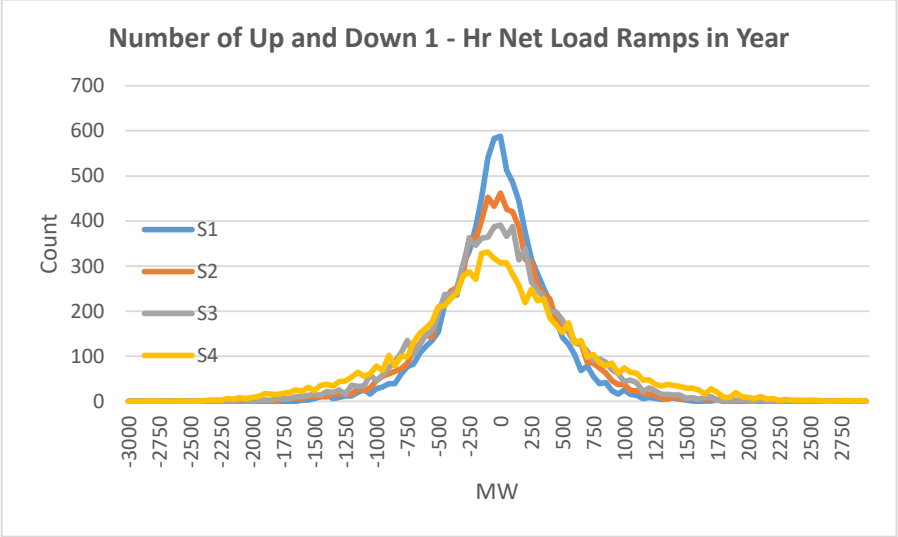

Figure 29: Scenarios 1 through 4 Net Load Hourly Ramps in 50 MW bins

The load and net load analysis provided additional insights into the hour to hour behavior when wind and solar PV is introduced. Plots of individual days and weeks are shown in the final presentation. The tables depicting the days and weeks of interest are shown in the four tables, Table 9, Table 10, Table 11 and Table 12

Table 9: January through March Interesting Days and Weeks

January - March	Base	S1	S2	S3	S4
Max Hr Load MW	6603	6603	6703	6805	6805
Max Hr Load MW Date	01/20/2022 19:00	01/20/2022 19:00	01/21/2027 19:00	01/22/2032 19:00	01/22/2032 19:00
Max Hr Net Load MW	6058	6464	6522	6590	6553
Max Hr Net Load MW Date	01/21/2022 18:00	01/20/2022 19:00	01/21/2027 19:00	01/22/2032 19:00	01/22/2032 19:00
Min Hr Load MW	3488	3488	3541	3595	3595
Min Hr Load MW Date	03/27/2022 04:00	03/27/2022 04:00	03/28/2027 04:00	03/28/2032 04:00	03/28/2032 04:00
Min Hr Net Load MW	1251	-481	-2144	-3261	-5827
Min Hr Net Load MW Date	03/13/2022 03:00	03/20/2022 05:00	03/13/2027 11:00	03/13/2032 11:00	03/13/2032 11:00
Max Week Load MWH	923,921	923,921	936,075	944,342	944,342
Max Week Load MWH Date	01/16/2022 01:00	01/16/2022 01:00	01/17/2027 01:00	01/18/2032 01:00	01/18/2032 01:00
Max Week Net Load MWH	709,374	597,506	518,296	443,318	319,683
Max Week Net Load MWH Date	01/16/2022 01:00	02/13/2022 01:00	02/14/2027 01:00	02/15/2032 01:00	02/15/2032 01:00
Min Week Load MWH	786,878	786,878	795,659	805,739	805,739
Min Week Load MWH Date	03/27/2022 01:00	03/27/2022 01:00	03/28/2027 01:00	03/28/2032 01:00	03/28/2032 01:00
Min Week Net Load MWH	501,000	315,524	178,836	104,853	-53,918
Min Week Net Load MWH Date	01/02/2022 01:00	01/02/2022 01:00	01/03/2027 01:00	01/04/2032 01:00	01/04/2032 01:00

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Table 10: April through Jun Interesting Days and Weeks

April - Jun	Base	S1	S2	S3	S4
Max Hr Load MW	8911	8911	9046	9183	9183
Max Hr Load MW Date	06/29/2022 17:00	06/29/2022 17:00	06/30/2027 17:00	06/29/2032 17:00	06/29/2032 17:00
Max Hr Net Load MW	8099	7485	7365	7250	7062
Max Hr Net Load MW Date	06/21/2022 18:00	06/29/2022 22:00	06/30/2027 22:00	06/29/2032 22:00	06/29/2032 22:00
Min Hr Load MW	3482	3482	3535	3589	3589
Min Hr Load MW Date	04/10/2022 04:00	04/10/2022 04:00	04/11/2027 04:00	04/10/2032 04:00	04/10/2032 04:00
Min Hr Net Load MW	1058	-638	-2418	-3749	-6535
Min Hr Net Load MW Date	04/10/2022 05:00	04/09/2022 10:00	04/10/2027 10:00	04/09/2032 11:00	04/09/2032 11:00
Max Week Load MWH	1,066,489	1,066,489	1,081,782	1,095,569	1,095,569
Max Week Load MWH Date	06/26/2022 01:00	06/26/2022 01:00	06/27/2027 01:00	06/27/2032 01:00	06/27/2032 01:00
Max Week Net Load MWH	867,717	714,510	602,513	523,868	340,510
Max Week Net Load MWH Date	06/26/2022 01:00	06/26/2022 01:00	06/27/2027 01:00	06/27/2032 01:00	06/27/2032 01:00
Min Week Load MWH	779,125	779,125	785,689	795,635	795,635
Min Week Load MWH Date	04/03/2022 01:00	04/03/2022 01:00	04/04/2027 01:00	04/04/2032 01:00	04/04/2032 01:00
Min Week Net Load MWH	507,815	254,625	100,659	6,179	-197,769
Min Week Net Load MWH Date	04/10/2022 01:00	04/03/2022 01:00	04/04/2027 01:00	04/04/2032 01:00	04/04/2032 01:00

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Table 11:July through September Interesting Days and Weeks

July - September	Base	S1	S2	S3	S4
Max Hr Load MW	9686	9686	9833	9982	9982
Max Hr Load MW Date	07/04/2022 17:00	07/04/2022 17:00	07/05/2027 17:00	07/05/2032 17:00	07/05/2032 17:00
Max Hr Net Load MW	9177	8484	7967	7963	7925
Max Hr Net Load MW Date	07/04/2022 16:00	07/25/2022 16:00	07/26/2027 16:00	07/20/2032 22:00	07/20/2032 22:00
Min Hr Load MW	3514	3514	3524	3577	3577
Min Hr Load MW Date	09/25/2022 04:00	09/25/2022 04:00	09/26/2027 04:00	09/26/2032 04:00	09/26/2032 04:00
Min Hr Net Load MW	1601	-434	-1960	-3020	-5508
Min Hr Net Load MW Date	09/25/2022 04:00	09/18/2022 05:00	09/19/2027 10:00	09/19/2032 10:00	09/19/2032 11:00
Max Week Load MWH	1,200,141	1,200,141	1,208,446	1,224,129	1,224,129
Max Week Load MWH Date	07/03/2022 01:00	07/03/2022 01:00	07/04/2027 01:00	07/04/2032 01:00	07/04/2032 01:00
Max Week Net Load MWH	1,017,212	901,174	819,052	756,299	604,318
Max Week Net Load MWH Date	07/03/2022 01:00	07/10/2022 01:00	07/11/2027 01:00	07/11/2032 01:00	07/11/2032 01:00
Min Week Load MWH	799,278	799,278	803,100	813,269	813,269
Min Week Load MWH Date	09/25/2022 01:00	09/25/2022 01:00	09/19/2027 01:00	09/19/2032 01:00	09/19/2032 01:00
Min Week Net Load MWH	593,868	385,900	260,208	191,055	16,225
Min Week Net Load MWH Date	09/18/2022 01:00	09/18/2022 01:00	09/19/2027 01:00	09/19/2032 01:00	09/19/2032 01:00

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Table 12: October through December Interesting Days and Weeks

October - December	Base	S1	S2	S3	S4
Max Hr Load MW	6635	6635	6736	6838	6838
Max Hr Load MW Date	12/22/2022 19:00	12/22/2022 19:00	12/23/2027 19:00	12/23/2032 19:00	12/23/2032 19:00
Max Hr Net Load MW	6273	6423	6508	6600	6600
Max Hr Net Load MW Date	12/20/2022 19:00	12/19/2022 19:00	12/20/2027 19:00	12/20/2032 19:00	12/20/2032 19:00
Min Hr Load MW	3599	3599	3653	3709	3709
Min Hr Load MW Date	11/06/2022 04:00	11/06/2022 04:00	11/07/2027 04:00	11/07/2032 04:00	11/07/2032 04:00
Min Hr Net Load MW	1296	-294	-1216	-2073	-4317
Min Hr Net Load MW Date	10/16/2022 04:00	11/25/2022 04:00	11/26/2027 04:00	10/16/2032 11:00	10/16/2032 11:00
Max Week Load MWH	905,301	905,301	914,530	926,315	926,315
Max Week Load MWH Date	12/11/2022 01:00	12/11/2022 01:00	12/12/2027 01:00	12/12/2032 01:00	12/12/2032 01:00
Max Week Net Load MWH	750,059	656,938	590,558	565,697	493,018
Max Week Net Load MWH Date	12/11/2022 01:00	12/18/2022 01:00	12/12/2027 01:00	12/12/2032 01:00	12/12/2032 01:00
Min Week Load MWH	792,647	792,647	744,272	753,603	753,603
Min Week Load MWH Date	11/13/2022 01:00	11/13/2022 01:00	12/19/2027 01:00	12/19/2032 01:00	12/19/2032 01:00
Min Week Net Load MWH	492,239	319,565	207,060	151,515	2,015
Min Week Net Load MWH Date	11/13/2022 01:00	11/13/2022 01:00	11/14/2027 01:00	11/14/2032 01:00	11/14/2032 01:00

An example of an interesting day and week is the week with the day April 10. April 10 has a high wind and solar PV production while the load on this day is relatively low. In each scenario as penetration increases the net load decreases. For the day the Base Load is 93,793 MWH the Base net load is 10,642 MW. Scenario 1 net load is 14,642 MWH. Scenario 2 is -28,596 MWH, Scenario 3 is -47,378 MWH, and Scenario 4 is -84,711 MWH. Figure 30, Figure 31, Figure 32, Figure 33 and Figure 34 show the effects of the renewable penetration on the NSP load. In the Base the net load is within the 1000 MW to 2000 MW range while as renewable penetration increases in each scenario there are hours when net load for NSP becomes negative in Scenario 1 and for the full day in Scenario 2, Scenario 3 and Scenario 4.

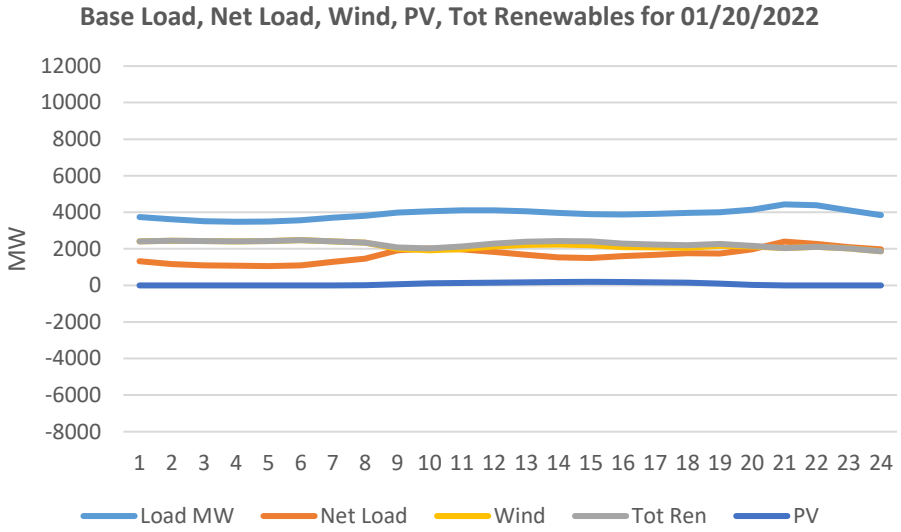

Figure 30: Base Case Interesting Day

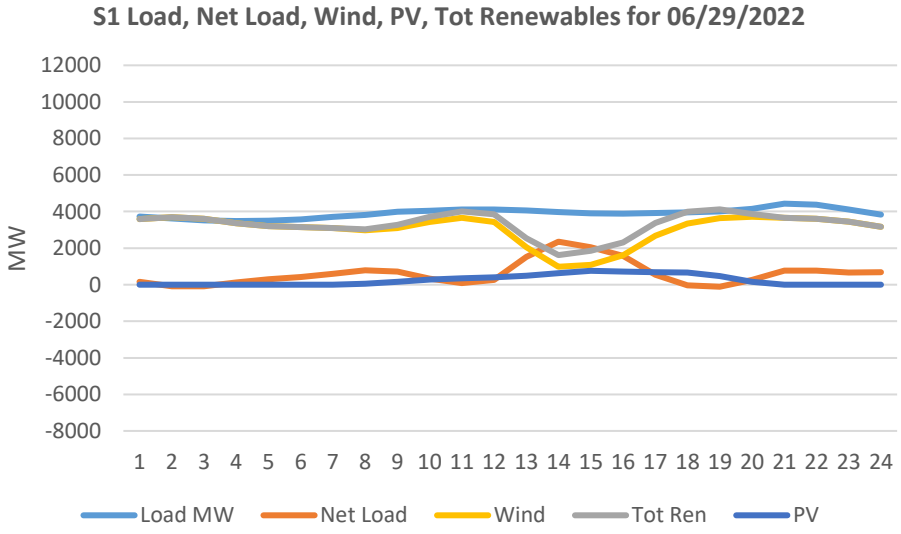

Figure 31: Scenario 1 Interesting Day

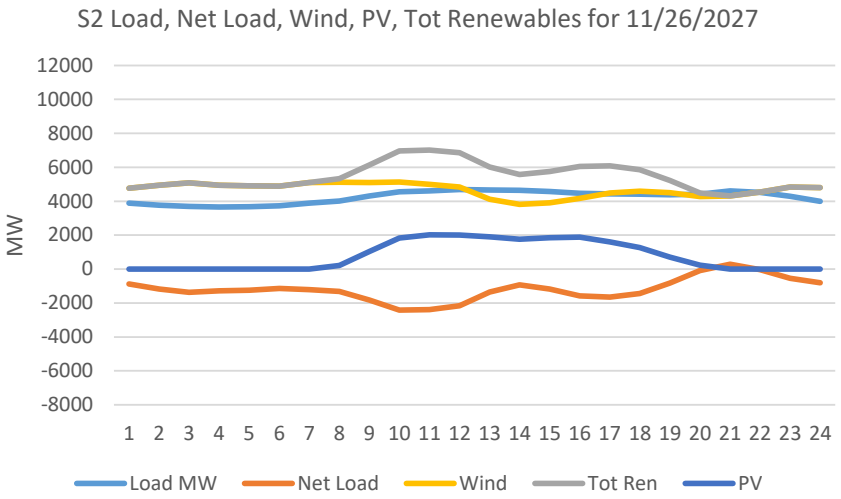

Figure 32: Scenario 2 Interesting Day

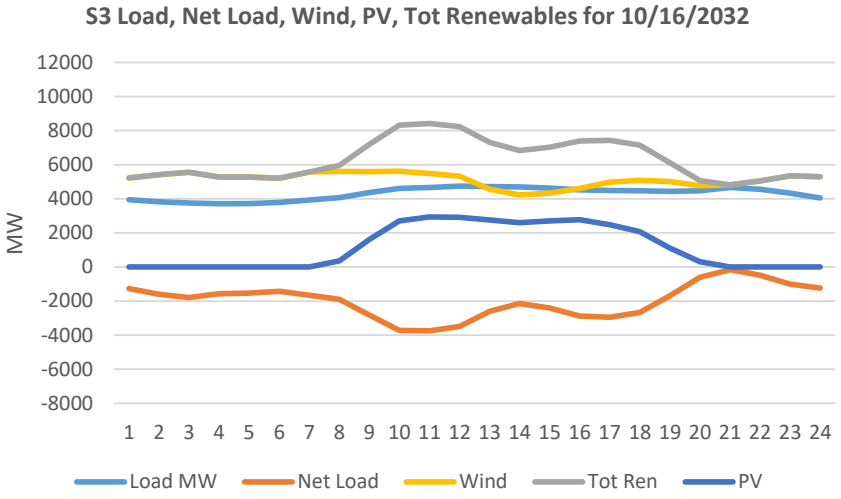

Figure 33: Scenario 3 Interesting Day

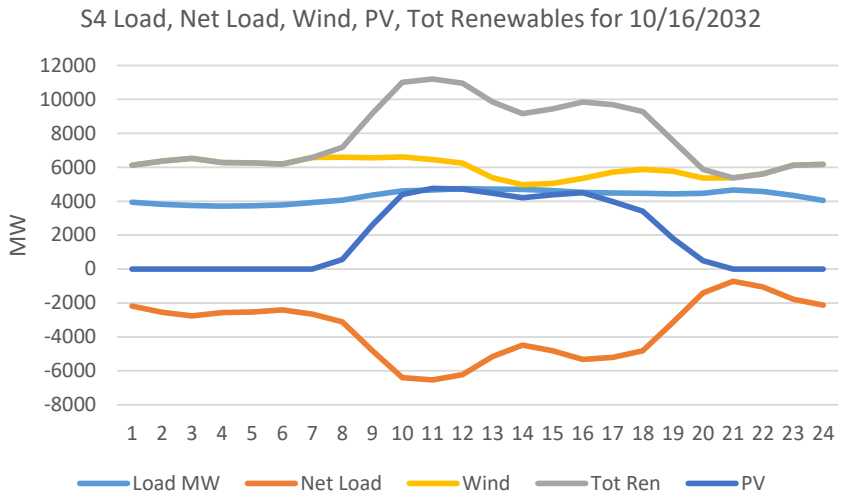

Figure 34: Scenario 4 Interesting Day

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SECTION 7 RESERVE

As described in the previous section Net Load shows there is an increase in the hour to hour load change as the penetration of renewables increases. Spinning reserves are typically established to account for these load variations that occur within the hour. Therefore, as the tendency for hour to hour load change increase with renewable penetration, the spinning reserves will also change. The changes in spinning reserves in this study were calculated statistically using the method applied in numerous other studies[1, 2, 3]. The Base Case set NSP Base Reserves at 27 MW, Spin at 65 MW and Supplement at 71 MW. The forecasts used in this analysis were persistence (next hour forecast is the same as present hour) for load and wind. The forecast for solar PV used the average three production values, the hour of, the hour before and the hour after. These forecasts provided a forecast error for the next hour forecast. Associating the forecast error to the level of wind and solar PV production the production levels for these renewable types were placed into histogram bins at 10% production intervals. From each of these bins the standard deviation of the forecast error was calculated and plotted against the production level. A curve fit of the plot results in a quadratic curve. From this curve the statistical standard deviation of the forecast error for wind and solar PV can be calculated. In addition statistically three standard deviations, or three times the calculated standard deviation of forecast error covers 99.7% of the possible forecast errors for wind or solar PV.

Because the Base Case includes renewables, the spinning reserve contribution to renewables was calculated and included in the spinning reserve analysis for each Scenario. The formula for calculating the 10 – minute spinning reserve is based on predictive operating levels of load, wind and solar PV forecast errors and is shown below.

$$3 * \sqrt{(\frac{\%Hourly\ Load}{3})^2 + \sigma(HourlyWind)^2 + \sigma(HourlySolarPV)^2}$$ = 65 MW for the Base Case

The calculated 10-minute spinning reserve changes demonstrate that as renewable penetration increases the average 10-minute spinning reserve requirement also increases. In general the analysis shows the contribution of 10-minute spinning reserves in this study ranges between 0.7% and 0.9% of the renewable rated capacity. Table 13 provides the calculated 10-minute spinning reserve requirements. The spinning reserve contribution of renewables increases from 25 MW in Scenario 1 to 76 MW in Scenario 4 more than doubling the reserve requirement in the Base Case.

[1] https://www.nrel.gov/docs/fy11osti/47078.pdf

[2] https://www.pjm.com/-/media/committees-groups/subcommittees/irs/postings/pris-executive-summary.ashx?la=en
https://www.pjm.com/-/media/committees-groups/subcommittees/irs/postings/pjm-pris-task-3a-part-b-statistical-analysis-and-reserves.ashx?la=en

[3] https://canwea.ca/wp-content/uploads/2016/07/pcwis-section05-statisticalandreserveanalysis.pdf

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Table 13: 10 – Minute Spinning Reserves for each Scenario

Average Contribution 10-min Spin Reserve (MW)			
Scenario	Load	Renewable	Total
Base	43	22	65
S1	43	47	90
S2	43	62	105
S3	43	73	116
S4	43	98	141

In order to verify these calculations a post analysis of the PROMOD runs was performed to determine if these levels of reserves were sufficient. The loading of NSP resources for each hour in the study were examined. The Headroom for each on line resource was calculated by subtracting the resource loading in the hour from its available capacity. This value was limited by the respective resource ramping rate. The headroom for all resources was aggregated by hour to provide the total available on line spinning generation. The number of hours in the year when the calculated 10 – minute spinning reserve was exceeded was determined. Table 14 depicts the results of the post analysis. The number of hours in the year when the calculated spinning reserve exceeds the NSP resource headroom, the percent of hours in the year when spinning reserve exceeds the NSP resource headroom, the maximum MW of NSP resources that exceeds the spinning reserve requirement and the hour of maximum deficiency for spinning reserves are shown. The worst case is in Scenario 4 when there is an hour when the NSP system is deficient of 145 MW of spinning reserves. In these hours the NSP system would rely on the MISO for mitigation.

Table 14: Spinning Reserve Post Analysis

10 - Min Spinning Reserve Post Analysis				
	Hours Deficient	**Percent**	**Max Excess MW**	**Max Deficient MW**
Scenario 1	36	0.4%	1,286	43
Scenario 2	65	0.7%	1,235	61
Scenario 3	105	1.2%	1,644	108
Scenario 4	139	1.6%	1,699	145

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SECTION 8 RESULTS

This section provides the PROMOD production costs for the Base Case and Each Scenario. The MTEP 18 PROMOD model includes all RTOs, ISOs, and balancing areas in the Eastern Interconnect. The results extracted from the runs were focused strictly on the NSP system.

There were two sets of PROMOD runs performed in this analysis. The first type (NE) modeled the NSP system without any renewable and load forecast error. This run performed both unit commitment and dispatch steps using the actual values for the hourly wind and solar PV energy and the NSP load. The second type of run (FE) performed the unit commitment using a day-ahead forecast for hourly wind and solar PV energy and NSP load, and then solved the unit dispatch optimization based upon actual values for hourly wind and solar PV energy and NSP load. This second run will have a different production cost than the first due to the forecast used in the commitment stage. An over forecast of wind or solar PV can result in an under commitment of system resources, as would an under forecast of system load. Similarly an under forecast of wind or solar PV would result in an over commitment of system resources. As would an over forecast of system load. Sometimes the over forecast of wind and solar PV is compensated by an under forecast of system load. The hourly chronological production costing model evaluates these combinations of over and under forecast and accounts for the forecast errors in the costs it provides.

Through the study scenarios from 2022 to 2032 the aggregated capacity of gas resources increase. The average annual gas prices modeled in the MTEP18 database are 4.36 $/MMBTU in 2022, 5.47 $/MMBTU in 2027 and 6.49 $/MMBTU in 2032.

The results of the production costs from PROMOD runs include forecast errors unless otherwise stated. Table 15 depicts the annual renewable production (MWH), Conventional resource production (MWH), system cost, cost per MWH, total NSP load MWH, wind and solar curtailment, and the NSP off system energy requirement. The Base Case is the only case where NSP is a net purchaser of power over the year. The average cost in $/MWH increases from 22.99 $/MWH in the Base Case to 42.40 $/MWH in Scenario 4.

The cost of integrating wind and solar PV based upon the forecast error is shown in Table 17. The cost of forecast error due to the integration of wind and solar PV range from 0.09 $/MWH in Scenario 1 to 0.42 $/MWH in scenario 4. The increase in renewable and reduction in traditional generation resulted in lower production costs in Scenario 4. The difference from forecast error is nearly the same in Scenario 3 as in Scenario 4. The % of cost increased over the % if cost increase of scenario 3.

Resource production by fuel type was analyzed over each of the scenarios in Table 18. Gas CT and combined cycle resources increased production as renewable penetration increased. Gas CT production increased in Scenario 1 from 349 TWH to 825 TWH in Scenario 4. Combined cycle production increased in Scenario 1 from 3,485 TWH to 12.368 TWH in Scenario 4. Coal resource production in combination with retirements decreased over the study. While coal capacity decreased from 2,479 MW in Scenario 1, to 1,054 MW in Scenario 2, to 528 MW in Scenario 3 and 4. The capacity factor of the aggregated coal resources increase as the renewable resource penetration increase from 70% in Scenario 1 to 82% in Scenario 4. This increase can be contributed to coal resource retirements that provides

production opportunity for the remaining coal resources. There is little difference in production for the other resources modeled.

Table 15: PROMOD Forecast Error Results for NSP

Scenario	Year	Wind (MWH)	Solar PV (MWH)	Other Resource (MWH)	Cost (M$)	NSP ($/MWH)	NSP Load (MWH)	Wind Curt. (MWH)	Solar PV Curt (MWH)	Off System (MWH)
Base 2022	2022	11,081,214	411,372	32,099,679	738.00	22.99	46,689,259	126,579	7,896	-3,231,469
Scenario 1	2022	17,184,813	2,262,501	31,260,438	713.97	22.84	46,689,259	827,958	46,326	3,144,209
Scenario 2	2027	21,459,009	4,238,311	24,555,275	669.01	27.24	47,284,693	1,109,598	104,447	1,753,857
Scenario 3	2032	22,794,690	6,121,946	26,906,024	872.97	32.45	47,887,784	1,575,148	204,112	6,155,616
Scenario 4	2032	26,039,342	7,296,502	17,175,912	728.25	42.40	47,887,784	1,853,498	296,508	473,966

Table 16: PROMOD Forecast Error Results for NSP by Conventional Resource Type

Other Resources (MWH)	CT Gas	Conv. Hydro	ST Coal	CC	CT Oil	Nuclear	CT Other	ST Gas	Total
Base 2022	414,664	797,912	13,754,230	3,798,813	1,146	13,330,759	71	2,085	32,099,679
Scenario 1	348,868	797,920	13,295,512	3,485,308	320	13,330,759	42	1,710	31,260,438
Scenario 2	751,205	798,234	3,222,766	6,891,534	11,594	12,877,915	474	1,554	24,555,275
Scenario 3	608,454	798,278	2,959,974	9,493,506	180	13,044,911	130	621	26,906,054
Scenario 4	825,470	798,280	3,182,140	12,368,017	536	0	390	1,079	17,175,912

Table 17: Integration Cost due to Forecast Error

Average $/MWH	Base 2022	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Perfect Forecast	22.97	22.82	27.15	32.27	42.31
Forecast Error	22.99	22.84	27.24	32.45	42.40
Increase	0.02	0.02	0.10	0.18	0.09
Integration Cost due to Forecast error	na	0.09	0.27	0.55	0.42

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Table 18: Aggregated Fuel Type Production Summary by Scenario

	Fuel Type	CT Gas	ST Gas	CT Other	CC	CT Oil	Hydro	ST Coal	Nuclear	Tot Ren	Tot NSP
S1 NE	Production MWH	346,332	1,678	42	3,420,772	145	797,916	13,319,836	13,330,759	18,577,422	49,794,902
	Available Production MWH	13,739,669	39,415	112,313	19,439,326	4,539,785	2,814,588	19,115,350	13,340,041	19,447,315	92,587,800
	Production/Available	2.5%	4.3%	0.0%	17.6%	0.0%	28.3%	69.7%	99.9%	95.5%	53.8%
	Capacity MW	2,142	29	15	2,561	605	321	2,479	1,673	5,476	15,303
S1 FE	Production MWH	348,868	1,710	42	3,485,308	320	797,920	13,295,512	13,330,759	18,573,030	49,833,468
	Available Production MWH	13,739,669	39,415	112,313	19,439,326	4,539,785	2,814,588	19,115,350	13,340,041	19,447,315	92,587,801
	Production/Available	2.5%	4.3%	0.0%	17.9%	0.0%	28.3%	69.6%	99.9%	95.5%	53.8%
	Capacity MW	2,142	29	15	2,561	605	321	2,479	1,673	5,476	15,303
S2 NE	Production MWH	744,481	1,448	479	6,727,612	11,087	798,224	3,228,928	12,877,915	24,496,397	48,886,571
	Available Production MWH	23,593,662	38,833	117,264	27,223,557	4,629,407	2,814,588	4,338,760	12,877,915	25,697,343	101,331,329
	Production/Available	3.2%	3.7%	0.4%	24.7%	0.2%	28.4%	74.4%	100.0%	95.3%	48.2%
	Capacity MW	**2,937**	5	15	**3,561**	605	321	**1,054**	1,673	**7,476**	**17,648**
S2 FE	Production MWH	751,205	1,554	474	6,891,534	11,594	798,234	3,222,766	12,877,915	24,483,275	49,038,550
	Available Production MWH	23,593,662	38,833	117,264	27,223,557	4,629,407	2,814,588	4,338,760	12,877,915	25,697,320	101,331,306
	Production/Available	3.2%	4.0%	0.4%	25.3%	0.3%	28.4%	74.3%	100.0%	95.3%	48.4%
	Capacity MW	**2,937**	5	15	**3,561**	605	321	**1,054**	1,673	**7,476**	**17,648**
S3 NE	Production MWH	595,970	508	88	9,136,143	142	798,258	2,977,973	13,044,911	27,164,561	53,718,553
	Available Production MWH	23,860,208	40,202	119,422	34,913,409	307,009	2,816,110	3,909,366	13,044,911	28,916,636	107,927,274
	Production/Available	2.5%	1.3%	0.1%	26.2%	0.0%	28.3%	76.2%	100.0%	93.9%	49.8%
	Capacity MW	**2,973**	5	15	**4,561**	37	321	**528**	1,673	**8,976**	**19,089**
S3 FE	Production MWH	608,454	621	130	9,493,506	180	798,278	2,959,974	13,044,911	27,137,376	54,043,430
	Available Production MWH	23,860,208	40,202	119,422	34,913,409	307,009	2,816,110	3,909,366	13,044,911	28,916,636	107,927,274
	Production/Available	2.6%	1.5%	0.1%	27.2%	0.1%	28.3%	75.7%	100.0%	93.8%	50.1%
	Capacity MW	**2,973**	5	15	**4,561**	37	321	**528**	1,673	**8,976**	**19,089**
S4 NE	Production MWH	815,004	769	333	12,028,857	417	798,247	3,196,709	0	31,203,106	48,043,442
	Available Production MWH	23,860,208	40,202	119,422	34,913,409	307,009	2,816,110	3,909,366	0	33,308,263	99,273,990
	Production/Available	3.4%	1.9%	0.3%	34.5%	0.1%	28.3%	81.8%	na	93.7%	48.4%
	Capacity MW	**2,973**	5	15	**4,561**	37	321	**528**	0	**11,976**	**20,416**
S4 FE	Production MWH	825,470	1,079	390	12,368,017	536	798,280	3,182,140	0	31,158,256	48,334,169
	Available Production MWH	23,860,208	40,202	119,422	34,913,409	307,009	2,816,110	3,909,366	0	33,308,262	99,273,989
	Production/Available	3.5%	2.7%	0.3%	35.4%	0.2%	28.3%	81.4%	na	93.5%	48.7%
	Capacity MW	**2,973**	5	15	**4,561**	37	321	**528**	0	**11,976**	**20,416**

An analysis of unit startups was conducted. In this analysis PROMOD produced hourly output for NSP resources of each different fuel type. The number of startups were counted in each scenario. In general the number of startups across the NSP fleet increases as renewable penetration increases. Coal resources in Scenario 4 show a decrease in startups while CC and Gas CT resources show an increase startups. Table 19 shows the number of resources by fuel type in each scenario. Table 20 shows the increase in unit startups over the year. Table 21 shows the number of resource startups over the year. Table 22 shows the average number of starts per resource type. Additional plots on number of starts can be found in the accompanying presentation.

Table 19: Number of Resources by Fuel Type

Number of Resources					
Type	Base 2022	Scenario 1	Scenario 2	Scenario 3	Scenario 4
CT Gas	27	27	22	18	18
Hydro	19	19	19	19	19
ST Coal	9	9	7	4	4
CC	6	6	8	10	10
CT Oil	11	11	11	2	2
Nuclear	3	3	3	3	0
CT Other	1	1	1	1	1
ST Gas	4	4	1	1	1
Total Resources	80	80	72	58	55

Table 20: Increase in Unit Startups by Fuel Type

Increase in Unit Startups over the year due to Forecast Error					
Type	Base 2022	Scenario 1	Scenario 2	Scenario 3	Scenario 4
CT Gas	17	18	35	52	61
Hydro	-1	1	0	1	-2
ST Coal	-12	-2	-4	-12	-13
CC	0	9	16	-35	-16
CT Oil	1	3	8	0	6
Nuclear	0	0	0	0	0
CT Other	0	0	2	2	4
ST Gas	-6	0	0	0	-4
Total Resources	80	80	72	58	55

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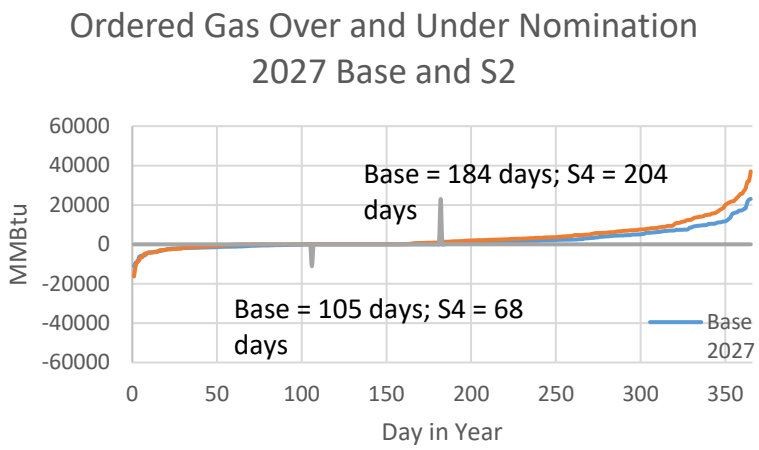
Table 21: Resource Startups by Fuel Type

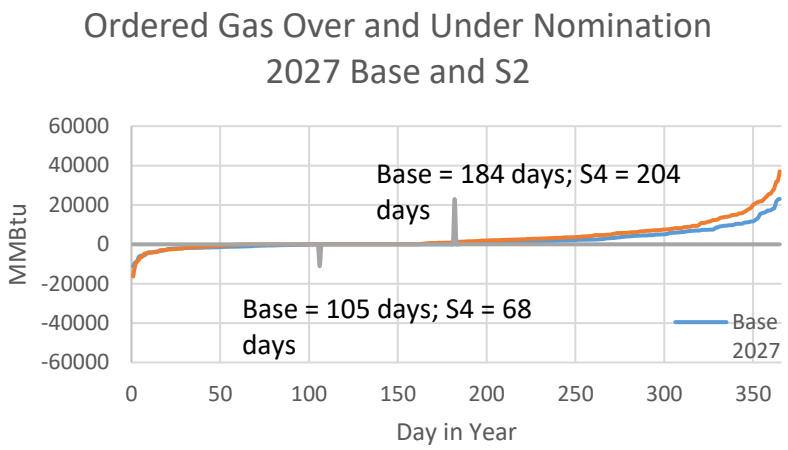
Number of Resource Startups over the Year					
Type	Base 2022	Scenario 1	Scenario 2	Scenario 3	Scenario 4
CT Gas	532	486	737	598	774
Hydro	34	31	33	36	37
ST Coal	263	255	220	161	114
CC	519	488	848	1016	1098
CT Oil	14	7	59	5	12
Nuclear	5	5	5	17	0
CT Other	4	2	9	4	9
ST Gas	27	32	16	7	9
Total startups	1398	1306	1927	1844	2053

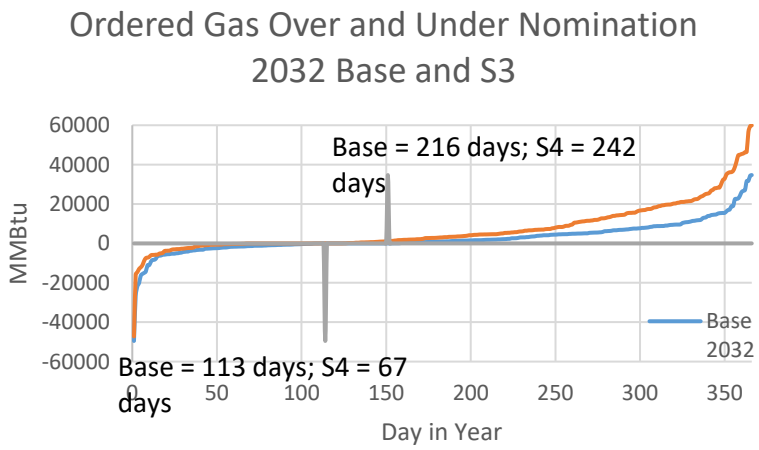
Table 22: Average Number of starts by Resource Type

Average Number of Starts per Resource Type					
Type	Base 2022	Scenario 1	Scenario 2	Scenario 3	Scenario 4
CT Gas	20	18	34	33	43
Hydro	2	2	2	2	2
ST Coal	29	28	31	40	29
CC	87	81	106	102	110
CT Oil	1	1	5	3	6
Nuclear	2	2	2	6	na
CT Other	4	2	9	4	9
ST Gas	7	8	16	7	9
All Resources	17	16	27	32	37

Gas Usage was evaluates by comparing the scenario runs with forecast error and without forecast error. The difference in these two runs provide estimations of gas over and underutilization. Over utilization occurs when more gas is burned than anticipated in the forecast while underutilization occurs when less gas is burned. The gas day in this analysis begins at 9:00 am Central Time. The Fuel burned in each run (Forecast Error and No Forecast Error) was computed then compared to determine the gas day for over or under utilization. The number of gas days of over nomination increases as renewable penetration increases. The plots shown are created by ordering the over and under nomination days from low to high. The blip on each curve in Figure 35 shows the number of days a nomination is low or high in each Scenario.







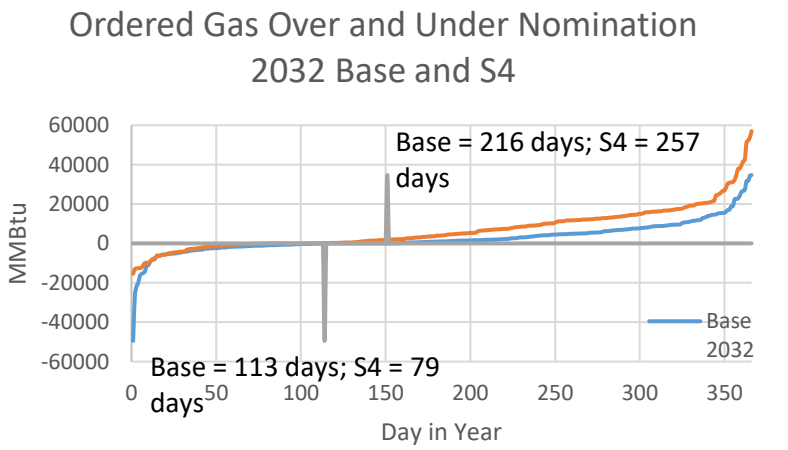


Figure 35: Over and Under Nomination for Gas Day

SECTION 9 CONCLUSIONS

The conclusions as well as findings and recommendations derived from this study are several.

- The average NSP production cost range is $22.99/MWH for the Base 2022 to $42.40/MWH for Scenario 4 (2013).
    - NSP is a net seller of power over the year in all studied scenarios.
    - Integration Cost due to forecast error ranges from 0.09 $/MWH to 0.55 $/MWH from Scenario 1 to Scenario 4.

Table 23: Summary of Project Production and Integration Costs

		Load and Production by Resource Type (GWh)				Production Cost ($/MWh)	Integration Cost Adder ($/MWh)	NSP Net Buyer/ Seller Position
Scenario	Year	NSP Load (GWh)	Wind Generation (GWh)	Solar Generation (GWh)	Other Resources (GWh)			
Base	2022	46,689	11,081	411	32,100	$22.99	---	Buyer
1	2022	46,689	17,185	2,263	31,260	$22.84	$0.09	Seller
2	2027	47,285	21,459	4,238	24,555	$27.24	$0.27	Seller
3	2032	47,888	22,795	6,122	26,906	$32.45	$0.55	Seller
4	2032	47,888	26,039	7,297	17,176	$42.40	$0.42	Seller

- Curtailment of wind and Solar PV increases as penetration increases; wind from 827,958 MWH to 1,853,498 MWH; solar PV from 46,326 MWH to 296,508, Table 24.
    - Wind energy production is greatest in the January through March months
    - Solar PV energy production is greatest in the April through September months.

Table 24: Summary of Projected Curtailment of Wind and Solar Resources

Wind and Solar Curtailment (GWh and % of resource production)				
Scenario	Wind Curtailment (GWh)	% of total Wind Production Curtailed	Solar Curtailment (GWh)	% of total Solar Production Curtailed
Base	126	1.1%	411	1.9%
1	827	4.8%	2,262	2.0%
2	1,109	5.2%	4,238	2.5%
3	1,575	6.9%	6,121	3.3%
4	1,853	7.1%	7,296	4.1%

- The number of hours of low net load increases as penetration increases, Table 25
    - The number of hours in the year when net load is less than 0 MW range from 179 hours in Scenario 1 (2022) to 2988 hours in Scenario 4 (2032).
    - The number of hours when net load is less than minimum load is significant ranging from 5035 hours in Scenario 1 (2022) to 6965 hours in Scenario 4 (2032).

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Table 25: Summary of Projected Hours of Low Net Load

Scenario	Number of Hours of Net Load < 0 MW	% of Hours of Net Load < 0 MW	Number of Hours of Net Load < Minimum Load MW	% of Hours of Net Load < Minimum Load MW
1	179	2.0%	5035	57.5%
2	1078	12.3%	5766	65.8%
3	1664	19.0%	6294	71.8%
4	2988	34.1%	6965	79.5%

- Spinning reserves increase as renewable penetration increases from 65MW for the Base (2022) to 141 MW for Scenario 4 (2032), Table 26.
    - With these spinning reserve increases there are a few hours in the year when NSP would rely on MISO for support. 36 hours with in Scenario 1 (2022) and 139 hours in Scenario 4 (2032). The maximum spinning deficiency in an hour being 43 MW and 145 MW respectively.
    - This supports the argument that the MISO operating reserve requirements will need to increase in the future to support the higher levels of renewable penetration.

Table 26: Summary of Projected Spinning Reserve Requirements

	Average Spinning Reserve Requirements (MW)			# of Hours When NSP would Rely on MISO Support(*)
Scenario	Load (MW)	Renewable (MW)	Total (MW)	
Base	43	22	65	
1	43	47	90	36
2	43	62	105	65
3	43	73	116	105
4	43	98	141	139

The number of gas CT and CC resource startups increase as renewable penetration increases, but cost impacts are expected to be minimal,

- Table 27.
    - CT Gas and CC resource types increase production as renewable penetration Increases.
    - Cost impacts directly associated with unit retirements are expected to be minimal.

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Table 27: Summary of Projected Annual Count of Resource Start-ups

	Number of Resource Startups over the Year				
	Base	Scenario 1	Scenario 2	Scenario 3*	Scenario 4*
CC	519	488	848	1,016	1,098
CT Gas	532	486	737	598	774
CT Oil	14	7	59	5	12
CT Other	4	2	9	4	9
ST Gas	27	32	16	7	9
ST Coal	263	255	220	161	114
Nuclear	5	5	5	17	0
Hydro	34	31	33	36	37
Total startups	1,398	1,306	1,927	1,844	2,053

(*) Coal Startups decrease largely due to unit retirements

- The number of days with over and under nomination of gas day requirements increase as penetration of renewables increase, but cost impacts are expected to be minimal, Table 28.

Table 28: Summary of Projected Natural Gas Nominations

		Natural Gas Nominations	
Year of Scenario Evaluated	(FE)Annual Production from Gas MWh	Number of days under nomination	Number of days over nomination
2022			
Base	4,215,562	73	152
Scenario 1	3,835,885	62	148
2027			
Base	9,057,391	105	184
Scenario 2	7,644,293	68	204
2032			
Base	12,749,560	113	216
Scenario 3	10,102,581	67	242
Scenario 4	13,194,566	79	257

- Results for NSP show benefits of operating within the MISO
  - This study examined NSP within the MISO as defined in the Continued Fleet Change scenario from the MTEP18 database.
  - Another study that examines NSP system as a standalone system could have different conclusions

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1. **Nature of the Material**: Prepared study.
2. **Authors:** The study was prepared by Excel Engineering.
3. **Importance:** The study contains competitively sensitive data related to project costs.
4. **Date the Information was Prepared**: The study was prepared during the fourth quarter of 2018.

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Technical and Economic Potential for Combined Heat and Power (CHP) Applications in Xcel Energy's Minnesota Territory

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Technical Update, June 2019

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ABSTRACT

Customer-sited fueled distributed generation (DG), often serving both heating and power needs, has served as a reliable source of distributed energy resources. A combination of technology improvements, project economics, policy incentives, and consumer choice in technology and energy service may impact the use of DG in the future. These changing needs and advancements have the potential to disrupt trajectories of load growth, driven by technical and economic decisions in technology adoption. Without adjustments to planning forecasts with respect to the driving factors, the forecasts may not adequately capture the range of load outcomes considered for system planning. The goal of this study is to estimate the technical and economic potential for commercial and industrial (C&I) combined heat and power (CHP) projects in the Minnesota service territory of Xcel Energy. Additionally, the expected market adoption for CHP is projected through 2039 with several sensitivity scenarios. This study serves as an update to a previous study performed in 2014.

Keywords
Distributed generation
Combined heat and power
CHP valuation
Microgrids
Reliability

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1
STUDY OBJECTIVE AND SUMMARY

This goal of this study is to estimate the technical and economic potential for commercial and industrial (C&I) combined heat and power (CHP) projects in the Minnesota service territory of Xcel Energy. Additionally, the expected market adoption for CHP was projected through 2039 with several sensitivity scenarios. This study serves as an update to a previous study performed in 2014.

As a first step, the technical potential for CHP in Xcel Energy's Minnesota territory was analyzed using customer data furnished by Xcel Energy. Data included commercial/industrial segment, maximum demand, and annual energy consumption for customers with maximum demands of 1 MW or larger. Power-to-heat ratios are estimated based on C&I segments and serve as input to the CHPower™[1] model to estimate the technical potential for CHP applications. The resulting technical potential is broken down by segment in Table 1-1.

Table 1-1
Technical Potential in Xcel Energy Minnesota (facilities with at least 1 MW peak demand)

Sector	Sites	Sum of Peak Demand (MW)	Technical Potential (MW)
Commercial	119	289	123
Industrial	120	492	196
Total	**239**	**781**	**319**

The 319 MW of technical potential from 239 sites is relatively small compared to the 941 MW of technical potential from 628 sites in the 2014 study. According to Xcel Energy, this difference was due to a combination of changes in data processing methods and customers implementing distributed energy resources and energy efficiency measures, resulting in lower peak demands.

After establishing the customers with technical potential for CHP, economics were analyzed using the CHPower Model™. Sites with economic potential (simple payback periods of less than 10 years) were broken down by payback period and sector, with the results shown in Table 1-2.

[1] ICF, CHPower Model. Fairfax, Virginia, 2019.

Table 1-2
Economic Potential in Xcel Energy Minnesota CHP, by Sector and Payback Period

	5-7 Years		7-10 Years		Total	
Sector	**Sites**	**Economic Potential (MW)**	**Sites**	**Economic Potential (MW)**	**Sites**	**Economic Potential (MW)**
Commercial	0	0	15	31	15	30
Industrial	<15	99	<15	16	19	115
Total	**<15**	**99**	**<30**	**47**	**34**	**145**

Overall there is an estimated 145 MW of economic potential CHP capacity that could achieve payback periods under 10 years. All of the economic potential came from sites capable of installing CHP sized larger than 1 MW. The economic potential in Minnesota is broken down by size range and payback period in Figure 1-1.

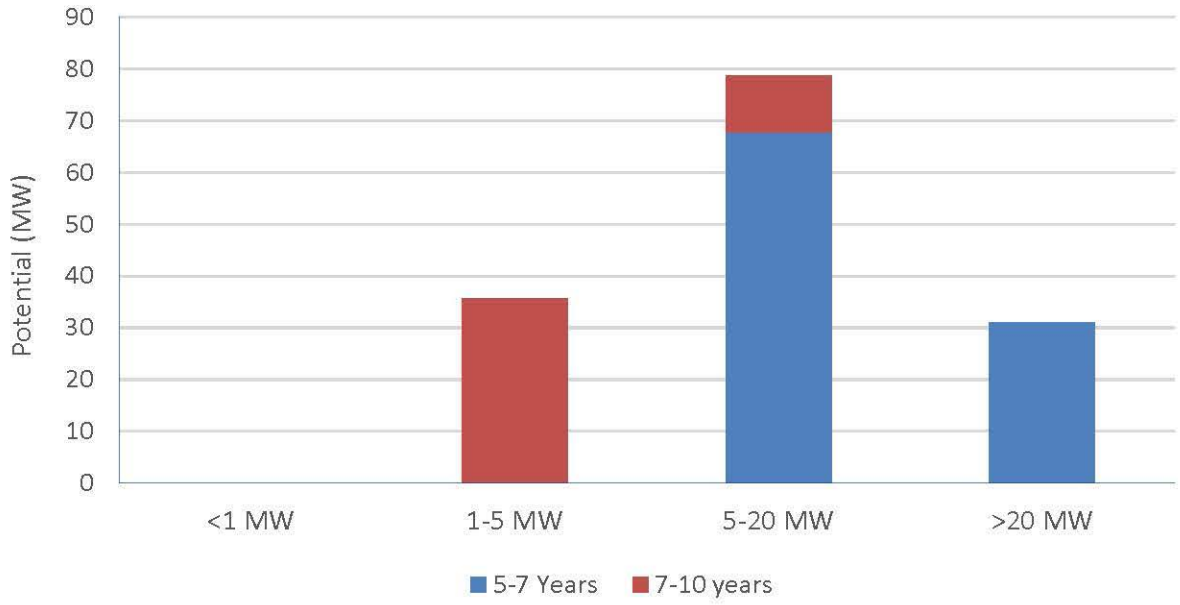

Figure 1-1
Economic Potential in Xcel Energy Minnesota by CHP Size Range and Payback

Out of the 145 MW of economic potential, 114 MW comes from industrial manufacturing facilities that tend to require a payback of less than five years on their energy investments in order to move forward with a project. For most of these customers, some form of large incentive would need to be available or they would need to have a high resilience need before they would consider installing a CHP system.

A market adoption analysis through 2039 was performed, and the base case results show 43 MW of total adoption (see Figure 1-2).

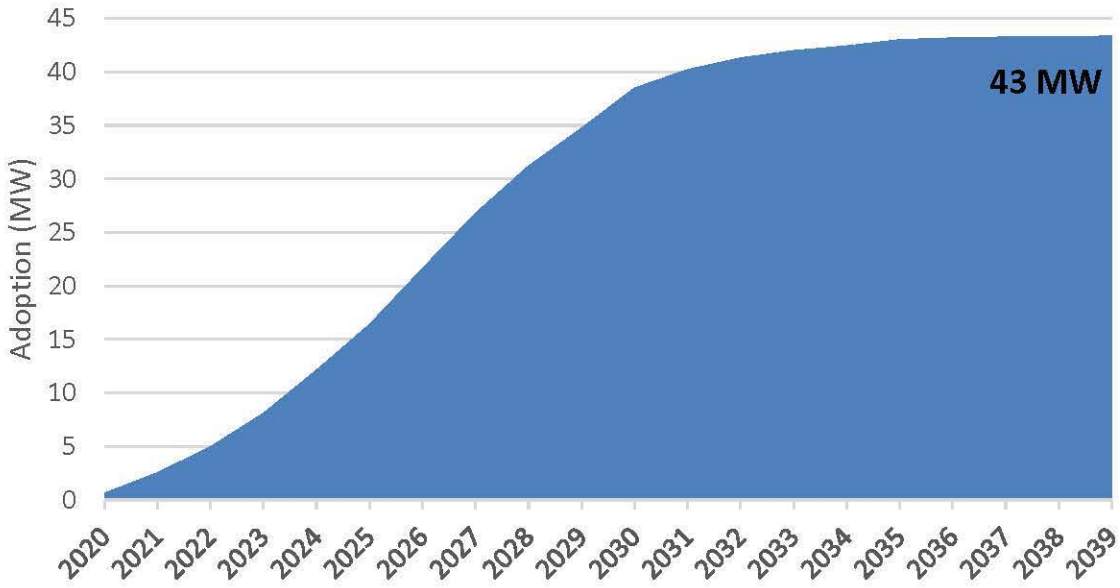

Figure 1-2
Estimated CHP Market Adoption in Minnesota through 2039

Sensitivities

Several sensitivities were performed for this analysis, including capital cost reductions, elimination of standby charges, and alternate electricity and natural gas escalation rates. The results were as follows:

- **Capital cost reduction** – At a 10% capital cost reduction for CHP installations, which mimics the current federal Investment Tax Credit, the overall impact on economic potential and market adoption was fairly minimal. At 30%, the economics for all sites improved, with economic potential increased by 50 MW and expected market adoption increased by 36 MW.
- **Eliminating standby charges** – This improved project economics for all facilities, reducing the payback period for several sites. The economic potential increased by 23 MW, but stronger long-term economics from the elimination of these charges would make facilities more likely to adopt, increasing estimated market adoption by 18 MW.
- **Using EIA escalation rates for electricity and natural gas** – Compared to Xcel Energy's internal forecasts, the EIA escalation rates are less favorable for CHP applications because they have natural gas prices increasing faster than electricity prices – total estimated market adoption decreased by 2 MW.
- **Simulating lower natural gas rates** – Instead of the natural gas escalation rate provided by Xcel Energy, there was no price escalation applied to natural gas rates. This improved CHP project economics, leading to a 9 MW increase in the estimated 20-year market adoption.

For all sensitivity scenarios considered, the total range of CHP market adoption through 2039 was between 41 MW and 79 MW. The results of the estimated 20-year market adoption for each sensitivity scenario are summarized in Table 1-3.

Table 1-3
Market Adoption in Xcel Energy Minnesota CHP, by Sensitivity Scenario

Sensitivity Scenario	Estimated 20-Year Adoption (MW)
Base Case	43
10% Capital Cost Reduction	52
30% Capital Cost Reduction	79
No Standby Charges	61
EIA Escalation Rates	41
Low Natural Gas Prices	52

Finally, the impact on carbon dioxide emissions was examined for both the base case market adoption and the 30% installed cost reduction sensitivity, to show how a relatively large CHP incentive might affect carbon emissions. With the expected CHP adoption, 42,000 tons of CO_2 would be reduced on an annual basis for the base case, compared to 66,000 tons with a 30% capital cost reduction.

Key Takeaways

The following are important findings from the analysis:

- Technical potential: 319 MW across 239 sites.
- Economic potential for base case: 145 MW of CHP, based on Xcel Energy forecasts for electricity/gas escalation, with payback periods ranging from 5 to 10 years.
- Market adoption: 43 MW is anticipated to be adopted through 2039 in the base case, with 39 MW being installed by 2030.
- A 30 percent cost reduction, in the form of a tax credit or grant, would have a large impact on economics, adding 36 MW of expected adoption through 2039, for a total of 79 MW.
- Removing standby rates improves payback periods, adding 18 MW of adoption through 2039.
- CHP installations could lead to a significant reduction in greenhouse gas emissions compared to separate heat and utility power, although emissions will decline over time as the grid becomes cleaner.
- There may be potential benefits to be explored or considered by offering utility-owned CHP systems to large customers with high CHP potential.

2
ASSESSMENT OF DG AND CHP TECHNICAL AND ECONOMIC POTENTIAL IN XCEL ENERGY'S MINNESOTA TERRITORY

As an update to a 2014 assessment of DG and CHP potential, this study aims to provide information on the projected impacts of natural gas-fueled DG and CHP applications in Xcel Energy's service areas, focusing on the large C&I customer base in the Minnesota service territory.

The objectives of the study were to:

- Estimate and analyze technical and economic potential for natural gas distributed generation in C&I end user applications.
- Identify key C&I segments where DG CHP applications could be cost effective for end-users.
- Evaluate the impact of sensitivity scenarios on expected market adoption.
- Present findings and results for the Minnesota service territories.

The focus of this study is on natural gas CHP applications that can utilize waste heat to displace site thermal loads. CHP systems are more efficient and economical than power-only generators. The 2014 study found that natural gas generators in Minnesota were not economical unless they incorporated heat recovery and utilization in a CHP configuration. Additionally, most C&I facilities with significant electric requirements also have a sizable thermal demand that can be served by CHP.

Technical Potential

This study estimated the technical potential for natural gas CHP applications in Xcel Energy's Minnesota service territory. Facility counts and sizes were provided by Xcel Energy, using actual customer data for electric demand (kW) and annual electricity consumption (kWh). This data, along with industry-specific thermal load estimates, is used to approximate the potential size for baseload CHP systems at each customer site. The data was anonymized so that customer names and addresses were not provided. The resulting technical potential estimates are broken down by market sector in Table 2-1.

Table 2-1
Technical Potential in Xcel Energy Minnesota (facilities with at least 1 MW peak demand)

Sector	Sites	Sum of Peak Demand (MW)	Technical Potential (MW)
Commercial	119	289	123
Industrial	120	492	196
Total	**239**	**781**	**319**

The 319 MW of technical potential from 239 sites is relatively small compared to the 941 MW of technical potential from 628 sites in the 2014 study. According to Xcel Energy, this difference was due to a combination of changes in data processing methods and customers implementing distributed energy resources and energy efficiency measures, resulting in lower peak demands.

Based on the economic CHP sizing, over half of these sites could only support CHP systems smaller than 1 MW in size. In this size range, equipment costs are higher on a per-kW basis, so project economics tend to not be as strong. The technical potential in Minnesota (based on economic CHP sizing) is broken down by size range in Table 2-2.

Table 2-2
Technical Potential in Xcel Energy Minnesota by Sector and CHP Size Range

	<1 MW		1-5 MW		5-20 MW		>20 MW	
Sector	**Sites**	**Technical Potential (MW)**	**Sites**	**Technical Potential (MW)**	**Sites**	**Technical Potential (MW)**	**Sites**	**Technical Potential (MW)**
Commercial	76	37	42	75	<15	11	0	0
Industrial	79	29	33	68	<15	68	<15	31
Total	**155**	**66**	**75**	**143**	**<30**	**79**	**<15**	**31**

All of these facilities were analyzed for economic potential, to determine how many sites would be capable of a 10-year or less payback period.

Economic Potential

Installed capital cost, maintenance costs, and performance information for the CHP systems were provided by EPRI from a Request for Information process that was deployed for the recent national study, using typical price and performance data for CHP units across three different size ranges[2]:

1. 100 – 1,000 kW (Medium Commercial/Light Industrial)
2. 1,000 – 5,000 kW (Large Commercial/Medium Industrial)
3. > 5,000 kW (Large Industrial)

The costs were adjusted to reflect inflation rates since the data was provided in 2014.[3] The price and performance data for engines, turbines and fuel cells in these size ranges are shown in Table 2-3.

[2] EPRI Report Natural Gas Distributed Generation Options Cost and Market Benchmarking Assessment 3002004191, October 2014.

[3] 6.1% inflation applied from 2014 to 2018 (US Inflation Calculator, https://www.usinflationcalculator.com); 1.9% 2018 inflation applied annually to 2020 (analysis starts in 2020).

Table 2-3
Price and Performance Data Used in Economic Analysis[4]

	100 - 1,000 kW			1 - 5 MW		5 - 50 MW	
	Engine	Fuel Cell	MT	Engine	Turbine	Engine	Turbine
Installed Cost ($/kW)	$3,310	$6,610	$3,080	$1,980	$2,420	$1,210	$1,380
Maintenance ($/kWh)	0.022	0.028	0.012	0.018	0.020	0.011	0.010
Electric Efficiency (HHV)	29.0%	45.0%	27.0%	37.0%	34.0%	41.0%	32.0%
CHP Efficiency (HHV)	79.0%	83.0%	65.0%	80.0%	68.0%	77.0%	74.0%

The Federal Investment Tax Credit for CHP – scheduled to ramp down from 10% (current rate) to 6% in 2021 and 0% after – was not incorporated into the economic potential results. State average natural gas prices[5] and Xcel Energy's current electricity tariffs were inputs to the model which estimated electricity bills before and after CHP is installed, considering the effect of standby charges, demand charges, and time-of-use components. Then, the installed cost of CHP was compared to the net annual savings when considering maintenance, fuel purchases, and energy bill savings. Economics were analyzed on a site-by-site basis using ICF's CHPower Model™, with the full assumptions and methodology outlined in Appendix A.

Overall, 145 MW of economic potential was found in Xcel Energy's Minnesota service territory, with 99 MW showing payback periods in the range of 5-7 years and the remainder in the range of 7-10 years. Economic potential comes from a mixture of large manufacturing facilities, mining operations, paper mills, chemical plants, commercial office buildings, and other commercial facilities. The results are broken down by sector and payback period range in Table 2-4.

Table 2-4
Economic Potential in Xcel Energy Minnesota by Sector and Payback Period Range

	5-7 Years		7-10 Years		Total	
Sector	Sites	Economic Potential (MW)	Sites	Economic Potential (MW)	Sites	Economic Potential (MW)
Commercial	0	0	15	31	15	30
Industrial	<15	99	<15	16	19	115
Total	**<15**	**99**	**<30**	**47**	**34**	**145**

All of the economic potential comes from sites capable of installing CHP sized larger than 1 MW. While the economics for hospitals and college campuses may not be as strong as large industrial facilities, they have typically been more willing to take on longer payback periods. Industrial facilities tend to require payback periods under five years. For hospitals and college

[4] EPRI Report Natural Gas Distributed Generation Options Cost and Market Benchmarking Assessment 3002004191, October 2014.

[5] The lower of the average industrial gas rate or average citygate price plus $1/MMBtu (EIA average 2017 prices)

campuses, their future is more certain than industrial sites, and they may take on projects with payback periods up to 10 years. Figure 2-1 provides a graphical representation of the economic potential by segment and payback period.

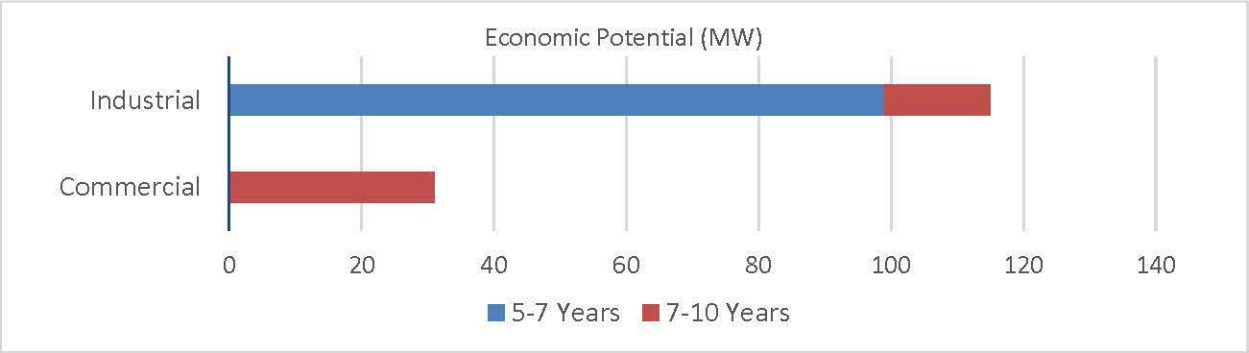

Figure 2-1
Economic Potential in Xcel Energy Minnesota by Sector and Payback Period

The economic potential in Xcel Energy's Minnesota territory is broken down by size range and payback period in Figure 2-2. It should be noted that all of the potential in the >20 MW range comes from fewer than 15 facilities.

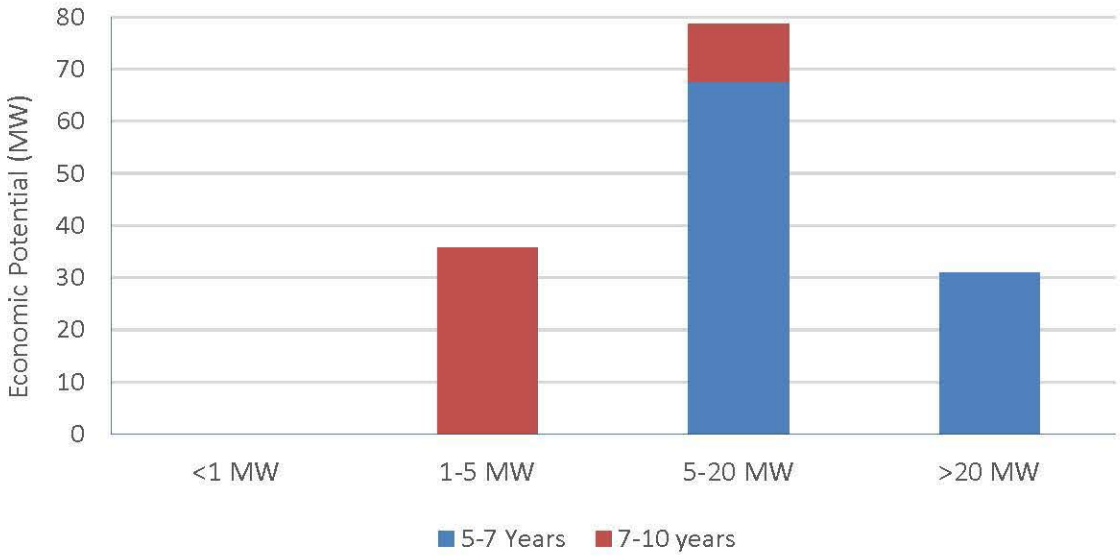

Figure 2-2
Economic Potential in Xcel Energy Minnesota by CHP Size Range and Payback Period

The economic potential analysis showed that project economics are strongest at large, high load factor facilities.

Market Adoption Analysis

The CHPower model™ can estimate the expected adoption of CHP over time. First, market acceptance percentages are applied to each potential installation, based on the sector and payback period. Facility owners in the commercial (and institutional) sectors are more likely to accept

projects with longer payback periods compared to industrial facility owners. Market acceptance curves were developed based on a combination of survey results (including the Primen survey used in the 2014 analysis[6]), interviews with current and potential CHP customers, and experience in the marketplace. The market acceptance curves are shown in Figure 2-3.

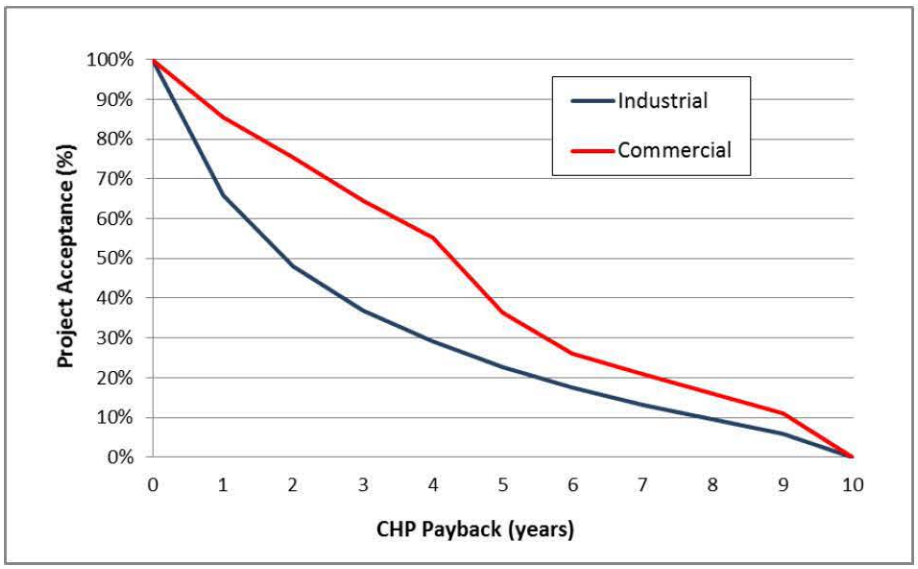

Figure 2-3
Market Acceptance Curves by Payback Period and Sector

The market-accepted potential defines the boundaries of CHP adoption, based on current market conditions. To estimate adoption over time, the model applied a Bass Diffusion model, which includes electricity and natural gas rate escalation with Xcel Energy-provided data, along with industry-specific market growth estimates from the 2018 EIA Annual Energy Outlook.[7] Market adoption was estimated on an annual basis with these changing factors built into the CHPower model calculations. The results for the base case scenario are shown in Figure 2-4, with an estimated 43 MW of CHP adoption from 2020 through 2039.

[6] *Converting Distributed Energy Prospects into Customers*, Primen, December 2003 (EPRI Number 1010294)

[7] U.S. Energy Information Administration, Annual Energy Outlook, 2018, https://www.eia.gov/outlooks/archive/aeo18/

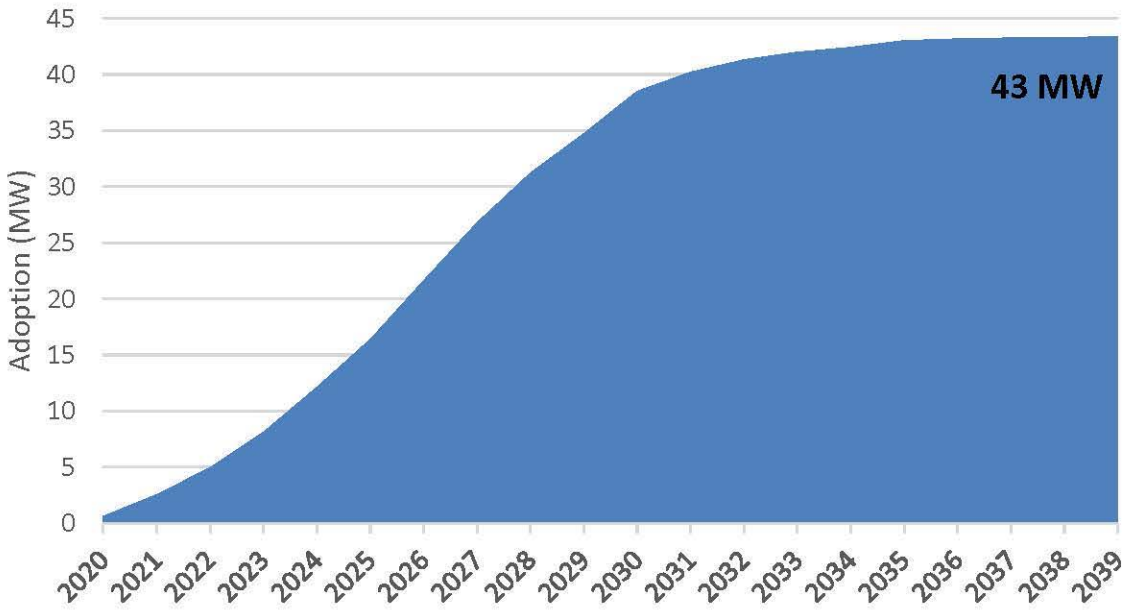

Figure 2-4
Xcel Energy Minnesota Base Case Market Adoption Through 2039

The majority of expected adoption occurs between 2020 and 2030. After 2030, adoption slows due to market limitations and less favorable economics from higher gas prices. Most of this adoption occurs in fewer than 15 sites. Figure 2-5 shows the estimated 20-year adoption by CHP size range. Overall, fewer than 15 sites are expected to adopt CHP, mostly within the 1-5 MW size range.

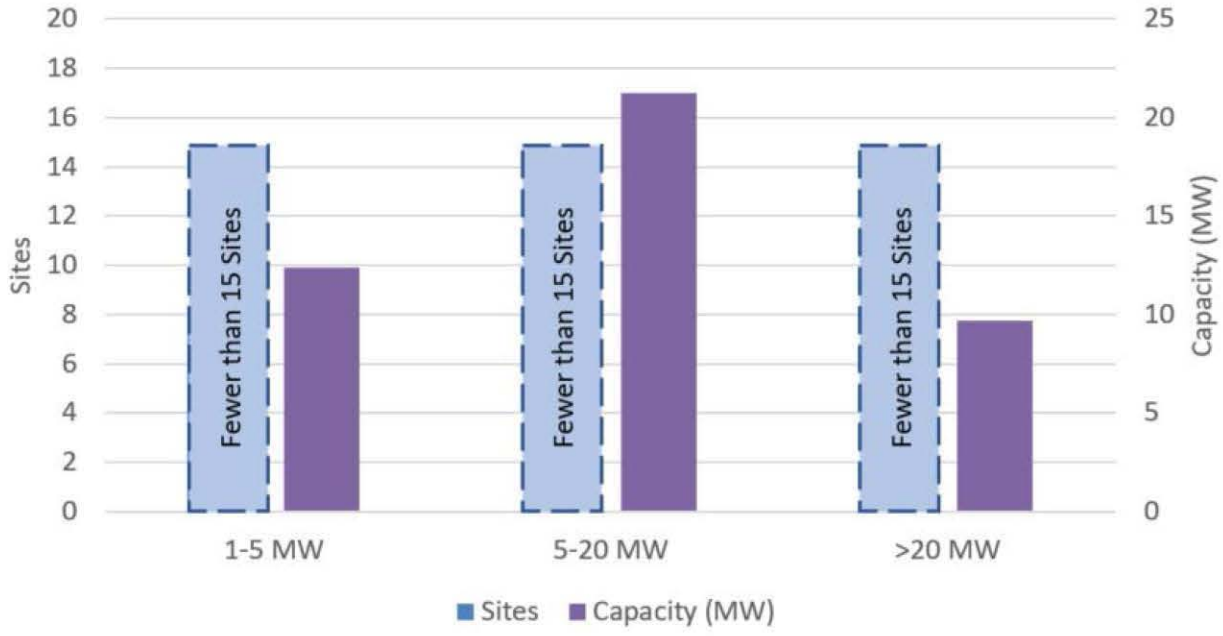

Figure 2-5
Xcel Energy Minnesota Base Case Market Adoption through 2039 by CHP Size Range

Sensitivity Analysis

Five sensitivities were performed for this analysis:

1. capital (installed) costs reduced by 10 percent to show the effect of a CHP incentive
2. capital (installed) costs reduced by 30 percent to show the effect of a larger CHP incentive
3. removal of standby charges
4. using EIA escalation rates for electricity and natural gas
5. removing the escalation of natural gas prices

For each sensitivity, the effects on economic potential and estimated market adoption are shown.

Sensitivity: 10% Installed Cost Reduction

The first sensitivity reduced the installed cost of CHP systems by 10 percent, representing a small government or utility capital incentive. With a 10 percent capital cost reduction, there is a modest increase of 7 MW of economic potential, all found in sites 1-5 MW in size. This new economic potential is found in manufacturing facilities, commercial buildings, colleges/universities, and hotels. While there was not much of an increase in economic potential, the 10 percent cost reduction shortens the payback period of the existing economic potential, moving 65 MW of potential to a payback period under five years (all in sites above 5 MW). The economic potential for this sensitivity is broken down by sector and payback period in Table 2-5.

Table 2-5
Sensitivity: Economic Potential in Xcel Energy Minnesota with 10% CHP Cost Reduction

	<5 Years		5-7 Years		7-10 Years		Total	
Sector	**Sites**	**Economic Potential (MW)**	**Sites**	**Economic Potential (MW)**	**Sites**	**Economic Potential (MW)**	**Sites**	**Economic Potential (MW)**
Commercial	0	0	<15	14	16	21	19	35
Industrial	<15	65	<15	41	<15	11	21	118
Total	**<15**	**65**	**<30**	**55**	**<30**	**32**	**40**	**153**

With a 10 percent capital cost reduction applied, there is a more noticeable change to the total estimated market adoption compared to the total economic potential. Under this sensitivity, expected market adoption increases from 43 MW to 52 MW through 2039, following a similar trend as the base case. The new 20-year market adoption curve with the 10 percent cost reduction can be seen in Figure 2-6.

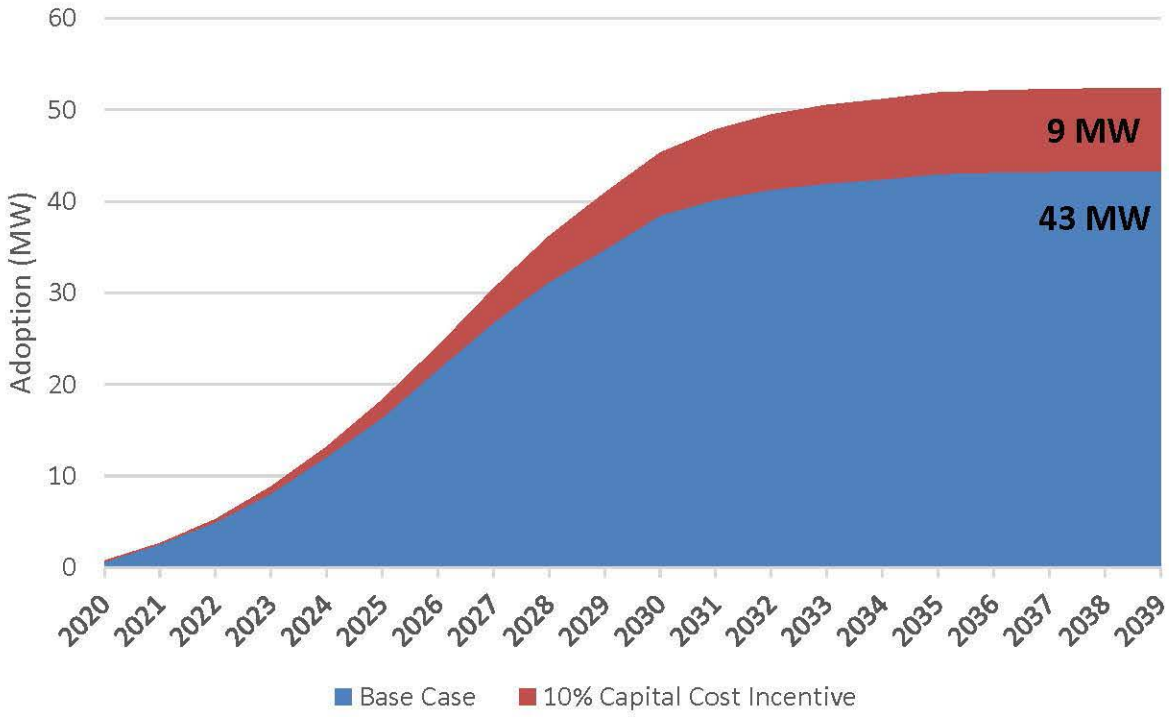

Figure 2-6
Sensitivity: Market Adoption through 2039 with 10% CHP Cost Reduction

Sensitivity: 30% Installed Cost Reduction

The next sensitivity reduced the installed cost of CHP systems by 30 percent, representing incentives similar to those from a larger government or utility capital incentive. With a 30 percent capital cost reduction, there is a much larger impact on economic potential – a total increase of 50 MW. This new economic potential is found in sites 1-5 MW in size across several industrial and commercial sectors. The 30 percent cost reduction also shortens the payback period of much of the existing economic potential. Nearly all of the economic potential at sites larger than 5 MW would now have payback periods under 5 years. The economic potential for this sensitivity is broken down by sector and payback period in Table 2-6.

Table 2-6
Sensitivity: Economic Potential in Xcel Energy Minnesota with 30% CHP Cost Reduction

	<5 Years		5-7 Years		7-10 Years		Total	
Sector	**Sites**	**Economic Potential (MW)**	**Sites**	**Economic Potential (MW)**	**Sites**	**Economic Potential (MW)**	**Sites**	**Economic Potential (MW)**
Commercial	0	0	15	31	16	30	31	61
Industrial	<15	99	<15	16	<15	20	28	134
Total	**<15**	**99**	**<30**	**47**	**<30**	**50**	**59**	**195**

Using a 30 percent capital cost reduction, there is also a large change to the total estimated market adoption. As expected, the additional expected market adoption is more than double that provided by the 10 percent capital cost reduction. Under this sensitivity, expected market adoption increases from 43 MW to 79 MW through 2039, the largest expected market adoption under any of the sensitivities. The new 20-year market adoption curve with the 30 percent cost reduction can be seen in Figure 2-7.

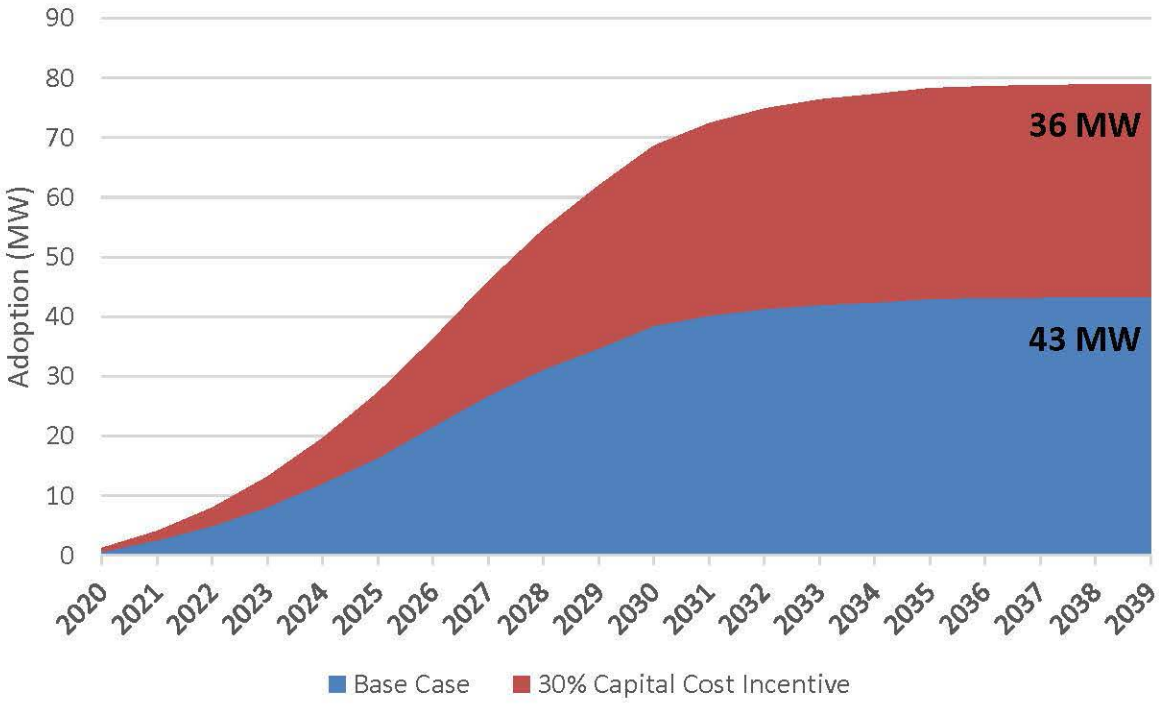

Figure 2-7
Sensitivity: Market Adoption through 2039 with 30% CHP Cost Reduction

Sensitivity: Removal of Standby Charges

Standby charges were modeled using the contract demand charge, assuming all maintenance occurs on a scheduled basis, and no unscheduled downtime or maintenance for the CHP unit that would add additional charges. The contract demand charges, in dollars per kW of CHP system size, are:

- $3.00 per kW for customers receiving service at secondary voltage (assumed to be sites with a maximum demand of less than 3,000 kW),
- $2.20 per kW for customers receiving service at primary voltage (maximum demand of 3,000 – 30,000 kW), or
- $0.65 per kW for customers receiving service at transmission-level voltage (maximum demand of 30,000 kW or higher).

There is a further reduction in standby charges for customers at the sub-transmission level, but for the purposes of this analysis, all customers were assumed to be on either secondary or primary voltage lines.

When the standby charges were removed, economics were improved, resulting in more economic potential and shorter payback periods. 23 MW of economic potential was added in the state, all at sites under 5 MW. Additionally, many of the large industrial facilities over 5 MW that were in the 5-7 year payback range have shifted to <5 year paybacks. The economic potential with no standby charges is presented by segment and payback period in Table 2-7.

Table 2-7
Sensitivity: Economic Potential in Xcel Energy Minnesota with No Standby Charges

	<5 Years		5-7 Years		7-10 Years		Total	
Sector	**Sites**	**Economic Potential (MW)**	**Sites**	**Economic Potential (MW)**	**Sites**	**Economic Potential (MW)**	**Sites**	**Economic Potential (MW)**
Commercial	0	0	<15	14	19	25	22	39
Industrial	<15	65	<15	41	<15	23	26	130
Total	**<15**	**65**	**<15**	**55**	<40	**48**	**48**	**169**

The removal of standby charges had a greater impact on market adoption trends than on the economic potential of sites, due to the longer-term benefits of reducing these costs. Under this sensitivity, expected market adoption increases from 43 MW to 61 MW through 2039. The new 20-year market adoption curve without standby rates can be seen in Figure 2-8.

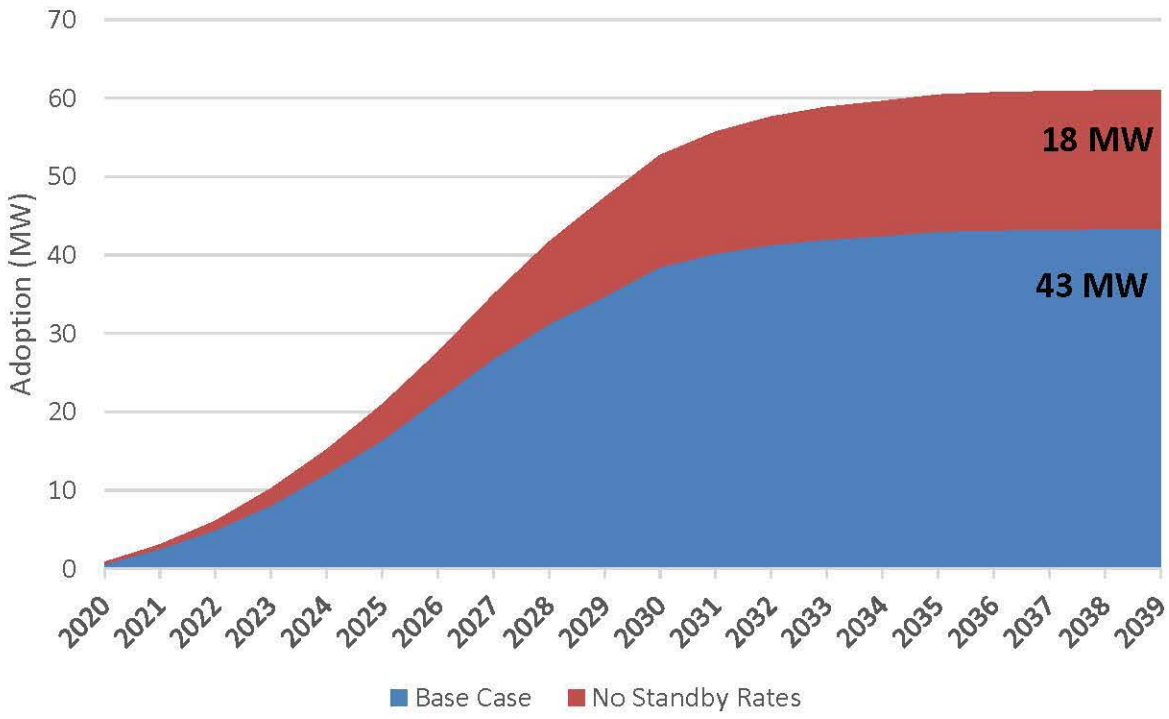

Figure 2-8
Sensitivity: Market Adoption through 2039 with No Standby Charges

Sensitivity: EIA Escalation Rates

Instead of the energy price escalation rates provided by Xcel Energy, the Energy Information Administration's projected escalation rates from the 2019 Annual Energy Outlook were used. With the EIA rates, both electricity (2.23%, compared to 2.70%) and natural gas (3.30%, compared to 4.15%) are projected to escalate at slower rates, leaving little impact on the base case results. This showed in the economic analysis, where there was no change in the economic potential compared to the base case.

However, using the EIA escalation rates did impact the expected 20-year market adoption. Because of the drop in electricity price growth, the economics for CHP projects worsened, leading to a small drop in the estimated adoption. Under this sensitivity, expected market adoption decreased from 43 MW to 41 MW through 2039. The new 20-year market adoption curve with the EIA escalation rates can be seen in Figure 2-9.

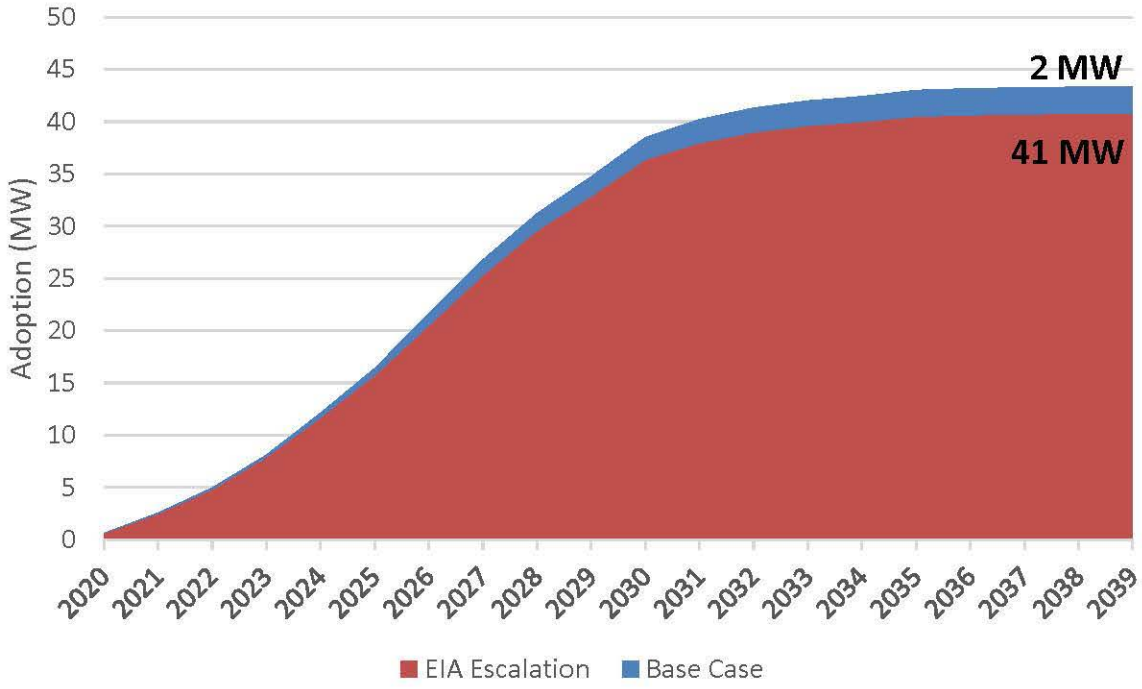

Figure 2-9
Sensitivity: Market Adoption through 2039 with EIA Escalation Rates

Sensitivity: Low Natural Gas Prices

Instead of using the natural gas escalation rate provided by Xcel Energy, there was no price escalation applied to natural gas rates in this sensitivity analysis, to mimic the impact of natural gas prices remaining lower than projected. This had no impact on the economic potential, with no difference in potential from the base case.

However, like with the EIA escalation rates, there was an impact on the expected 20-year market adoption. As expected, with lower gas prices, the economics for CHP projects improves, resulting in a sizeable increase in the estimated adoption. Under this sensitivity, expected market

adoption increased from 43 MW to 52 MW in 2039. The new 20-year market adoption curve with low natural gas prices can be seen in Figure 2-10.

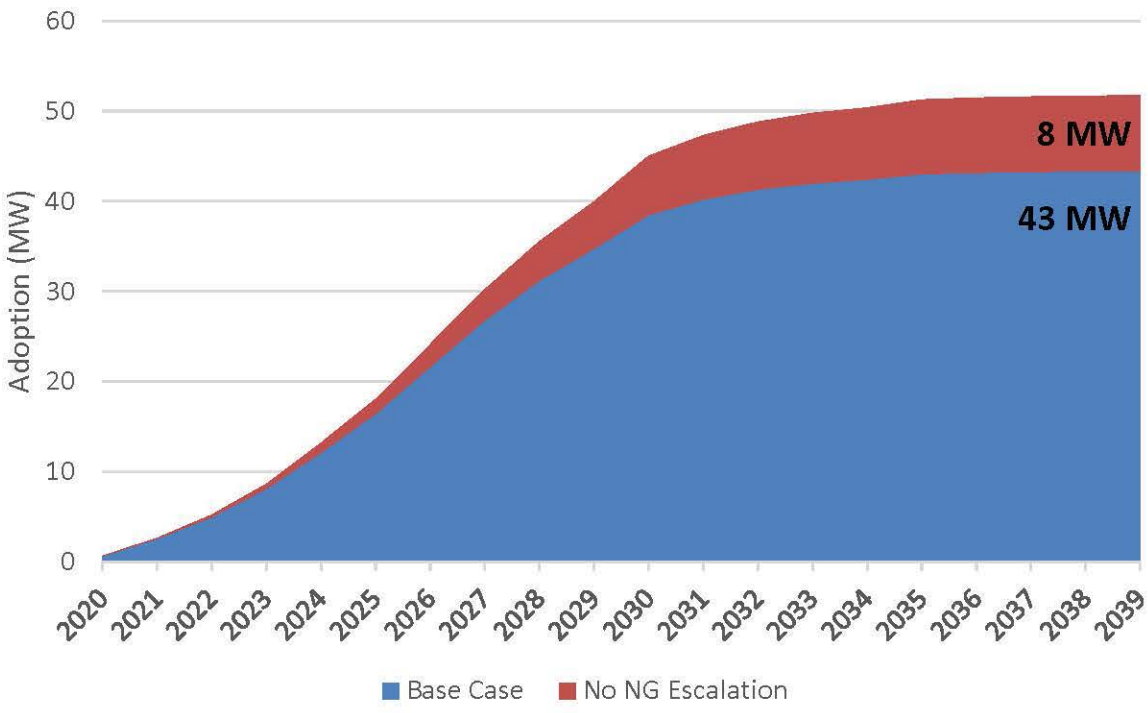

Figure 2-10
Sensitivity: Market Adoption through 2039 with Low Natural Gas Prices

Impact of Adopted CHP on CO_2 Emissions

Efficient CHP systems have a positive impact on CO_2 emissions compared to separate heat and utility power. When a baseload CHP system comes online, demand is reduced and utilities turn down fossil fuel generators in response. For baseload CHP, EPA guidance is to use the eGRID average fossil fuel emissions rate for displaced utility electricity.[8] For Minnesota, the average fossil fuel emissions rate is estimated at 1,854 lbs/MWh. In addition, transmission and distribution line losses produce an average loss of 5.13 percent for delivered electricity. For the customer, natural gas combustion – both for CHP fuel and boiler fuel – produces approximately 117 lbs CO_2 per MMBtu of fuel consumed. However, Xcel Energy recently announced an initiative to become 100 percent carbon-free by 2050, so the grid mix is expected to change significantly over the next twenty years. Between 2030 and 2040, Xcel Energy is expected to retire its coal plants, leaving only natural gas generators to accompany zero-emission nuclear/hydro/renewable resources.

[8] U.S. Environmental Protection Agency, Combined Heat and Power Partnership, Fuel and Carbon Dioxide Emissions Savings Calculation Methodology for Combined Heat and Power Systems, February 2015, https://www.epa.gov/chp/fuel-and-carbon-dioxide-emissions-savings-calculation-methodology-combined-heat-and-power

These factors were combined to develop an estimate of potential emission reductions from expected CHP deployments, both for the base case and the 30% capital cost reduction scenario. The results of this analysis are shown in Figure 2-11. The dotted lines represent the estimated emissions savings using current marginal utility emission rates, while the solid lines represent the estimated emissions savings with Xcel Energy's planned reductions in fossil fuel generation.

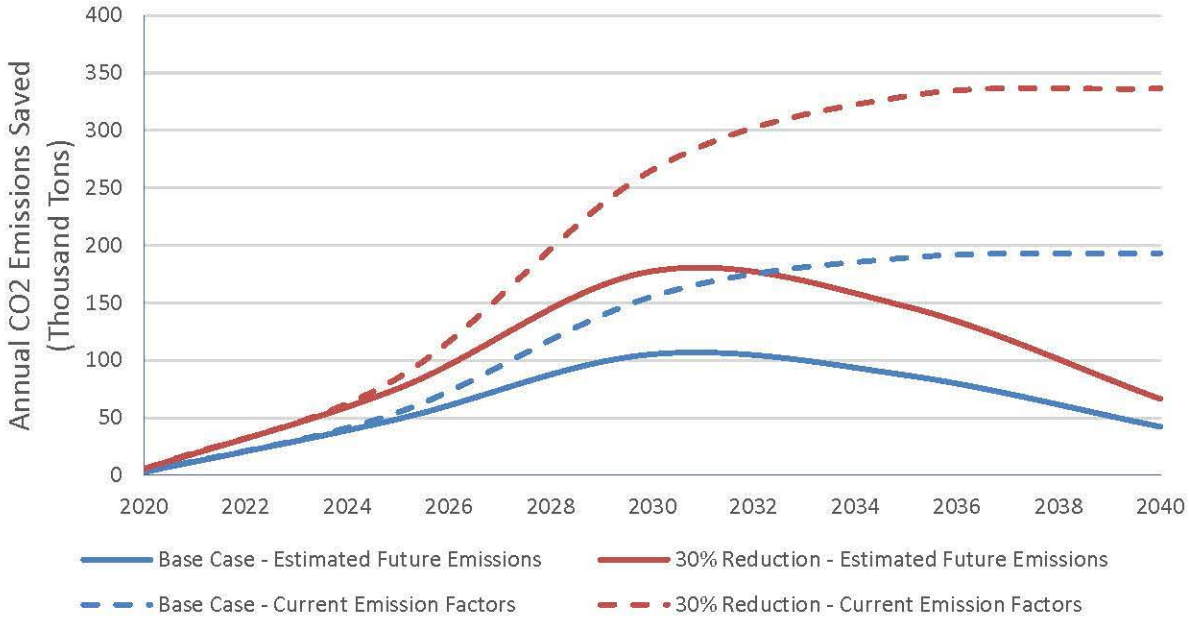

Figure 2-11
Annual Impact of Adopted CHP on Carbon Dioxide Emissions by 2040

Considering the potential impact on CO_2 emissions with 43 MW of base case adoption, an estimated 42,000 tons of CO_2 would be reduced on an annual basis by 2040, down from a maximum of approximately 108,000 tons in 2031. Looking at the increased adoption from deploying a 30 percent cost reduction, a total of 66,000 tons of CO_2 would be avoided on an annual basis by 2040, down from a maximum of 180,000 tons in 2031. While emissions reductions from CHP will be lessened over time compared to Xcel Energy's cleaner grid, there is still expected to be a significant amount of greenhouse gas savings from CHP installations that are installed over the next ten years.

3
CONCLUSION

This study estimates a total of 319 MW of technical potential from 239 sites and 145 MW of economic CHP potential in Xcel Energy's Minnesota service territory. Under current market conditions, large facilities that can install CHP systems over 5 MW in size have the strongest project economics for CHP applications, with payback periods ranging from 5-7 years. Project economics are not attractive for most potential industrial customers, who tend to desire payback periods of five years or less, so CHP adoption is likely to be a relatively slow process in these segments. Under the base case scenario, about 43 MW of adopted CHP is expected through 2039.

When installed costs for CHP systems are reduced by 30 percent, some sites can achieve payback periods below five years, and an additional 36 MW of CHP would likely be adopted through 2039. Removing standby rates has a positive effect on project economics, with an additional 18 MW of expected adoption. Using the EIA's predicted escalation rates for the U.S., the estimated 20-year adoption is reduced from 43 MW to 41 MW. Finally, low natural gas prices over the next 20 years would lead to a modest increase in estimated adoption, from 43 MW to 52 MW.

Overall, the effect of CHP adoption on Xcel Energy's Minnesota territory should be relatively modest in the foreseeable future given current conditions, with economics not strong enough to encourage more widespread adoption. State or utility incentives could speed up adoption, but the ceiling for total economic CHP potential is currently estimated to be less than 150 MW. Even at this relatively modest adoption rate, customers switching to self-generation through CHP can impact current load growth forecasts. There may be potential benefits to be explored or considered by offering utility-owned CHP systems to large customers with high CHP potential. There are a growing number of utilities who are developing rate-based utility owned CHP systems at customer sites to provide customers with energy cost savings on thermal energy, increased resilience, and economic development opportunities.[9]

[9] Utility CHP – A Least Cost Baseload Resource. https://www.icf.com/resources/white-papers/2017/utility-chp-ownership

A
ASSUMPTIONS AND METHODOLOGY FOR CHPOWER MODEL

The CHPower Model

The market analysis of DG/CHP systems was performed using ICF's CHPower Model[10]. This spreadsheet-based model is used to evaluate the technical, economic, and market potential for combined heat and power (CHP) applications across the United States and Canada. The model determines which combination of size, rate schedule, and operating mode is the most economical, and forecasts the commercial and industrial facilities most likely to install CHP systems based on cash flows and simple payback. The model also determines the cumulative CHP market penetration over an analysis timeframe, and provides long-term market forecast for CHP systems operating in commercial, institutional, and industrial sectors. The database of sites for use in the model was provided by Xcel Energy. Figure A-1 illustrates how the CHPower model organizes the key data inputs, performs calculations, and generates the desired outputs.

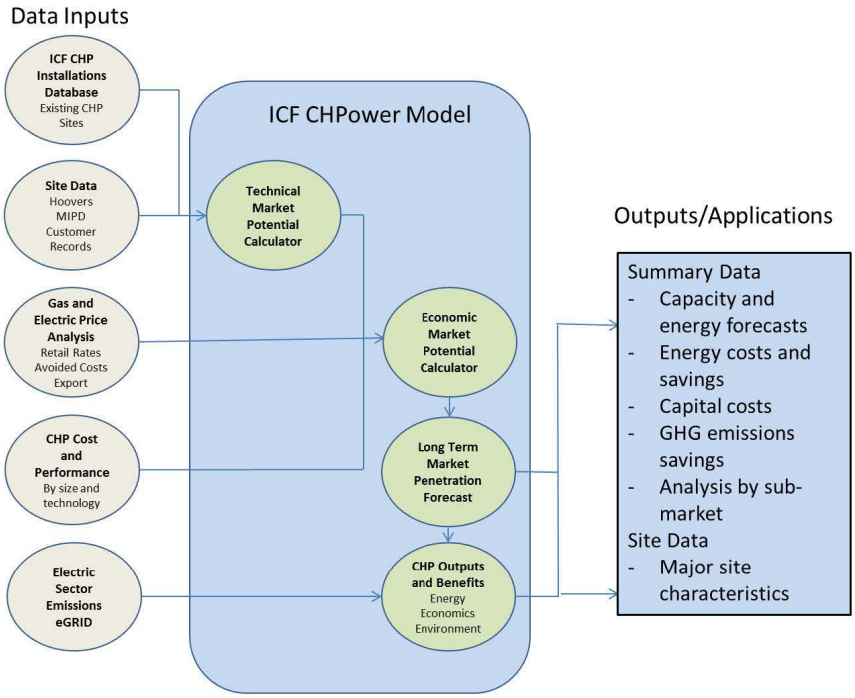

Figure A-1
CHPower Model

[10] ICF, CHPower Model. Fairfax, Virginia, 2019.

The CHPower model has been used for a variety of different geographic, economic, and technical scenarios on projects for utilities, equipment manufacturers, and research organizations. For this effort, the CHPower model was configured to:

- Evaluate the potential for CHP in Xcel Energy's Minnesota and Colorado territory with provided customer data
- Examine the potential for DG/CHP applications at a variety of commercial and industrial sites
- Process the costs and benefits for each DG/CHP unit at each site (versus utility power) and determine the DG/CHP system with the optimal payback period for each site that is analyzed for five different sensitivity scenarios
- Forecast CHP adoption over the 20-year analysis timeframe in Xcel Energy's Minnesota and Colorado territory
- Calculate estimated CO_2 emissions reductions for each site and for each sensitivity over the analysis timeframe

Key Inputs and Assumptions

There are four main components of the model are as follows:

- **Technical Potential Calculator** – Customer data from Xcel Energy was converted into site-by-site estimates of CHP potential using a series of relationships between building type and electric and thermal use.
- **Economic Potential Calculator** – For each site, the simple payback period is calculated based on the appropriate CHP system and energy rates for that system size and application. The payback determines the likelihood that a particular system will be installed by the site.
- **Market Acceptance** – The market acceptance factor or propensity to participate and is based on a national survey of potential CHP customers. The sum of the technical potentials multiplied by the market acceptance factors represents the total market potential – or the estimated quantity of CHP that will ultimately enter the market.
- **Long Term Market Penetration Forecast** – Based on the economic potential estimates, the market penetration over a 10-25 year time horizon is estimated using a diffusion model that provides a realistic representation of how the economic potential will enter the market over time.
- **CHP Outputs and Benefits** – Summary and detailed outputs for each forecast/scenario are characterized including cumulative and annual estimates of market penetration, net effect on gas and electricity consumption, customer economic savings, and emissions both at the site and avoided from the electric power grid.

CHPower has several primary inputs necessary in order to run the model. The key inputs are:

1. Electricity Prices (modeled Xcel Energy rates)
2. Natural Gas Prices (EIA)
3. CHP Technical Potential (Xcel Energy customer data)
4. Market Growth Rates (EIA Annual Energy Outlook (AEO 2018) market sector growth rates)

5. CHP Cost and Performance Assumptions (EPRI)
6. Market Acceptance and Bass Diffusion for expected deployments (ICF)

Key Assumptions Made for Xcel Energy Minnesota

Key assumptions for the DIPSERSE model in this analysis for Xcel Energy are provided in Table A-1, with a comparison to assumptions used in the 2014 analysis.

Table A-1
Assumptions Used for 2019 Analysis (compared to 2014)

Model Inputs	2014 Assumptions/Data	2019 Assumptions/Data
Cost/Performance	2014 EPRI National CHP Assessment	2016 DOE Fact Sheets (or 2014 EPRI Assessment)
Federal ITC	10% reduction for capital costs	10% reduction for capital costs
Discount Rate	7 percent	Simple payback calculation – taxes and depreciation are not applied
Depreciation Schedule	10 year straight line	
Tax Percentage	35 percent	
Property Taxes, Insurance	35 percent	
Natural Gas Pricing	2013 average prices – lower of state average industrial price or city gate price plus $1/MMBtu	2018 average prices – lower of state average industrial price or city gate price plus $1/MMBtu
Natural Gas Escalation	Provided by Xcel Energy	Probided by Xcel Energy
Electricity Pricing	Based on Xcel Energy's latest electricity tariff	Based on Xcel Energy's latest electricity tariff
Electricity Escalation	Provided by Xcel Energy	Provided by Xcel Energy
Standby Service	Contract demand charges for secondary (<3,000 kW) and primary (>3,000 kW) service customers	Contract demand charges for secondary (<3,000 kW) and primary (>3,000 kW) service customers
Value of Backup Power	$0	$0
Part-Load Efficiency	Reductions to 50% of peak load, based on load profile following	DG/CHP sized to operate near full-load, switch to standby during low-load periods
DG Maintenance Escalation	2 percent	N/A (not expected to escalate beyond inflation)
Commercial Load Profiles	Generated from DOE2model building simulations and matched to consumer sites	Annual hours of operation applied to average loads, CHP utilization percentage from load shape
Industrial Load Profiles	Weekday/weekend load shapes collected from representative facilities, matched to consumer sizes	Annual hours of operation applied to average loads, CHP utilization percentage from load shape
CO_2 Emission Reductions	Average Xcel Energy emission rates as of 2014 applied throughout 15-year analysis timeframe	Marginal Xcel Energy emission rates, adjusted over the 20-year analysis period based on plans to reduce fossil fuel generation (100% carbon free by 2050)

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